Hawaiian Electric Company, Inc.

Docket No. 2008-0083

Application for Approval of Rate Increases and
Revised Rate Schedules and Rules

DIRECT TESTIMONIES AND EXHIBIT SPONSORSHIP LIST

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HECO T-1
DOCKET NO. 2008-0083

TESTIMONY OF
ROBERT A. ALM

EXECUTIVE VICE PRESIDENT
PUBLIC AFFAIRS
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Policy Statement

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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 Executive Vice President of Public Affairs at Hawaiian Electric Company, Inc. ("HECO" or "Company"). HECO-100 provides my educational background and work 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 is our core activity and most of the increases sought are to recover costs incurred to maintain and improve our basic electrical service.

Just as importantly, the world is rapidly changing with respect to how it looks to meet its future energy demand, and Hawaii is at the forefront of that

effort. Traditional fossil fuel electrical generation is giving way to renewable energy and other pathways to control energy use, driven by rapidly rising fuel oil prices, and international, national and state-by-state initiatives to reduce greenhouse gas ("GHG") emissions and to increase the use of renewable energy and energy efficiency resources, as evidenced by the Kyoto Protocol, the National Energy Policy Act of 2005, state and possible federal renewable portfolio standards ("RPS"), state GHG regulations, and other policies and regulations.

Hawaii has abundant renewable energy resources. We recognize the need to facilitate and accelerate the development of these renewable resources, not only because of the challenge to achieve the requirements under the RPS law, but even more importantly to further our State's goal of energy independence. In addition, there is a compelling global mandate to reduce GHG emissions. Thus, encouraging renewable energy has become vital to the HECO Companies' ability to fulfill their compact with the State of Hawaii to provide reliable electric utility service and comply with the RPS law.

This requires us to do two things well - keep the current system providing reliable power to businesses and residences alike, and transition the system to one that focuses on renewable energy, energy efficiency, and energy conservation. Both are critical, both require support, and we fully intend to deliver on both.

Thus, our first objective is to provide adequate and reliable service to our customers. Our second objective is to facilitate achievement of the State's energy goals, including substantially reducing the State's reliance on fossil fuels and increasing the efficiency with which we use our energy resources. At the same time, we have an obligation to help our customers manage their energy usage and

bills, and maintain our financial integrity and ability to attract capital on reasonable terms.

Q. What significant challenges does HECO face in achieving these objectives?

A. In order to continue to provide reliable and adequate service, we have to operate, maintain and enhance our core utility infrastructure – including the aging generating units that still generate most of the electricity used by our customers, and the aging transmission and distribution systems that deliver the electricity to our customers. To facilitate achievement of the State's energy goals, we have to support and help accelerate Hawaii's transition to a clean and sustainable energy future. To maintain our financial integrity and credit standing, we need to be able to recover our costs as we incur them, in order to have a realistic opportunity to earn a fair and reasonable return on the investments in utility assets by our investors. As the cost of generating and delivering energy continues to rise, we need to increase our customers' options to help them manage their energy usage and bills.

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

A. Hawaii's economy and population have grown over the last economic cycle – but 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. Besides dealing with an aging infrastructure, the City is also adding new infrastructure to address and alleviate our traffic situation (rail system) as well as the State with its North-South Road. 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 as well as to accommodate future load, such as our rail system. "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 get to your workplace, all require a continuous and reliable supply of electricity.

- Reliability of our electric system is key to public safety and the security of our State and City and to our ability to respond to emergencies.
- Reliability is 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.
- Reliability and stability of our grid are key to integrating substantial amounts of renewable energy resources, such as wind, into our system.
- Reliability is an integral part of our nation's defense efforts, especially given Hawaii's strategic location. The Department of Defense and the Department of Home Land Security are continuing to build their presence in Hawaii and the Pacific to combat the current Global War on Terrorism, with the Striker Brigade, C-17, and a possible addition of a carrier strike group.

RATE RELIEF REQUESTED

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

A. HECO's current effective rates are the result of its existing "base" rates, plus the interim rate increase approved in HECO's pending 2007 test year rate case, Docket No. 2006-0386. HECO's existing base rates are the result of the Commission's Final Decision and Order ("D&O") No. 24171 issued May 1, 2008, in HECO's 2005 test year rate case (Docket No. 04-0113), and D&O No. 24229 issued May 15, 2008 in Docket No. 2006-0497 which approved standby service rates. In addition, the current effective rates include the surcharges resulting from the interim rate increase that the Commission approved on June 20, 2008 in its Order Granting Hawaiian Electric Company, Inc.'s Motion to Adjust Interim Increase Filed on May 21, 2008 in HECO's 2007 test year rate case. As of the date of this filing, the final decision and order for the 2007 test year rate case 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 $97,011,000 (based on April 2008 fuel oil prices), or 5.2%, over revenues at current effective rates for a normalized 2009 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 $174,348,000.

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 2009 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 these revenues and the associated costs from the 2009 test year because D&O No. 23258 in Docket No. 05-0069 (the Energy Efficiency Proceeding) ordered the transition of all of the HECO Companies' energy efficiency DSM programs to a non-utility market structure by January 1, 2009. Under the non-utility market structure, the Commission would appoint a public benefits fund ("third-party") administrator to administer the DSM programs. The HECO Companies' load management programs are excluded from the third-party administrator's area of responsibility. Because of this, HECO has excluded from its 2009 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 this rate case.

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

A. HECO requests the revenue increase in three steps to more closely match cost recovery with cost incurrence:

Step Increase	Amount ($1,000)	Effective Date
1) Interim Increase	$73,064	On or before May 1, 2009
2) Campbell Industrial Park ("CIP") Combustion Turbine Unit 1 ("CT-1")[1] Step Increase	$23,947	At the in-service date of CIP CT-1 (scheduled for July 31, 2009)
3) General Increase	Balance	Final Decision and Order
Total Rate Increase	$97,011	

1. Interim Increase – a revenue increase (based on the Company's revenue requirement exclusive of the 2009 CIP CT-1 Generating Unit costs[2]) to which the Commission determines HECO is "probably entitled" based on the evidentiary record before it, in accordance with Section 269-16(d) of the Hawaii Revised Statutes ("HRS").[3]
2. CIP CT-1 Step Increase – a revenue increase based on the return on investment (net of accumulated deferred income tax and investment tax credit impacts) of the CIP CT-1 generating unit and recovery of the associated on-going production operation and maintenance ("O&M") expenses, employee benefits and payroll taxes. The CIP CT-1 Step Increase is equal to the difference between the revenue requirement of $1,964,401,000 (HECO-2301) reflecting the full cost of the CIP CT-1 (with the net investment of the CIP CT-1 in both

[1] HECO's testimonies also refer to the CIP CT-1 project as the CIP1 project.
[2] The interim increase includes certain 2008 plant additions associated with the CIP CT-1 project. See HECO-1703.
[3] If the Commission rejects the CIP CT-1 Step Increase, it should approve an interim increase of $85,189,000 as shown on HECO-2303 rather than $73,064,000. The interim increase of $85,189,000 (referred to as "Base Case" in the Company's testimonies in this proceeding) includes the 2009 CIP CT-1 plant additions (net of deferred income taxes) in the end of test year rate base balance but not in the beginning of test year rate base balance.

the beginning and end of test year balances) and the revenue requirement of $1,940,454,000 (HECO-2302) which is exclusive of the cost of the CIP CT-1. HECO anticipates that the CIP CT-1 will go into service on July 31, 2009 and requests the CIP CT-1 Step Increase to be effective on that date.

3. General 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 Increase or the CIP CT-1 Step Increase.

HECO requests that the rate design changes requested in the Application, and described in HECO T-22, be implemented when the General Increase is implemented.

<u>Interim Increase</u>

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 10 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 rate decision prior to expiration of the nine-month period?

A. Yes, as the Commission ruled in Interim D&O No. 13431 ("Interim D&O 13431"), issued August 8, 1994 in Docket No. 7764, HELCO's 1994 test year rate case.

Q. Has the Commission granted an Interim Rate Increase prior to expiration of the nine month period?

A. Yes. For example, Interim D&O 13431 was issued on August 8, 1994, 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."

In addition, in HECO's 1992 test year rate case, Docket No. 6998, the Commission authorized the interim increase after eight months. (Interim D&O No. 11559 was filed on March 31, 1992, and HECO's application was filed on July 29, 1991.)

Q. If the Commission were to grant an interim rate increase at the statutory deadline (i.e., 10 or 11 months after the filing of the application for this rate case), will HECO be in a position to earn the return found to be reasonable by the Commission?

A. No. Ten or 11 months from the July 3, 2008 filing date of the application would be May 3 or June 3, 2008. Although HECO has filed its application at the earliest possible time allowed by the Hawaii Administrative Rules ("HAR") §6-61-87(4), it would not have a realistic opportunity to earn the return found to be reasonable by the Commission, because by the time the interim decision is issued, at least a third of the year will have passed. 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 at the beginning of the test year. Unless a rate increase is effective at the beginning of a test year, the utility will not 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 actually received in the test year will be proportionately lower than that determined to be necessary.

Q. What will HECO's return on rate base be in 2009 without rate relief?

A. Absent rate relief, HECO's return on average rate base (including the full cost of CIP CT-1) is expected to be 4.97% for the normalized test year, assuming the 2007 test year interim rate increase surcharge continues to be in effect (or 1.92% without the revenues from the 2007 test year interim rate increase surcharge). In HECO's last rate case, Docket No. 2006-0386, which used a 2007 test year, the Commission found an 8.62% return on rate base to be appropriate and reasonable for interim decision purposes.

Q. Is it realistic for the procedural steps in this rate case to be concluded in time for the Commission to issue an interim decision by the beginning of the 2009 test year?

A. The operations of the Company are complex and in previous rate cases, there has been substantial discovery on the Company's testimonies, exhibits, workpapers and other documentation that the Company submitted in response to information requests. However, the Company and the other parties have worked towards addressing and dispensing with issues as soon as practicable in recent rate cases. If the parties are able to complete the discovery phase efficiently, settle all issues and agree to waive evidentiary hearings, it is conceivable to achieve an interim decision in six months. However, if there are unsettled issues and evidentiary hearings and a heavy regulatory calendar in other proceedings, achieving an interim decision in six months would be unlikely. It may be worthwhile for the Company to propose and for the Commission to consider the possibility of revising the Commission's rules to advance the allowable date to file a general

rate increase application so that there is consistency between that time frame and the statutory deadline for issuance of an interim decision. Without such a structural change to the rate case process, it would be difficult for a utility to obtain interim rate relief by the beginning of the test year and to achieve a fair return on its utility property in the test year. Later in this testimony and in HECO T-23, other possibilities to address the structural lag in the current rate case process are discussed.

In any event, receiving interim rate relief before the statutory deadline would do much to mitigate any shortfall in cost recovery in the test year. Given the Company's proposed interim increase of $73 million over current effective rates, every week without interim rate relief beyond the beginning of the test year means $1.4 million of cost recovery foregone for the Company. An early interim decision would mitigate the financial impact of the structural lag in the current rate case process. The Company would encourage the Commission to consider issuing its interim decision earlier than the statutory deadline if the parties are able to complete the procedural steps in time for the Commission to take such action.

<u>CIP CT-1 Step Increase</u>

Q. What is the CIP CT-1 Step?

A. This is a proposed step increase to reflect an increase in annual revenue requirements associated with the addition of CIP CT-1 after the generating unit goes into service.

Q. What is the amount of the CIP CT-1 Step?

A. HECO estimates that the amount of the CIP CT-1 Step will be $23,947,000. This is the total increase HECO has requested for the normalized test year, assuming

the completed CIP CT-1 generating unit is in service for the entire year (which is labeled the CIP CT-1 case), less the increase requested in the Interim Step.

Q. Has HECO included the depreciation expenses in the CIP CT-1 Step Increase?

A. No. HECO's current practice is to record depreciation expense for financial reporting purposes in the year following the in-service date of the asset being depreciated. Since the CIP CT-1 is scheduled to go into service on July 31, 2009, the Company will not begin recording depreciation expense associated with CIP CT-1 until 2010. Therefore, HECO has not included depreciation expense associated with CIP CT-1 in the 2009 test year revenue requirement.

Q. When does HECO request that the CIP CT-1 Step be effective?

A. HECO requests that the CIP CT-1 Step be effective when CIP CT-1 goes into commercial operation, which is expected to be on or about July 31, 2009.

Q. Why is HECO proposing a step increase for the CIP CT-1 generating unit?

A. There are a number of important reasons for proposing the CIP CT-1 Step increase. First, HECO will incur substantial costs for the CIP CT-1 generating unit, and should be allowed to recover the full amount of the costs it incurs for CIP CT-1 as soon as it begins incurring the costs. The use of a step increase also will ensure that customers do not have to pay for the costs of CIP CT-1 until HECO begins incurring such costs. In short, the use of a step increase will better time the revenue increase to match the cost increase that necessitates the proposed step increase.

Q. Why is HECO proposing to include the full capital cost of CIP CT-1 in its average rate base, and the full O&M expense for CIP CT-1 in its results of operations, for the test year?

A. Accounting for the full costs in this manner will allow HECO the opportunity to earn a reasonable rate of return on the total investment in its major generation project, from the time it goes into service. CIP CT-1 is scheduled to be completed and fully operational on or about July 31, 2009. The 2009 plant additions for this project will be $153 million. (See Table 1 on page 24.) If an average rate base were used without including the full cost of CIP CT-1, the estimated cost for this project would only be added to the 2009 year-end plant balance. This would mean that only one-half of the 2009 plant additions for this project, or about $76 million, would be added to the rate base, instead of the Company's full $153 million investment in 2009 plant additions for this project. Therefore, including the full cost for CIP CT-1 would allow the Company to earn a fair return on 100% of its investment beginning from the date when the project is fully operational and continuing into the future.

Q. Is HECO proposing to begin recovering the full cost for CIP CT-1 through a rate increase at the beginning of 2009, or an interim increase before CIP CT-1 goes into commercial operation?

A. No. HECO is not proposing to increase its rates to reflect the impact of adding CIP CT-1 before the project goes into service. Rather, HECO is proposing to increase its rates to reflect the impact of the project when it does go into service and customers receive the benefits of the additional generation capacity and increased reliability provided by the project. HECO is entitled to a reasonable opportunity to earn a fair return on its investment in utility property, and permitting HECO to increase its rates to recover its investment in a major project when it goes into service is fair to both HECO and its customers.

Q. Would it be proper to have a CIP CT-1 step increase when the unit goes into commercial operations based only on the average cost of the project for the test year?

A. No. It is essential that the step increase be based on the full cost of the project. Including the full cost of the project cost will permit HECO to include the full impact of the project in its rates.

Q. Has the Commission recognized the appropriateness of including the full costs associated with major generating unit and transmission line additions in the test year results of operations?

A. Yes. The Commission has recognized the need to include the full costs associated with major generating unit and major transmission line additions in a number of rate cases. For example, in MECO Docket No. 7000, which utilized a 1993 test year as well as a 1992 test year, the Commission authorized two step increases in 1993 (timed to coincide with the addition of the units to MECO's system) based on the annual costs and benefits of adding M16 and M15 to MECO's system. The annual costs included depreciation expenses. (The impact of the adjustment to include the full costs of these generating units on revenue requirements was offset to some extent in the final decision and order by recognizing annual sales and revenues (net of fuel expense) for new customers added in 1993.) In Docket No. 7766, which utilized a 1995 test year, the Commission authorized, on an interim basis, a step increase in August 1995 based on the annual costs of adding the Waiau-CIP transmission lines to HECO's system.

Q. Has the Commission also approved the use of step increases for purchase power agreement ("PPA") capacity costs, based on the full annual costs of such PPAs, in prior cases?

A. Yes. In Docket No. 6531, which utilized a 1990 test year, the Commission authorized the inclusion of the annual costs and benefits associated with the Kalaeloa Partners, L.P. ("Kalaeloa") PPA (by which HECO added 180 MW to its system) in revenue requirements, and a step increase based on the annual costs and benefits, even though the Kalaeloa facility went into commercial operation five months after the conclusion of the 1990 test year.

In Docket No. 6998, which utilized a 1992 test year, the Commission authorized a step increase in September 1992 for HECO's PPA with AES Barbers Point, Inc. ("AES-BP", now known as AES Hawaii, Inc.), by which HECO added another 180 MW to its system. The 1992 test year revenue requirements in Docket No. 6998 included the annual costs and benefits for the AES-BP PPA, even though AES-BP went into commercial operation in September 1992.

In the case of firm capacity PPAs for non-fossil fuel producers, the Firm Capacity Surcharge allows for step increases, based on annual firm capacity costs, outside of a rate case. For example, Puna Geothermal Venture ("PGV") went into commercial service in June 1993, adding $4.4 million in capacity payments and revenue taxes to HELCO's expenses on an annual basis. HELCO was able to recover the full costs of adding this capacity to its system as of the PGV in service date by means of HELCO's Firm Capacity Surcharge. MECO also was allowed to recover the additional capacity payment costs that it incurred pursuant to its Amended and Restated PPA with HC&S beginning in December 1990.

Q. Does HECO anticipate an increase in sales to help offset the costs related to CIP CT-1?

A. No. Mr. Willoughby describes HECO's relatively flat sales in HECO T-2. While capacity additions are often predicated on increased demand for electricity, the

primary benefit of CIP CT-1 in the near-term will be reliability, as the addition of CIP CT-1 will enable HECO to increase its reserve generating margin. As the Commission is aware, HECO has been operating with a smaller reserve margin than it would have under ordinary conditions.

Q. Did the adjustments described above to include the full costs of new generating units in rates when the units commenced commercial operation allow the utility to earn an excessive return in the years following the test year?

A. No. For example, HECO was able to earn a rate of return on rate base of only 7.71% in 1993 (7.97% calculated taken into account ratemaking disallowances), even though the Commission authorized a rate of return for HECO of 10.06% in Docket No. 6998 (which utilized the 1992 test year). As indicated above, the 1992 test year revenue requirements in Docket No. 6998 included the annual costs and benefits for the AES-BP PPA, even though AES-BP went into commercial operation in September 1992. If the 1992 revenue requirements had included AES-BP for only the last four months (i.e., if only one-third of the annualized costs and benefits had been included), HECO's return on common equity for 1993 could have been negative without further rate relief based on a 1993 test year rate case.

Q. Ratemaking generally requires the matching of revenues, expenses and rate base (which is termed the "matching principle"). Does this principle require that revenue requirements be based on an average test year (i.e., average revenues, expenses and rate base for a given period) without any adjustments?

A. No. "Proper" ratemaking requires that the end results be reasonable, and that the utility be provided with a realistic opportunity to earn a fair return on its investment in plant actually used or useful. The "matching principle" is a useful

starting point, but it should not be used to dictate the result if the result is unreasonable. This Commission has explicitly departed from the matching principle in prior rate cases under circumstances such as this (e.g., through step increases based on annual costs).

Q. Is HECO's proposal consistent with the test year concept of setting rates?

A. Yes. The purpose of a rate case is to adjust the rate schedules of the utility in order to give the utility the opportunity to earn a fair return on its property actually used or useful for public utility purposes. Basic to the test year method of setting rates is the assumption that the test year is representative of the actual operating conditions that the utility will experience during the time frame that the rates are in effect. However, the test year is only representative of future operating conditions within certain limits. For example, the Commission found in Docket No. 2781 that "the assumption that the test year results accurately reflect future operating conditions is invalidated by the existence of attrition." (Docket No. 2781, D&O No. 4802 dated August 18, 1977 ("D&O 4802"), page 22.) For this and other reasons, Commissions are often required to make adjustments or normalizations to the actual test year results to make the test year representative of future operating conditions.

Q. What is attrition?

A. The Commission has defined attrition as a "wearing away or decrease in rate of return due to capital additions or increase in expenses coupled with a slow growth in revenues, thus causing a decline in rate of return." (Docket No. 2296, D&O No. 3546 (Aug. 19, 1974), page 7; also see D&O 4802, page 20.)

Q. The rate of inflation has been relatively low, although it is increasing. Does this mean that HECO will not suffer from attrition?

A. No. It is critical to recognize, as the Commission has in prior cases, that attrition can be caused by current inflation, which causes expenses to increase faster than revenues, or by the addition of substantial capital projects. During periods when substantial capital additions are taking place, past inflation causes new plant additions and replacements to cost substantially more per unit of capacity than the depreciated original cost for an equivalent existing unit of capacity. As current or incremental costs rise above average and embedded costs on a per-unit basis, and with electric rates fixed on a per-unit basis, the return declines. (See D&O 4802, page 20.) Thus, the rate increase needed to recover the capacity costs of new generation can be substantial. For example, when HECO added the 180 MW provided by AES-BP in 1992, the 1992 test year base rate increase approved by the Commission was 23.7%.

Q. Has the Commission recognized that the avoidance of back-to-back test year rate cases is a significant consideration in allowing the annualized costs of a major generation or transmission addition to be included in the test year revenue requirements?

A. Yes. In allowing the annualized costs and benefits of the Waiau-CIP transmission lines to be included in a step increase effective at the end of August 1995, the Commission explicitly found that "the avoidance of annual rate cases is a legitimate objective of a rate proceeding." (Docket No. 7766, Interim D&O 14195 (August 30, 1995), page 6.)

Q. If the full cost for the project is not recognized in a step increase for CIP CT-1, how should the average cost be treated for ratemaking purposes?

A. If the full cost of the CIP CT-1 project is not included in determining the amount of the CIP CT-1 step increase, then the cost of the project should be included in

the average rate base in determining the interim increase granted at or near the beginning of the test year.

General Step

Q. What is the General Step?

A. The proposed General Step, to be effective when the Commission issues its final decision and order, provides for the amount of the total requested revenue increase not included in other steps authorized by the Commission.

Q. When is HECO requesting the General Step?

A. The timing of the General Step will depend on the timing of the Commission's final decision and order in this docket.

Q. How would the General Step be calculated?

A. The amount of the General Step would be calculated by (1) taking the amount of the annual increase granted over then current effective rates, and (2) subtracting the amounts of any of the foregoing step increases not then in effect (and which will follow the General Step Increase). The amounts of any prior Step increases approved in this docket would be incorporated into the General Step Increase.

Implementation of Rate Increase

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

A. HECO is proposing that only the General Increase in this proceeding involve base rate changes. The interim increase and the CIP CT-1 step increase implemented prior to the final step would be structured as surcharges for the various classes based on a cents per kilowatt-hour charge derived separately for each rate class as the dollar increase allocated to the class divided by the class test year sales. The Company will allocate the increase in revenues as an equal percentage increase to current effective revenues at all rate schedules. The allocation of the proposed

increase over present rates to each rate schedule is shown on HECO-107. The allocation of the proposed increase over current effective rates to each rate schedule is shown on HECO-108.

Q. Why is the Company proposing to implement the interim increase and the CIP CT-1 step increase on a cent per kilowatt-hour basis?

A. The Company proposes to implement the Interim Increase and the CIP CT-1 step increase on a cent per kilowatt-hour basis because of the simplicity of the rate design, ease and efficiency of rate administration, and the clarity provided to customer bills.

NEED FOR RATE RELIEF

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

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

1) The costs of adding the new facilities, including the new biofueled generating unit scheduled for July 2009, necessary to meet HECO's obligation to provide adequate and reliable service to its customers;
2) The higher costs of operating and maintaining HECO's existing utility infrastructure; and
3) The need to maintain the Company's financial integrity.

Adding New Facilities to Serve Oahu's Customers

Q. What is the increase in net cost of plant in service from end of year 2007 to end of test year 2009?

A. There is a 15% increase in the net cost of plant in service from end of year 2007 to end of test year 2009. The recorded balance for the net cost of plant in service at

end of year 2007 was $1,355,111,000. The estimated balance for the net cost of plant in service at end of test year 2009 is $1,558,053,000.

Q. What projects are included in the plant additions for 2008 and 2009?

A. In total, there are more than 200 projects amounting to over $350 million in 2008 and 2009 plant additions. The major contributor is the CIP CT-1 Generating Unit project. Besides the CIP CT-1 Generating Unit, these projects include:

- New substations and related subtransmission lines in the Kapolei, Ewa and Leeward areas to support new residential and commercial developments such as Ko Olina, Ocean Pointe, and the new UH West Oahu campus.
- Projects to address deteriorating underground cable, such as the Waikiki Rehabilitation Program project 3, and the Maunalani Heights project.
- Projects to replace aging fiber optic cable to maintain the reliability of HECO's communications system.
- Power Supply Process Area upgrades or replacements to increase reliability of existing aging generating units.
- Overhead and underground cables replacements, as well as transformers, poles, shield wire, and other facility replacements to maintain reliable service and fulfill new service requests from customers.

Q. What facilities are included in the CIP1 Generating Unit project?

A. The CIP1 Generating Station and Transmission Addition ("CIP1 Generating Unit") Project involves: (1) the construction, purchase and installation of a new generating facility, which includes the purchase and installation of a nominal 110MW simple-cycle combustion turbine generator and its support equipment (including blackstart generation installed on site to enable the combustion turbine unit to be started even in the event of an island-wide power outage) at a new

generating facility site located at HECO's existing Barbers Point Tank Farm; (2) the purchase of 3.80 acres of land to expand the existing Barbers Point Tank Farm to accommodate the new generating facility, and the purchase of easements from Chevron and Campbell Estate for the new transmission line; (3) the purchase and construction of a new two-mile overhead 138 kV transmission line from HECO's AES Substation to HECO's CEIP Substation in Campbell Industrial Park; (4) modifications and additions to HECO's AES Substation and Kalaeloa Relay, additions to HECO's CEIP Substation, modifications to HECO's Kahe Generating Station Substation; and (5) the purchase and installation of communication components of the CIP CT-1 Generating Unit consisting of fiber communications and the microwave communications.

Q. What is the estimated cost of the project?

A The CIP1 Generating Unit Project has estimated plant additions of $153 million in 2009, $9 million in 2008 and $2 million included in Property Held for Future Use. The CIP1 Generating Unit project Plant Additions are shown on HECO-1703, and are summarized in the following table:

Table 1
CIP1 Generating Unit Plant Additions

Description	2008	2009	2010	Total
CIP1 CEIP Substation Mod	620,572	3,966		624,538
CIP1 Unit Addition-Microwave	759,695			759,695
CIP1 Unit Addition-Kalaeloa	178,574			178,574
CIP1 Unit Addition-Easements	6,185,183			6,185,183
CIP1 Land - Gen Station	1,261,761			1,261,761
CIP1 AES-CEIP#2 Trans Line		5,192,149		5,192,149
CIP1 AES Substation Add		3,110,097		3,110,097
CIP1 Unit Addition-Fiber		503,051		503,051
CIP1 Unit Addition-Kahe Bkrs		1,755,643		1,755,643
CIP1 Unit 1 Addition		142,353,685	50,000	142,403,685
Plant Additions	9,005,785	152,918,591	50,000	161,974,376
Parcel between Hanua Street and AES Substation (TMK 9-1-26:38) included in Property Held for Future Use (acquired in 2007)				1,809,875
Total Project Cost				163,784,251

Q. Has the Commission approved the project?

A. Yes, the Commission approved HECO's CIP1 Generating Unit Project in D&O No. 23457 issued May 23, 2007 in Docket No. 05-0145.

Q. Why was the CIP1 Generating Unit Project approved?

A. HECO's obligation to serve means it needs to have enough generating capacity on the system to reliably serve the expected system loads. In order to have enough

generating capacity to serve customer loads with some units unavailable due to planned maintenance or forced outages, HECO needs to maintain a sufficient reserve margin. The new generating unit will help address HECO's need to increase its reserve margin to acceptable levels, while providing peaking generation that will be needed in the renewable energy system of the future.

Q. What is the status of the reserve capacity shortfall identified in recent Adequacy of Supply reports, and in HECO's IRP-3 Evaluation report filed in 2007, that drove the need for the new unit?

A. In its 2008 AOS Report filed January 30, 2008, HECO reported that its reserve capacity shortfall estimate is approximately 80 MW in the 2008 period for a "Reference Scenario" (which incorporates updated forecasts and planning assumptions, and includes the impact of 29.5 MW of temporary leased, distributed generating units at HECO sites to mitigate the shortfall, pending the installation of new long-term capacity). After the planned mid-2009 addition of the nominal 110 MW Campbell Industrial Park combustion turbine (if the temporary, utility-sited distributed generation units are not included), we anticipate the potential for continued reserve capacity shortfalls in the range of 20 MW to 80 MW in 2010, up to a range of 70 MW to 130 MW in 2014 based on sensitivity analyses for possible alternative scenarios.

As we have reported, HECO has taken a number of steps to mitigate the effects of reserve capacity shortfalls, such as (1) installing temporary, limited run-hour distributed generators ("DG") at substations or other sites, (2) implementing additional load management and other demand reduction measures, (3) pursuing efforts to improve the availability of generating units, (4) negotiating and obtaining approval of the Kalaeloa amendments adding 28 MW of firm capacity

in 2005, and (5) permitting and designing the next generating unit so that it can be installed by 2009.

HECO is currently conducting the IRP-4 process, which includes an assessment of the firm capacity resource additions needed to address the continuing reserve capacity shortfall.

Higher Costs to Operate and Maintain Existing Utility Infrastructure

Q. What are the reasons for the increasing costs to operate and maintain HECO's existing system?

A. For operation and maintenance expenses, a key factor is HECO's aging infrastructure which requires regular and thorough maintenance in order to sustain reliable service. Active maintenance programs in both the Power Supply Process Area (i.e., Production) and the Energy Delivery Process Area (i.e., Transmission and Distribution) require increasing expenditures for both labor and non-labor. Another factor driving expenses higher, as explained by Mr. Dan Giovanni in HECO T-7, is that the costs for labor, materials and services have escalated significantly in recent years and this has directly contributed to increases in the Other Production O&M Expense. With regard to Transmission and Distribution O&M expense increases, Mr. Robert Young observes in HECO T-8 that the two biggest reasons for increasing O&M expenses are rising labor costs and inflation of non-labor costs that result from substantial increases in the prices of commodities such as copper.

Q. Please describe HECO's aging Production infrastructure.

A. As explained by Mr. Giovanni, as of 2009, the average age of the steam-electric units is 45.7 years. The newest HECO generating unit is CIP CT-1, a combustion turbine, which is scheduled to start commercial operation in mid-2009. The

second-to-the-newest HECO generating unit is Kahe 6 which started commercial operation in 1981. The average age of HECO's six cycling steam units and eight baseload steam units as of 2009 are 54.3 years and 39.3 years, respectively. HECO's two peaking combustion turbines, Waiau 9 and 10, are 36 years of age. Some of the Waiau Power Plant infrastructure still in use today dates back to 1938. The Honolulu Power Plant infrastructure dates back to 1930. Not only are generating units aging, but they have been operating at very demanding duty levels. For example, during the most recent 5-year period, from 2003 to 2007, the Capacity Factors (the measure of a unit's power generation in a given year) for HECO's baseload units (units that run continuously except when out of service for maintenance) ranged from 42.0% to 69.9%, and averaged 58.6%. For units of the design and age of the HECO generating units, Capacity Factors of 50% or higher are considered to be indicative of extreme duty. Generating units that have experienced Capacity Factors of 50% or greater for many years would have experienced considerable wear and tear over their life, and would require comprehensive maintenance to sustain reliable performance.

Q. Why does HECO continue to operate aging equipment?

A. HECO's generating units continue to operate with a high degree of reliability despite their age and duty. Comprehensive maintenance, replacement and upgrade of equipment, and process improvements on these aging units benefit the ratepayer by avoiding the need to replace existing generating capacity.

Mr. Giovanni in HECO T-7 states that maintaining HECO's existing units remains the least cost option even though it is a significant Production O&M Expense.

Q. Is the situation similar with respect to the Transmission and Distribution assets?

A. Yes. Mr. Robert Young in HECO T-8 notes that the last major addition to the 138 kV overhead transmission system was in 1995 with the completion of the Waiau to Ewa Nui lines. The average age of the overhead lines increases each year, with a 2009 estimated average of 38.1 years. In addition, of the 213.6 overhead circuit miles, approximately 78% (167 miles) will be 30 years old or older. The 2009 estimated average age of the 138 kV transmission transformers is 32.5 years. The average age of the distribution substation transformers is forecasted to be 31.7 years in 2009.

Q. How are T&D O&M expenses affected by aging plant?

A. As the T&D facilities age, more emphasis must be placed on inspection and maintenance to identify and correct potential failures before they happen. These programs are needed to ensure customer service reliability. Mr. Young in his testimony observes that the overall trend in the T&D O&M expenses has been increasing to meet the system maintenance demands.

Q. What is the increase in expense for Production Maintenance?

A. As shown in Mr. Giovanni's HECO T-7 testimony, Production Maintenance expense increased from a 2007 actual expense of $41,000,000 to a base case 2009 test year estimate of $47,991,000 for an increase of $6,991,000.

Q. What is the increase in expense for Transmission and Distribution Maintenance?

A Mr. Young's HECO T-8 testimony discusses the increases in Transmission and Distribution Maintenance expenses. Transmission Maintenance expense increased from a 2007 actual expense of $5,845,000 to a 2009 test year estimate of $7,016,000 for an increase of $1,171,000. Distribution Maintenance expense

increased from a 2007 actual expense of $14,908,000 to a 2009 test year estimate of $16,880,000 for an increase of $1,972,000.

Q. Have rising costs of materials contributed to the increase in both Production and T&D O&M expenses?

A. Yes. Price indices discussed in Mr. Young's HECO T-8 testimony show that copper and aluminum have risen 162.8% and 55.5%, respectively, from January, 2005 to March, 2008. E-steel (electrical steel) prices have risen 214.4% during the same period. Many of HECO's inventory stock items including cables and conductors are made of copper and aluminum. Key commodity price indices discussed in Mr. Young's testimony show a recent dramatic escalation from December 2007 through March 2008, with end-of-March 2008 indices showing a quarterly increase ranging of 14.9% for crude oil (which affects fuel costs for HECO's fleet of vehicles), 26.6% for aluminum, 26.1% for copper and 36.0% for hot rolled steel sheet. As noted in Mr. Giovanni's HECO T-7 testimony, a sampling of 50 items purchased by the Power Supply Operation and Maintenance Department, including boiler tubes, electronic components, turbine material, and generator material have risen in cost. The average price increase for the items in this sampling was 34.5% for the three-year period 2004 to 2007. The average price increase from 2006 to 2007 for all items in the sample was 8.1%.

<u>Maintaining Financial Integrity</u>

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

A. Financial integrity is important for both the Company and its ratepayers. If HECO's financial integrity is protected, the Company should be able to attract capital on reasonable terms that it needs to provide service to its customers, and should be able to attract capital under whatever economic conditions might exist

at the time HECO needs to raise capital. HECO's customers can also count on the Company providing reliable electric service in the future. HECO and its customers will ultimately benefit from this.

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 in HECO's 2007 test year rate case, HECO's current effective rates would result in a rate of return on average rate base (including the full cost of the CIP CT-1) of 4.97% in the normalized test year. As shown in HECO T-20, a fair and reasonable rate of return on average rate base for HECO in the 2009 test year would be 8.81%. This return is based on the fair rate of return on common equity recommended in HECO T-19 of 11.25%. Thus, a 4.97% 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.

BACKGROUND

Q. When did HECO file its Notice of Intent?

A. HECO filed its Notice of Intent on May 1, 2008 and the Commission assigned Docket No. 2008-0083 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 July 3, 2008. 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 March 31, 2008, and an unaudited income statement and statement of retained earnings for the three months ending March 31, 2008.

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

HECO-104 is a copy of HEI's latest proxy statement dated March 26, 2008, which was sent to stockholders.

HECO-105 is HECO’s current Table of Contents, Rule No. 7, and rate schedules.

HECO-106 is HECO’s proposed Table of Contents, Rule No. 7, and rate schedules.

HECO-107 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 2009.

HECO-108 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 2009.

HECO-109 is a summary of HECO's estimated earnings on its average rate base (including the full cost of CIP CT-1) at present rates for the normalized 2009 test year.

HECO-110 is a summary of HECO's estimated earnings on its average rate base (including the full cost of CIP CT-1) at current effective rates for the normalized 2009 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	Electricity Sales and Customer Forecasts
T-3	Peter C. Young	Total Operating Revenue
T-4	Ross H. Sakuda	Fuel Oil Expense and Generation Efficiency
T-5	Ronald R. Cox	Fuel Price, Fuel-Related Expense, Fuel Inventory
T-6	Daniel S. W. Ching	Purchased Power Expense
T-7	Dan V. Giovanni	Production O&M Expenses, Production Materials Inventory
T-8	Robert K. S. Young	Transmission and Distribution System, T&D Operations and Maintenance Expense, T&D Materials Inventory
T-9	Darren S. Yamamoto	Customer Accounts Expense includes Customer Information System (CIS), Customer Deposits, Interest on Customer Deposits, Revenue Lag Days, Non-Sales Electric Utility Charges

T-10	Alan K.C. Hee	Customer Service Expense, Demand-Side Management Program Expense, Integrated Resource Planning Expense, Energy Cost Adjustment Clause
T-11	Patsy H. Nanbu	Administrative & General Expense; Standard Labor Rates; Information Technology Services; Accounting for Computer Software Development Costs; Abandoned Capital Project Costs; Unamortized Gain on Sale of Land; Iolani Court Plaza Lease Premium; Accounting for Reverse Osmosis Water Pipeline Costs; Accounting for Pensions and Postretirement Benefits Other than Pensions; General Accounting Department Staffing
T-12	Russell R. Harris	Insurance as included in A&G Expenses
T-13	Julie K. Price	A&G Expenses - Employee Benefits, Human Resources Suite Project, Wage and Salary Increase
T-14	Bruce Tamashiro	Miscellaneous A&G Expenses, Research and Development Expenses, Depreciation Expense and Accumulated Depreciation
T-15	Faye Chiogioji	Employee Headcount
T-16	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-17	Lorie Ann Nagata	Plant Additions, Property Held for Future Use, Contributions in Aid of Construction, Customer Advances, and Budget Process
T-18	Darren Doi	Rate Base
T-19	Roger A. Morin, Ph.D.	Rate of Return on Common Equity
T-20	Tayne S. Y. Sekimura	Rate of Return on Rate Base

T-21	Steven M. Fetter	Financial Integrity
T-22	Peter C. Young	Cost-of-Service Study and Rate Design
T-23	William A. Bonnet	Results of Operations, including Revenue Requirements, Rate Increase Implementation, Alternative Ratemaking Structures, and Summary

Mr. Lon Okada is an employee of Hawaiian Electric Industries, Inc. ("HEI"). Dr. Roger Morin is Emeritus Professor of Finance at the College of Business, Georgia State University. Mr. Steven Fetter is President of Regulation UnFettered, a utility advisory firm. 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 seven policy areas that I will discuss in this section:

1) HECO's strategy for the preparation of testimony
2) The revenue increase allocation
3) Amortization periods between rate cases
4) The status of renewable energy and energy efficiency initiatives
5) The need to maintain HECO's financial integrity
6) Energy Cost Adjustment Clause
7) Helping customers manage their electricity use and bills

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 2009 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 2009 estimates, and to normalize their test year 2009 estimates, where appropriate.

Q. How did HECO estimate its revenue requirements for the 2009 test year?

A. Generally, the revenue requirements are based on HECO's March 2008 sales forecast update, its 2009 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 8.81%, 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 May 2008. However, individual adjustments and corrections were made to certain items in June 2008.

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, non-compounded wage increases for bargaining unit employees are 3.5% on November 1, 2007, and 4.0% on January 1, 2009. The percentage increases are applied to bargaining unit wage rates as of October 31, 2007. The labor agreement which included a wage increase effective November 1, 2007, was not ratified until March 2008, thus the higher wages for November and December 2007, were not paid until March of 2008.

2) For merit employees, wage rates increased by an average of 3.5% on May 1, 2007 and 0.25% on September 1, 2007 over wage rates as of April 30, 2007. Merit wages were also increased 0.25% effective November 1, 2007. However, the retroactive payment was made in January 2008. Merit wage rates are estimated to increase by 3.5% effective May 1, 2008, 0.30% effective September 1, 2008, and 0.20% effective December 2008 applied to merit wage rates as of April 30, 2008 and 4.0% effective May 1, 2009, 0.30% effective September 1, 2009 and 0.20% effective December 1, 2009 with the percentage increases being applied to merit wage rates as of April 30, 2009.

3) Base nonlabor estimates on information available for the specific item. Where none is available, assume a 2.5% general inflation factor for 2009. A listing of O&M expenses derived with the use of a general inflation factor is presented in HECO T-17. Additional discussion of the assumptions is also covered by Ms. Lorie Nagata in HECO T-17.

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 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 2009 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 2007 and budget 2009 expenses by activity and code block.

<u>Revenue Increase Allocation</u>

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 is HECO using this method of allocation?

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 rate design proposals in Docket No. 2006-0386.

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

A. Yes. As addressed in the testimony of Peter Young in HECO T-22, the more significant proposals are listed below:

- Inclining Rate Block Structure for Residential Customers – This proposal applies to Schedule R and is the same as HECO's proposal in its 2007 rate case (Docket No. 2006-0386) which is pending before the Commission. . 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.
- Schedule DS (Directly Served) and Schedule P – In the settlement agreement in HECO's 2007 rate case (Docket No. 2006-0386), HECO agreed to include in the cost of service and propose in rate design a separate rate class for customers who are directly served from a dedicated substation. Schedule DS is the proposed rate class for customers who are directly served from a dedicated substation, and it is comprised of customers from existing Schedules PS, PP, and PT. A new Schedule P rate class is proposed to include all other existing Schedule PS, PP, and PT

customers who are not served under Schedule DS. In addition, the Company proposes to simplify the demand charges and energy charges in Schedule DS and Schedule P. The Company proposes a single demand charge rate and a single energy charge rate in both rate schedules, in contrast to the three part demand and energy charge rates that exist in the current Schedule PS, PP, and PT (HECO has also proposed a single energy charge rate in Schedule J and Schedule F in this case).

- Schedule H - In the settlement agreement in HECO's 2007 rate case (Docket No. 2006-0386), HECO agreed to eliminate Schedule H in its rate design proposal in the next HECO rate case. The forecast Schedule H customers and energy usage have been allocated to Schedule G and Schedule J in the determination of the revenue estimates for this rate case.

<u>Amortization Period – Period Between Rate Cases</u>

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 two years.

Q. What is the basis for the two years?

A. It is a normal time period between rate cases. The time interval between Docket No. 04-0113 (HECO's 2005 test year rate case), Docket No. 2006-0386 (HECO's 2007 test year rate case) and this rate case was approximately two years between each rate case. There are a number of interrelated factors, such as flat sales, the

success of demand-side management programs, energy conservation, the high price of fuel oil, higher operations and maintenance costs of an aging infrastructure and capital investment needs, that are putting downward pressure on the Company's financial condition. Without sales growth in times of rising costs, the only way for the Company to achieve a fair return on its utility property is through regulatory rate relief. If the Company does not receive approval of its proposed revenue step increase that would incorporate the full cost of CIP CT-1 in rate base and include an appropriate level of associated O&M expenses in its revenue requirement, it is a virtual certainty that the Company will file an application for a general rate increase in the 2010 test year. Approval of the Company's proposal for a step increase would have a significant positive impact on the Company's financial condition and decrease the chances that it will have to file a 2010 test year rate case. There will be certain substantial recovery needs in 2010, including depreciation on the new CIP CT-1 (which is not included in the 2009 test year) and the installation of the East Oahu Transmission System ("EOTP"). The Company will have to assess the need for rate relief in the 2010 test year when the Company's financial picture for 2010 becomes more definite in 2009. To be conservative, the Company is proposing in this rate case a two-year amortization period for regulatory commission expenses which would be consistent with the timing of the Company's most recent rate cases.

<u>Renewable Energy and Energy Efficiency</u>

Q. You earlier explained that in addition to ensuring the provision of reliable electrical power, the Company must transition its system to one that focuses on renewable energy, energy efficiency, and energy conservation. Please describe the Company's efforts to pursue renewable energy and energy efficiency.

A. In the sections below, I will first explain the state legislation and initiatives that express our society's desire to move towards renewable energy and energy self-sufficiency. I will then explain the challenges to adding renewable energy resources onto HECO's grid and describe the various renewable energy programs and projects and energy efficiency measures that the Company is either proposing or is already engaged in.

1. Renewable Portfolio Standards

Q. What does the RPS law require?

A. Section 269-92(a) of the HRS, as amended by Act 162 (2006), provides that each electric utility company that sells electricity for consumption in Hawaii shall establish a renewable portfolio standard of:

(1) 10% of its net electricity sales by December 31, 2010;

(2) 15% of its net electricity sales by December 31, 2015; and

(3) 20% of its net electricity sales by December 31, 2020.

HRS §269-91 defines "renewable portfolio standard" to mean "the percentage of electrical energy sales that is represented by renewable electrical energy." HRS §269-92(b)(1) requires that at least fifty per cent of the renewable portfolio standards be met by electrical energy generated using renewable energy as the source.

HRS §269-93 provides that: "An electric utility company and its electric utility affiliates may aggregate their renewable portfolios in order to achieve the renewable portfolio standard."

Q. What is the definition of "renewable electrical energy?"

A. HRS §269-91 defines "renewable electrical energy" to mean:

(1) Electrical energy generated using renewable energy as the source;

(2) Electrical energy savings brought about by the use of renewable displacement or off-set technologies, including solar water heating, seawater air-conditioning district cooling systems, solar air-conditioning, and customer-sited, grid-connected renewable energy systems; or

(3) Electrical energy savings brought about by the use of energy efficiency technologies, including heat pump water heating, ice storage, ratepayer-funded energy efficiency programs, and use of rejected heat from co-generation and combined heat and power systems, excluding fossil-fueled qualifying facilities that sell electricity to electric utility companies and central station power projects.

Q. What forms of energy are considered to be renewable energy resources?

A. HRS §269-91 defines "renewable energy" to mean "energy generated or produced utilizing the following sources:

(1) Wind;

(2) The sun;

(3) Falling water;

(4) Biogas, including landfill and sewage-based digester gas;

(5) Geothermal;

(6) Ocean water, currents and waves;

(7) Biomass, including biomass crops, agricultural and animal residues and wastes, and municipal solid waste;

(8) Biofuels; and

(9) Hydrogen produced from renewable energy sources."

Q. Has the Commission adopted an RPS Framework?

A. Yes, at least with respect to the penalty provisions in the law. By Order No. 23191, issued January 11, 2007 in Docket No. 2007-0008, the Commission initiated a proceeding pursuant to Act 162, which among other things, authorized the Commission to establish and issue penalties against electric utility companies who fail to meet the RPS. On October 12, 2007, the Consumer Advocate, HREA, the Companies and KIUC (jointly, the Stipulating "Parties") executed and filed a Stipulation and Joint RPS Framework. In D&O No. 23912, filed December 21, 2007 ("D&O 23912"), the Commission adopted in part, and denied, in part, the Stipulated Framework. Specifically, the Commission adopted the proposed RPS penalty framework (with certain modifications), but denied the incentives framework and interim Renewable Energy Infrastructure ("REI") Program included in the stipulated Joint RPS Framework, instead electing to open a separate docket (Docket No. 2007-0416) for the contemporaneous examination of the REI Program. D&O 23912 further directed the parties to file supplemental briefs in the RPS Docket addressing (1) the reasonable range of non-compliance penalties ($/MWh), if any, for inclusion in the RPS Framework; (2) whether RPS non-compliance penalties should be paid into a special fund or to the State of Hawaii; and (3) the appropriateness of an express prohibition on the recovery of RPS penalty costs in rates.

Q. Has HECO been successful to date in meeting the RPS?

A. HRS §269-93 provides that: "An electric utility company and its electric utility affiliates may aggregate their renewable portfolios in order to achieve the renewable portfolio standard." HECO, HELCO and MECO achieved a consolidated Renewable Portfolio Standard (RPS) of 16.1% in 2007, up from the

13.8% achieved in 2006. HECO's percentage was 11.0%, compared to 39.8% for HELCO and 24.7% for MECO. The higher percentage in 2007 was primarily the result of the new neighbor island wind farms and additional demand-side management ("DSM") implemented in 2007. Renewable energy generation (as compared to electrical energy savings from renewable displacement or energy efficiency technologies) comprises the majority of the utilities' RPS addition in 2007, as well as a majority of the total RPS percentage for 2007. New DSM program participants in 2007 contributed approximately 122 gigawatt hours of additional electrical energy savings.

Q. Does that mean that HECO can rest on its "laurels"?

A. Absolutely not. The HECO Companies need to be able to acquire the renewable energy resources that are necessary for them to meet not only the current RPS, but any revised goals that may be established as a result of the 70% Clean Energy Initiative announced by the State of Hawaii and the U.S. Department of Energy, and any GHG emissions reductions targets that may be set as a result of Act 234 (Haw. Leg. 2007) or national legislation. Moreover, the addition of renewable energy resources to the HECO Companies' systems needs to be accelerated, since soaring world oil costs, which have risen from $40/barrel in 2004 to $80/barrel in May 2007 to $130/barrel as of May 21, 2008, are driving electricity prices rapidly upwards, and renewable energy projects can often be structured to offer a "fixed" energy price that is delinked from fluctuations in oil prices at the time the energy is delivered.

2. State Energy Objectives

Q. What are the State's energy objectives?

A. The State of Hawaii's energy objectives include (per H.R.S §226-18(a)):

- Dependable, efficient, and economical statewide energy systems capable of supporting the needs of the people;
- Increased energy self-sufficiency where the ratio of indigenous to imported energy use is increased;
- Greater energy security in the face of threats to Hawaii's energy supplies and systems; and
- Reduction, avoidance, or sequestration of greenhouse gas emissions from energy supply and use.

Q. How are Hawaii's laws being modified to support these energy objectives?

A. The RPS law, which was significantly enhanced in 2006, is a prime example.

The continuing development of new laws and policies in this area is demonstrated by actions taken by the Hawaii Legislature in the 2007 and 2008 Sessions. With respect to renewable energy, the 2007 Hawaii State Legislature passed a measure that explicitly states that the Commission may consider the need for increased renewable energy in rendering decisions on utility matters. Potentially, if energy from a renewable source were more expensive than energy from fossil fuel, the Commission may still approve the purchase of energy from the renewable source. Act 177, signed June 13, 2007; effective July 1, 2007. In enacting Act 177, the Legislature found that: "Progressive energy policy-making at the state level is one of the most important issues on the current legislative agenda."

In July 2007, Act 234 of the 2007 Hawaii State Legislature became law and requires a statewide reduction of GHG emissions by January, 1, 2020 to levels at or below the statewide GHG emission levels in 1990. It also establishes a task force, comprised of representatives of state government, business (including the electric utilities), the University of Hawaii and environmental groups, which is charged with preparing a work plan and regulatory approach for "implementing the maximum practically and technically feasible and cost-effective reductions in

greenhouse gas emissions from sources or categories of sources of greenhouse gases" to achieve 1990 statewide GHG emission levels. The electric utilities are participating in the Task Force, as well as in initiatives aimed at reducing their GHG emissions. The Director of the Hawaii Department of Health is also required to adopt rules, before December 31, 2011, which establish emission limits for specific sources or categories of sources of emissions and provide for reporting and verification of statewide emissions and monitoring and compliance. The legislation became law in July 2007. (Act 234, signed June 30, 2007, effective July 1, 2007.)

Signed into law on July 1, 2008, Act 207 was enacted to establish a renewable energy facility siting process for state and county permits required for siting, development, construction, and operation of a new renewable energy facility with a capacity of at least 200 MW. The Act is predicated on the Legislature's finding that coordinating the process for required permits is in the State's interests, and will encourage the timely development of renewable energy projects in Hawaii. The law is intended to promote efficiency and transparency in the renewable energy facility permitting process.

3. Hawaii Clean Energy Initiative

Q. What is the HCEI?

A. In January, the State of Hawaii and United States Department of Energy ("DOE") signed a memorandum of understanding establishing the Hawaii Clean Energy Initiative ("HCEI"). The stated purpose of the HCEI is to establish a long-term partnership between the State of Hawaii and DOE that will result in a fundamental and sustained transformation in the way in which renewable energy efficiency resources are planned and used in the State, thereby providing a replicable global

model for achieving similar results. The implementation plan for the HCEI involves the creation of working groups to address, among other things: (1) the use of renewable energy at remote locations; (2) transmission and distribution improvements, grid management improvements, and energy storage to ensure that the existing and future infrastructure facilitates optimal use of renewable energy resources and readily adapts to and incorporates new developments in system planning and transmission technologies while maintaining system reliability; (3) the development of innovative public and private financing vehicles for alternative energy sources and clean technologies at the state and county levels; and (4) design and enactment of comprehensive regulatory mechanisms that provide appropriate incentives for all stakeholders in the energy supply chain to proactively transition to a renewable energy-based future.

Q. Have there been other steps in addition to the creation of working groups?

A. In April, the DOE sponsored Hawaii workshops supporting the initiative for the Commission, Consumer Advocate, DBEDT, Hawaii energy utilities and other invited stakeholders. The workshops addressed topics such as the objectives of the HCEI (which include meeting 70% of Hawaii's "business as usual" energy needs in the ground transportation and energy utility sectors through clean energy resources by 2030), utility incentives and disincentives, and renewable energy and other "clean" resources (such as energy efficiency). At the last workshop, the Commission announced plans to open an "Incentive Alignment" proceeding, and to formulate an alternative regulation "strawman" proposal to be considered in later workshops and proceedings.

Q. What can the Company do to facilitate the objectives of the HCEI?

A. First, we will work with other stakeholders to align the utility's energy plans with the State's plans. In addition, we need to maintain and enhance the Power Supply and T&D systems to be able to accommodate substantial amounts of intermittent and distributed renewable energy resources. Further, we will need to implement Advanced Metering Infrastructure ("AMI") to add the platform for demand response technologies and a smart grid.

4. Challenges in Adding Renewable Energy Resources

Q. What are some of the recognized challenges encountered in adding renewable energy resources?

A. One of the greatest challenges to the development of renewable energy in Hawaii, as well as in the nation, is the lack of infrastructure to support renewable energy resources. In July of 2006, a report was issued in Washington, D.C. entitled Siting Renewable Energy Facilities. One of its principal conclusions was that one of the greatest challenges to the development of renewable energy nationwide is the lack of infrastructure to support it. The fact is that while most fossil fuel facilities are not site dependent and can be located with other fossil fuel facilities or at other various locations, renewable energy exists at specific locations based on the resource involved and is geographically constrained, often in remote locations away from load centers and existing electric transmission infrastructure. In addition, the intermittent nature of many of these resources requires an infrastructure that can take into account and handle such resources.

The challenges faced by developers of renewable energy projects in Hawaii, and by the HECO Companies in facilitating these projects in their respective service areas, can be even greater for their small, isolated island electrical

systems. The current electric infrastructure was not designed or built to interconnect with a variety of renewable electrical energy generation resources developed at remote locations away from the current transmission grid. It was designed to consolidate generation facilities in a few places (as permitted by government regulations) and transmit the power to the major load centers in a reliable and efficient manner. In order for the Companies to use these renewable resources, new transmission lines (and supporting infrastructure such as substations) will have to be designed and built to these remote locations.

However, simply building transmission lines to the renewable projects will not completely solve the issues related to placing additional renewable generating resources on electrical transmission grids. Because of the intermittent nature of many of these renewable resources, additional infrastructure may be required to account for and handle the variability of electrical output from such intermittent resources.

Hawaii's current electric infrastructure was designed for "firm power" resources – resources that provide steady flows of energy and, by design, vary their output relatively slowly to provide stable power in concert with the steady and predictable change in customer demand. Renewable resources, on the other hand, are often times not "firm power" and may exhibit wide fluctuations in the amount of electric power generated at any given moment. A good example is wind power. The electrical power generated by wind will fluctuate depending on the changing speed, force and direction of the wind, and appropriate infrastructure must be developed to accommodate increasing amounts of it. Infrastructure such as energy control systems will help to regulate the variability of electrical output from intermittent resources such as wind power.

Small island systems currently can integrate only limited amounts of intermittent renewable energy resources like wind power. There is a need for substantial energy storage infrastructure to allow the systems to convert intermittent power to firm, dispatchable capacity. Potential examples involve the use of battery energy storage systems or pumped hydroelectric storage systems.

Hawaii's RPS law explicitly points to factors such as the impact of electricity generated from renewable energy resources on utility system reliability and stability. Under HRS § 269-95, the studies to be conducted by December 31, 2007 must include findings and recommendations regarding the -

> capability of Hawaii's electric utility companies to achieve renewable portfolio standards in a cost-effective manner, and shall assess factors such as the impact on consumer rates, utility system reliability and stability, costs and availability of appropriate renewable energy resources and technologies, permitting approvals, impacts on the economy, culture, community, environment, land and water, demographics, and other factors deemed appropriate by the commission . . . .

The energy industry at large has also recognized that the intermittent nature of renewable energy resources requires the installation of additional infrastructure to accommodate the development of those resources:

> Not only is availability of transmission a major issue, but there are other physical limitations of the grid specific to renewable energy. To varying degrees, renewable resources are intermittent, only available at certain times of the day or year. The changing availability of these resources and their unpredictability impose serious technical constraints on a grid that requires extremely tight coordination and control of electricity dispatch and delivery.
>
> S. Vajjhala, Resources for the Future Discussion Paper, Siting Renewable Energy Facilities, (July 2006) at 5.

Q. What steps need to be taken by the HECO Companies to address these challenges?

A. If Hawaii's abundant renewable energy resources are to be fully developed in a timely fashion, the Companies need to be able to do their part to aggressively facilitate the development of renewable energy. The HECO Companies need to lay down the "highway" to known sites of this energy, and enhance their systems with control features that will facilitate acceptance of these renewable energy resources, in particular, non-firm renewable energy power.

Q. What are some of the challenges faced in developing the needed infrastructure?

A. The first challenge is simply maintaining the existing infrastructure, as explained earlier in my testimony.

In addition, infrastructure projects are capital intensive, both for the developers as well as the Companies. The siting difficulties, substantial costs and long lead times typically associated with the installation of renewable energy infrastructure make it difficult to finance these types of projects. The HECO Companies need to raise the additional funds for these renewable infrastructure capital/deferred software development projects, while still continuing to make other investments required to maintain the reliability of the existing system.

The Companies' current capital expenditure budgets are already significant given increased loads and the aging infrastructure on each system. At the same time, the HECO Companies' credit ratings have been downgraded, and adding to their capital requirements without demonstrating support for their timely ability to earn on and recover that investment would exacerbate that situation.

Thus, the HECO Companies need to be able to raise the capital to construct and install these infrastructure projects in the financial markets without degrading

credit quality, or increasing the cost of capital, either of which would be detrimental to ratepayers and the development of third-party renewable energy projects.

5. Proposed Renewable Energy Infrastructure Program

Q. What steps have the HECO Companies proposed to address these challenges?

A. One important step is the implementation of our proposed REI Program.

Q. What is the REI Program?

A. HRS §269-95(1), as amended by Act 162 (2006), directed that the Commission:

> By December 31, 2007, develop and implement a utility ratemaking structure, which may include but is not limited to performance-based ratemaking, to provide incentives that encourage Hawaii's electric utility companies to use cost-effective renewable energy resources found in Hawaii to meet the renewable portfolio standards established in section 269-92, while allowing for deviation from the standards in the event that the standards cannot be met in a cost-effective manner, or as a result of circumstances beyond the control of the utility that could not have been reasonably anticipated or ameliorated . . . .

In response to this provision, the HECO Companies proposed a "Renewable Energy Infrastructure Program", consisting of (1) renewable energy infrastructure projects to encourage development of third party renewable energy resources, maintain current renewable energy resources, and/or enhance energy choices for customers while maintaining acceptable levels of reliability and (2) the creation and implementation of a "Renewable Energy Infrastructure Surcharge" ("REI Surcharge") that may facilitate raising capital by providing investors assurance of a mechanism to recover the utilities' investment in renewable infrastructure in a timely fashion.

The HECO Companies also proposed that the Commission adopt a consolidation incentive mechanism ("Consolidation Incentive") that generally would operate to credit customers of electric utility affiliates within a consolidated electric utility whose service territories exceed their RPS percentage on a stand-alone basis, to be paid for through a compensation payment or surcharge on customers of the affiliated electric utilities, if any, whose service territories fall short of their RPS percentage on a stand-alone basis.

Q. What types of projects would be included in the REI Program?

A. The Renewable Energy Infrastructure Program will include projects that deal with traditional utility activities, including those that are considered uniquely utility activities and those for which the utility is the logical party to execute the activity, such as transmission lines, meters that measure electrical service and consumption, and interconnection facilities. Interconnection facilities are the interface between the renewable project and the utility's grid. Interconnection facilities between the point of interconnection and the utility transmission system have historically fallen on the renewable energy developer.

In addition, the proposed program would allow the Companies to explore other avenues to accept non-firm renewable energy onto the system. For example, a utility activity which has been used in other states to regulate and control grid stability and which makes eminent sense here, involves energy storage and control systems such as pumped hydroelectric storage and battery energy storage. Renewable distributed generation is another possibility. Also, infrastructure projects and other projects that encourage renewable choices and/or otherwise allow customers to control their own energy use may be covered by the program.

Q. Can these projects be divided into categories?

A. The HECO Companies have proposed three general categories of infrastructure projects that may be covered under the REI Program.

The first category encompasses projects that are necessary to maintain current renewable energy resources and/or connect new renewable energy projects to any of the Companies' respective systems. This category of projects consists of renewable energy infrastructure projects such as transmission lines, interconnection equipment, substations, and related equipment necessary to bring renewable energy to the system.

The second category consists of projects that encourage development of renewable energy resources by making it possible to accept more renewable energy on a utility's electric system. This category of projects includes infrastructure projects that assist in the integration of as-available and other non-dispatchable renewable projects onto the electrical grid. Facilities such as battery energy storage systems and pumped hydroelectric storage facilities can allow a utility to accept and accommodate more as-available renewable energy.

The third category generally consists of those projects that encourage renewable choices and/or otherwise enhance renewable energy choices for customers. Infrastructure projects and other utility projects can encourage renewable choices by facilitating conservation and efficient energy use or otherwise enhancing renewable energy choices for customers. For example, smart meters added as part of an Advanced Metering Infrastructure project should allow customers to monitor their own consumption and use of electricity and allow for future time-based pricing programs.

Q. What is the purpose of the REI Program?

A. The purpose of the program is to encourage development of and investment in renewable infrastructure projects in order to facilitate development of third-party renewable energy resources, maintain current renewable energy resources, and/or enhance energy choices for the Companies' respective customers.

Q. What is the purpose of the REI Surcharge?

A. The proposed Renewable Energy Infrastructure Surcharge is the mechanism that would facilitate the development of renewable energy resources by encouraging the funding of renewable energy infrastructure through the recovery of renewable infrastructure costs on a more timely basis than is afforded by the traditional rate case process.

Q. Is there precedent for such a provision?

A. From a regulatory standpoint, this renewable infrastructure surcharge is similar in principle to other surcharges that are presently used to implement certain regulatory policies. Ratemaking mechanisms that allow cost recovery to begin as soon as new facilities go into service have been used by this Commission to allow recovery of demand-side management program costs to encourage the development of such programs, and firm capacity payments to nonfossil fuel project developers as soon as the utility begins purchasing power to encourage the development and retention of non-fossil fuel facilities, by the Federal Energy Regulatory Commission ("FERC") to encourage the installation of transmission infrastructure, and by the California Public Utilities Commission ("California PUC" or "CPUC") to encourage renewable energy infrastructure.

Q. When did the Commission open the REIP Docket?

A. By Order No. 23913, also filed December 20, 2007 ("Order 23913"), and in accordance with D&O 23912, the Commission opened a new docket, Docket No. 2007-0416 (the "REIP Docket"), separate from and contemporaneous to the RPS Docket for the examination of the HECO Companies' proposed REI Program. The Commission conducted public hearings in May on all the islands served by the HECO Companies to obtain public comment and input on the proposed REI Program.

6. Renewable Energy Projects

Q. How much of the energy purchased by HECO is derived from renewable energy resources?

A. In 2007, the amount of energy purchased by HECO that was derived from renewable energy resources included (1) 24 gwh from AES, which reflects the amount of energy derived from burning shredded tires, waste oil, and used activated carbon, and 302 gwh from H-Power. This subject is covered by Dan Ching in HECO T-6.

Q. What is the Company doing to accelerate the addition of energy generated from renewable energy resources?

A. We are planning to purchase substantial amounts of renewable electrical energy from third-party developers of renewable energy projects, as a result of on-going negotiations with developers of projects that are exempt from the new competitive bidding process, our on-going renewable energy competitive bidding process, and future renewable energy requests being considered in the on-going IRP-4 process. We are biofueling our new CIP CT-1 generating unit, and testing the ability of our steam units to burn biofuels. We are conducting research and development

activities, taking advantage of outside expertise, to analyze how we can reliably integrate large amounts of intermittent renewable electrical energy into our system. We also are actively working to incorporate significant amounts of distributed renewable energy.

a. Additional Purchased Energy

Q. Please summarize the on-going activities directed at increasing the amount of purchased renewable energy.

A. In the purchased power area, HECO's efforts are governed by the Framework for Competitive Bidding (the "Framework") established by the Commission on December 8, 2006, in D&O No. 23121. We are actively engaged in negotiations with the developers of three potential renewal energy projects that are exempt from the Framework process ("grandfathered proposals") because they were submitted to the utilities prior to the adoption of the Framework in Docket No. 03-0372. The grandfathered proposals consist of approximately 30 MW of wind energy located on the north shore of Oahu, 5 MW of energy from synthetic gas derived from waste products, and 25 MW of energy from ocean thermal conversion which could potentially increase to 100 MW. Thus, the grandfathered proposals could result in power purchase agreements for approximately 60 – 135 MW of renewable energy. HECO also is working with the City and County of Honolulu ("City and County") on its planned expansion of the H-Power facility.

In parallel with the on-going negotiations, the Competitive Bidding Division is actively pursuing HECO's Request for Proposals for Renewable Energy Projects on the Island of Oahu. Through this process, we are seeking to acquire approximately 100 MW of non-firm renewable energy for the Island of Oahu, as identified in HECO's IRP-3 2007 Evaluation. The process also allows for

consideration of larger, "non-conforming" proposals. In addition, the Company is working on its future plans to acquire additional renewable energy resources in the IRP-4 process that is currently underway, and in conjunction with the Hawaii Clean Energy Initiative discussed in my testimony.

b. Biofuels

Q. Why are biofuels an important part of HECO's renewable energy strategy?

A. Biofuels are a critical component of a "green" energy future because they can be used to generate energy from conventional generators, which provide essential grid services, including load following, frequency response, voltage control and on-line operating and spinning reserves, as Dan Giovanni addresses in HECO T-7.

Q. Why are HECO generating units needed to support intermittent as-available renewable generation such as wind or photovoltaic ("PV") generation on the HECO system?

A. As Mr. Giovanni explains, power systems require that the generation resources on the system collectively provide several characteristics that the system fundamentally needs for reliable operation. These characteristics include adequate firm generating capacity, controlled dispatch of generation, frequency regulation, and sufficient rotational inertia to maintain system stability. Baseload, cycling, and peaking generating units are commonly referred to as "firm" power, and their power output can be dispatched as needed. These forms of "conventional generation", to the extent that they are fully dispatchable from minimum to full load by the utility, are capable of load-following, and also provide frequency control and voltage support. As-available resources like wind and PV are not firm, can not be dispatched, and are unable to provide prescribed amounts of power upon command or at scheduled times.

Q. What will be the major challenges to the HECO as more renewable energy sources are added to the grid?

A. The challenges for us as a utility will be to (1) optimize the performance of the generation that provides the critical ancillary services of load following, frequency control, voltage support, as well as back up when intermittent resources are not available, and (2) convert even conventional generation to "green" generation as sustainable biofuels become available.

Q. What is HECO doing with biofuels?

A. HECO plans for the new generating unit at Campbell Industrial Park, CIP CT-1, to be operated on biodiesel, instead of an oil-based fuel, pursuant to a stipulation with the Consumer Advocate that was approved by the Commission in approving the installation of the new generating unit. In accordance with the air permit, CIP CT-1 will be commissioned firing petroleum diesel (i.e., No. 2 oil) in mid-2009. A test will subsequently be performed to characterize the performance and air emissions firing biodiesel. The test results will be used as a basis to modify the air permit to allow for continuous operation firing 100% biodiesel. Once the modified air permit is issued, CIP CT-1 will be operated firing biodiesel

Q. Please explain the Company's commitment to use biodiesel in CIP CT-1?

A. In response to the Consumer Advocate's recommendation to use 100% ethanol or some other biofuel in the new CT unit, HECO committed to use 100% biofuels in the new unit in a stipulation dated December 14, 2006 in Docket No. 05-0145 between HECO and the Consumer Advocate, and set forth the steps that it planned to take in order to fulfill that commitment. (Exhibit A to the Joint Stipulation, entitled "Position on Biofuels for the New Combustion Turbine Unit.)

Q. What did the Commission find with respect to HECO's commitment to use biofuels in the new unit?

A. The Commission found that commitment to be reasonable and consistent with State policy to reduce Hawaii's dependence on imported fossil fuels and encourage sustainability through economic diversification, export expansion, and import substitution:

> As an island State without oil resources, Hawaii has had to rely on imported oil, contributing to an undesirable "large imbalance between the amount of goods and services exported from Hawaii in comparison to the amount of goods and services imported to Hawaii."
>
> Accordingly, by Act 272, 2001 Session Laws of Hawaii ("Act 272"), Hawaii's RPS Law was enacted with the purpose of "lessen[ing] Hawaii's dependence on imported oil[.]" Likewise, in modifying Act 272, the Legislature, in Act 95, intended to, "decrease Hawaii's need to import large amounts of oil, and increase import substitution, economic efficiency, and productivity, by increasing the use and development of Hawaii's renewable energy resources through a partnership between the State and the private sector." Importantly, the RPS law specifically defines renewable energy as including "biofuels."

(D&O No. 23457 (May 23, 2007), Docket No. 05-0145, pages 45-46.)

Thus, the Commission found that State law explicitly supports HECO's commitment to use biofuels for the Project. The Commission further agreed with HECO and the Consumer Advocate that the Project supports the State's goal of encouraging development of local agriculture, in that HECO expects the Project to provide a stable market for locally grown and produced biofuels. The Commission also found that using biofuels, which may eventually be locally grown and produced, is preferable to burning fossil fuel for the CIP CT-1 Project, and will advance the State's policies of reducing the State's dependence on fossil fuels and diversifying the State's economy.

Q. Please identify recent legislation that promotes the use of biofuels.

A. In the 2006 legislative session, which focused on energy policy, the Governor and the Legislature working together enacted four bills, which are a significant statement in what the state policy is on energy. Three of the four bills specifically raised biofuels as an important component.

Act 196 addresses the use of biofuels in vehicles. Act 162, which amended the RPS law, added a definition of biofuels. By defining renewable energy to include biomass and biofuels, it makes the distinction and promotes both. And then the RPS standards were amended in a way to measure the use of biofuels in our units, specifically allowing for biofuels to be measured when they are cofired with a fossil fuel.

Act 240 provided specific support for biofuel research, a specific biofuel preference and a $150,000 appropriation to the Department of Agriculture to support the agricultural community of Hawaii in trying to meet the needs.

The 2007 Hawaii State Legislature added two more measures. Act 159 has the stated purpose to encourage further production and use of biofuels in Hawaii, establishes that biofuel processing facilities in Hawaii are a permitted use in designated agricultural districts, and establishes a program with the Hawaii Department of Agriculture to encourage the production in Hawaii of energy feedstock (i.e., raw materials for biofuels). (Act 159, signed June 8, 2007; effective July 1, 2007.)

Act 253 requires the Hawaii Department of Business, Economic Development, and Tourism to develop and prepare a bioenergy master plan that sets the course for the coordination and implementation of policies and procedures to develop a bioenergy industry in Hawaii. The primary objective of the

bioenergy master plan is to develop a Hawaii renewable biofuels program to manage the State's transition to energy self-sufficiency based in part on biofuels for power generation and transportation. (Act 253, signed June 5, 2007; effective July 1, 2007.)

Q. What steps is HECO taking to investigate the feasibility of using biofuels in its existing generating units?

A. This is covered by Mr. Giovanni in HECO T-7 and by Mr. Bruce Tamashiro in HECO T-14.

Q. Has HECO developed a plan for biodiesel testing in a steam boiler.

A. Yes. As explained by Mr. Tamashiro in HECO T-14, the Biofuel Co-Firing Project is part of a multi-year R&D program to examine biofuels for stationary power generation consisting of the following phases:

Phase 1 – Biofuels resource assessment (completed);

Phase 2 – Combustion testing (completed);

Phase 3 – Generating unit assessment and infrastructure and operational assessment (completed); and

Phase 4 – Utility-scale demonstration (2009 – Biofuel Co-Firing Project).

Q. What is the current status of the Biofuel Co-Firing Project?

A. The Company has gone through a selection process to determine which steam boiler will be tested. The Company has selected Kahe steam boiler #3 based on various criteria such as space availability for biofuel fuel storage and delivery, infrastructure availability (e.g., pump size and pressure rating), minimum modifications, and timing of the next planned maintenance outage. HECO is targeting biofuel testing in late September 2009 after the scheduled mid-year overhaul of this unit. A test plan, detailed schedule, and budget are being

developed. The testimony of Mr. Tamashiro, HECO T-14, contains a full discussion of the Biofuel Co-Firing Project.

Q. Can HECO create a biofuels industry in Hawaii?

A. HECO cannot itself create a biofuels industry. HECO is not in the agriculture business, does not own land suitable for agricultural production and has no expertise in refining biofuels. HECO can, however, play a critical role by providing a stable market for biofuels. A fuel contract to supply HECO is, according to the biofuel industry, one of the best means of securing financing for their business plans. HECO has entered into a contract with Imperium Services, LLC, for the supply of biofuel for HECO's CIP CT-1 combustion turbine.

Q. Is the Company pursuing research regarding biofuels agriculture?

A. Yes. As described in the testimony of Mr. Tamashiro, HECO T-14, the Company is working with the Hawaiian Agriculture Research Center ("HARC") on a biofuels agriculture crop research project. HARC is conducting research and is coordinating the work of the University of Hawaii at Manoa's College of Tropical Agriculture and Human Resources ("CTAHR") and University of Hawaii at Hilo's College of Agriculture, Forestry and Natural Resources Management ("CAFNRM"). HECO executed an agreement with HARC in 2007 and will use matching funds from the Electric Power Research Institute ("EPRI") to co-fund this research. With EPRI's cost-matching of $53,000 and HECO's participation, Phase 1 of the biofuel agriculture crop research project cost was $103,000 in 2007. The EPRI agreement was amended in 2008 (Phase 2) with a similar HECO grant award and EPRI co-share totaling $100,000.

Q. What are HECO's plans in 2009 for biofuels agriculture crop research?

A. HECO plans to provide a third installment of seed funding to HARC in 2009 (Phase 3) with EPRI cost-sharing. HECO will provide $50,000 (test year 2009 estimate) and EPRI will provide another $50,000 towards this effort.

Q. What are the study results to date of the biofuels agriculture crop research project?

A. HARC, the University of Hawaii at Manoa, and the University of Hawaii at Hilo are each responsible for separate projects in the research effort. As of April 30, 2008, HARC had established two test plots of *Moringa oleifera* trees; CTAH is developing a method to produce identical jatropha trees to increase uniformity of growth and yield in the field; and, CAFNRM was overseeing the growth of 10,000 seedlings of oil palm. A more detailed discussion of the status of the projects is contained in Mr. Tamashiro's HECO T-14 testimony.

Q. Is the Company taking any steps to mitigate the environmental impact of the increasing use of biofuels?

A. Yes. Mr. Ronald Cox in HECO T-5 states that HECO is aware of the environmental issues arising out of the use of biofuel feedstock, such as palm oil. In conjunction with its commitment in Docket No, 05-0145 to use 100% biofuels in CIP CT-1, HECO has undertaken a project to develop an environmental policy for sourcing biofuel feedstock. Community meetings were held on Oahu, Big Island and Maui in late June and early July to discuss the study's preliminary findings, and receive community feedback on the draft. HECO and the Natural Resources Defense Council (NRDC) released the final policy on August 21, 2007, which is intended to ensure that HECO, MECO and HELCO purchase only biodiesel fuel produced from locally grown sustainable feedstocks and palm oil that complies with international standards established by the Roundtable on

Sustainable Palm Oil. The eight components of the policy are: (1) local feedstock support mechanisms, (2) sourcing requirements for palm oil, (3), baseline criteria for all biodiesel feedstocks, (4) chain of custody tracking for feedstocks and oils, (5) global warming pollution accounting and reporting, (6) establishment of a Biofuels Public Trust Fund, (7) public review and notification, and (8) public progress reporting and contingencies.

Q. Has HECO taken any steps to implement this policy?

A. Yes. As explained in the testimony of Mr. Ronald Cox, HECO T-5, in August 2007 HECO entered into a contract with Imperium Services, LLC, for the supply of biofuel for CIP CT-1. The contract was submitted to the Commission for approval in October 2007 in Docket No. 2007-0346, and a decision is pending. Imperium intends to build a transesterification plant adjacent to Kalaeloa Harbor and produce biodiesel from sustainable imported and locally grown feedstock.

The contract contains a provision that provides for a local feedstock incentive. This incentive reflects the State of Hawaii Legislature's intent to "decrease Hawaii's need to import large amounts of oil, and increase import substitution, economic efficiency, and productivity, by increasing the use and development of Hawaii's renewable energy resources through a partnership between the State and private sector." Act 95, section 1. In addition, the incentive is intended to advance the State's goal of encouraging development of local agriculture by providing a market for locally grown and produced biofuels.

c. Research and Development

Q. What steps have the HECO Companies taken to enhance the ability of intermittent renewable energy facilities to be reliably integrated into their systems?

A. The HECO Companies will need to enhance their systems by developing and adding control systems and facilities that will facilitate acceptance of these renewable energy resources. Potential examples include electronic shock absorbers, which are being pioneered in Hawaii, and the use of energy storage systems. R&D activities targeted at designing, testing and developing the facilities (and the use of already developed technologies) for these applications are a critical component of that effort.

To help stabilize the operation of grid-connected wind turbines and minimize power fluctuations on a grid that is connected to a number of windfarms, HECO, HELCO, and MECO have developed the Electronic Shock Absorber ("ESA") device to help the electric utility ride through short duration power fluctuations (frequency, voltage, etc.) from the windfarm caused by the variable nature of wind. The ESA is the first-of-a-kind demonstration unit developed from idea, patent approval, to design, procurement and construction of a demonstration unit dealing with wind integration issues. HECO, HELCO and MECO teamed with S&C Electric Company to conduct a study and design the device for installation between a windfarm and the utility grid. A patent on the ESA device was accepted and awarded to HECO in 2005. An ESA demonstration unit was installed at the Lalamilo substation with testing taking place in 2006, until the test unit was irreparably damaged during the October 15, 2006, earthquake.

Q. What steps are the HECO Companies taking to analyze ways to increase the amount of intermittent renewable energy that can be reliably integrated into their systems?

A. HECO, HELCO and MECO are collaborating with the Hawaii Natural Energy Institute ("HNEI") on a Department of Energy ("DOE") funded project called the Hawaii Energy Roadmap, which has been conducted by GE Global Research Center ("GEGRC") under contract to HNEI. The primary objective of the project is to develop and execute an unbiased energy scenario analysis that answers to the future interests and goals of the Big Island and initiates further study of a technology-specific project that serves as another step on a path toward meeting the island's energy objectives. This study should help to better understand and quantify the effects of integrating intermittent resources onto the relatively small electrical grids in Hawaii and will help to chart a clearer course to achieve the maximum integration of renewable resources on the HECO, MECO, and HELCO systems.

The electric system on Maui is being analyzed in a study conducted similar to the Hawaii Energy Roadmap Study. As discussed by Mr. Tamashiro in his testimony at T-14, the primary objective of the Maui Electric System Analysis is to address potential issues with future wind farms (and other renewable resources). The proposed effort is to characterize the current challenges of integrating intermittent renewable energy (e.g., wind energy) into the electrical grid, evaluate the impact of currently planned renewable expansion scenarios on MECO's grid operation, and formulate controls, storage and interconnection recommendations to help achieve renewable energy targets. For additional details, please refer to HECO T-13, pages 9-12, of the Company's 2007 Test Year Rate Case (Docket No. 2006-0386).

HECO expects to spend approximately $419,000 ($344,000 for Phase 1 and $75,000 for Phase 2) for the Maui Electric System Analysis. The USDOE is

providing $60,000 of cost share funding and the HNEI is providing $20,000 of in-kind cost share for coordination and management throughout the project in 2008 and 2009. MECO's cost-share in this project is in-kind as the technical lead, coordinating and collaborating with GE, HNEI and HECO engineers in the various work activities.

Q. What is the status of the Maui Electric System Analysis?

A. In late 2007, the Company signed an agreement with the University of Hawaii's HNEI, which has an agreement with General Electric ("GE") for this study on Maui. Phase 1 of the project commenced in late 2007 and is being led by MECO. Numerous team meetings among MECO, HECO, HNEI and GE personnel have been held on Maui and project discussions have also occurred through email and telephone. HECO and MECO have provided information to GE to populate the simulation model and anticipate that the review, comment and approval of the results will occur in the summer of 2008. The completion of Phase 1 of the Maui Electric System Analysis is expected in late 2008. HECO anticipates Phase 2 to commence in late 2008 and finish in 2009.

Q. What is the Oahu Electric System Analysis?

A. As explained in Mr. Tamashiro's testimony HECO T-14, the Oahu Electric System Analysis is similar to the Maui Electric System Analysis. It is an R&D project to characterize, evaluate and formulate controls, storage and interconnection recommendations with the objective of increasing the Company's renewable energy portfolio. The study will be performed on the Company's electric system on the island of Oahu. The Oahu Electrical System Analysis is needed to address the challenges of integrating renewable energy resources to the Company's electrical grid on Oahu. With the recent negotiations for a

commercial wind farm on the north shore of Oahu, possible additional wind farm(s) resulting from the Company's Request for Proposals for Renewable Energy Projects (Docket No. 2007-0331), and interest by large wind farm developers on neighboring islands to transport this energy to Oahu via undersea cables, the Company will be faced with challenges of integrating these potential wind farms and other renewable energy projects on the HECO grid. The primary objective of this study is to address integrating future wind farms (and other intermittent renewable resources) on the HECO grid. It will assess the challenges of integrating intermittent renewable energy into the electrical grid, evaluate the impact of currently planned renewable expansion scenarios on the Company's grid operation, and formulate controls, storage and interconnection recommendations to help achieve the renewable energy targets for the island. HECO anticipates that the Oahu Electric System Analysis will commence in late 2008 with the bulk of the work being conducted in 2009.

d. Renewable Distributed Energy

Q. What is the Company doing to accelerate the addition of energy generated from distributed energy resources?

A. The Company is doing a number of activities to accelerate the addition of energy generated from distributed energy resources. These activities include: (1) pursuing development of a utility-sited photovoltaic ("PV") system, (2) continuing the Sun Power for Schools Program, (3) continuing the Net Energy Metering Program and proposing a Net Energy Metering Pilot Program that will be offered to some larger PV installations that would not be eligible for the existing Net Energy Metering Program, and (4) exploring other PV options.

Q. Please discuss the Company's efforts with respect to a utility-sited PV system.

A. As discussed by Mr. Daniel Ching in HECO T-6, HECO is pursuing development of a utility-sited PV system in 2008 consistent with HECO's IRP-3 Evaluation Report filed with the Commission on May 31, 2007. On March 22, 2007, HECO issued a request for proposals to non-utility PV developers, seeking development of a PV system on the rooftop of Archer Substation, located at HECO's Ward Avenue facility. After reviewing and evaluating bids, HECO awarded the project to Hoku Solar on May 25, 2007. On November 16, 2007, HECO and Hoku Solar executed a Solar Energy Purchase Agreement ("SEPA") governing Hoku Solar's development of a PV system of up to 300 kW and HECO's purchase of energy from the system. On December 27, 2007, HECO submitted an application for Commission approval of the SEPA and on May 13, 2008, by D&O No. 24225 (Docket No. 2007-0425) the Commission approved the SEPA. Hoku Solar estimates the size of the PV system will be 218 kWdc. The Archer PV system is expected to be placed in service in late 2008.

Q. Please discuss the Sun Power for Schools Program.

A. Sun Power for Schools is a three-way partnership between HECO and the State of Hawaii Department of Education ("DOE") and HECO's customers in which HECO installs, operates and maintains (for a specified time) solar electric systems using PV technology in selected schools. (HELCO and MECO have similar programs.) The Sun Power for Schools program promotes the concept of PV systems as an alternative to conventional fuels used for the production of electricity. To date, over 35,000 watts of PV systems on 27 schools have been installed. The Sun Power for Schools program was funded through HECO Companies' contributions of $140,000 and voluntary customer and non-customer

contributions backed by a two-year program commitment from the HECO Companies. The DOE has been developing the educational material component of the Sun Power for Schools program for integration into the existing energy and environmental curricula. The HECO Companies initiated this demonstration and education program in 1996 and are extending the program another two years to 2010.

Q. How many systems have been installed at schools under the Sun Power for Schools Program?

A. HECO has installed 14 PV systems under this program. HELCO and MECO together have installed another 13 PV systems under this program.

Q. Please briefly describe what is Net Energy Metering.

A. Sections 269-101 to 269-111, of the HRS require net energy metering ("NEM") to be available to eligible customer-generators with a capacity of not more than 50 kilowatts until the total rated generating capacity of eligible customers equals 0.5 percent of the electric utility's system peak demand. The NEM law states that eligible customers who own and operate a solar, wind turbine, biomass, or hydroelectric energy generating facility, or a hybrid system consisting of two or more of these facilities, with a capacity of not more than 50 kilowatts, shall be credited at the retail rate (of the rate class the customer is normally assigned to) for electrical energy generated by the eligible customer-generator and fed back to the electric grid. Over a monthly billing period, the difference (i.e., net) between the customer-generated electrical energy and the electrical energy supplied through the electric grid is determined. In essence, customers are able to "bank" the excess renewable energy they generate and feed into the Company's grid for later use.

On April 10, 2006, the Commission issued Order No. 22380 in Docket No. 2006-0084, that opened an investigative proceeding to address whether the Commission should increase: (1) the maximum capacity of eligible customer-generators to more than 50 kilowatts; and (2) the total rated generating capacity produced by eligible customer-generators to an amount above 0.5 percent of an electric utility's system peak demand.

Q. Were the parties that that docket able to reach agreement on these issues?

A. Yes. HECO (along with HELCO and MECO) were able to reach agreement with the parties in the docket to increase the maximum capacity of eligible customer-generators and the total rated generating capacity produced by eligible customer generators. The parties filed a stipulated agreement on September 17, 2007. On March 13, 2008, the Commission issued D&O No. 24089 approving the stipulated agreement submitted by the parties on September 17, 2007 that: (1) Increased the maximum size of the eligible customer-generator that can qualify for a NEM agreement from 50 kW to 100 kW; (2) Increased the total rated generating capacity produced by eligible customer-generators from 0.5% to 1.0% of the utility's system peak demand; (3) Reserved 40%, 50%, and 50% of the total rated generating capacity produced by eligible customer-generators for HECO, HELCO, and MECO, respectively, for residential and smaller commercial NEM customers (system sizes of 10 kW or less); and (4) Utilizes the Integrated Resource Planning (IRP) process to evaluate impacts to the Utilities' systems and determine further adjustments to the NEM system size and cap limits (limits re-examined on an annual basis). In addition to the agreed-upon terms of the stipulation, the Commission ordered that HECO (along with MECO and HELCO) design and propose a NEM Pilot Program for the Commission's review and

approval, which will allow on a trial basis a limited number of larger generating units for NEM.

Q. Did the Company submit its proposed NEM Pilot Program?

A. Yes, the Company submitted its proposed pilot program on April 28, 2008. The proposed NEM Pilot Program covers the service territories of HECO, HELCO, and MECO and consists of a phased, 4-year program that comprises both analytical investigations and field monitoring, which will be designed to collect and analyze the information needed to evaluate the impacts of incorporating large NEM systems and high penetration levels of these systems. Like HECO's existing Rule 18 NEM tariff, the participants in the NEM Pilot Program will be eligible to receive a credit for any excess energy provided to the Companies. The credit will be provided on a kWh basis, and will be equal to the customer's retail rate. The methodology to compute the amount of the credit will be the same one currently used by the Companies for customers on the existing Rule 18 NEM tariff. The size of the renewable generator that is eligible under HECO's proposed NEM Pilot Program is greater than 100 kW but less than or equal to 500 kW, with the possibility of allowing greater than 500 kW renewable generators under certain situations.

Q. What is the amount of installed NEM on HECO's system?

A. As of May 31, 2008, there was approximately 900 kW of NEM installed on Oahu, about 788 kW installed for HELCO and 961 kW installed for MECO.

Q. Please discuss the Company's efforts to explore other PV options.

A. The Company is actively evaluating options for broader utility acquisition of PV energy. These options include pursuing development of additional utility-sited PV projects using the same approach as the Archer PV project. In addition, the

Company is evaluating options to apply this general approach to customer sites, including a possible arrangement where the Company leases sites from customers, arranges for third party PV developer-owners to install PV systems, and purchases the PV energy. The Company also regularly monitors and evaluates PV initiatives by mainland utilities, such as the recent 2008 PV program filings by Southern California Edison and Duke Energy.

7. Demand-Side Management Programs

Q. What is HECO doing to promote the efficient use of electricity?

A. One of the things HECO does to promote the efficient use of electricity is to provide demand-side management ("DSM") programs.

Q. What are DSM programs?

A. DSM programs are designed to influence how utility customers use energy to produce desired changes in demand. They include load management and energy efficiency programs.

Q. Please identify HECO's DSM programs.

A. HECO currently administers and implements 11 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) Residential Low Income ("RLI")
8) SolarSaver Pilot ("SSP")
9) Residential Customer Energy Awareness ("RCEA")

10) Commercial and Industrial Direct Load Control ("CIDLC")

11) Residential Direct Load Control ("RDLC")

A brief description of the programs is included in HECO-1011. The first eight programs are energy efficiency programs, which are designed to reduce both energy consumption and demand by customers. The RCEA Program is a customer information program, which is designed to increase residential customer awareness of energy options and encourage customers to adopt energy efficient appliances and behavior. The last two programs are load management programs, which are designed to primarily reduce customer demand.

Q. How long has HECO been offering energy efficiency DSM Programs?

A. HECO has aggressively implemented energy efficiency demand-side management ("DSM") programs since 1996, in the form of the first five DSM Programs included in the list of programs. These programs have provided incentives to our customers to implement measures that reduce their use of electricity or allow them to use electricity more efficiently.

HECO began its energy efficiency DSM programs in late 1996 with a standard set of commercial and industrial energy efficiency measures contained in three programs: (1) the Commercial and Industrial Energy Efficiency Program; (2) the Commercial and Industrial Customized Rebate Program; and (3) the Commercial and Industrial New Construction Program. In late 1996 HECO also began its energy efficiency DSM programs for the residential market segment with customer incentives for solar water heating systems in both the retrofit (Residential Efficient Water Heating Program) and new construction (Residential New Construction Program) sectors. For the nine years between 1996 and 2004, HECO's energy efficiency programs achieved an annual average

of 38 GWh of energy savings each year[4] such that by the end of 2004 cumulative savings each year from all measures installed between 1996 and 2004 was 343 GWh, as shown in HECO-1043.[5] During the same period, HECO DSM programs achieved an annual average of 6.4 MW of demand reductions each year[6] such that by the end of 2004 the total annual demand reduction from all measures installed was nearly 58 MW[7].

In 2005, HECO introduced two new load management programs: (1) the Commercial and Industrial Direct Load Control Program; and (2) the Residential Direct Load Control Program. The addition of these two programs (for a total of seven DSM programs) increased incremental demand reductions in 2005 and 2006 to 13 and 18 MW, respectively, more than twice the 9-year average annual peak demand reduction of 6.4 MW achieved by HECO's energy efficiency programs since 1996. In 2006, HECO's programs achieved incremental demand savings equal to 1.4% of HECO's 2006 annual demand peak of 1315 MW (at the system level)[8].

Q. Have additional programs been added since 2006?

A. Yes. In 2007, HECO introduced four new DSM programs: (1) the Energy Solutions for the Home Program; (2) the Residential Low Income Program; (3) the Solar Saver Pilot Program; and (4) the Residential Customer Energy Awareness Pilot Program. In 2007, these four programs, plus the seven existing programs, achieved additional energy and demand savings of 121 GWh and

[4] At the gross generation (system) level, including free riders.
[5] Assuming that all of the measures installed remain in service.
[6] At the gross generation (system) level, including free riders.
[7] Assuming that all of the measures installed remain in service.
[8] 1265 MW at the net-to-system level.

39.8 MW. The incremental demand reduction was equivalent to 3.2% of HECO's 2007 annual demand peak of 1261 MW (at the system level)[9].

Assuming (for illustration) that all measures installed since 1996 were still in service, these measures represent a cumulative annual savings of 568 GWh and an annual demand reduction of 129 MW, which is equivalent to a generating unit at Kahe Power Plant. Mr. Hee discusses the energy and savings impact of HECO's DSM programs in more detail in his testimony, HECO T-10.

Q. Has HECO proposed any enhancements to the programs?

A. Yes. In its November 2007 DSM Program Modifications and Evaluation Report HECO proposed that the customer incentive for seawater district cooling ("SDC") be increased to $300/ton of air conditioning, from the present approximately $200/ton incentive level. Honolulu Seawater Air Conditioning, LLC is developing a 25,000 ton seawater air conditioning system for downtown Honolulu, scheduled to be in-service in 2010. SDC is a renewable DSM resource that can provide major benefits in terms of energy and demand savings, the longevity of these savings, contribute to the lowering of greenhouse gas emissions, and be a major contributor to the State's Renewable Portfolio Standards energy goal. However, the project faces large challenges because of the high initial capital cost of infrastructure, including seawater lines and the district cooling distribution system. This economy of scale presents a major hurdle for a SDC system to overcome. Therefore, in order to help motivate customers to adopt this proven cost-effective energy efficiency measure and to help overcome market barriers including customers' lack of knowledge and experience with this

[9] 1216 MW at the net-to-system level.

technology, HECO proposed an increase in the customer incentive for this technology. This request is pending at the Commission.

Q. Please discuss HECO's Rider SSP SolarSaver ("SolarSaver") Pilot Program.

A. As discussed in Mr. Hee's testimony in HECO T-10, the SolarSaver Pilot Program is a pilot program designed to overcome the barrier of up-front costs in the residential solar water heating market. Residential customers participating in the program incur no upfront cost and pay for the cost of the installed solar water heating system over time through savings in the customer's electricity bill. The SolarSaver Pilot Program has a three-year pilot program period. The Commission approved, with modifications, HECO's (as well as HELCO's and MECO's) SolarSaver Pilot Program on June 29, 2007. HECO filed its SolarSaver Pilot Program tariff with the Commission on July 9, 2007. As of mid-June 2008, there have been 50 solar water heating systems installed under this pilot program.

Q. What is HECO doing to educate the public about conserving energy and using energy efficiently?

A. HECO currently runs the Residential Consumer Energy Awareness ("RCEA") pilot program on complementary advertising and marketing to encourage the use of specific DSM energy efficiency measures such as solar water heating, EnergyStar appliances, and compact fluorescent lights. The Company also expends dollars over and above its RCEA budget to fund needed informational advertising to educate the public about energy conservation and how to use energy efficiently.

Q. Does the Company assume that it will run the RCEA program in the 2009 test year?

A. No. As explained by Mr. Alan Hee in HECO T-10, the RCEA program is one of the DSM programs that the Commission has identified for transitioning to a third-party administrator. Further, the RCEA pilot ends at the end of 2008 and the Commission will have to decide whether the program should continue.

Q. Will the Company continue to educate the public about conservation and energy efficiency through informational advertising beyond this year?

A. Yes, definitely. Even if the RCEA program is run by a third-party administrator or is terminated after this year, HECO will continue its conservation and energy efficiency informational programs and has included the associated dollars in the 2009 test year revenue requirement. The Company still has a responsibility to continue to aggressively increase customer awareness of energy efficiency and conservation measures and the importance of making such actions an everyday habit. These programs are instrumental in driving reductions in demand, which are especially critical as the Company continues to operate under tight generating reserve margins and as the Company must still achieve the required goals under the Renewable Portfolio Standards law, as well as those promulgated by the State of Hawaii Global Warming Solutions Act of 2007 and the Hawaii Clean Energy Initiative. The Company also has a responsibility to provide such information to assist customers in managing their energy costs, an expectation that is even greater during this time of rising fossil fuel prices.

Such education also directly supports the State's Energy Policy. Specifically, Section 226-18(c) of the HRS states the following:

> (c) To further achieve the energy objectives, it shall be the policy of this State to:
>
> (4) Promote cost-effective conservation of power and fuel supplies through measures including:

(A) Development of cost-effective demand-side management programs;
(B) Education; and
(C) Adoption of energy-efficient practices and technologies.

Q. Please describe how HECO would aggressively inform customers about energy efficiency and conservation measures.

A. To educate Oahu customers on the importance of conserving electricity requires a comprehensive effort. The Energy Education and Conservation Campaign is designed to reach people with multiple messages in a variety of different media. The ultimate goal is to educate Oahu consumers of electricity about energy issues and options, and ultimately help households on Oahu adopt energy efficient products and strategies. To change people's habits of energy usage requires a well-planned, sustained effort and it is important to continue the momentum built up as a result of the Company's existing successful RCEA and informational advertising efforts.

In 2009, HECO plans to deliver conservation messages across a variety of media, using a broad-based television, radio, newspaper, and magazine schedule. Themes will range from personal to global perspectives. On the personal level, energy conservation will help households save money on their electricity bills. On the global level, energy conservation will help reduce the level of greenhouse gasses, which will make Hawaii and the world a healthier place for future generations.

Q. Please further explain the transition of HECO's DSM programs to a third-party administrator.

A. Administration of the energy efficiency programs and the RCEA Program is being transitioned to a third-party administrator, with the transfer currently expected to

occur in January 2009. HECO will continue to administer the SolarSaver Pilot ("SSP"), as well as the two load management programs.

Q. Why is administration of the energy efficiency DSM Programs being transferred?

A. By Order No. 21698, issued March 16, 2005, in Docket Nos. 04-0113 and 05-0069, the Commission opened the Energy Efficiency Docket to review the DSM programs proposed by HECO in its 2005 test year rate case, and to consider DSM policies. Act 162, signed into law in June 2006, gave the Commission the authority to redirect all or a portion of the funds collected through the current electric utility demand-side management surcharge into a Public Benefits Fund, for the purpose of supporting customer DSM programs approved by the Commission. The Commission is required to appoint a fund administrator (other than an electric public utility or an electric public utility affiliate) to operate and manage any programs established under the Public Benefits Fund, and the fund administrator will be subject to Commission regulation.

On February 13, 2007, the Commission issued final D&O No. 23258 ("D&O 23258"), which authorized HECO to implement its proposed EE DSM Programs, with certain modifications, but required that the administration of all EE DSM programs be turned over to a non-utility, third-party administrator. The utilities' ability to obtain future (after 2008) electrical energy savings brought about by the use of energy efficiency technologies and electrical energy savings brought about by the use of renewable displacement or off-set technologies, including solar water heating, seawater air-conditioning district cooling systems, and solar air-conditioning, will depend on the third-party administrator, who will be supervised under its contract with the Commission, and not by the utilities.

Q. What are the implications for HECO of the change to third-party administration of the energy efficiency DSM programs?

A. HECO has a definite interest in the performance of the energy efficiency DSM programs because of their past success and future potential to reduce load and help ameliorate the Company's reserve capacity shortfall situation. As I have indicated earlier, these programs have been very successful under the Company's administration. To HECO, third-party administration of the DSM programs would mean a loss of control and greater uncertainty of how the programs will be run and what their impacts on load reduction will be. The greater uncertainty would impact the Company's resource and facilities planning. HECO would be less willing to rely on the DSM impact projections provided by an outside third party and it would likely need to implement additional contingency planning and mitigation measures in the event the third party administrator does not achieve its projected amount of load reduction.

Q. Does HECO intend to participate in the implementation of energy efficiency DSM programs as a subcontractor to potential DSM Administrators?

A. HECO is exploring a role as subcontractor with potential bidders for the PBF Administrator role. HECO has requested clarification of its possible participation as a subcontractor in its comments filed on March 27, 2008 on the draft PBF Administrator RFP. If HECO participates as a subcontractor, the costs associated with its role as a subcontractor will not be recovered through the DSM Surcharge or through base rates.

Q. What is the status of the selection of the third-party administrator?

A. The Commission opened a new docket in 2007 to select a PBF administrator and to refine details of the new market structure.

Q. Does HECO plan to offer any new demand-side management programs?

A. The Company plans to implement and administer a Dynamic Pricing Pilot Program. HECO filed an application requesting the Commission's approval of this program on April 24, 2008 (Docket No. 2008-0074).

Q. What is the Dynamic Pricing Pilot ("DPP") Program?

A. The DPP Program is a demand response program that provides peak time customer incentives, or rebates ("PTR"). A PTR program provides monetary incentives to customers for every kilowatt-hour saved during the applicable time period. The objective of this pilot is to test the effect of a demand response program on a sample of residential customers for system reliability purposes. The dynamic pricing pilot is considered to be a demand-side load management program because incentives are paid to encourage customer curtailment of load through price incentives during critical peak periods when there is insufficient generation to meet a projected peak demand period (in a manner similar to the Company's RDLC and CIDLC Programs).

Q. What is the schedule for implementing the DPP Program?

A. HECO plans to implement the DPP Program upon Commission approval. The schedule anticipates that pilot program participants would be recruited beginning in September 2008, the pilot study would begin January 2009 and end in December 2009, and an evaluation of the pilot would be completed in February 2010.

Q. What will be required to implement a full-scale DPP Program?

A. To implement a full-scale DPP Program, the Company would have to establish an Advanced Metering Infrastructure using meters capable of both collecting

time-based customer consumption data and transmitting that data wirelessly to the utility data repository for billing purposes.

Maintaining Financial Integrity

Q. As is addressed in the testimonies of Tayne Sekimura, HECO T-20, and Dr. Roger Morin, HECO T-19, one of the criteria for a "fair" rate of return is that the return should be sufficient to assure confidence in the financial integrity of the enterprise so as to maintain its credit and capital-attracting ability. What is meant by maintaining financial integrity?

A. As explained by Ms. Tayne Sekimura in HECO T-20, 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. Why is it important for the Company to maintain its financial integrity?

A. Financial integrity is important for both the Company and its ratepayers. If HECO's financial integrity is protected, the Company should be able to attract capital on reasonable terms that it needs to provide service to its customers, and should be able to attract capital under whatever economic conditions might exist at the time HECO needs to raise capital. HECO's customers can also count on the

Company providing reliable electric service in the future. HECO and its customers will ultimately benefit from this.

Q. Why must financial strength also be considered?

A. Financial strength is the ability to sell the type of securities the Company needs to sell on reasonable terms, no matter what the conditions of the financial markets. It also represents the ability of the Company to continue to meet its obligations, even under adverse conditions.

HECO's financial strength (as measured by the Company's ability to fulfill its obligations to suppliers and meet the return expectations of investors) also is key to attracting bidders for new renewable energy developments, because independent power producers ("IPPs") rely on the Company's credit in order to finance their projects.

Mr. Steven Fetter, HECO T-21, and Dr. Roger Morin, HECO T-19, elaborate on the importance of maintaining financial strength in HECO T-21. Mr. Fetter was formerly Chairman of the Michigan Public Service Commission and formerly Group Head and Managing Director of the Global Power Group within Fitch Ratings ("Fitch"), a credit rating agency. Dr. Roger Morin, is a Professor of Finance and a recognized and published expert on utility finance.

Q. What are the Company's current credit ratings?

A. In May 2007, Standard and Poor's ("S&P") downgraded HECO's corporate credit, unsecured debt and preferred stock ratings. The Company currently has corporate credit ratings of BBB by S&P and Baa1 by Moody's. The BBB rating by S&P is of particular concern because that rating puts the Company only one notch above the minimum "investment grade credit rating". A further credit rating downgrade to the "BB" category or below would categorize HECO's debt

issues as non-investment grade or "speculative grade" investments or "junk bonds".

Q. Why do IPPs rely on the Company's credit in order to finance their projects?

A. The ability of third-party project developers to finance their projects is based on their PPAs with credit-worthy purchasers of their power - the electric utilities. Thus, degradation of the utility's credit quality also would be detrimental to third-party developers of renewable energy projects.

Q. What are some of the specific current challenges that the Company faces, which make it particularly imperative that the Company improve (or at a minimum maintain) its financial strength?

A. First, the Company faces high capital requirements to maintain aging infrastructure, to add the new infrastructure necessary to reliably integrate renewable energy resources, and to establish the platform for customers to effectively manage their use of electricity. In order to raise capital at a reasonable cost, the Company needs to demonstrate the ability to repay investors at expected rates or return.

Second, the Company has significant power purchase obligations, which will increase as new and renewed purchase power contracts are completed. The Company expects to purchase approximately 42% of its energy from independent power producers ("IPPs") in 2009. Power purchase agreements ("PPAs") have been entered into based on the Company's obligations under the Public Utility Regulatory Policies Act of 1978 ("PURPA") and state laws and rules encouraging the purchase of power from non-fossil fuel producers and qualifying facilities under PURPA, and are filed with the Commission for its review and approval.

Q. HECO has received interim rate increases in September 2005 and October 2007, and recovers increases in fuel purchase energy costs due to higher fuel and purchased energy prices through its Energy Cost Adjustment Clause ("ECAC"). Have these steps enabled HECO to earn the returns found to be fair by the Commission in HECO's rate cases?

A. The Company's actual rates of return on simple average rate base and on simple average common equity as filed with the Commission have been:

	Return on Rate Base	Return on Common Equity
2005	6.20%	6.92%
2006	6.78%	7.61%
2007	4.92%	4.52%

Interim and final rates in HECO's 2005 test year rate case (Docket No. 04-0113) were based on a 8.66% rate of return on rate base ("ROR") and a 10.7% rate of return on common equity ("ROE"), and interim rates in HECO's 2007 test year rate case (Docket No. 2006-0386) were based on a 8.62% ROR and 10.7% ROE.

Q. Why have the returns that HECO has actually earned been so much lower than those used to establish rates in its recent rate cases?

A. There have been a number of reasons. First, although interim rate orders in HECO's most recent rate cases have been issued within the time frames set by law, the lag between the start of the test year and the interim rate relief has not allowed HECO the opportunity to actually earn the allowed return in the test year. Part of that is due to the timing of the rate case applications by HECO. However, even if the Company were to file its rate case at the earliest possible time allowed under the Commission's rules, as it has done in this rate case (i.e., six months before the beginning of the test year), the statutory deadline for an interim

decision would be May at the earliest (and June if the evidentiary hearing has not been held). Because of this structural lag, it would be difficult for the Company to achieve its authorized return in the test year even if it were to file its rate case application at the earliest allowed date. The Company would encourage the Commission to consider issuing its interim decision earlier than the statutory deadline if the parties are able to complete the procedural steps in time for the Commission to take such action. An early interim decision would mitigate the financial impact of the structural lag in the current rate case process.

Second, kilowatt hour sales were lower than forecast in the rate cases, resulting in insufficient revenue dollars, which deteriorated returns. Actual sales in 2005 and 2006 were less than the sales assumed in the 2005 rate case. Additionally, actual stales in 2007 were less than the sales assumed in the 2007 rate case.

Third, costs are increasing substantially faster than the revenues received to pay for those costs. In 2006, HECO received a full year of the 2005 test year interim rate increase, but still was unable to achieve its authorized returns. Likewise, in 2008, the Company will have a full year of the 2007 test year interim rate increase, but faces higher O&M than what was included in the test year revenue requirement. As long as cost increases outpace sales growth and revenues are based on sales, the Company will be in an endless cycle of catch-up, struggling to achieve a fair return on its utility property.

Q. What steps can the Company take to maintain its financial integrity?

A. Under the current regulatory structure, HECO has to manage its O&M expenses, and periodically seek general rate increases when its current rates do not provide enough revenues to cover all of its costs (including the return on investment). As

a result, there are times when HECO has to deliberately constrain spending, to the extent that it can do so without compromising reliability. However, such constraints in the level of spending can not continue for an indefinite period of time.

By way of example, HECO has constrained certain expenditures in 2008 by assigning "target" budget reductions to the various process areas, as explained by Lorie Nagata in HECO T-17. Each process area was given discretion as to how to achieve the reduction, as long as safety, reliability and service were not put at risk.

While referred to as "target adjustments", the "targets" do not represent a mandatory reduction in spending, and the Company recognizes that they may not be achieved, as the Company will do what needs to be done to provide safe and reliable service. For example, once a generating unit is opened and the overhaul is fully underway, it is possible that the length and costs of the overhaul will be longer and higher than originally budgeted.

Q. From a ratemaking policy viewpoint, if the Company has not incurred expenses in 2008 at the levels now proposed, in part due to financial constraints, why should the Company's rates set in this rate case include these costs?

A. From a ratemaking policy viewpoint, the rates should be representative of the future period when rates will be in effect. Even if the Company has not incurred expenses at the same levels in prior years, if the expenses are known and measurable, they should be included for ratemaking purposes during the period when the rates are in effect. If they are not, there will be a short fall in recovery and the Company will not have the opportunity to earn a fair rate of return on its investments from the first day the new rates are in effect.

Q. What steps are essential for HECO to actually have a realistic opportunity to earn a fair and reasonable return given the circumstances that you have described?

A. The rate relief allowed in HECO's periodic rate cases must be both adequate and timely. To be adequate, test year revenue requirements must fully reflect test year costs, as adjusted to account for known and measurable changes in the way the Company does business (for example, by reflecting the full costs of the new CIP CT-1 generating unit). To be timely, rate relief must be timed to coincide when cost increases incur (for example, when the new generating unit commences commercial operations).

In addition, HECO must be allowed to continue to flow through changes in fuel and purchased energy costs through its ECAC. Further, mechanisms that allow HECO to begin recovering substantial new or increased costs that occur between rate cases need to be implemented. An example is the REI Surcharge mechanism proposed in Docket No. 2007-0416.

Q. Please explain?

A. The Company currently faces rapidly rising O&M costs and rising capital expenditures. It is essential that cost recovery be aligned with cost incurrence if the Company is to have a realistic opportunity to actually earn the return found to be fair by the Commission, because sales are not growing and therefore cannot offset the increases in costs. If traditional rate cases do not allow cost recovery to keep up with cost increases, then new mechanisms need to be developed.

Under traditional ratemaking, utilities have to wait for rate cases to be processed to begin recovering costs incurred to install new infrastructure, which means there can be a substantial lag in recovering costs, and even substantial cost under-recovery – which can result in credit degradation and a higher cost of

capital. To help avoid this, traditional ratemaking must be supplemented with other ratemaking tools, such as mechanisms that allow cost recovery to begin as soon as new facilities go into service.

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 in HECO's 2009 test year rate case, HECO's current effective rates would result in a rate of return on average rate base (including the full cost of CIP CT-1) of 4.97% in the normalized test year. As shown in HECO T-20, a fair and reasonable rate of return on average rate base for HECO in the 2009 test year would be 8.81%. This return is based on the fair rate of return on common equity recommended in HECO T-19 of 11.25%. Thus, a 4.97% 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. What other steps can be taken to maintain the Company's financial integrity?

A. Alternative ratemaking mechanisms that delink revenues from sales, and better time cost recovery with cost incurrence should be evaluated and implemented. It is our understanding that the Commission intends to initiate a docket to investigate such mechanisms, as part of proceeding seeking to better align "utility incentives" with State policy objectives.

Q. What do you mean by "utility incentives"?

A. As others have indicated, most recently in the Hawaii Clean Energy Initiative workshops in which the energy utility industry, regulators, State and federal energy agencies, and public stakeholders participated, all regulatory structures are

inherently incentive mechanisms, since they impose obligations and costs on utilities, and dramatically impact their ability to recover costs and earn a fair return.

Q. What are examples of regulatory mechanisms intended to further the State's objective of accelerating the use of renewable resources?

A. Examples include (1) the Renewable Portfolio Standards law, which I have explained earlier in this testimony and the REI Surcharge mechanism that has been proposed to facilitate investment in the infrastructure necessary to reliably add the energy generated from renewable energy resources into electric utility grids; and Chapter 269-27.2 of the HRS, which authorizes a Firm Capacity Surcharge to allow electric utilities to begin recovering capacity payments to developers of firm renewable energy projects when the utilities begin making the payments. The Senate's Committees on Agriculture, Energy and Ocean Resources, and on Public Utilities found, in adding HRS §269-27.2(d), that, "The recovery of payments made to nonfossil fuel producers by an electric public utility will encourage the public utility to utilize the nonfossil fuel sources." Agreeing with this position, the Legislature's subsequent conference committee report stated in part: "This interim rate relief would properly compensate the electric utility in a timely manner and thereby encourage their use of nonfossil fuel generated electricity."

<u>Energy Cost Adjustment Clause</u>

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.

As Mr. Alan Hee explains in HECO T-10, 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 74% 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.

In HECO T-21, Mr. Steven Fetter, a former Chairman of the Michigan Public Service Commission and Managing Director and Group Head at the credit rating agency Fitch, Inc., states that the existence of an ECAC is a key factor for investors, and discontinuation or limitation on the scope or timeliness of such mechanism would place HECO at a competitive disadvantage in attracting capital in the current economic environment. He also points out the following:

- The presence of an ECAC is the predominant policy position among regulatory bodies across the U.S. This is especially true within the states operating under a traditional cost of service regulatory framework.
- Consideration of fuel costs in a manner that lowers uncertainty and risk represents the mainstream position on this issue across the United States. Thus, the financial community takes the presence of an ECAC as virtually a given when comparing utilities across jurisdictions for possible investment.
- It is crucial that the Commission allow HECO to continue to use an ECAC. ECACs attempt to align the costs that a utility expends for fuel and purchased power with its recovery of those costs on a timely basis. By being able to recover prudently incurred costs expeditiously, a utility lowers the risk of its operations and achieves consistency with the level of risk faced by a wide majority of other utilities within the United States, all of which are chasing the same investor funds. It is wholly consistent with rational utility economics for customers to pay the actual costs of fuel and purchased power that are procured for customers' benefit, whether those costs are in an escalating mode or actually going down.

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-19, 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. 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 incentives that will encourage utilities to engage in renewable activities, which is exactly what the Renewable Energy Infrastructure Program proposed by the Company in Docket No. 2007-0416 attempts to do,

without causing major harm to the financial health of the Company. Docket No. 04-0113, Tr. (9/16/05) at 48.

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.

1. Act 162

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 HECO's position on whether its ECAC complies with Act 162.

A. As Mr. Hee explains in HECO T-10, HECO and HELCO retained the services of Dr. Jeff D. Makholm, a Senior Vice President at National Economic Research Associates, Inc. ("NERA"), who provided testimony in the HECO 2007 test year rate case (Docket No. 2006-0386) and the HELCO 2006 test year rate case (Docket No. 05-0315) explaining the role of fuel adjustment clauses ("FACs") in utility ratemaking in the United States, and addressing the compliance of HECO's ECAC with Act 162. Mr. Makholm concluded that (1) FACs are a standard and longstanding part of U.S. 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.

In testimony in the same proceedings, Mr. Eugene T. Meehan, who also is a Senior Vice President at NERA, provided a summary in 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-20 also addresses how HECO's current ECAC mechanism complies with the requirements of Act 162.

Q. Act 162 authorizes the Commission to evaluate the ECAC from the perspective of fuel price risk-sharing between the Company and its ratepayers. What is HECO's position on the appropriate level of fuel price risk sharing in the ECAC?

A. As discussed in HECO's 2007 test year rate case, the Company's position is that the current level of ECAC fuel price risk-sharing is appropriate and that no change is necessary to the current ECAC risk-sharing approach.

The ECAC does not necessarily pass 100% of any change in fuel expenses to ratepayers. As indicated above, HECO's ability to recover its fuel expenses is subject to an efficiency factor, which measures how efficiently HECO converts fuel energy into electrical energy. If HECO cannot meet the efficiency factor embedded in the ECAC, it recovers only a portion of its fuel expenses. Thus, HECO is already at risk for the non-recovery of fuel expense and this risk profile is inherent in the currently employed ECAC mechanism.

The risk associated with meeting the efficiency factor is one that HECO can address through the overhaul and maintenance of its generating units and unit commitment schedule among others. Thus, it is reasonable for the Commission to

hold the Company responsible for not meeting the efficiency standard and for its fuel expenses to be subject to the risk of non-recovery as a result.

However, fuel prices are subject to market forces and geopolitical events that HECO cannot control. A risk-sharing mechanism which penalizes the Company because prices increase above an expected base price, even one which provides a symmetric positive incentive when prices are below the base, holds the Company financially responsible for events beyond its control. Such a risk-sharing mechanism places the Company in an untenable financial position, for which it is not compensated.

Therefore, HECO maintains that the current level of ECAC risk-sharing is appropriate, and that no change is necessary to the current ECAC risk-sharing approach.

Q. What is HECO's position on partial pass-through versus full pass-through of fuel and purchased energy costs?

A. HECO maintains that partial pass-through of fuel and purchased energy costs is not a viable option for Hawaii. Partial pass-through mechanisms and their impact on utility financial health were discussed in a study conducted by NERA in a *Report on Power Cost Adjustments and Hedging Fuel Risks* that was forwarded to the Commission in Docket No. 2006-0386 (HECO's 2007 Test Year Rate Case) on December 29, 2006. In that study, NERA concluded:

1) Some states, e.g., Arizona, Colorado, Idaho, and Washington, have adopted partial pass-through mechanisms. These are not "risk sharing" mechanisms because the utility is a price taker.

2) These partial pass-through states actually represent a broad movement towards less risk imposed on the utilities. For example, Idaho Power had

been subject to a zero pass-through and moved toward a 90% pass-through.

3) Oil generally plays an insignificant role in these utilities' generation mix. These utilities typically get most of their power from hydro, nuclear, and coal.

The study concludes that a well established, frequently updated FAC is essential to maintain a utility's credit and operational viability. Sharing of the risk of oil price fluctuations between customers and shareholders is not good regulatory policy when the utility has no control over world oil markets. Such sharing would not exempt consumers from ultimately having to pay the full amount for their power usage, (assuming that the utility can defer the recovery of costs not passed through a FAC to a future rate case) and thereby harm the utility's financial position.

Q. How prevalent are 100% full pass-through fuel adjustment clauses in the United States?

A. They are very prevalent. In HECO T-10, Mr. Hee reports that in March 2008 HECO requested NERA to conduct a survey of all 50 states and the District of Columbia to determine to what extent FAC mechanisms were used in the United States.

Q. What was the result of the survey?

A. The survey found that thirty-three (33) traditionally regulated states incorporate FAC mechanisms into their regulation of electric utilities. Of those 33 states twenty-two (22) states allow 100% pass through of fuel and power costs (including Hawaii, which is subject to an energy efficiency factor), as shown in

HECO-1041. Thus, Hawaii is not the only state which allows full pass-through of fuel and purchased energy costs.

Q. Why do eighteen (18) states (including the District of Columbia) not have FAC mechanisms?

A. Adjustment clauses in fifteen (15) of those 18 states are not applicable because the utilities there are typically restructured, distribution-only, utilities that do not have their own generation. Thus, those utilities do not need a FAC. These distribution-only utilities pass on the full cost of generation to customers in the cost of the electricity that the customers purchase from producers. Two additional states, Nebraska and Alaska, are public power states where there are no investor-owned utilities. Finally, Utah is an investor-owned utility, that has not restructured, that does not have a FAC. It recovers its fuel costs through temporary rate increases.

Q. Of the 33 states that have FACs, 22 states have 100% pass-through of fuel and power costs. Please briefly describe the FACs in the remaining eleven (11) states.

A. The FACs in the remaining 11 states utilize some form of dead-bands, sharing, or caps on fuel cost pass-through. The primary source of fuel in these states is either coal or hydro[10]. Coal is generally secured under long-term contracts and exhibit less volatility than oil or natural gas. Hydroelectric power has low marginal costs. Thus, in those states using primarily coal or hydro, the change in costs of generation are low relative to states that use oil or natural gas. Therefore, 100% pass-through does not have the financial significance in those states that it does in Hawaii.

[10] The exception is Arizona, which has a mix of coal, nuclear, and natural gas.

Q. What would be the impact on HECO if the pass-through in the change in the cost of power is limited to 80%, 90%, or 95%?

A. In HECO T-10, Mr. Hee demonstrates that limiting the change in the cost of power to 80%, 90%, or 95% would decrease HECO's test year 2009 ECA revenues at current effective rates by approximately $110,600,000, $55,300,000, or $27,600,000, respectively, as shown in HECO-1042. Had the limitation been in effect it would have resulted in severe financial hardship for the utility.

In HECO T-20, Ms. Tayne Sekimura states that any modification to the existing ECAC to include 80%, 90%, or 95% of the fuel and purchased energy costs would result in an increase in investors' risks associated with fuel and purchased energy. This increase in risks would require an increase in investor compensation through a higher cost of capital for bearing the increased risks. Customers would ultimately bear the higher costs for this increase in cost of capital. Further, the financial strength of the utility as the off-taker of IPP renewable energy is a critical criterion that supports financing of renewable energy projects. The presence of the ECAC contributes significantly to the financial strength of the Company, which in turn makes finding financing by renewable energy developers more likely. If the ECAC was changed from a full pass-through to a partial pass-through mechanism, the financial health of the Company would be undermined and this would make financing for renewable energy projects in the state more difficult.

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.

Helping Customers Manage Their Electricity Use and Bills

Q. What has HECO done to help customers manage their electricity usage and bills?

A. HECO has aggressively implemented energy efficiency demand-side management ("DSM") programs since 1996. These programs have helped our customers save over 568 gwh of energy annually from measure installed between 1996 through 2007[11]. The Company has also engaged in extensive conservation informational advertising which I have covered at length earlier in this testimony. Below I will describe two other items that the Company is or will be proposing to help customer manage their usage and bills: rate initiatives and AMI

1. Rate Initiatives

Q. Is HECO proposing time-of-use ("TOU") rates for residential and commercial customers?

A. Yes.

Q. What is proposed for residential time of use rates?

A. With the approval of final rates in the HECO test year 2005 rate case on June 20, 2008, HECO now has a Schedule TOU-R Residential Time-of-Use Service option for residential customers. For the test year 2009, HECO proposes to modify the Schedule TOU-R to make it simpler and easier to use: the proposed Schedule TOU-R has two daily energy use periods, one on-peak and one off-peak; the proposed on-peak hours are short enough in duration to widen opportunities for residential customers to shift energy consumption to off-peak hours to create bill savings.

Q. How can commercial customers use these rate options to create bill savings?

[11] Assuming that all measures remain in service.

A. Commercial customers can use these rate options to create bill savings by changing their energy consumption patterns. To the extent that a commercial customer can shift energy consumption from priority peak hour or mid-peak hour usage to the off-peak hours, that customer could potential realize bill savings from service under one of these rate options.

Q. Will the new Customer Information System ("CIS") help the Company in calculating complex billing structures and pricing programs (e.g., TOU rates)?

A. Yes. As discussed by Mr. Darren Yamamoto in HECO T-9, HECO's existing legacy CIS (called ACCESS) does not fully support calculating complex customer bills. In contrast, the new CIS will have this capability and provide other features and capabilities.

2. Advanced Metering Infrastructure

Q. In discussing the DPP Program, you indicated that to implement a full-scale program, the Company would have to establish an AMI. What is AMI and how can it enhance customers' ability to understand and manage their energy usage?

A. AMI refers to systems that measure, collect and analyze energy usage, from advanced devices such as electricity meters, gas meters, and/or water meters, through various communication media on request or on a pre-defined schedule. This infrastructure includes hardware, software, communications, customer associated systems and meter data management software. AMI provides two-way communications between the utility and customer meters to allow utilities to obtain consumption reads, energized states, and voltage status at individual premises much more frequently than the monthly billing cycle, as well as "on demand."

The network between the measurement devices and business systems allows collection and distribution of information to customers, suppliers, utilities and service providers. This enables them to either participate in, or provide, demand response solutions, products and services. By providing information to customers, the system assists a change in energy usage from their normal consumption patterns, either in response to changes in price, or in response to incentives designed to encourage lower energy usage use at times of peak-demand periods or higher wholesale prices, or during periods of low operational systems reliability.

Q. What is the Company doing to implement AMI?

A. The Company is moving toward a full-scale advanced metering infrastructure ("AMI") project roll-out following approval of its AMI application, which the Company expects to file in the second half of 2008.

Q. Has the Company conducted any pilot projects with respect to AMI in order to facilitate the full-scale deployment of AMI in Hawaii?

A. Yes. HECO has conducted three pilot AMI projects using Research and Development ("R&D") funding: (1) an initial investigation into the functionality of Sensus' FlexNet technology with 500 AMI meters on Oahu and two Tower Gateway Basestation ("TGB") sites in Waikiki and Salt Lake; (2) an investigation into the ability of Sensus' FlexNet technology to collect data reliably for billing purposes in three meter reading routes, involving 3,120 residential and commercial meters in the Ocean Pointe area along with a third TGB tower at Mauna Kapu; and (3) the addition of two more TGB sites at Koko Head and Pu'u Papa'a, involving approximately 400 residential meters to support AMI meters in the collection of baseline electricity profiles to support a Critical Peak Pricing/Peak Time Rebate pilot program. HECO is continuing to evaluate,

develop and demonstrate AMI as a component of their on-going R&D study. Additional details regarding the R&D study and its costs are provided by Mr. Bruce Tamashiro in HECO T-14.

Q. What is the Company currently doing to develop its AMI project?

A. Through its AMI group, HECO and its AMI consultant have been working with (1) Sensus Metering Systems to plan the project's two-way, wireless communications networks ("Networks") and the purchase of advanced, solid state meters, (2) possible vendors for a centralized meter data management system ("MDMS") and other related technologies, and (3) MECO and HELCO to develop and coordinate plans for their commercial deployment of AMI. In connection with this effort, HECO estimates that the Companies' expenses for the AMI project in 2008 and 2009 will be $2.93 million ($1.8 million for HECO, $0.57 million for MECO and $0.56 million for HELCO). This projection includes the labor and outside services costs for project management, preliminary engineering, and regulatory support for the AMI application to the Commission. See Mr. Robert Young's testimony in HECO T-8.

Q. Have other utilities implemented AMI?

A. Yes. The implementation of AMI is being driven by significant developments in the evolution and availability of AMI-related technologies, AMI's increasing popularity on the U.S. mainland, and drastic worldwide increases in the cost of fuel. AMI has – particularly in recent years – received wide support at both federal and state levels. In line with this support, AMI has also been proposed in the Companies' RPS/REIP dockets as a Renewable Energy Infrastructure Project under the Proposed Renewable Energy Infrastructure Program.

Q. What benefits can AMI provide for the utility and its customers?

A. The benefits of AMI can generally be broken down into two types: (1) operational benefits directly attributable to the AMI system (e.g., labor savings, meter accuracy gains and energy theft reduction); and (2) customer and system benefits derived from programs that the AMI system supports or provides a platform for developing (e.g., customer service, demand response, distribution asset utilization and outage management), which give customers increased flexibility and satisfaction while empowering them to make wiser energy choices.

Q. How does AMI relate to demand response?

A. In conjunction with a future demand response program, AMI will empower the Companies' customers to reduce and/or shift energy usage in response to time-differentiated energy prices. Further, demand response technologies, such as smart programmable/controllable thermostats, smart load cycling controls, in-premise displays, etc., can allow customers to execute their choices conveniently.

AMI communication and smart metering infrastructure also provides a foundation for the implementation of Smart Grid technology, which combines intelligent electronic devices (i.e., smart relays and distribution automation devices) and advanced applications that utilize timely data on customer loads and voltages through AMI and potential load reductions through demand response. It provides unparalleled capabilities in monitoring, controlling, optimizing and automating the restoration of the electric power delivery system. Thus, AMI and demand response together offer important alternatives, in addition to renewable energy, to help address global energy supply and environmental issues.

Q. What are the Company's plans to introduce AMI?

A. The AMI project will consist of replacement of approximately 90% of the commercial, industrial, and residential electric meters with advanced, solid state meters that collect and transmit real-time data on demand and energy use. The AMI project will also include MDMS and Networks to provide communications between the advanced meters and the MDMS. AMI meters and communications networks would be installed on the islands of Oahu, Maui and Hawaii, and a shared MDMS will be centrally located at HECO.

HECO currently plans to file an application for approval of a full-scale AMI project in the second half of 2008. Depending on the time required to obtain approval of the project and the related accounting and cost recovery mechanisms necessary to finance the project, the Company would go forward with installation of a MDMS and the Networks, and also the installation of advanced meters on Oahu over a three-year period, to be followed by installation of advanced meters on the islands of Maui and Hawaii

SUMMARY

Q. Please summarize your testimony.

A. HECO's total requested increase in revenues is $97,011,000, or 5.2%, over revenues at current effective rates (which include revenues from the interim rate increase surcharge) for the normalized 2009 test year (using April 2008 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 $174,348,000 for the normalized 2009 test year (using April 2008 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:	Executive Vice President Public Affairs	
Years of Service:	7	
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:	1995-2001	First Hawaiian Bank Executive Vice President & 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

Previous Positions: (continued)	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, 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

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

Catholic Charities Hawaii – Board of Directors

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. 2008-0083
	)	
For Approval of Rate Increases and	)	
Revised Rate Schedules and Rules	)	
	)	

APPLICATION
and
CERTIFICATE OF SERVICE

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BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF HAWAII

----------In the Matter of the Application of----------)		
HAWAIIAN ELECTRIC COMPANY, INC.	)	Docket No. 2008-0083
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", "HECO" or "Company") 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 $97,011,000, or 5.2%, 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 interim rate increase that the Commission approved on June 20, 2008 in its Order Granting Hawaiian Electric Company, Inc.'s Motion to Adjust Interim Increase Filed on May 21, 2008 in HECO's 2007 test year rate case (Docket No. 2006-0386).

If revenues from the interim rate increase are excluded, the requested relief over the resulting revenues (i.e., revenues at present rates) would be $174,348,000.

The requested increase is based on estimated total revenue requirements of $1,964,401,000 for the normalized 2009 test year, based on April 2008 fuel oil and purchased energy prices and an 8.81% rate of return on HECO's rate base including the full cost of the Campbell Industrial Park ("CIP") Combustion Turbine Unit 1 ("CT-1").

HECO requests the revenue increase in three steps to more closely match cost recovery with cost incurrence:

Step Increase	Amount ($1,000)	Effective Date
1) Interim Increase	$73,064	On or before May 3, 2009
2) CIP CT-1 Step Increase	$23,947	At the in-service date of CIP CT-1 (scheduled for July 31, 2009)
3) Final Increase	Balance	Final Decision and Order
Total Rate Increase	$97,011	

1. Interim Increase – a revenue increase (based on the Company's revenue requirement exclusive of the 2009 CIP CT-1 Generating Unit costs[1]) to which the Commission determines 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.").[2]

[1] The interim increase includes certain 2008 plant additions associated with the CIP CT-1 project. See HECO-1703.
[2] If the Commission rejects the CIP CT-1 Step Increase, it should approve an interim increase of $85,189,000 as shown on HECO-2303 rather than $73,064,000. The interim increase of $85,189,000 (referred to as "Base Case" in the Company's testimonies in this proceeding) includes the 2009 CIP CT-1 plant additions (net of deferred income taxes) in the end of test year rate base balance but not in the beginning of test year rate base balance.

2. CIP CT-1 Step Increase – a revenue increase based on the return on investment (net of accumulated deferred income tax and investment tax credit impacts) of the CIP CT-1 generating unit and recovery of the associated on-going production operation and maintenance ("O&M") expenses, employee benefits and payroll taxes. The CIP CT-1 Step Increase is equal to the difference between the revenue requirement of $1,964,401,000 (HECO-2301) reflecting the full cost of the CIP CT-1 (with the net investment of CIP CT-1 in both the beginning and end of test year balances) and the revenue requirement of $1,940,454,000 (HECO-2302) which is exclusive of the cost of CIP CT-1. HECO anticipates that CIP CT-1 will go into service on July 31, 2009 and requests the CIP CT-1 Step Increase to be effective on the in-service date.

3. 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 Increase or the CIP CT-1 Step Increase.

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 these revenues and the associated costs from the 2009 test year because Decision and Order No. 23258 in Docket No. 05-0069 (the Energy Efficiency Proceeding) ordered the transition of all of the HECO Companies' energy efficiency DSM programs to a non-utility market structure by January 1, 2009. Under the non-utility market structure, the Commission would appoint a public benefits fund administrator to administer the DSM programs. The HECO Companies' load

management programs are excluded from the third-party administrator's area of responsibility.

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 current effective revenues at all rate schedules.

Applicant further requests that the Interim Increase and the CIP CT-1 Step Increase implemented prior to the final step be structured as surcharges for the various classes based on a cents per kilowatt-hour charge derived separately for each rate class as the dollar increase allocated to the class divided by the class test year sales.

As shown in HECO-2301, the requested revenue increase of $97,011,000 over current effective rates represents a 5.2% increase over revenues at HECO's current effective rates for the normalized 2009 test year (based on April 2008 fuel oil and purchased energy prices and a rate of return on rate base of 8.81%). As shown in HECO-2304, the amount of the increase over revenues based on present rates, which exclude revenues from the interim surcharge, is $174,348,000, or 9.7%, for the normalized 2009 test year (based on April 2008 fuel oil and purchased energy prices and a rate of return on rate base of 8.81%). 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 2009 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
Manager, Regulatory Affairs
Hawaiian Electric Company, Inc.
P. O. Box 2750
Honolulu, Hawaii 96840-0001

and

Thomas W. Williams, Jr., Esq.
Peter Y. Kikuta, Esq.
Damon L. Schmidt, 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 $333,333,333), 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 $933,333,333 for Common Stock and Cumulative Preferred Stock.

As of March 31, 2008, 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 2003-2007 and the common stock balance at the end of each of those years is as follows:

Year	Dividends Paid	Common Stock Balance
2007	$27,084,000	$85,387,140
2006	29,381,000	85,387,140
2005	50,895,000	85,387,140
2004	11,613,000	85,387,140
2003	57,719,000	85,387,140

As of March 31, 2008, 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 2003-2007 and the preferred stock balance at the end of each of those years is as follows:

Year	Dividends Accrued	Preferred Stock Balance
2007	$1,079,907	$22.293,140
2006	1,079,907	22,293,140
2005	1,079,907	22,293,140
2004	1,079,907	22,293,140
2003	1,079,907	22,293,140

As of March 31, 2008, HECO had outstanding $31,546,400 in Junior Subordinated Deferrable Interest Debentures ("QUIPs") hybrid securities. Details concerning the QUIPs are on file with the Commission under various dockets as set forth in HECO-103 and are incorporated herein by reference.

As of March 31, 2008, HECO had outstanding $551,580,000 in obligations to the State of Hawaii for the repayment of Special Purpose Revenue Bonds, of which $7,599,100 remained on deposit with trustee. 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 March 31, 2008, HECO had no outstanding borrowings from its parent, HEI, or from Hawaii Electric Light Company, Inc. ("HELCO"), but had outstanding $500,000 of short-term borrowing from Maui Electric Company, Limited ("MECO"), and $89,108,448 of short-term borrowings from non-affiliates.

During 2007, HECO accrued $2,050,516 in interest on QUIPs, $28,650,758 in interest on Special Purpose Revenue Bonds, $75 on borrowings from HEI and $148,498 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-2018 and is incorporated herein by reference.

VI

HECO's audited financial statements for the year ended December 31, 2007 (audited by KPMG LLP) are included in HECO's and HEI's Securities and Exchange Commission ("SEC") Form 8-K dated February 21, 2008, which was routinely filed with the Commission on March 4, 2008, and are incorporated herein by reference.

HECO's unaudited balance sheet as of March 31, 2008, and unaudited income statement and statement of retained earnings for the three months ended March 31, 2008, are attached hereto as HECO-102. The unaudited income statement for the period from January 1, 2008 to May 31, 2008 and the balance sheet as of May 31, 2008 were filed with the Commission on June 27, 2008 and are incorporated herein by reference.

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 March 31, 2008 balance sheet, as well as in the written direct testimonies and exhibits filed herewith.

HEI's 2007 Summary Report to Shareholders, including Appendix A, and its SEC Form 10-K report for the year ended December 31, 2007, were routinely filed with the Commission on April 1, 2008, and March 4, 2008, respectively, and are incorporated herein by reference. HEI's latest Proxy Statement (dated March 26, 2008) is attached hereto as HECO-104.

VII

HECO's current effective rates are the result of its existing "base" rates, plus the $77,867,000 interim rate increase approved in HECO's pending 2007 test year rate case (Docket No. 2006-0386). HECO's existing base rates are the result of the Commission's Final Decision and Order No. 24171 issued May 1, 2008, in Docket No. 04-0113, which utilized a 2005 test year, and include standby service rates that the Commission approved on May 15, 2008 in Docket No. 2006-0497. In addition, the current effective rates include the surcharges on Sheet No. 50.4 of HECO's Tariff resulting from the interim rate increase approved by the Commission on June 20, 2008 in its Order Granting Hawaiian Electric Company, Inc.'s Motion to Adjust Interim Increase Filed on May 21, 2008 in Docket No. 2006-0386. As of the date of this filing, the final decision and order for Docket No. 2006-0386 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 Table of Contents, Rule No. 7, and rate schedules are set forth in HECO-105, which is attached hereto.

HECO-106 sets forth HECO's proposed Table of Contents, Rule No. 7, and rate schedules. The proposed revisions to HECO's rate schedules are described in HECO T-22, and the exhibits and workpapers thereto, which are incorporated herein by reference. HECO's proposed Table of Contents and proposed Rule 7 reflects HECO's proposal to increase the returned payment charge from $16.00 to $22.00 per returned

check or returned payment as described in HECO T-22 (this proposal originated in HECO's 2007 test year rate case, Docket No. 2006-0386).

The proposed rate increases by rate classes for the normalized 2009 test year are shown in HECO-108. This exhibit shows revenues at current effective rates, and the total increase requested in terms of dollars and by percentage. As shown on HECO-108, 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 $174,348,000 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 2009 test year are shown in HECO-107.

A summary of HECO's estimated earnings on its average rate base (including the full cost of CIP CT-1) at present rates for the normalized 2009 test year is shown in HECO-109. A summary of HECO's estimated earnings on its average rate base (including the full cost of CIP CT-1) at current effective rates for the normalized 2009 test year is shown in HECO-110. 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, Alternative Ratemaking Structures and Summary), have been prepared on a consistent basis reflecting normalized conditions, and are shown in HECO-2301 through HECO-2306, which are incorporated herein by reference.

The recorded results of operations for calendar year 2007 were filed with the Commission on March 4, 2008 and are incorporated herein by reference. The latest publicly available recorded results of operations for the 12 months ending December 31, 2007 were filed with the Commission on March 4, 2008 and are incorporated herein by reference.

Significant projected changes since December 31, 2007 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-16, 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 May 1, 2008, HECO filed a Notice of Intent to file a general rate increase application, at which time the rate case was assigned Docket No. 2008-0083. 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, Alternative Ratemaking Structures 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 (including the full cost of CIP CT-1) would be 4.97% for the normalized 2009 test year, as compared to the 8.66% authorized by the Commission in Docket No. 04-0113 for test year 2005, and the 8.81% justified in this docket. At present rates (i.e., if revenues from the interim increase in Docket No. 2006-0386 are not considered), HECO's rate of return on its average rate base (including the full cost of CIP CT-1) is estimated to be 1.92% for the normalized 2009 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 $174,348,000 over present rates (or $97,011,000 over current effective rates) for the normalized 2009 test year (based on April 2008 fuel oil and purchased energy prices and a rate of return on rate base of 8.81%), 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, determines 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 CIP CT-1 Step Increase to be effective on the in-service date of CIP CT-1;

6. That the Commission approve a Final Increase (which would incorporate the Interim Increase), such that the combined impact of the Interim, CIP CT-1 Step and Final Increases yields the requested revenue increase of $174,348,000 over present rates (or $97,011,000 over current effective rates) for the normalized 2009 test year (based on April 2008 fuel oil and purchased energy prices and a rate of return on rate base of 8.81%);

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

DATED: Honolulu, Hawaii, July 3, 2008.

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 3rd day of July, 2008.

DEBORAH ICHISHITA NOTARY 04-409 PUBLIC STATE OF HAWAII

Deborah Ichishita
Notary Public, State of Hawaii

My commission expires: JUL 18 2008

Doc. Date: 7/3/08 # Pages: 5,532
Name: DEBORAH ICHISHITA First Circuit
Doc. Description Application, Written Direct Testimonies, Exhibits, Workpapers & Certificate of Service.
Signature Date 7/3/08
NOTARY CERTIFICATION

CERTIFICATE OF SERVICE

I hereby certify that on July 3, 2008, 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:

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

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

DATED: Honolulu, Hawaii, July 3, 2008.

HAWAIIAN ELECTRIC COMPANY, INC.

Lyndon Haack

Hawaiian Electric Company, Inc.
BALANCE SHEET
(Unaudited)
As of March 31, 2008

UTILITY PLANT AT COST :	
In Service :	
Land	$ 25,755,926
Plant and Equipment	2,520,856,800
Utility Plant in Service	2,546,612,726
Property Held for Future Use	3,592,519
Construction Work in Progress	114,743,038
Less Accumulated Provision for Depreciation	(998,826,007)
Net Utility Plant	1,666,122,276
Other Property:	
Non-Utility Property	6,474,306
Less Accumulated Provision for Depreciation	(1,075,329)
Net Other Property	5,398,977
Investment in wholly-owned subsidiaries	419,097,444
CURRENT ASSETS :	
Cash	10,494,778
Notes Receivable from Associated Companies	43,000,000
Customer Accounts Receivable	103,131,093
Less Allowance for Uncollectible Accounts	(500,985)
Net Customer Accounts Receivable	102,630,108
Accrued Unbilled Revenues, net	77,175,607
Other Accounts Receivable, net	5,558,355
Fuel Oil Stock, at Average Cost	74,032,710
Construction & Operating Materials & Supplies, at Average Cost	17,028,853
Other	5,820,710
Total Current Assets	335,741,121
OTHER ASSETS	
Regulatory Assets	209,195,068
Unamortized Debt Expense	10,354,736
Other	24,955,982
Total Other Assets	244,505,786
TOTAL ASSETS	$ 2,670,865,604

Hawaiian Electric Company, Inc.
BALANCE SHEET
(Unaudited)
As of March 31, 2008

CAPITALIZATION :		
Common Stock Equity		
Common Stock @ $6 2/3 Par Value	$	85,387,140
Premium on Capital Stock, net of Capital Stock Expense		299,213,830
Retained Earnings		735,199,996
Accumulated Other Comprehensive Income, Net of Income Taxes		1,214,315
Total Common Stock Equity		1,121,015,281
Cumulative Preferred Stock of $20 Par Value		22,293,140
Total Stockholders' Equity		1,143,308,421
QUIDS		31,546,400
Long-Term Debt		
Revenue Bonds, net of discount, and Less Funds on Deposit with Trustee		542,935,821
Total Capitalization		1,717,790,642
CURRENT LIABILITIES		
Borrowings from non-affiliates		89,108,448
Borrowings from affiliates		500,000
Accounts Payable		96,136,161
Payable To Associated Companies		700,372
Customer Deposits		7,438,595
Customer Advances		920,687
Taxes Accrued		92,135,452
Interest and Preferred Dividends Payable		11,102,909
Other		27,443,883
Total Current Liabilities		325,486,507
DEFERRED CREDITS		
Deferred Income Taxes		126,547,792
Unamortized Tax Credits		32,748,735
Regulatory Liabilities		186,031,247
Other		106,434,371
Total Deferred Credits		451,762,145
CONTRIBUTIONS IN AID OF CONSTRUCTION		175,826,310
TOTAL CAPITALIZATION & LIABILITIES	$	2,670,865,604

Hawaiian Electric Company, Inc.
STATEMENT OF INCOME
(Unaudited)
For the Three Months Ended March 31, 2008

OPERATING REVENUES		
Electric Revenues	$	413,309,858
Other		1,202,581
Total Operating Revenues		414,512,439
OPERATING EXPENSES		
Production		
Fuel Oil		172,152,455
Purchased Power		99,779,369
Other Production		7,366,747
Transmission and Distribution Operations		3,874,152
Maintenance		15,276,012
Customer Accounts & Customer Service		8,606,449
Administrative and General		18,121,706
Depreciation		20,551,829
Taxes, Other Than Income Taxes		38,447,534
Tax Credits, Deferred, Net		263,862
Income Taxes		9,230,252
Total Operating Expenses		393,670,367
OPERATING INCOME		20,842,072
OTHER INCOME AND DEDUCTIONS		
Allowance for Equity Funds Used During Construction		1,501,709
Equity in Earnings of Subsidiaries		9,300,605
Other		1,410,820
Total Other Income & Deductions		12,213,134
INTEREST CHARGES		
Interest on Long-Term Debt		7,524,935
Amortization of Net Bond Premium & Expense		399,505
Other Interest Charges		861,608
Allowance for Debt Funds Used During Construction		(585,360)
Total Interest Charges		8,200,688
NET INCOME		24,854,518
Preferred Stock Dividends		269,977
NET INCOME FOR COMMON STOCK	$	24,584,541

Hawaiian Electric Company, Inc.
STATEMENT OF RETAINED EARNINGS
(Unaudited)
For the Three Months Ended March 31, 2008

Retained Earnings, Beginning of Period	$	724,704,455
Net Income for Common Stock		24,584,541
Common Stock Dividends		(14,089,000)
Retained Earnings, End of Period	$	735,199,996

Hawaiian Electric Company, Inc.

DETAILS OF OUTSTANDING ISSUES OF
PREFERRED STOCK, HYBRID SECURITIES
AND OTHER LONG-TERM DEBT
FOR INCORPORATION BY REFERENCE
As of March 31, 2008

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 3/31/08		$ 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 March 31, 2008

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
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
2007	4.65% Series 2007A due 2037	100,000,000	05-0330 12/29/2005	23292 3/9/2007
2007	4.60% Refunding Series 2007B due 2026	62,000,000	2006-0383 9/21/2006	23100 12/4/2006
TOTAL OUTSTANDING 3/31/08		$ 551,580,000		

Hawaiian Electric Company, Inc.

DETAILS OF OUTSTANDING ISSUES OF
PREFERRED STOCK, HYBRID SECURITIES
AND OTHER LONG-TERM DEBT
FOR INCORPORATION BY REFERENCE
As of March 31, 2008

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 3/31/08		$ 31,546,400		

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

Constance H. Lau
President and
Chief Executive Officer

March 26, 2008

Dear Fellow Shareholder:

On behalf of the Board of Directors, it is my pleasure to invite you to attend the Annual Meeting of Shareholders of Hawaiian Electric Industries, Inc. (HEI). The meeting will be held on HEI's premises in Room 805 on the eighth floor of the American Savings Bank Tower in Honolulu, Hawaii on May 6, 2008, at 9:30 a.m., local time. A map showing the location of the meeting site appears on page 66 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 2007 and their impact on you and HEI. Officers and Board members will be available before and after the meeting to talk with you and answer questions.

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.

The Board and management team of HEI would like to express their appreciation to you for your confidence and support. I look forward to seeing you at the Annual Meeting in Honolulu.

Sincerely,

Constance H. Lau

Recycled

Hawaiian Electric Industries, Inc.
900 Richards Street
Honolulu, Hawaii 96813

NOTICE OF ANNUAL MEETING

Date and Time

Tuesday, May 6, 2008, at 9:30 a.m., local time.

Place

American Savings Bank Tower, 1001 Bishop Street, 8th floor, Room 805, Honolulu, Hawaii 96813.

Items of Business

1. Elect five Class III directors.
2. Ratify appointment of KPMG LLP, as HEI's independent registered public accounting firm.
3. Approve the 1990 Nonemployee Director Stock Plan, as amended and restated.
4. Approve the 1987 Stock Option and Incentive Plan, as amended and restated.
5. Transact any other business properly brought before the meeting.

Proxy Record Date

February 27, 2008.

Annual Report

The 2007 Annual Report to Shareholders (Appendix A) and Summary Report to Shareholders, which are not a part of the proxy solicitation materials, have been mailed or made available electronically 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.

Important Notice Regarding the Availability of Proxy Materials for the Shareholders Meeting to Be Held on May 6, 2008

The proxy statement, annual report, and summary report to shareholders are at www.hei.com/proxymatl.html

By Order of the HEI Board of Directors.

March 26, 2008

Patricia U. Wong
Vice President-Administration and Corporate Secretary

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Proxy Statement

HEI is soliciting proxies for the Annual Meeting of Shareholders scheduled for May 6, 2008 at 9:30 a.m., local time, at the American Savings Bank Tower, 1001 Bishop Street, 8th floor, Room 805, Honolulu, Hawaii. The mailing address of the principal executive offices of HEI 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, 2007, is March 26, 2008. 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 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 HEI 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 HEI 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 five Class III directors for a three-year term expiring at the 2011 Annual Meeting of Shareholders.
- Ratification of appointment of KPMG LLP as HEI's independent registered public accounting firm.
- Approval of the Amended and Restated 1990 Nonemployee Director Stock Plan.
- Approval of the Amended and Restated 1987 Stock Option and Incentive Plan.

Voting Procedures

Who is eligible to vote?

Only shareholders of record at the close of business on February 27, 2008 (the proxy record date) are entitled to vote.

How many shares are outstanding and entitled to vote?

On February 27, 2008, 83,580,279 shares of HEI Common Stock were outstanding. Each shareholder is entitled to one vote for each share held. Under the Bylaws of HEI, 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 5, 2008, 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 5, 2008, 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 ratification of the independent registered public accounting firm) under New York Stock Exchange rules. However, your broker or nominee will not be able to vote your shares on the other proposals to be presented at the Annual Meeting without instructions and the Board of Directors requests and encourages you to provide instructions on these matters.

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 or the HEI Retirement Savings Plan?

If you own shares held in the Dividend Reinvestment and Stock Purchase Plan or the HEI Retirement Savings Plan (including shares previously received under the Tax Reduction Act Stock Ownership Plan), the respective plan trustees will vote the shares of stock held in these Plans according to your directions. For both Dividend Reinvestment and Stock Purchase Plan and HEI Retirement

Savings Plan, the respective trustees will vote all the shares of HEI 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 Corporate Secretary of HEI in writing; or
- vote in person at the Annual Meeting (if your shares are registered directly on HEI's books or, if your shares are held in "street name" and 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,
- appointment of HEI's independent registered public accounting firm shall be ratified if more votes are cast in favor than against, and
- The Amended and Restated 1990 Nonemployee Director Stock Plan and the Amended and Restated 1987 Stock Option and Incentive Plan shall be approved if a majority of the votes cast are in favor of the amendments and, in the case of the Amended and Restated 1990 Nonemployee Director Stock Plan, the total votes cast on the proposal represent 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 ratification of the appointment of HEI's independent registered public accounting firm. Abstentions and broker nonvotes will not affect the outcome of the proposals to approve the Amended and Restated 1990 Nonemployee Director Stock Plan or the Amended and Restated 1987 Stock Option and Incentive Plan, unless, in the case of the Amended and Restated 1990 Nonemployee Director Stock Plan, 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.

Could other matters be decided at the Annual Meeting?

HEI knows of no business to be presented at the 2008 Annual Meeting other than the items set forth in this proxy statement. If other business is properly brought before the Annual Meeting, or any adjournment thereof, the persons named on the enclosed proxy will vote your stock in accordance with their best judgment, unless authority to do so is withheld by you in your proxy.

What happens if the Annual Meeting is postponed or adjourned?

If the Annual Meeting is postponed or adjourned, your proxy will still be good and may be voted at the postponed or adjourned meeting. You will still be able to change or revoke your proxy until it is voted at the Annual Meeting.

Proposals You May Vote On

1. Election of Class III Directors

The Board of Directors currently consists of 13 directors divided into three classes with staggered terms so that one class of directors must be elected at each Annual Meeting.

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

- Don E. Carroll
- Richard W. Gushman, II
- Victor H. Li
- Bill D. Mills
- Barry K. Taniguchi

Mr. Gushman, who joined the Board in June 2007, is being proposed for election to the Board by the shareholders for the first time. His nomination was recommended by nonmanagement directors.

Each nominee is currently a member of the Board and has consented to serve for the new term expiring at the 2011 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 III DIRECTORS.

Detailed information on each nominee and Class I and II directors is provided on pages 16-18.

2. Ratification of appointment of Independent Registered Public Accounting Firm

KPMG LLP, an independent registered public accounting firm, has been the auditor of HEI since 1981. The Audit Committee selected KPMG LLP as HEI's independent registered public accounting firm for 2008. The Board, upon the recommendation of its Audit Committee, recommends the ratification of KPMG LLP as the independent registered public accounting firm of HEI for fiscal year 2008 and thereafter until its successor is appointed. 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 AND THE AUDIT COMMITTEE RECOMMEND THAT YOU VOTE FOR THE RATIFICATION OF KPMG LLP AS THE INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM OF HEI.

3. Approval of the proposed Amended and Restated 1990 Nonemployee Director Stock Plan

The 1990 Nonemployee Director Stock Plan, as previously amended, provides nonemployee directors with incentives to improve HEI'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, the Board has amended the Nonemployee Director Stock Plan, subject to your approval of this proposal, as follows: (a) increase the annual stock award from 1,400 shares to 1,800 shares, (b) reflect the change in jurisdiction over director compensation from the Nominating and Corporate Governance Committee to the Compensation Committee, (c) reserve an additional 75,000 shares of HEI Common Stock for issuance (currently 300,000 shares of HEI Common Stock have been reserved for issuance under the Nonemployee Director Stock Plan, 236,922 of which have been issued as of the date hereof), and (d) extend the term of the Nonemployee Director Stock Plan from the current date of April 27, 2010, until May 6, 2018.

Attached as Appendix B to this Proxy Statement is a copy of the Nonemployee Director Stock Plan as it would be amended and restated upon approval of the proposed amendment. The summary of the Nonemployee Director Stock Plan set forth below is qualified in its entirety by reference to the full text of the Nonemployee Director Stock Plan (as it would be amended), which is incorporated herein by reference.

Equity Compensation Plan Information

Information as of December 31, 2007 about HEI Common Stock that may be issued upon the exercise of awards granted under all of HEI's equity compensation plans was as follows:

	(a)	(b)	(c)
Plan category	**Number of securities to be issued upon exercise of outstanding options, warrants and rights(1)**	**Weighted-average exercise price of outstanding options, warrants and rights**	**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	699,276	$ 19.68	4,158,745
Equity compensation plans not approved by shareholders	—	—	—
Total	699,276	$ 19.68	4,158,745

(1)
Includes 603,800 shares subject to outstanding nonqualified stock options and 95,476 of dividend equivalent shares accrued as of December 31, 2007 for such options.

(2)
This represents the number of shares remaining available as of December 31, 2007, including 4,095,667, net of any shares underlying outstanding grants, under the 1987 Stock Option and Incentive Plan, as amended, and 63,078 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 HEI Common Stock. Of the shares remaining available for issuance under the 1987 Stock Option and Incentive Plan, as amended, 309,000 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).

Summary of Plan Terms

The Nonemployee Director Stock Plan was originally adopted by HEI in 1990. It was subsequently amended in certain respects and, in 2002, was amended to incorporate provisions formerly memorialized in HEI's 1999 Nonemployee Company Director Stock Grant Plan, which was thereupon superseded. In 2005, the Board amended the Nonemployee Director Stock Plan to reserve an additional 100,000 shares of HEI Common Stock for issuance, bringing the maximum number of shares of HEI Common Stock that may be issued under the Nonemployee Director Stock Plan, when taken together with any shares ever granted under the Nonemployee Director Stock Plan, to 300,000 (as

adjusted for HEI's 2004 stock split and subject to appropriate adjustments upon changes in capitalization, such as a stock split). The shareholders approved that amendment at the 2006 Annual Meeting of Shareholders. The Nonemployee Director Stock Plan has been amended in certain other respects from time to time.

Pursuant to the amendment subject to this proposal, the Nonemployee Director Stock Plan will be administered in the discretion of the Compensation Committee or such other committee as may be appointed from time to time by the Board. The Nonemployee Director Stock Plan provides benefits to nonemployee directors of HEI and nonemployee directors of HEI's operating subsidiaries (American Savings Bank, F.S.B., and Hawaiian Electric Company, Inc.) whose participation in the Nonemployee Director Stock Plan has been approved by the Board. Currently, 12 HEI and 9 subsidiary directors participate in the Nonemployee Director Stock Plan.

Under the terms of the Nonemployee Director Stock Plan: (i) each nonemployee HEI director who serves in that capacity immediately following the date of an Annual Meeting of Shareholders of HEI receives 1,400 shares of HEI Common Stock (subject to an increase to 1,800 shares of HEI Common Stock pursuant to the amendment subject to this proposal), and (ii) each nonemployee director of subsidiaries who serves in that capacity immediately following the date of an Annual Meeting of Shareholders receives 1,000 shares of Common Stock. Each individual who, during any calendar year, becomes a nonemployee HEI director or nonemployee director of a subsidiary for the first time, other than at the Annual Meeting of Shareholders (whether by election or appointment as a director of HEI or one of its subsidiaries), receives 2,000 shares of HEI Common Stock as a HEI director or 1,000 shares of Common Stock as a subsidiary company director. The dollar value of such stock payment will vary with changes in the fair market value of HEI Common Stock. Such stock payments are paid by HEI as soon as practicable following the date the director is first elected or appointed to the HEI Board of Directors or a subsidiary, as the case may be. Once granted, the shares of HEI Common Stock are not subject to forfeiture.

The Board in its discretion may amend, suspend or terminate the Nonemployee Director Stock Plan at any time. However, no such amendment will, without approval of the shareholders of HEI, change the class of persons eligible to receive stock grants under the Nonemployee Director Stock Plan or otherwise modify the requirements as to eligibility for participation in the Nonemployee Director Stock Plan, or increase the number of shares of HEI Common Stock which may be issued under the Nonemployee Director Stock Plan. Moreover, no amendment, suspension or termination of the Nonemployee Director Stock Plan will, without the consent of any affected nonemployee HEI director or nonemployee director of a subsidiary company, alter, terminate, impair or adversely affect any right or obligations under any stock payment previously granted under the Nonemployee Director Stock Plan unless such amendment, suspension or termination is required by applicable law. Notwithstanding the foregoing, the Board may, without further action by the shareholders of HEI, amend the Nonemployee Director Stock Plan or modify the grants of stock under the Nonemployee Director Stock Plan in response to changes in securities or other laws, or rules, regulations or regulatory interpretations thereof, applicable to the Nonemployee Director Stock Plan, or to comply with stock exchange rules or requirements. Unless terminated earlier by the Board, and subject to shareholder approval of this proposal, the Nonemployee Director Stock Plan will expire on May 6, 2018.

YOUR BOARD RECOMMENDS THAT YOU VOTE FOR THE APPROVAL OF THE AMENDED AND RESTATED 1990 NONEMPLOYEE DIRECTOR STOCK PLAN.

4. Approval of the proposed Amended and Restated 1987 Stock Option and Incentive Plan

HEI's 1987 Stock Option and Incentive Plan, as amended and restated in 1992, 1996, 2001, 2003 and 2004, provides a means to attract and retain high caliber personnel and provides participating employees with long-term stock and other incentives to align their interests with the interests of

shareholders. The Board has approved and adopted amendments to the Stock Option and Incentive Plan, effective as of January 22, 2008, subject to the approval of shareholders.

At this time, HEI is seeking shareholder approval of all of the performance goals set forth in the Stock Option and Incentive Plan, including three new performance goals added to the Stock Option and Incentive Plan by the amendment.

A summary of the amendments and the remaining material provisions of the Stock Option and Incentive Plan is set forth below.

The Stock Option and Incentive Plan, as restated to incorporate the amendments, is printed in full and attached to this Proxy Statement as Appendix C and is incorporated herein by reference. The following summary of the Stock Option and Incentive Plan is qualified in its entirety by reference to the full text of the Stock Option and Incentive Plan.

Addition of Performance Goals

Prior to the amendment, the Stock Option and Incentive Plan provided that the Compensation Committee may condition payment of an option or other incentive award permitted under the Stock Option and Incentive Plan in whole or in part on the attainment of one or more of the following performance goals, applied to a participant and/or a business unit or HEI and/or a parent or subsidiary of HEI: (1) total return to shareholders; (2) earnings per share of Common Stock; (3) net income (before or after taxes); (4) earnings before all or any interest, taxes, depreciation and/or amortization; (5) gross revenue; (6) return on assets; (7) market share; (8) cost reduction goals; (9) earnings from continuing operations, levels of expense, cost or liability; (10) performance against operational budgets; (11) a participant's individual operational project goals; (12) return on average common equity; (13) individual performance goals; and (14) any combination of, or a specified increase or decrease of, one or more of the foregoing over a specified period, in each case, as applicable, as determined in accordance with generally accepted accounting principles, where applicable.

The amendment adds free cash flow, modified free cash flow (net income plus depreciation and amortization less net capital expenditures) and shareholder value added to the above list of performance goals.

In order to comply with the requirements of Section 162(m) of the Internal Revenue Code of 1986, as amended (hereinafter "Internal Revenue Code"), HEI seeks shareholder approval of all of the above performance goals, including the three new performance goals added to the Stock Option and Incentive Plan by the amendment.

Additional Revisions

Certain other revisions were made to the Stock Option and Incentive Plan by the amendments, including those intended to (1) revise the definition of average fair market value by (a) eliminating the reference to the average of the daily high and low sales prices on the composite tape for stocks listed on the New York Stock Exchange as quoted in the New York Stock Exchange Composite Transactions published in the Western Edition of The Wall Street Journal and (b) streamlining such definition to mean simply the average of the daily high and low sales price of the Common Stock as quoted on the New York Stock Exchange; (2) revise the definition of fair market value by (a) eliminating the references to the average of the daily high and low sales prices on the composite tape for stocks listed on the New York Stock Exchange as quoted in the New York Stock Exchange Composite Transactions published in the Western Edition of The Wall Street Journal and, if there is no trading of Common Stock on the determination date, to the average of the daily high and low sales prices of the Common Stock as quoted in such Composite Transactions on the next preceding date on which there was trading and (b) streamlining such definition to mean simply the average of the daily high and low sales price of

the Common Stock as quoted on the New York Stock Exchange or, if there is no trading of Common Stock on such date, the next preceding date on which there was trading, as quoted on the New York Stock Exchange; (3) clarify that specified adjustments to the Stock Option and Incentive Plan and incentive awards *must* be made in the case of certain events (e.g., increase/decrease in outstanding shares of Common Stock, distribution of additional, new or different shares, other securities or property with respect to shares of Common Stock or other securities through merger, consolidations, asset sale, reorganization, etc.) and not that such adjustments *may* be made; (4) permit the Compensation Committee, as it deems appropriate, to amend or terminate the Stock Option and Incentive Plan and/or amend, restructure, terminate or replace an incentive award to either not be subject to Section 409A of the Internal Revenue Code, as amended, or to comply with Section 409A; and (5) make certain other technical or clarifying changes to the provisions of the Stock Option and Incentive Plan to reflect changes in applicable law.

Summary of Remaining Material Provisions of the Stock Option and Incentive Plan

The Stock Option and Incentive Plan is administered by the Compensation Committee, which consists of two or more persons who are "non-employee directors" within the meaning of Rule 16b-3 under the Securities Exchange Act of 1934 and "outside directors" within the meaning of Section 162(m) of the Internal Revenue Code.

Subject to the express provisions of the Stock Option and Incentive Plan, the Compensation Committee has complete authority to interpret and implement the Stock Option and Incentive Plan and its actions and decisions will be final and binding upon participants. The Board, Compensation Committee and officers and employees of HEI or designees acting on their behalf, will be indemnified to the extent permitted by law in respect of any action, determination or interpretation taken in good faith with respect to the Stock Option and Incentive Plan or any transaction arising under the Stock Option and Incentive Plan.

The Compensation Committee selects from all regular full-time employees of HEI and its subsidiaries those who are eligible to receive awards under the Stock Option and Incentive Plan. As of December 31, 2007, HEI and its subsidiaries had approximately 3,682 employees, of which approximately 3,520 were regular full-time employees.

No determination has yet been made concerning which individuals will receive future awards under the Stock Option and Incentive Plan. Although it is contemplated that the principal participants will be the key employees of HEI and its subsidiaries, the Compensation Committee has broad discretion under the Stock Option and Incentive Plan in selecting employees.

The Stock Option and Incentive Plan provides that the Compensation Committee may grant to eligible individuals any combination of incentive awards in the form of nonqualified stock options, incentive stock options, restricted stock, stock appreciation rights, performance awards, stock payments, dividend equivalents or restricted stock units (which awards are described more fully below). Each incentive award will be evidenced by either a written instrument or a written plan adopted by the Committee, in either case indicating the type and terms of the award. The applicable instrument or plan may include any other terms and conditions consistent with the Stock Option and Incentive Plan as the Committee may in its discretion determine, including without limitation terms and conditions that would prohibit a participant from transferring or otherwise disposing of a share of Common Stock issued under an incentive award for a period identified in the incentive award agreement or require the forfeiture of a share of Common Stock issued under an incentive award if the participant engages in any conduct that is identified in the incentive award agreement. The Committee may, on such terms and conditions as it determines, permit a participant to elect to defer all or any portion of cash or shares payable under an incentive award and credit such deferred amounts with an interest rate or other rate of return determined by the Committee.

The number of shares of Common Stock for which incentive awards may be granted during the term of the Stock Option and Incentive Plan (prior to the adjustment for the stock split in June 2004) is 4,650,000 shares; provided that, of these shares, the 2,000,000 shares that were added to the Stock Option and Incentive Plan by amendment effective January 21, 2003 may not be made subject to any incentive awards other than nonqualified stock options, incentive stock options, or stock appreciation rights. Either authorized but unissued shares or previously issued shares reacquired by HEI, including shares purchased on the open market, may be issued under the Stock Option and Incentive Plan.

On February 27, 2008, the per share closing price of the HEI Common Stock on the New York Stock Exchange was $23.31. As of December 31, 2007, approximately 4,794,943 shares of Common Stock remained available for grant under the Stock Option and Incentive Plan, options to purchase 699,276 shares of Common Stock were outstanding, no shares of Common Stock were subject to outstanding stock appreciation rights and 146,000 shares of Common Stock subject to restricted stock awards were outstanding.

The 4,650,000 share limit, as well as the maximum number of incentive awards that may be granted, as described below, the prices of options and other incentive awards outstanding under the Stock Option and Incentive Plan and the number of shares subject to options and other incentive awards outstanding under the Stock Option and Incentive Plan, will be appropriately adjusted for stock dividends, stock splits, recapitalizations, combinations of shares and other changes affecting HEI's stock. All shares for which awards have terminated or expired, or were settled in cash, including awards that provide the grantee with dividend and voting rights, will again be available for issuance pursuant to incentive awards under the Stock Option and Incentive Plan. In addition, to the extent that payment for an option upon exercise is made with shares of Common Stock or shares of Common Stock are withheld from payment of an incentive award in satisfaction of any federal, state or local tax withholding requirements, these shares will again be available for issuance pursuant to incentive awards under the Stock Option and Incentive Plan.

The Stock Option and Incentive Plan is designed to enable the Board to ensure that compensation payable in the form of certain incentive awards under the Stock Option and Incentive Plan will qualify as performance-based compensation within the meaning of Section 162(m) of the Internal Revenue Code, at such time as the Board determines that it is advisable for such compensation to so qualify. To this end, the Compensation Committee may grant incentive awards that will be payable solely by reason of the attainment of certain pre-established performance goals listed above (see section above entitled " *Addition of Performance Goals* ") and set forth in the Stock Option and Incentive Plan. With respect to compensation not intended to qualify as performance-based under Section 162(m) of the Internal Revenue Code, the Committee may condition payment of an incentive award in whole or in part on the attainment of the performance goals listed above or other performance goals.

To comply with Section 162(m), the Compensation Committee must establish any of the pre-established performance goals not later than 90 days after the commencement of the period of service to which the incentive award relates (or if less, 25% of this period of service), and once granted, the Committee may not have discretion to increase the amount payable under the incentive award. Nevertheless, the Committee will have the authority to make appropriate adjustments in performance goals under an incentive award to reflect the impact of extraordinary items not reflected in these goals. These extraordinary items include: (1) any profit or loss attributable to acquisitions or dispositions of stock or assets; (2) any changes in accounting standards that may be required or permitted by the Financial Accounting Standards Board or adopted by HEI after the goal is established; (3) all items of gain, loss or expense for the year related to restructuring charges for HEI; (4) all items of gain, loss or expense for the year determined to be extraordinary or unusual in nature or infrequent in occurrence or related to the disposal of a segment of a business; (5) all items of gain, loss or expense for the year related to discontinued operations that do not qualify as a segment of a business as defined in Statement of Financial Accounting Standards No. 144; (6) such other items as

may be prescribed by Section 162(m) and the applicable Treasury Regulations as may be in effect from time to time, and any amendments, revisions or successor provisions; and (7) with respect to incentive awards not intended to constitute qualified performance-based compensation within the meaning of Section 162(m), such other items as the Committee may deem appropriate.

The Stock Option and Incentive Plan provides maximum limits on the number of incentive awards that may be granted under the Stock Option and Incentive Plan. Commencing with the 2003 calendar year, the aggregate number of shares of Common Stock with respect to which incentive awards may be granted to any individual participant during any calendar year may not exceed 100,000 (including shares with respect to incentive awards payable in cash but denominated in Common Stock, like cash-settled stock appreciation rights and restricted stock units, which are described below). Moreover, the total number of shares that may be subject to restricted stock, stock payments or stock-settled restricted stock units granted on or after April 23, 2003 may not exceed 5% of the total number of shares of Common Stock authorized under the Stock Option and Incentive Plan as of such date but not subject to an incentive award immediately before such date.

In addition, with respect to performance awards under the Stock Option and Incentive Plan (which are a particular type of incentive award settled in cash or stock, or a combination, and the value of which is based on the achievement of performance goals or other criteria as may be determined by the Compensation Committee), commencing with the 2003 calendar year, (1) no performance award may relate to a performance period in excess of three years; (2) no more than two performance awards may be granted to any individual participant during any calendar year; (3) with respect to any performance award that relates to a performance period of not more than one year, the maximum value of the performance award may not exceed $2,000,000 (to the extent payable in shares of Common Stock, based on either fair market value or average fair market value (both as defined below) at the time of award or payment, as determined by the Committee); and (4) with respect to any performance award that relates to a performance period of more than one year, the maximum value of the performance award may not exceed $2,500,000 (to the extent payable in shares of Common Stock, based on either fair market value or average fair market value at the time of award or payment).

Nonqualified stock options will provide for the right to purchase Common Stock at a price that is not less than the lesser of the fair market value and the average fair market value on the date of the grant. These options will be granted for a term that may not exceed ten years. HEI's current practice is to grant nonqualified stock options with an exercise price equal to the fair market value of the underlying Common Stock on the date of grant.

As amended, subject to shareholder approval of this proposal, the term "fair market value" under the Stock Option and Incentive Plan means, as of any determination date, the average of the daily high and low sales prices of the Common Stock as quoted on the New York Stock Exchange on the date as of which fair market value is to be determined, or if there is no trading of Common Stock on that date, the average of the daily high and low sales prices of the Common Stock as quoted on the New York Stock Exchange on the next preceding date on which there was trading in the shares; and the term "average fair market value" means, as of any determination date, the average of the daily high and low sales prices of the Common Stock as quoted on the New York Stock Exchange for all trading days during the calendar month preceding the determination date. If the Common Stock is no longer traded on the New York Stock Exchange, fair market value and average fair market value will be determined in such reasonable manner as the Compensation Committee determines.

Incentive stock options will be designed to comply with the provisions of the Internal Revenue Code, and will be subject to restrictions contained in the Internal Revenue Code. Incentive stock options will be granted at not less than the fair market value of the Common Stock subject to such options on the date of grant and will extend for a term of up to ten years. However, incentive stock options granted to any person who owns more than 10% of the combined voting power of HEI's

outstanding securities must be granted at prices that are not less than 110% of fair market value on the date of grant and may not extend for more than five years.

The purchase price of Common Stock purchased upon the exercise of a stock option must be paid in full on the date of exercise in cash or its equivalent, or in such other manner acceptable to the Compensation Committee, including other Common Stock of HEI owned by the participant and valued at its fair market value on the exercise date.

Grants of restricted stock are awards of Common Stock that a participant may purchase at a price determined by the Compensation Committee, or Common Stock to which the participant may become entitled without payment of any price, upon the lapse of restrictions specified by the Committee in the applicable award agreement at time of grant. The Committee may provide that a restricted stock award will vest based on continuing employment or upon the satisfaction of pre-established performance objectives and may impose such other conditions as the Committee deems advisable. In general, restricted stock may not be sold, transferred or hypothecated until the restrictions lapse, are removed or expire. Recipients of restricted stock awards, unlike recipients of options, may have voting rights and may receive dividends prior to the time when restrictions lapse.

Restricted stock units are rights to receive, when the units vest, shares of Common Stock or a cash amount equal to the fair market value or average fair market value of the restricted stock units (as determined by the Compensation Committee), plus, in either case, the aggregate amount of cash dividends paid with respect to the shares of Common Stock represented by these units, from the date of grant of the units until the vesting date. The Committee may provide that a restricted stock unit award will vest upon the satisfaction of certain restrictions or conditions.

Stock appreciation rights may be granted in tandem with either nonqualified or incentive stock options, or as free-standing stock appreciation rights, which are stock appreciation rights that are granted independent of, and not in connection with, the grant of options. Free-standing stock appreciation rights will permit the participant to exercise the stock appreciation rights by surrendering them in exchange for an amount equivalent to the difference between the fair market value of the shares subject to the stock appreciation rights and the exercise price of such shares. Tandem stock appreciation rights will permit the participant to exercise the stock appreciation rights by surrendering the unexercised options in exchange for an amount equivalent to the difference between the fair market value of the option shares with respect to which the stock appreciation rights are exercised and the option price of such shares.

The Compensation Committee may elect to pay stock appreciation rights in cash or in Common Stock or in a combination of cash and Common Stock. The stock appreciation rights will provide that the holder of the stock appreciation rights may exercise the stock appreciation rights or the tandem option in whole or in part. Stock appreciation rights granted in tandem with options may not extend beyond the term of the related option and will be transferable only to the extent that the related option is transferable. To the extent that an option is exercised, any related stock appreciation rights will be reduced by the number of shares with respect to which the option is exercised. To the extent any stock appreciation rights are exercised, any related option will be reduced by the number of shares with respect to which the stock appreciation rights are exercised.

Performance awards may be granted by the Compensation Committee on an individual basis. These awards may be paid in cash or shares of Common Stock and will be based either upon specific written instruments or upon specific incentive performance plans. The written instrument or plan will set forth the performance criteria to be utilized to calculate the value of the performance awards, the term over which such performance will be measured, the events which will give rise to payment of the awards and the form and time of payment of the awards. The Committee may also provide for interest or earnings to be credited on any cash or stock payments that are deferred at a rate specified by the Committee.

The Compensation Committee may approve a stock payment in Common Stock to any employee who otherwise may be entitled to a cash payment other than base salary, such as the payment of a performance award or a bonus under one of HEI's bonus plans. In the event Common Stock is issued in lieu of such a cash compensation payment, the Common Stock will be valued at its fair market value or average fair market value at the time of payment, as determined by the Committee.

Under the Stock Option and Incentive Plan, the Compensation Committee has discretion to prescribe the time period during which an option may be exercised after termination of employment. Unless an option award agreement provides otherwise, however, upon a participant's termination of employment for any reason, all of the participant's options that have not yet vested will be forfeited. In the case of performance awards, if a participant's employment with HEI is terminated for any reason prior to the occurrence of the events that vest a performance award, the performance award will expire unless the applicable award instrument or plan provides otherwise. Similarly, all of a participant's restricted stock and restricted stock units remaining subject to restrictions on the date of termination of employment will be forfeited unless the applicable restricted stock award or restricted stock unit agreement provides otherwise.

The Stock Option and Incentive Plan further provides that the Compensation Committee may include, in any incentive award instrument or plan, provisions to the effect that the time at which the award is vested, exercisable, payable or free from restrictions, as the case may be, may be accelerated by the occurrence of certain events, either automatically or upon a further determination made by the Committee at the time of the events.

Except as otherwise provided in an incentive award agreement, plan or other written instrument, upon the occurrence of a change-in-control (as defined in the Stock Option and Incentive Plan, unless otherwise provided in an award agreement), outstanding incentive awards will immediately become fully vested, exercisable, payable, or free from restrictions.

The Stock Option and Incentive Plan provides that HEI may make whatever provisions it deems appropriate to withhold any taxes it is required to withhold with respect to incentive awards and to require participants to satisfy any tax requirements before making payments pursuant to incentive awards or authorizing the issuance of shares of Common Stock to the participants.

The Stock Option and Incentive Plan may be amended, suspended or terminated by the Board at any time. However, no amendment may be made without shareholder approval to the extent such approval is required in order to comply with the requirements of Rule 16b-3, or if applicable, Section 162(m) of the Internal Revenue Code. No amendment, suspension or termination may alter or impair the rights or obligations of the participant under an incentive award previously granted under the Stock Option and Incentive Plan, without the participant's consent. Moreover, the Stock Option and Incentive Plan prohibits any amendment to decrease the purchase price of any outstanding option under the Stock Option and Incentive Plan, unless first approved by the requisite vote of shareholders. Finally, pursuant to the amendment, notwithstanding anything to the contrary contained in the Stock Option and Incentive Plan or in any incentive award agreement, to the extent the Compensation Committee deems it appropriate, the Committee reserves the right to amend or terminate the Stock Option and Incentive Plan and/or amend, restructure, terminate or replace an incentive award in order to cause the incentive award to either not be subject to Section 409A or to comply with the applicable provisions of Section 409A.

Unless earlier terminated by the Board, the Stock Option and Incentive Plan terminates on January 20, 2013, but previously granted incentive awards may extend beyond that termination date.

The benefits to be derived from the Stock Option and Incentive Plan to the eligible participating individuals and groups cannot be determined, as grants will be made at the sole discretion of the

Compensation Committee, based on a variety of factors, and the ultimate value of the awards also will depend on a variety of factors, including the future market value of the Common Stock.

Federal Income Tax Consequences

The following is a summary of certain federal income tax consequences of transactions relating to options, stock appreciation rights and restricted stock under the Stock Option and Incentive Plan based on current federal income tax laws. This summary is not intended to be exhaustive and does not describe state, local or other tax laws.

Nonqualified Stock Options

The grant of a nonqualified stock option under the Stock Option and Incentive Plan will not result in the recognition of taxable income to the participant or in a deduction for HEI. Upon exercise, a participant will recognize income in an amount equal to the excess of the fair market value of each share of Common Stock purchased over the exercise price. HEI is required to withhold taxes on the amount of income so recognized, and, subject to the provisions of Section 162 of the Internal Revenue Code is entitled to a tax deduction equal to the amount of such income. Gain or loss upon a subsequent sale of any shares of Common Stock received upon the exercise of a nonqualified stock option is generally taxed as capital gain or loss to the participant (long-term or short-term, depending upon the holding period of the stock sold).

A participant who pays the exercise price of a nonqualified stock option, in whole or in part, by delivering shares of Common Stock already owned by the participant will recognize no gain or loss for federal income tax purposes on the shares surrendered, but will otherwise be taxed in accordance with the rules described above for nonqualified stock options. With respect to shares of Common Stock acquired upon exercise which are equal in number to the shares of Common Stock surrendered, the basis of such shares will be equal to the basis of the shares surrendered, and the holding period of such shares will include the holding period of the shares surrendered. The basis of additional shares received upon exercise will be equal to the fair market value of such shares on the date of exercise, and the holding period for such additional shares will commence on such date.

Incentive Stock Options

In general, no income will be recognized by a participant and no deduction will be allowed to HEI with respect to the grant or exercise of an incentive stock option granted under the Stock Option and Incentive Plan, provided that the option is exercised within three months after the termination of the participant's employment (one year in the case of the participant's disability or without limitation in the case of the participant's death). The difference between the exercise price and the fair market value of the shares of Common Stock on the date the option is exercised is, however, an adjustment item for the participant for purposes of the alternative minimum tax. When the stock received upon exercise of the option is sold, provided that the stock is held for more than two years from the date of grant of the option and more than one year from the date of exercise, the participant will recognize long-term capital gain or loss equal to the difference between the amount realized and the exercise price of the option related to such stock. If the above-mentioned holding period requirements of the Internal Revenue Code are not satisfied, the subsequent sale of stock received upon exercise of an incentive stock option is treated as a "disqualifying disposition." In general, a participant will recognize taxable income at the time of a disqualifying disposition as follows: (1) ordinary income in an amount equal to the excess of (A) the lesser of the fair market value of the shares of Common Stock on the date the incentive stock option is exercised or the amount realized on such disqualifying disposition over (B) the exercise price and (2) capital gain to the extent of any excess of the amount realized on such disqualifying disposition over the fair market value of the shares of Common Stock on the date the incentive stock option is exercised (or capital loss to the extent of any excess of the exercise price over

the amount realized on disposition). Any capital gain or loss recognized by the participant will be long-term or short-term depending upon the holding period for the stock sold. HEI may claim a deduction at the time of the disqualifying disposition equal to the amount of ordinary income the participant recognizes, subject to the provisions of Section 162 of the Internal Revenue Code.

If an incentive stock option is not exercised within three months after the termination of the participant's employment (one year in the case of disability of the participant or without limitation in the case of the participant's death), it will be treated for federal income tax purposes as a nonqualified stock option, as described above.

In general, a participant who pays the exercise price of an incentive stock option, in whole or in part, by delivering shares of Common Stock already owned by the participant will recognize no gain or loss for federal income tax purposes on the shares surrendered. However, if the shares delivered to exercise the incentive stock option were acquired pursuant to the prior exercise of an incentive stock option and the holding period requirements discussed above have not been met with respect to such shares, the delivery of such shares to exercise the incentive stock option will be considered a taxable disposition of the shares. A portion of shares received upon exercise of an incentive stock option equal in number to the shares surrendered will have a basis equal to the basis of the shares surrendered (increased, if applicable, by any income recognized as a result of the exchange) and the holding period of such shares will include the holding period of the shares surrendered (except for purposes of determining whether there has been a disqualifying disposition of the shares). The basis of the additional shares received upon such exercise will be zero, and the holding period of such shares for all purposes will begin on the date the shares are transferred.

Stock Appreciation Rights

The grant of a stock appreciation right to a participant under the Stock Option and Incentive Plan will not result in the recognition of taxable income to the participant or in a deduction for HEI. In general, upon exercise of a stock appreciation right, the participant will recognize ordinary income for federal income tax purposes equal to the amount of any cash received plus the fair market value of any shares of Common Stock received. HEI is entitled to a tax deduction equal to the amount of income recognized by the participant, subject to Section 162 of the Internal Revenue Code.

Restricted Stock

A participant generally will not be subject to Federal income tax upon the grant of a restricted stock award. Rather, the participant will recognize ordinary income in an amount equal to (i) the fair market value of the shares at the time the shares become transferable or are otherwise no longer subject to a substantial risk of forfeiture (as defined in the Internal Revenue Code) minus (ii) the price, if any, the participant paid upon receipt of the shares. Subject to the limitations of Section 162 of the Internal Revenue Code, HEI is entitled to a tax deduction at the same time and in the same amount that the participant recognizes ordinary income. However, the participant may elect (not later than 30 days after acquiring the shares), pursuant to Section 83(b) of the Internal Revenue Code, to recognize ordinary income at the time the restricted shares are awarded in an amount equal to their fair market value at that time, notwithstanding the fact that the shares are subject to restrictions or a substantial risk of forfeiture. If the participant makes such an election, the participant will not recognize any additional taxable income at the time the restrictions lapse or the shares become transferable. If the shares in respect of which such an election was made are later forfeited, the participant will not be allowed a tax deduction in respect of the forfeited shares, and HEI will be deemed to recognize ordinary income equal to the amount of the deduction allowed to HEI at the time of the election in respect of the forfeited shares.

Prior Option Grants

The following table sets forth information as of December 31, 2007 with respect to the amount of options that have been granted pursuant to the Stock Option and Incentive Plan to the named executive officers and the specified groups set forth below.

Name and Position*	Amount of Stock Options
Constance H. Lau HEI President and Chief Executive Officer, American Savings Bank Chair, President and Chief Executive Officer, and Hawaiian Electric Company Chair	150,000
Eric K. Yeaman** HEI Financial Vice President, Treasurer and Chief Financial Officer	80,000
T. Michael May Hawaiian Electric Company President and Chief Executive Officer	150,000
Patricia U. Wong HEI Vice President-Administration and Corporate Secretary	28,000
Curtis Y. Harada HEI Controller	28,000
Current Executive Officer Group	436,000
Current Non-Executive Director Group	0
Each nominee for election as a director	0
Each associate of the above-mentioned directors, executive officers or nominees	0
Each other person who received or is to receive five percent of such options, warrants, or rights	0
Employee Group other than Executive Officer Group	923,000

*
Positions as of December 31, 2007

**
Mr. Yeaman was appointed Hawaiian Electric Company Senior Executive Vice President and Chief Operating Officer, effective February 1, 2008.

YOUR BOARD RECOMMENDS THAT YOU VOTE FOR APPROVAL OF THE AMENDED AND RESTATED 1987 STOCK OPTION AND INCENTIVE PLAN, INCLUDING ALL PERFORMANCE GOALS IN THE PLAN AS AMENDED.

Nominees for Class III directors with a term expiring at the 2011 Annual Meeting

Don E. Carroll
Age 66
Director Since 1996

Chairman of Oceanic Time Warner Cable Advisory Board 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., Island Insurance Company, Pacific Guardian Life, American Red Cross-Hawaii Chapter, and The 200 Club. Member of the advisory boards of Oceanic Time Warner Cable and Boy Scouts of America-Aloha Council.

Richard W. Gushman, II
Age 62
Director Since 2007

President and Owner of DGM Group since 1988.

Director of American Savings Bank, F.S.B., Outrigger Enterprises, Servco Pacific Inc., and James Campbell Corp., LLC. Managing Partner of Summit Financial Resources. Trustee of the Estate of James Campbell and Hawaii Community Foundation. Member of advisory boards of Boys and Girls Club of Hawaii and Department of Hawaiian Home Lands.

Victor H. Li, S.J.D.
Age 66
Director Since 1988

Co-chairman, Asia Pacific Consulting Group since 1992. President, Li Xing School Foundation since 1989.

Director of American Saving Bank, F.S.B. Trustee, Japan America Institute of Management Science and Pan Asian Repertory Theatre.

Bill D. Mills
Age 56
Director Since 1988

Chairman of The Mills Group since 1989.

Director of Grace Pacific Corporation, Hawaii Public Television and Sunrise Capital, Inc., a private equity aquaculture development company. Trustee, Hawaii Pacific University, St. Andrew's Priory, The Nature Conservancy of Hawaii, and Iolani School board of governors.

Barry K. Taniguchi
Age 60
Director Since 2004

President and Chief Executive Officer of KTA Super Stores since 1989.

Director of Hawaiian Electric Company, Inc., American Savings Bank, F.S.B., Hawaii Electric Light Company, Inc., Maui Electric Company, Limited, Hawaii Employers Mutual Insurance Corporation, Hawaii Island Economic Development Board, and Better Business Bureau. Trustee, Hawaii Community Foundation, Public Schools of Hawaii Foundation, Tax Foundation of Hawaii, and Lyman House Memorial Museum. Chair, The Food Basket-Hawaii Island's Foodbank. Vice Chair, Hawaii Health System Corporation Corporate Board.

Continuing Class I directors whose terms expire at the 2009 Annual Meeting

Shirley J. Daniel, Ph.D., C.P.A.
Age 54
Director Since 2002

Professor of Accountancy, Shidler College of Business, University of Hawaii-Manoa since 1986.
Director of American Savings Bank, F.S.B.

Constance H. Lau
Age 55
Director 2001 to 2004 and since May 2006

President and Chief Executive Officer of Hawaiian Electric Industries, Inc. since May 2006. Chairman and Chief Executive Officer of American Savings Bank, F. S. B. since February 2008. Chairman, President and Chief Executive Officer of American Savings Bank, F.S.B. from May 2006 to January 2008. President, Chief Executive Officer and director of American Savings Bank, F.S.B. from June 2001 to May 2006.
Chairman of Hawaiian Electric Company, Inc. Director of Hawaiian Electric Industries Charitable Foundation, Alexander & Baldwin, Inc., Hawaii Bankers Association, Consuelo Zobel Alger Foundation and Maunalani Foundation. Trustee, Punahou School Member, Hawaii Business Roundtable.

A. Maurice Myers
Age 67
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 BIS Industries, Ltd. and member of the Oceanic Time Warner Cable advisory board.

James K. Scott, Ed.D.
Age 56
Director Since 1995

President of Punahou School since 1994.
Director of Hawaii Public Television and Hawaii Association of Independent Schools. Chairman, Secondary School Admission Test Board. Trustee, Blood Bank of Hawaii and Barstow Foundation.

Continuing Class II directors whose terms expire at the 2010 Annual Meeting

Thomas B. Fargo
Age 59
Director Since 2005

President, Trex Enterprises Corporation (research and development for defense and homeland security) since April 2005. Commander, U.S. Pacific Command from May 2002 to February 2005.

Director of Hawaiian Electric Company, Inc., Hawaiian Holdings, Inc., United Services Automobile Association and Japan-America Society of Hawaii. Trustee, Hawaii Pacific University and Iolani School board of governors. National Vice Chair, Pearl Harbor Memorial Fund.

Kelvin H. Taketa
Age 53
Director Since 1993

President and Chief Executive Officer of the Hawaii Community Foundation since 1998.

Director of Hawaiian Electric Company, Inc., Independent Sector, and Sunrise Capital, Inc., a private equity aquaculture development company.

Jeffrey N. Watanabe
Age 65
Director Since 1987

Honorary Of Counsel in the law firm of Watanabe Ing & Komeiji LLP since July 2007. Senior partner, Watanabe Ing & Komeiji LLP from 1972 to June 2007.

Chairman of Hawaiian Electric Industries, Inc. Director of Hawaiian Electric Company, Inc., American Savings Bank, F.S.B., Hawaiian Electric Industries Charitable Foundation, Alexander & Baldwin, Inc., Cellular Bioengineering, Inc., First Insurance Company of Hawaii, Ltd., Grace Pacific Corporation, Mid-Week Printing, Inc./Oahu Publications, Inc., Tissue Genesis, Inc., and Trex Enterprises Corporation. Trustee, Consuelo Zobel Alger Foundation, Punahou School, and Sesame Workshop.

Diane J. Plotts
Age 72
Director Since 1987

Business advisor since 2000.

Director of American Savings Bank, F.S.B. Trustee, Kamehameha Schools.

Corporate Governance

What are HEI's governance policies and guidelines?

In 2007, the Board and management continued to review and monitor corporate governance trends and best practices to comply with the corporate governance requirements of the New York Stock Exchange Listed Company Manual 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), and charters for the Audit, Compensation, Executive, and Nominating and Corporate Governance Committees were reviewed and revised as deemed appropriate by the Board. Current copies of these documents may be found on HEI'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 by 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 Nominating and Corporate Governance 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 candidates are identified, the Nominating and Corporate Governance 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 of the Committee 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 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 nonemployee Chairman of the Board and any employee director or (2) the nonemployee directors as a group, by mail. To communicate with the Board, any individual director or any group of directors, correspondence should be addressed to the Board 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 Chairman of the Board.

How does the Board evaluate itself?

The Board follows 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, meetings, 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 meetings, contributions to the group, knowledge of the issues and concerns of HEI and understanding of the role of the Board in the governance of HEI. 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 Committee or the nonemployee Chairman of the Board may meet with individual directors to discuss their performance, as appropriate.

As required by the New York Stock Exchange 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. The Audit Committee also reviewed and evaluated its duties and responsibilities, its relationships with management and the internal and external auditors and the qualifications of its members, including financial expertise.

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 HEI, in compliance with the New York Stock Exchange corporate governance listing standards. 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 HEI 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 HEI, 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 HEI 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 HEI'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, HEI 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 HEI 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 each director and nominee for director has no material relationship with HEI and is independent, with the exception of Constance H. Lau, an employee director. With respect to each of the nonemployee directors, the Board considered relationships to ensure that they were not inconsistent with the best interests of HEI, its subsidiaries or shareholders. In particular, the Nominating and Corporate Governance Committee, which is charged with reviewing and approving relationships that may impact director independence, considered the relationships listed below:

- Don E. Carroll has a son who was hired by American Savings Bank in 2007 in a non-officer capacity.

- Shirley J. Daniel, Ph.D. is a Professor of Accountancy for the Shidler College of Business, University of Hawaii-Manoa. HEI and its subsidiaries have made charitable contributions to the University of Hawaii Foundation.

- Diane J. Plotts is a trustee of Kamehameha Schools, a private trust that is the lessor of the land underlying the Hawaiian Electric Company office building.

- James K. Scott serves as the President of Punahou School, to which HEI and its subsidiaries have made charitable contributions. In addition, Constance H. Lau, HEI's President and Chief Executive Officer, is a member of the Punahou School board of trustees. Ms. Lau has reported her recusal in matters relating to Dr. Scott's compensation.

- Kelvin H. Taketa serves as the President and Chief Executive Officer of Hawaii Community Foundation, to which HEI and its subsidiaries make charitable contributions. In addition, Eric K. Yeaman, who was HEI's Financial Vice President, Treasurer and Chief Financial Officer in 2007 and became Hawaiian Electric Company's Senior Executive Vice President and Chief Operating Officer, effective February 1, 2008, sits on the executive committee of Hawaii Community Foundation. Mr. Yeaman has reported his recusal in matters relating to Mr. Taketa's compensation.

- On July 1, 2007, Jeffrey N. Watanabe retired from and became honorary Of Counsel for Watanabe Ing & Komeiji LLP, a law firm that performed legal services for HEI and its subsidiaries in 2007.

The Board also considered the transactions described under "Other Relationships and Related Person Transactions" on pages 60-61.

The Board also considered (1) the amount of charitable contributions HEI and its subsidiaries made to charitable organizations for which the nonemployee director or any member of the director's immediate family serves as an officer, director or trustee, none of which exceeded the greater of $1 million or 2% of such tax exempt organization's consolidated gross revenues, (2) the amount of electricity purchased from HEI's electric utility subsidiaries by the nonemployee directors or their respective places of employment and (3) financial transactions involving HEI's bank subsidiary and the nonemployee directors and their respective places of employment.

The Board determined that the above relationships do not interfere with the independent judgment of the applicable director on matters concerning HEI. The directors have agreed to recuse themselves from any discussions or decision-making on any matter involving the organizations with which they are affiliated or other significant relationships.

What other Board practices does HEI have?

The nonemployee directors meet regularly in executive sessions without management present. In 2007, these sessions were chaired by Jeffrey N. Watanabe, who is the Chairman of the Board. Mr. Watanabe may request that other nonemployee directors chair the executive sessions.

Information related to issues to be considered at a Board or Committee meeting and other materials 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 2007?

In 2007, there were fourteen (14) regular and seven (7) special 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 2007 Annual Meeting of Shareholders. HEI encourages the directors to attend each year's Annual Meeting of Shareholders.

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. Members of these committees are generally appointed annually by the Board taking into consideration the recommendation of the Nominating and Corporate Governance Committee. The names of the current committee members are shown on the table below. In addition, the table below also shows the number of meetings of each committee held in 2007.

Name	Audit	Compensation	Executive	Nominating and Corporate Governance
Don E. Carroll		X		
Shirley J. Daniel	X			
Thomas B. Fargo	X	X***		
Richard W. Gushman, II				
Constance H. Lau*			X	
Victor H. 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 2007	14	7	0	4

*
Employee director

**
Committee chair

***
Appointed to Compensation Committee on August 7, 2007

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 Board and may be found on HEI's website at www.hei.com and is available in print to any shareholder who requests it. The Committee provides independent and objective oversight of HEI's (1) financial reporting processes, (2) appointment, compensation and oversight of the independent registered public accounting firm performing audits of HEI's financial statements, (3) internal controls, (4) risk assessment and risk management policies set by management and (5) oversight of related person transactions of officers. The Committee also reviews and approves or disapproves related person transactions for officers 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 New York Stock

Exchange and none of them are members of audit committees of other publicly traded companies. See pages 62-63 for the Audit Committee Report.

- Compensation Committee

The Compensation Committee operates and acts under a written charter, which was adopted and approved by the Board and may be found on HEI's website at www.hei.com and is available in print to any shareholder who requests it. The Committee oversees HEI's employee and director compensation and employee benefit plans and practices, including its executive compensation plans and its incentive compensation and equity-based plans. See "Compensation Discussion and Analysis" below for additional discussion of the role of the Compensation Committee.

The Compensation Committee consists of three or more directors as determined from time to time by the Board. Each member of the Committee is qualified to serve on the Committee pursuant to the requirements of the New York Stock Exchange. At least a majority of the members of the Committee qualifies as "nonemployee directors" within the meaning of Rule 16b-3 promulgated under the Securities Exchange Act of 1934, as amended, and "outside directors" within the meaning of Section 162(m) of the Internal Revenue Code. The Committee may form subcommittees of its members and delegate its authority to the subcommittee. The Nonemployee Director Subcommittee of the Compensation Committee has the authority to make equity grants on behalf of the Committee.

See Compensation Committee interlocks and insider participation on page 61.

- Executive Committee

The Executive Committee operates and acts under a written charter, which was adopted and approved by the Board and may be found on HEI's website at www.hei.com and is available in print to any shareholder who requests it. The Committee 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 HEI that may arise from time to time. The Committee is currently comprised of the Chairman of the Board, the HEI President and Chief Executive Officer and two additional independent directors.

- 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 Board and may be found on HEI's website at www.hei.com and is available in print to any shareholder who requests it. All members of the Committee are independent directors as defined in the listing standards of the New York Stock Exchange. 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 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 related person transactions and (6) overseeing corporate governance matters generally.

See the section on Corporate Governance on pages 19-21 for a discussion concerning the involvement of this Committee on matters relating to corporate governance.

Compensation Committee Report

The Compensation Committee has reviewed and discussed with management the Compensation Discussion and Analysis that follows. Based on that review and discussion, the Compensation Committee recommended, and the Board concurred, that the Compensation Discussion and Analysis be included in this proxy statement.

SUBMITTED BY THE COMPENSATION COMMITTEE OF
THE HEI BOARD OF DIRECTORS
Bill D. Mills, Chair
Don E. Carroll
Thomas B. Fargo
Victor H. Li
A. Maurice Myers
Diane J. Plotts

Compensation Discussion and Analysis

Who is responsible for determining appropriate executive compensation?

The Compensation Committee has the responsibility for recommending the total compensation program for HEI and its subsidiaries, subject to the approval of the Board. The Committee approves, modifies or rejects its consultant's or management's recommendations regarding executive compensation programs. The Board approves the actions of the Committee, and where the executive works at a subsidiary of HEI, the actions of the Committee are also approved by the subsidiary board.

The Board conducts an evaluation of the performance of the President and Chief Executive Officer. The Compensation Committee, with the assistance of its independent compensation consultant, recommends an executive compensation package for the President and Chief Executive Officer. The independent directors of the Board approve the compensation of the President and Chief Executive Officer.

Does the Compensation Committee have the authority to modify or terminate executive compensation programs?

The Compensation Committee reserves the right to amend, suspend or terminate incentive programs or any other executive compensation program. The Committee can exercise its discretion to reduce or (except to the extent an award or payout is intended to satisfy the requirements of Section 162(m) of the Internal Revenue Code) increase the size of any award or payout.

In making its compensation determinations, the Compensation Committee will consider financial accounting consequences if appropriate. For instance, the Committee may determine that there should not be any incentive payout that would otherwise result solely from a new way of accounting for a financial measure. The Committee will also consider tax consequences if appropriate. For instance, the Committee will take into account tax deductibility in establishing executive compensation, but it reserves the right to award compensation even when not deductible, if it is reasonable and appropriate.

Did the Compensation Committee exercise its discretion to award a bonus?

At its meeting on February 19, 2008, the Compensation Committee recommended the award of a discretionary bonus of $100,000 to T. Michael May, Hawaiian Electric Company President and Chief Executive Officer. On March 14, 2008, the Hawaiian Electric Company Board of Directors approved the award to Mr. May for the utility's success in meeting project milestones that set the groundwork for improved financial performance in operational areas such as regulatory affairs, demand side management, and distributed and central unit generation.

What is the role of the compensation consultant?

The Compensation Committee's independent compensation consultant is Towers Perrin. The Committee engages Towers Perrin to provide the Committee with advice and data with respect to compensation benchmarking and best practices. Towers Perrin works with the Compensation Committee Chair and Committee members in recommending executive compensation initiatives on behalf of the Committee.

Towers Perrin works with the HEI President and Chief Executive Officer, HEI Vice President-Administration, the HEI Financial Vice President and the subsidiary human resource executives and their staffs in implementing executive compensation initiatives on behalf of the Compensation Committee.

In 2007, the HEI President and Chief Executive Officer and HEI Vice President-Administration discussed proposed executive compensation offers for new HEI and subsidiary executives and issues concerning executive compensation program design with Towers Perrin. The HEI President and Chief Executive Officer did not discuss her own compensation with Towers Perrin.

At the Compensation Committee's direction and pursuant to approved agreements detailing the scope of work, Towers Perrin provided the following services and support to the Committee in 2007:

- Board of Directors compensation analysis;
- Work related to HEI's definitive proxy statement for its 2007 Annual Meeting, including assisting with responses to comments by the Securities and Exchange Commission;
- Preliminary work on an executive compensation analysis;
- Competitive benchmarking analysis for new executive positions; and
- Change-in-control policy review.

What is the role of executive officers in determining named executive officer compensation?

Constance Lau, HEI President and Chief Executive Officer, reviews and may make recommendations to the Compensation Committee regarding named executive officer compensation. In 2007, Ms. Lau requested that she not receive a base salary increase in 2007. She recommended base salary increases for the other named executive officers. Ms. Lau also worked with the compensation consultant in making recommendations to the Compensation Committee on compensation and benefits for new HEI executives. Although Ms. Lau is a director on the HEI Board, she did not make any Board decisions impacting her own compensation.

Patricia Wong, Vice President-Administration and Corporate Secretary, has the overall responsibility for administering executive compensation programs. She works with the Compensation Committee, Towers Perrin, the HEI and subsidiary chief executive officers, the HEI Financial Vice President, Treasurer and Chief Financial Officer and subsidiary human resources and finance executives to review, to recommend revisions to, and to implement new executive compensation programs. In 2007, Eric Yeaman, then HEI Financial Vice President, Treasurer and Chief Financial Officer, and the subsidiary human resources and finance executives recommended the methodology and metrics for computing executive incentives.

What are the objectives of HEI's compensation programs?

The following are the primary objectives of HEI's compensation programs:

- provide compensation opportunities that relate pay with individual and company annual and long-term performance goals that support shareholder value;
- maintain compensation that is fair in a competitive marketplace and will attract and retain highly qualified executives needed to enhance shareholder value; and
- align the interests of executives with shareholders to promote shareholder value.

Who were the named executive officers in 2007?

In 2007, the named executive officers for HEI were:

Name	Position
Constance H. Lau	HEI President and Chief Executive Officer, American Savings Bank Chair, President and Chief Executive Officer, and Hawaiian Electric Company Chair
Eric K. Yeaman	HEI Financial Vice President, Treasurer and Chief Financial Officer
T. Michael May	Hawaiian Electric Company President and Chief Executive Officer
Patricia U. Wong	HEI Vice President-Administration and Corporate Secretary
Curtis Y. Harada	HEI Controller

At its meeting on January 22, 2008, the HEI Board approved the Nominating and Corporate Governance Committee's recommendations regarding (1) the appointment of Mr. Yeaman as Hawaiian Electric Company Senior Executive Vice President and Chief Operating Officer, reporting to Mr. May; (2) the interim appointment of Mr. Harada as HEI Acting Financial Vice President, Treasurer and Chief Financial Officer, while retaining his position as HEI Controller, reporting to Ms. Lau; and (3) the appointment of Timothy K. Schools as American Savings Bank President, reporting to Ms. Lau, who remains HEI President and Chief Executive Officer, Hawaiian Electric Company Chair, and American Savings Bank Chair and Chief Executive Officer.

What is the compensation methodology for competitive benchmarking?

HEI is a Hawaii-based holding company with a unique blend of two regulated operating subsidiaries, a bank and a utility. Shareholders of HEI benefit when the fundamental values of both businesses are supported. In 2007, Mr. May was focused primarily on the success of the utility. His compensation, therefore, was benchmarked against peer utilities. The other HEI executives had their compensation benchmarked against both bank and utility companies. The results of this benchmarking were compared to the compensation practices of the general industry segment of the Towers Perrin data bank.

The Compensation Committee determines the compensation strategy for each element of the executive compensation program. The Committee generally targets the overall compensation of the named executive officers at the 50th percentile or median of compensation practices found in the benchmark companies.

The Compensation Committee periodically reviews the total compensation for executives. The Committee examines the positions and responsibilities of executives against similar positions in similar organizations. The benchmarking data reflects the relevant industry experience and scope of authority of each executive. Utility and financial services companies used in the benchmark group are companies comparable to HEI and its operating subsidiaries. Below is a listing of the utility and financial services companies that were used as benchmarks for HEI executives:

Utility and Energy Benchmark Companies	Financial Services Benchmark Companies
Allegheny Energy, Inc.	Associated Banc-Corp.
Ameren Corp.	BancWest
Aquila Inc.	Bank of Hawaii Corp.
Avista Corp.	BankUnited Financial Corp.
Constellation Energy Group Inc.	Central Pacific Financial Corp.
Northeast Utilities	Citizens Banking Corp.
NSTAR	City National Bank Corp.
OGE Energy Corporation	CoBank
Peoples Energy Corp.	Commercial Federal Corp.
Pinnacle West Capital Corp.	Compass Bancshares, Inc.
PNM Resources, Inc.	Downey Financial Corp.
Portland General Electric	Federal Home Loan Bank of San Francisco
PPL Corp.	First Fed Financial Corp.
Progress Energy Inc.	Freemont General Corp.
Puget Energy Inc.	Golden West Financial Corp.
Questar Corporation	Greater Bay Bancorp
Sempra Energy	Irwin Financial Corp.
TECO Energy Inc.	People's Bank
UIL Holdings Corp.	SVB Financial Group
UniSource Energy Corp.	Union Bank of California
Vectren Corp.	Washington Mutual, Inc.
	Zions Bancorporation

The general industry segment of the Towers Perrin Data Bank represents multiple industries with market capitalizations that ranged from $1.1 billion to $25 billion. For its HEI analysis, Towers Perrin applied a revenue scope of $1.9 billion in annual revenue to the regression equations to adjust the general industry compensation levels. A listing of those companies is attached as Appendix D. The general industry companies were used primarily for comparative purposes to ensure that compensation elements were in line with other companies and to provide blended survey data.

Towers Perrin did not conduct a new overall executive compensation benchmarking study in 2007. Instead, the Compensation Committee requested that Towers Perrin provide competitive benchmarking analyses for certain new executive positions, none of which were named executive officer positions.

From time to time, the Committee may request that its compensation consultant prepare tally sheets or an executive compensation benchmarking study on each executive officer to determine how each executive's elements of pay, such as base salary, annual incentives, benefits and long-term incentives, compared to peers.

What are the elements of executive compensation?

To meet the compensation objectives described above, the compensation for our named executive officers includes the following elements:

- Base salary,
- Annual performance-based cash incentive compensation,
- Long-term performance-based equity and non-equity incentive compensation,
- Perquisites and other personal benefits, and
- Retirement and other post-retirement benefits.

How is base salary determined?

Base salary is the foundation of a total compensation program. Base salary for services rendered during the year recognizes the market rate for the individual's position, responsibilities, experience, and performance. The Compensation Committee also considers internal equity relative to other executive officers. The Committee generally targets the base salary of the named executive officers at the 50th percentile or median of compensation practices found in the benchmark companies. Periodically, the Committee may adjust the HEI salary structure and salary grades based upon competitive salary structure trends. Base salary levels are also reviewed when there are significant changes in job responsibility. The 2005 and 2006 studies conducted by Towers Perrin at the request of the Committee found that named executive officer base salaries were, on average, slightly below the utility and bank benchmark peer group median, although this varied by individual.

What are the base salaries of the named executive officers?

In April 2007, Ms. Lau recommended base salary increases for Mr. May, Mr. Yeaman and Ms. Wong, while Mr. Yeaman recommended a base salary increase for Mr. Harada. Ms. Lau requested that she not receive a base salary increase in 2007. The Compensation Committee and the Board decided to honor her request. Taking into consideration these recommendations, the Committee approved the following increases, effective May 1, 2007:

Name	% Base Salary Increase	$ Base Salary Increase	Base Salary, Effective May 1, 2007
Constance H. Lau	0%	$ —	$ 736,000
Eric K. Yeaman	4.0%	15,500	404,000
T. Michael May	3.6%	21,000	598,000
Patricia U. Wong	4.0%	10,300	266,300
Curtis Y. Harada	3.5%	6,700	199,000

At its meeting on September 17, 2007, the Compensation Committee eliminated the automobile and gas allowance benefit for named executive officers, other than Mr. May, effective December 31, 2007. The Committee replaced these benefits with a one-time $10,000 increase to the HEI executive's base salary, beginning on January 1, 2008. Mr. May continued to have his automobile and gas allowance, along with other subsidiary utility executives, and so he did not receive a base salary

increase related to the automobile allowance elimination. Consequently, the named executive officers received the following salary increases, effective January 1, 2008:

Name	$ Base Salary Increase	Base Salary, Effective January 1, 2008
Constance H. Lau	$ 10,000	$ 746,000
Eric K. Yeaman	10,000	414,000
T. Michael May	—	598,000
Patricia U. Wong	10,000	276,300
Curtis Y. Harada	10,000	209,000

At its meeting on January 22, 2008, the Board approved the Compensation Committee's recommendation of an annual base salary for Mr. Yeaman of $430,000, an increase of $16,000 or 3.9%, effective February 1, 2008, in his new role as Hawaiian Electric Company Senior Executive Vice President and Chief Operating Officer. Mr. Yeaman is also eligible for a base salary increase of up to $20,000 six months after joining Hawaiian Electric Company, based on satisfactory performance to be determined by Mr. May. At the same meeting on January 22, 2008, the Board approved the Compensation Committee's recommendations regarding the compensation of Mr. Harada as HEI Controller and Acting Financial Vice President, Treasurer and Chief Financial Officer. Effective February 1, 2008, Mr. Harada will receive a $15,000 monthly bonus for every month he serves as Acting HEI Financial Vice President, Treasurer and Chief Financial Officer, while retaining his role and compensation as HEI Controller. The promotion increase for Mr. Yeaman and the bonus for Mr. Harada were based on the increased responsibilities in their new positions.

The Compensation Committee is aware of the internal pay levels within the organization and believes that the comparative compensation among executives is fair, considering job scope, experience, value to the organization, and duties relative to the other named executive officers: Ms. Lau holds multiple positions, as (i) President and Chief Executive Officer of HEI, (ii) Chairman of the Boards of Hawaiian Electric Company and American Savings Bank, and (iii) Chief Executive Officer of American Savings Bank. Her compensation reflects her leadership of a publicly traded mid-cap holding company and her responsibilities for guiding two diverse and regulated operating subsidiaries. Mr. May, President and Chief Executive Officer at Hawaiian Electric Company, is the next highest paid named executive officer and his compensation reflects his role as head of a major operating subsidiary. In 2007, Mr. Yeaman, the next highest paid named executive officer, was the HEI Financial Vice President, Treasurer and Chief Financial Officer and a certifying officer responsible for overseeing the financial performance of the holding company. For 2008, Mr. Yeaman has taken on significant operating responsibility with his new position at Hawaiian Electric Company. The compensation of Ms. Wong, HEI Vice President-Administration and Corporate Secretary, is based on the scope of her duties in that role. In 2007, Mr. Harada was the HEI Controller; which is a manager position, and his compensation was commensurate with that role.

What is HEI's annual executive incentive compensation program?

The Compensation Committee establishes annual incentive awards based upon the achievement of financial and operational goals. Annual incentive awards for the executives are percentages of the executives' respective salary midpoints (the middle salary level in a salary range for a particular job grade or position). The annual incentive goals motivate executives and encourage their commitment to HEI's success. Shareholders benefit from the achievement of these goals.

The Compensation Committee believes that if HEI has not performed well enough to promote shareholder value, incentives should not be paid. The Committee establishes minimum financial performance thresholds that HEI must meet before annual incentive awards are paid. Even if HEI meets other goals, the annual incentives are not paid if these minimum financial performance thresholds are not met.

What were the goals and award ranges for the 2007 annual incentive plan?

The following were the award ranges, shown as a percentage of the salary midpoint, that the Compensation Committee approved for the 2007 annual incentive plan:

Name	Minimum	Target	Maximum	2007 salary midpoint
Constance H. Lau	42.5%	85%	170%	$ 756,000
Eric K. Yeaman	25.0%	50%	100%	394,000
T. Michael May	30.0%	60%	120%	566,000
Patricia U. Wong	22.5%	45%	90%	298,000
Curtis Y. Harada	20.0%	40%	80%	207,000

In 2007, Ms. Lau, Mr. Yeaman, Ms. Wong and Mr. Harada had an HEI earnings per share (as defined below) minimum threshold of $1.15 per share for their annual incentives. Mr. May had a consolidated utility net income threshold of $62.252 million for his annual incentive. (Consolidated utility means the combined utility results for (1) Hawaiian Electric Company, which provides electricity to the Island of Oahu, (2) Hawaii Electric Light Company, Inc., which provides electricity to the Island of Hawaii, and (3) Maui Electric Company, Limited, which provides electricity to the islands comprising the County of Maui.)

In addition to the minimum thresholds, the Compensation Committee established the following annual financial and other operational goals for the named executive officers for 2007:

Name	Weight		Performance Metric	Target Goal
Constance H. Lau Eric K. Yeaman Patricia U. Wong Curtis Y. Harada	40%	(1)	HEI Earnings Per Share	$1.28 per share
	30%	(2)	Utility Consolidated Modified Free Cash Flow	$14.183 million
	30%	(3)	Bank Return on Assets	0.887%
	100%			
T. Michael May	35%	(4)	Utility Consolidated Net Income	$69.2 million
	35%	(2)	Utility Consolidated Modified Free Cash Flow	$14.183 million
	20%	(5)	Hawaiian Electric Company Return on Average Common Equity	7.34%
	6%	(5)	Hawaii Electric Light Company Return on Average Common Equity	3.32%
	4%	(5)	Maui Electric Company Return on Average Common Equity	5.55%
	100%			

The above goals were approved by the Compensation Committee and were designed to align management decisions with shareholder value. Particular goals and weightings were assigned to executives, depending on their areas of focus.

(1)
HEI Earnings Per Share represents the portion of HEI's profit allocated to a share of common stock using the average outstanding for the period. It is a common performance metric of publicly held companies. It is also a Generally Accepted Accounting Principles measure.

(2)
Utility Consolidated Modified Free Cash Flow represents the cash that the utilities generate after financing their operations and the expansion of their asset bases. It excludes the change in the working capital component. It is calculated by adding utility net income, plus depreciation and amortization expense, less net capital expenditures.

(3)
Bank Return on Assets is an indicator of how efficiently the bank utilizes its assets to generate earnings and is a common financial institution measurement. It is calculated by dividing bank net income by average total assets. This measure is derived from Generally Accepted Accounting Principles measures (net income and total assets).

(4)
Utility Consolidated Net Income is a basic financial measurement of the consolidated utility's earnings for the year. The utility's consolidated net income contributes directly to HEI's net income and its earnings per share. Net income is a Generally Accepted Accounting Principles measure.

(5)
Utility Return on Average Common Equity is the ratio of each respective utility's net income to average common equity. It is a key indicator of profitability from a utility investor standpoint; a key measure of reasonable return from a regulatory standpoint; and a key measure that drives the level of net income that the respective utility company can earn. This measurement is derived from Generally Accepted Accounting Principles measures (net income and total common equity).

Each target goal was based on the forecast for HEI. The minimum performance goal was set at a minimum expectation level for a particular goal and the maximum performance goal was set at a level above the target that is a stretch goal.

What were the payouts for the 2007 annual incentive plan?

In 2007, HEI did not meet its minimum HEI earnings per share threshold of $1.15 per share and did not achieve its consolidated utility net income threshold of $62.252 million. Thus, no payouts were earned in 2007 by any named executive officer and none was paid.

What are the metrics and award ranges for the 2008 annual incentive plan?

At its meeting on February 19, 2008, the Compensation Committee approved the following award ranges for the named executive officers, shown as a percentage of the salary midpoint, for the 2008 annual incentive plan:

Name	Minimum	Target	Maximum	2008 projected salary midpoint
Constance H. Lau	42.5%	85%	170%	$ 776,000
Eric K. Yeaman (1)	25.0%	50%	100%	405,000(HEI) 441,000 (HECO)
T. Michael May	30.0%	60%	120%	581,000
Patricia U. Wong	22.5%	45%	90%	306,000
Curtis Y. Harada	20.0%	40%	80%	213,000

(1)
For the 2008 annual incentive plan, Mr. Yeaman's salary midpoint will be prorated with 1 month at his HEI Financial Vice President, Treasurer and Chief Financial Officer grade and 11 months at his Hawaiian Electric Company Senior Executive Vice President and Chief Operating Officer grade.

An HEI earnings per share minimum threshold for Ms. Lau, Ms. Wong and Mr. Harada has been set under the 2008 annual incentive plan. A consolidated utility net income minimum threshold for Mr. May and Mr. Yeaman has been set under the utility 2008 annual incentive plan at 10% below HEI's target forecast. Even if HEI meets other goals, the annual incentives will not be paid if the thresholds are not met. Over the last ten-year period, HEI met the minimum earnings per share threshold 70% of the time.

The Committee established the following performance metrics for the named executive officers for the 2008 annual incentive plan:

Name	Weight	Performance Metric
Constance H. Lau	40%	HEI Earnings Per Share
Patricia U. Wong	30%	Utility Consolidated Free Cash Flow
Curtis Y. Harada	30%	Bank Return on Assets
	100%	
T. Michael May	35%	Utility Consolidated Net Income
Eric K. Yeaman	35%	Utility Consolidated Free Cash Flow
	30%	Utility Operational Goals
	100%	

The calculation of the utility's free cash flow in 2008 will not exclude the change in working capital component. Free cash flow is equal to net cash provided by operating activities less net capital expenditures and is more commonly used as a measurement than modified free cash flow. Free cash flow is a more useful measurement for annual incentive determination purposes. The utility operational goals for Mr. May and Mr. Yeaman focused on operational milestones regarding expanding renewable energy generation, regulatory filings, and progress with respect to critical utility projects.

Disclosure of the specific minimum, target and maximum goals of an ongoing or future performance period would result in competitive harm to HEI. American Savings Bank has several competitors who could determine what American Savings Bank's proprietary market strategy is with the publication of American Savings Bank's specific operational metrics. It would be especially hard to compete with private financial institutions that do not have to disclose their performance metrics or strategies. Disclosure could give independent power producers a better view of the utility's cost structures and information concerning company strategies and other sensitive matters to which they otherwise would not have access. Furthermore, HEI has a long-held policy of not providing earnings guidance for critical business reasons and this policy differentiates us from competitors. HEI believes that providing the quantitative disclosure of the financial and operational goals established for the annual or long-term incentive plans before the performance period has ended would in effect provide earnings guidance that it does not currently provide.

The minimum, target and maximum award levels for the 2008 annual incentive plan have been set based on the forecast and/or operational schedules. The 2008 annual incentive goals are not easy to achieve and payout is by no means guaranteed. The two core operating subsidiaries face tough external challenges in 2008. The utility needs to make major capital investments in the next few years, which requires timely regulatory approval and adequate cost recovery of such investments. The bank faces higher funding costs and loan loss provision expenses due to the credit and tough yield curve environment and plans new strategic initiatives to offset these expenses. The Compensation Committee believes that the targets set by HEI are challenging but achievable. If HEI is successful in achieving these goals, shareholder value is expected to increase. The 2008 incentive compensation program is critical to supporting management's execution of key initiatives that are required to build a strong strategic and financial foundation for future years. It is important to have a program that balances the interests of shareholders and the need to retain and motivate management.

What is HEI's long-term incentive plan?

HEI's long-term incentive plan rewards executives based on HEI's successful financial performance over rolling three year performance periods. The three-year performance period provides balance with the shorter-term focus of the annual incentive compensation plan. HEI pays long-term incentive awards in a combination of cash (60%) and HEI Common Stock (40%). HEI awards a portion of the long-term incentive payout in shares to promote HEI Common Stock ownership. The Compensation Committee establishes long-term incentive goals based on achievement of strategic goals that enhance long-term shareholder value. A new three-year performance period starts each year.

The Compensation Committee establishes award levels and performance goal weightings for each of the participants. The Committee generally targets the long-term incentive of the named executive officers at the 50th percentile or midpoint of pay practices found in the bank and utility peer companies listed above. Long-term incentive awards for the executives are percentages of the executives' respective salary midpoints.

What were the goals and award ranges for the 2005-2007 long-term incentive plan?

The Committee approved the following award ranges, shown as a percentage of the salary midpoint, for the 2005-2007 long-term incentive plan:

Name	Minimum	Target	Maximum	2007 salary midpoint
Constance H. Lau (1)	37.5%	75%	150%	$ 624,000(ASB) 756,000(HEI)
Eric K. Yeaman	30%	60%	120%	394,000
T. Michael May	37.5%	75%	150%	566,000
Patricia U. Wong	30%	60%	120%	298,000
Curtis Y. Harada	20%	35%	70%	207,000

(1)
For the 2005-2007 long-term incentive plan, Ms. Lau's salary midpoint was prorated with 16 months at her American Savings Bank President and Chief Executive Officer grade and 20 months at her HEI President and Chief Executive Officer grade.

The Compensation Committee established the following long-term incentive goals for the named executive officers for the 2005-2007 performance period:

Name	Weight		Performance Metric	Target Goal
Constance H. Lau	40%	(1)	Bank Return on Equity	11.34%
	40%	(2)	Bank Net Income	$66.983 million
	10%	(3)	Bank Fee Income	$45.452 million
	10%	(4)	Bank Efficiency Ratio	59.62%
	100%			
T. Michael May	50%	(5)	Utility Consolidated Return on Average Common Equity vs. Allowed Return	95%
	30%	(6)	HEI Annual Return on Average Common Equity	10.98%
	20%	(7)	HEI Total Return to Shareholders	50th percentile of the Edison Electric Institute Index*
	100%			
Eric K. Yeaman Patricia U. Wong	60%	(6)	HEI Annual Return on Average Common Equity	10.98%
Curtis Y. Harada	40%	(7)	HEI Total Return to Shareholders	50th percentile of the Edison Electric Institute Index*
	100%			

The Compensation Committee established long-term incentive goals for the named executive officers, depending on their role in providing long-term shareholder value.

On February 29, 2005, when the award ranges were set by the Compensation Committee for the 2005-2007 long-term incentive awards, Ms. Lau's 2005-2007 long-term incentive plan goals were focused on the success of the bank. Mr. May's goals were a blend of HEI and utility goals. The goals for Mr. Yeaman, Ms. Wong and Mr. Harada were focused on HEI.*(1)*
Bank Return on Equity reveals how much profit is generated by the bank with its equity. It is based on the capital structure of American Savings Bank. No adjustment is made for the holding company debt to acquire and support the equity of the bank.

(2)
Bank Net Income is a basic financial measurement revealing the bank's bottom-line earnings. Net income and net income growth are the most significant sources of funding from the bank for HEI's external dividend. This measure reflects the results of the bank's financial performance in alignment with its strategic plan.

(3)
Bank Fee Income is generated by products such as account service charges, overdrafts, and fees for insufficient funds.

(4)
Bank Efficiency Ratio reveals how efficiently the bank spends its funds in relation to the income it generates. The efficiency ratio is calculated as follows:

$$\frac{\text{Noninterest Expense (excluding amortization of intangible assets)}}{\text{Net interest income + noninterest income}}$$

(5)
Utility Consolidated Return on Average Common Equity vs. Allowed Return is a useful measurement for comparing the utility's earnings to the earnings regulators have determined is reasonable in the

ratemaking proceeding of each respective utility. It encourages each utility to earn near its allowed regulated return.*(6)*
HEI Annual Return on Average Common Equity is a useful measurement for comparing profitability. It is derived from Generally Accounting Principles measures and calculated by dividing net income by average common equity.

(7)
HEI Total Return to Shareholders is a performance measure to show the return of a stock to an investor. HEI's total return is compared to that of the Edison Electric Institute Index of investor-owned electric companies. It is a primary measure that reflects value created for shareholders in comparison with the value being generated by other companies in the electric utility industry.

*
The Edison Electric Institute is an association of U.S. investor-owned electric companies and is representative of companies that are comparable investment alternatives to HEI. The Institute's members serve 95% of the ultimate customers in the investor-owned segment of the industry and represent approximately 70% of the U.S. electric power industry. The Edison Electric Institute Index measures performance data for over 60 U.S. investor-owned electric utilities. The performance of the companies in the Index is calculated on a noncapitalized weighted basis so as not to give a disproportionate emphasis to the larger companies. In 2007, the following companies were in the Edison Electric Institute Index:

Allegheny Energy Inc.
Allete Inc.
Alliant Energy Corp
Ameren Corp.
American Electric Power Co.
Aquila Inc.
Black Hill Corp
Avista Corp.
Centerpoint Energy Inc.
Central Vermont Public Service Corp
CH Energy Corp
CLECO Corp
CMS Energy Corp
Consolidated Edison Inc.
Constellation Energy Group Inc.
Dominion Resources Inc.
DPL Inc.
DTE Energy Co.
Duke Energy Corp
Edison International
El Paso Electric Co.
Empire District Electric Co.
Energy East Corp
Entergy Corp
Exelon Corp
Great Plains Energy Inc.
Hawaiian Electric Industries Inc.
Idacorp Inc.
Integrys Energy Group
Maine and Maritimes Corp
MDU Resources Group Inc
MGE Energy Inc.
NISOURCE Inc.
Northeast Utilities
Northwester Corp.
NSTAR
Otter Tail Corp
Pepco Holdings Inc.
PG&E Corp
Pinnacle West Capital Corp.
PPL Corp
PNM Resources, Inc.
Progress Energy, Inc.
Public Service Enterprise Group, Inc.
Puget Energy Inc.
Scana Corp
Sempra Energy
Sierra Pacific Resources
Southern Co
TECO Energy Inc.
TXU Corp
UIL Holdings Corp.
UniSource Energy
Westar Energy Inc.
Xcel Energy Inc
Vectren Corp.
Wisconsin Energy Corp.

What were the payouts under the 2005-2007 long-term incentive plan?

The only long-term incentive goal set by the Compensation Committee for the 2005-2007 performance period that was met was the American Savings Bank fee income goal. This fee income incentive is paid if the actual average fee income achieved meets the minimum hurdle at least two out of three years. The target goal for bank fee income was $45.452 million. The actual average fee income achieved in this three-year period was $47.400 million and the minimum hurdles were also achieved in all three out of the three years.

Consequently, Ms. Lau was the only named executive officer who achieved a long-term incentive goal during this period. She received an actual award payout of $67,245, 60% of which was paid in cash and 40% of which was paid in HEI Common Stock.

What are the metrics and award ranges for the 2007-2009 long-term incentive plan?

At its meeting on February 20, 2007, the Compensation Committee approved long-term incentive goals for the 2007-2009 period for each of the named executive officers. The award ranges, shown as a percentage of the salary midpoint, for the named executive officers are as follows:

Name	Minimum	Target	Maximum	2009 projected salary midpoint
Constance H. Lau	65%	130%	260%	$ 794,000
Eric K. Yeaman (1)				414,000(HEI)
	30%	60%	130%	451,000 (HECO)
T. Michael May	40%	80%	170%	595,000
Patricia U. Wong	30%	60%	120%	313,000
Curtis Y. Harada	20%	40%	80%	217,000

(1)
For the 2007-2009 long-term incentive plan, Mr. Yeaman's salary midpoint will be prorated with 13 months at his HEI Financial Vice President, Treasurer and Chief Financial Officer grade and 23 months at his Hawaiian Electric Company Senior Executive Vice President and Chief Operating Officer grade.

The Committee established the following performance measures for the named executive officers:

Name	Weight	Performance Metric
Constance H. Lau	40%	HEI Total Return to Shareholders
Eric K. Yeaman	15%	Utility Consolidated Modified
Patricia U. Wong		Free Cash Flow
Curtis Y. Harada	15%	Utility Consolidated Ratemaking Return on Average Common Equity vs. Allowed Return
	15%	Bank Net Income
	15%	Bank Return on Assets
	100%	
T. Michael May	50%	Utility Consolidated Modified Free Cash Flow
	30%	Utility Consolidated Ratemaking Return on Average Common Equity vs. Allowed Return
	20%	HEI Total Return to Shareholders
	100%	

The awards were set based on forecast. Specific minimum, target and maximum goals are not disclosed here because disclosure for the ongoing performance periods would result in competitive harm to HEI for the reasons described above in regard to the 2008 annual incentive plan. In the 2007-2009 horizon, the two core operating subsidiaries face tough external challenges. Extraordinary leadership on the part of the named executive officers will be needed to achieve the long-term strategic objectives required for incentive payouts. The utility needs to make major capital investments in the next few years, which requires timely regulatory approval and adequate cost recovery of such investments. The bank faces higher funding costs and loan loss provision expenses due to the credit and yield curve environment. The Compensation Committee believes that the long-term incentive targets set

by HEI are aggressive and if HEI is successful in achieving these goals, shareholder value is expected to increase.

What are the metrics and award ranges for the 2008-2010 long-term incentive plan?

At its meeting on February 19, 2008, the Compensation Committee approved long-term incentive performance metrics for the 2008-2010 period for each of the named executive officers. The award ranges, shown as a percentage of the salary midpoints, for the named executive officers are as follows:

Name	Minimum	Target	Maximum	2010 projected salary midpoint
Constance H. Lau	65%	130%	260%	$ 815,000
Eric K. Yeaman (1)				426,000(HEI)
	30%	60%	130%	463,000 (HECO)
T. Michael May	40%	80%	170%	610,000
Patricia U. Wong	30%	60%	120%	321,000
Curtis Y. Harada	20%	40%	80%	224,000

(1)
For the 2008-2010 long-term incentive plan, Mr. Yeaman's salary midpoint will be prorated with 1 month at his HEI Financial Vice President, Treasurer and Chief Financial Officer grade and 35 months at his Hawaiian Electric Company Senior Executive Vice President and Chief Operating Officer grade.

The Committee established the following performance measures for the named executive officers:

Name	Weight	Performance Metric
Constance H. Lau		
	40%	HEI Total Return to Shareholders
Patricia U. Wong		
	15%	Utility Consolidated Free Cash Flow
Curtis Y. Harada		
	15%	Utility Consolidated Ratemaking Return on Average Common Equity vs. Allowed Return
	15%	Bank Net Income
	15%	Bank Return on Assets
	100%	
T. Michael May		
	50%	Utility Consolidated Free Cash Flow
Eric K. Yeaman		
	30%	Utility Consolidated Ratemaking Return on Average Common Equity vs. Allowed Return
	20%	HEI Total Return to Shareholders
	100%	

As noted above, the focus of these goals is to create shareholder value. Awards were set based on budget forecasts. Disclosure of the specific minimum, target and maximum goals for the 2008-2010 performance period would result in competitive harm to HEI for the reasons described above. Over the last ten-year period HEI achieved a long-term incentive plan total return to shareholders payout and a long-term incentive plan utility consolidated return on average common equity payout approximately 40% of the time. The Compensation Committee believes that the long-term incentive targets set by HEI are aggressive.

How does HEI award stock and options to executive officers?

HEI provides stock awards to executives to strengthen the link of executive interests with improvement in shareholder value. The long-term incentive awards described above are performance-based and paid partially in stock. Other stock awards granted to the executives increase the total long-term compensation opportunities of the executives. The Compensation Committee determines the number of shares awarded in time-vesting stock grants, versus the shares that are performance-based under the long-term incentive plan, in consultation with Towers Perrin, considering peer practices. Towers Perrin's December 8, 2006 total rewards assessment for HEI's named executive officers found that HEI's long-term incentive compensation, including stock awards, was below long-term compensation opportunities at peer companies and that target long-term incentive grants need selective upward adjustments to be competitive. Those adjustments were not made in 2007, in light of HEI's financial challenges in 2007.

Under the 1987 Stock Option and Incentive Plan, as amended effective January 22, 2008, HEI may grant nonqualified stock options, incentive stock options, restricted stock, stock appreciation rights, stock payments and dividend equivalents. Before 2006, HEI typically granted equity awards in the form of nonqualified stock options and stock appreciation rights with dividend equivalents. Section 409A of the Internal Revenue Code, enacted in 2004, caused HEI to change the way that dividend equivalents are paid to executives. As a result, since 2006, HEI has been utilizing grants of restricted stock to provide executives with equity-based compensation. Restricted stock awards represent an increasingly prevalent long-term incentive approach to equity-based compensation. Quarterly dividends on the restricted stock shares are paid in cash to the executives during the vesting period.

On April 12, 2007, the Compensation Committee granted restricted shares of HEI Common Stock that will cliff vest four years from the grant date, meaning that they will all vest at once at the end of the vesting year. In determining the number of shares to grant the named executive officers, the Committee considered the recommendations of Towers Perrin with respect to practices in peer banking and utility companies and the need to retain valued executives through multi-year vesting.

What perquisites do executive officers have?

Company executive perquisites are limited. During 2007, the named executive officers were eligible for an automobile and gas allowance and business parking, club memberships, and voluntary annual physical exams. HEI reimbursed Ms. Lau and Mr. May for their spouses' travel expenses when their spouses accompanied them to meetings where spouse attendance was required or expected; the reimbursement is imputed as taxable income to Ms. Lau and Mr. May. In 2007, Mr. May and Ms. Lau received a residential electricity discount. Ms. Lau also received a preferential rate loan and additional Internet service at home in order to monitor residential security.

In 2007, named executive officers, as well as certain subsidiary executives, were allowed to take an indeterminate number of vacation days, consistent with the heavy workload demands of their positions. Based on the recommendation of the Compensation Committee, which was approved by the HEI Board, executives will be subject to the standard vacation policy of their respective companies effective January 1, 2008. The HEI President and Chief Executive Officer has the discretion to approve exceptions for individual executives to take up to four weeks of vacation and to waive any waiting period.

Do executive officers have change-in-control agreements?

HEI has change-in-control agreements with the named executive officers. HEI gives change-in-control agreements to executives to recruit them and to protect them in the event HEI is sold or otherwise disposed of, jeopardizing their employment. The agreements define a change-in-control to mean essentially a change in ownership of HEI or substantial change in the voting power of HEI's securities or a change in the majority of the composition of the Board following a merger, tender offer or similar transaction. From HEI's perspective, change-in-control agreements

protect against executive flight during the transaction when key executives may sign with competitors. These agreements encourage the continued attention of key executives to the performance of their assigned duties without distraction. The Compensation Committee considers change-in-control agreements very carefully, taking into account the executive's expected role in a potential transaction, value to the organization, service to HEI, and fairness.

HEI's change-in-control agreements are double-trigger, meaning that even if a change-in control were to occur, an executive who retains his or her job for two years after the change-in-control would not get any payments under the agreement. An executive is paid only if both (1) a change-in-control occurs and (2) either the executive (a) is terminated without cause or (b) leaves for good reason. The agreements generally define "cause" as intentional or willful acts of executive misconduct, such as fraud, embezzlement or misappropriation of assets, or acts causing material harm to HEI. "Good reason" is defined generally as failure by HEI to live up to its commitments, such as material breaches of its compensation, job responsibilities or benefits arrangements with the executive.

Components of compensation under HEI's change-in-control agreements are based on preserving the full tax deductibility of the benefits and providing total compensation that is competitive with peer group practices. Using principles developed under Section 280G of the Internal Revenue Code, HEI will pay a named executive officer who is terminated without cause or leaves for good reason within two years after a change-in-control a lump sum severance payment equal to 2.99 times his or her average Internal Revenue Service Form W-2 earnings for the most recent five years. Any payment will be subject to withholding taxes and will be limited to an amount that is not subject to a deduction disallowance when aggregated with other amounts required to be considered under the tax law. Where a termination without cause has occurred, HEI also will pay outplacement service fees on the key executive's behalf, not to exceed 30% of his or her annual base salary at the time of the change-in-control. These outplacement benefits were determined taking into consideration peer group practices and the amount of benefits considered fair and appropriate.

In 2007, HEI did not pay any benefits under the change-in-control agreements.

Do executive officers have executive death benefits?

HEI provides all named executive officers with death benefits payable to their beneficiaries upon the executive's death under the Executive Death Benefit Plan of HEI and Participating Subsidiaries. The plan provides death benefits equal to two times the executive's base salary if the executive dies while actively employed or, if disabled, dies prior to age 65. The plan provides death benefits equal to the executive's base salary if the executive dies after retirement. Death benefits are grossed up by the amount necessary to pay income taxes on the grossed up benefit amount.

What retirement benefits do executive officers have?

Qualified Plans

HEI Retirement Plan. All regular employees of HEI (including the named executive officers) participate in the Retirement Plan for Employees of HEI and Participating Subsidiaries (HEI Retirement Plan), a noncontributory, qualified defined benefit pension plan. Retirement benefits under the plan are based on a formula calculated as a percentage of years of service (up to a maximum of 67%) multiplied by final average base salary as defined under the plan. Early retirement benefits are available for participants who meet the age and service requirements, starting at age 50, with 15 years of service, and benefits are reduced for participants who retire prior to age 60. Benefits are vested when a participant completes five years of service or attains age 65.

Nonqualified Plans

HEI Excess Pay Plan. HEI has also adopted the HEI Excess Pay Supplemental Executive Retirement Plan (HEI Excess Pay Plan), a noncontributory, nonqualified plan, to make up for the

portion of benefits that cannot be paid from the HEI Retirement Plan due to Internal Revenue Code limits. Under the Internal Revenue Code, the amount of annual compensation for purposes of calculating benefits payable from qualified plans such as the HEI Retirement Plan is limited (to $225,000 in 2007). The HEI Excess Pay Plan provides the excess benefits so that highly compensated employees may have a similar percentage of their base salary included in calculating retirement benefits as other employees who are not subject to these limits. As of December 31, 2007, Ms. Wong is the only named executive officer participating in and is eligible for immediate pension benefits under the HEI Excess Pay Plan.

HEI Supplemental Executive Retirement Plan. HEI has adopted the HEI Supplemental Executive Retirement Plan, a noncontributory, nonqualified plan for its Chief Executive Officer and other executives designated by the Compensation Committee in recognition of the integral role of these critical executives. Unlike the above plans, this enhanced supplemental executive retirement plan gives participants the potential for additional retirement income by including annual incentive compensation awards in the calculation of benefits. In determining which executives to include in this enhanced retirement benefit plan, the Compensation Committee considered the need to attract and retain HEI's top talent and the benefits available to top executives in peer companies. Currently, Ms. Lau, Mr. Yeaman and Mr. May participate in the HEI Supplemental Executive Retirement Plan.

Retirement benefits under these plans specific to the named executive officers are discussed in further detail in the Pension Benefits table and related notes on pages 47-49.

Executive Compensation

Summary Compensation Table

The following summary compensation table shows the base salary, annual bonus, stock awards, option awards, non-equity incentive compensation, change in pension value and nonqualified deferred compensation earnings, and all other compensation and benefits earned by the named executive officers during 2006 and 2007.

SUMMARY COMPENSATION TABLE

Name and 2007 Principal Positions	Year	Salary ($)	Bonus ($) (1)	Stock Awards ($) (2)	Option Awards ($) (3)	Non-Equity Incentive Plan Compensation ($) (4)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($) (5)	All Other Compensation ($) (6)	Total ($)
Constance H. Lau	2007	736,000	—	273,540	84,562	67,245	499,747	51,326	1,712,420
HEI President & Chief Executive Officer	2006	680,667	—	143,202	144,312	191,449	2,500,135	41,555	3,701,320
American Savings Bank Chair, President & Chief Executive Officer, Hawaiian Electric Company Chair									
Eric K. Yeaman	2007	398,575	—	55,267	90,896	—	69,220	18,277	632,235
HEI Financial Vice President, Treasurer and Chief Financial Officer	2006	382,333	—	63,240	113,021	—	44,141	16,606	619,341
T. Michael May	2007	590,650	—	88,427	84,562	—	—	28,757	792,396
Hawaiian Electric Company President and Chief Executive Officer	2006	571,334	—	36,955	144,312	—	389,129	21,317	1,163,047
Patricia U. Wong	2007	262,695	—	33,160	19,452	—	174,994	17,640	507,941
HEI Vice President—Administration and Corporate Secretary	2006	252,667	—	13,858	63,182	—	124,448	19,629	473,784
Curtis Y. Harada	2007	196,655	—	22,107	16,490	—	88,455	15,570	339,277
HEI Controller	2006	190,300	—	9,239	25,362	—	90,298	15,896	331,095

(1)
No discretionary bonuses without pre-established goals were given to named executive officers in 2006 or 2007.

(2)
Represents recognition of stock expense in HEI's financial statements, without reduction for forfeitures for restricted stock awards. For a discussion of the assumptions underlying the amounts set out for restricted stock, see Note 9 to HEI's Notes to Consolidated Financial Statements under Item 8 of HEI's Form 10-K for the year ended December 31, 2007.

(3)
Represents recognition of option expense in HEI's financial statements, without reduction for forfeitures, for nonqualified stock options with dividend equivalents granted in 2002 and 2003 and stock appreciation rights with dividend equivalents granted in 2004 and 2005. For a discussion of the assumptions underlying the amounts set out for option awards, see Note 9 to HEI's Notes to Consolidated Financial Statements under Item 8 of HEI's Form 10-K for the year ended December 31, 2007.

(4)
No annual Executive Incentive Compensation Plan awards were earned by the named executive officers in 2007 or 2006. Long-term incentive plan awards are determined in the first quarter of

each year for the three-year cycle ending on December 31 of the previous calendar year. Ms. Lau achieved long-term incentive plan awards for the 2004-2006 and 2005-2007 performance periods.*(5)*
The 2007 amounts represent the change in pension and executive death benefit values from December 31, 2006 to December 31, 2007. The 2006 amounts represent the change in pension and executive death benefit values from December 31, 2005 to December 31, 2006. No named executive officer currently participates in the HEI Nonqualified Deferred Compensation Plan. Ms. Lau participates in the American Savings Bank Deferred Compensation Plan, but she was credited with no preferential earnings during 2007 or 2006. At the beginning of 2006, Ms. Lau participated in the ASB Supplemental Executive Retirement Plan; upon her promotion to HEI President and Chief Executive Officer, she was granted participation in the HEI Supplemental Executive Retirement Plan. Ms. Lau's credited years of service under the HEI Supplemental Executive Retirement Plan reflects her actual years of service with all HEI affiliated companies. The aggregate increases and decreases in value of Mr. May's individual pension and executive death benefit plans resulted in a negative change in pension value for 2007 and is not included in Mr. May's change in pension value above. For a further discussion of these plans, see the Pension Benefits table and related notes on pages 47-49 and Nonqualified Deferred Compensation Table and notes on page 50.

(6)
In 2007, Ms. Lau received the benefit of preferential mortgage loan interest valued at $27,375, an automobile and gas allowance, business parking, club memberships, spousal travel expenses, internet service at home in order to provide extra home security protection, and an electricity discount at her residence. Mr. Yeaman received an automobile and gas allowance, business parking, and club memberships. Mr. May received an automobile and gas allowance, business parking, club memberships, and spousal travel expenses. Ms. Wong and Mr. Harada each received an automobile and gas allowance, business parking, and a club membership. Ms. Wong also received a physical exam.

One of the purposes of the stock awards is retention and there are no conditions to vesting other than the four-year cliff vesting period. Additional narrative disclosure about salary, bonus, stock awards, option awards, non-equity incentive plan compensation, change in pension value, nonqualified deferred compensation, and other compensation can be found in the Compensation Discussion and Analysis on pages 25 to 41.

Grants of Plan-Based Awards

The following table relates to awards to the named executive officers in 2007 under the annual Executive Incentive Compensation Plan tied to performance for 2007 and under the Long-Term Incentive Plan tied to performance over the 2007-2009 period. Also shown are the restricted stock awards granted under the Stock Option and Incentive Plan in 2007.

2007 GRANTS OF PLAN-BASED AWARDS

		Estimated Future Payouts Under Non-Equity Incentive Plan Awards (1)			Estimated Future Payouts Under Equity Incentive Plan Awards						
Name	Grant Date	Threshold ($)	Target ($)	Maximum ($)	Threshold (#)	Target (#)	Maximum (#)	All Other Stock Awards: Number of Shares of Stock or Units (#) (2)	All Other Option Awards: Number of Securities Underlying Options (#)	Exercise or Base Price of Option Awards ($/Sh)	Grant Date Fair Value of Stock and Option Awards ($) (3)
Constance H. Lau	2/20/07	321,300	642,600	1,285,200	—	—	—	—	—	—	—
	EICP	516,100	1,032,200	2,064,400	—	—	—	—	—	—	—
	2/20/07 LTIP	NA	NA	NA	NA	NA	NA	16,000	NA	NA	416,320
	4/12/07 RS										
Eric K. Yeaman (4)	2/20/07	98,500	197,000	394,000	—	—	—	—	—	—	—
	EICP	124,200	248,400	538,200	—	—	—	—	—	—	—
	2/20/07 LTIP	NA	NA	NA	NA	NA	NA	5,000	NA	NA	130,100
	4/12/07 RS										
T. Michael May	2/20/07	169,800	339,600	679,200	—	—	—	—	—	—	—
	EICP	238,000	476,000	1,011,500	—	—	—	—	—	—	—
	2/20/07 LTIP	NA	NA	NA	NA	NA	NA	8,000	NA	NA	208,160
	4/12/07 RS										
Patricia U. Wong	2/20/07	67,050	134,100	268,200	—	—	—	—	—	—	—
	EICP	93,900	187,800	375,600	—	—	—	—	—	—	—
	2/20/07 LTIP	NA	NA	NA	NA	NA	NA	3,000	NA	NA	78,060
	4/12/07 RS										
Curtis Y. Harada	2/20/07	41,400	82,800	165,600	—	—	—	—	—	—	—
	EICP	43,400	86,800	173,600	—	—	—	—	—	—	—
	2/20/07 LTIP	NA	NA	NA	NA	NA	NA	2,000	NA	NA	52,040
	4/12/07 RS										

NA
Not applicable
EICP
Executive Incentive Compensation Plan (annual incentive)
LTIP
Long-Term Incentive Plan (2007-2009 period)
RS
Restricted stock

(1)
Includes awards under, respectively, HEI's 2007 annual Executive Incentive Compensation Plan and 2007-2009 Long-Term Incentive Plan based on meeting performance goals at threshold, target and maximum levels. See further discussion of the features of the awards in the Compensation Discussion and Analysis above on pages 31-32 and 37-38.

(2)
Represents shares of restricted stock that vest 100% after the four-year vesting period, with no incremental vesting. Dividends are payable on the shares prior to and after vesting at the same rate declared on all outstanding shares of HEI Common Stock.

(3)
Grant date fair value is based on the closing price of HEI Common Stock on the New York Stock Exchange on the date of the grant.

(4)
Mr. Yeaman's 2007-2009 long-term incentive plan award will be prorated based upon 13 months at his projected 2009 HEI salary midpoint and 23 months at his projected Hawaiian Electric Company salary midpoint.

One of the purposes of the stock awards is retention and there are no conditions to vesting other than the four-year cliff vesting period. Additional narrative disclosure about salary, bonus, stock awards, option awards, non-equity incentive plan compensation, change in pension value, nonqualified deferred compensation, and other compensation can be found in the Compensation Discussion and Analysis on pages 25 to 41.

Outstanding Equity Awards at Fiscal Year-End

OUTSTANDING EQUITY AWARDS AT 2007 FISCAL YEAR-END

		Option Awards (1)					Stock Awards (2)			
		Number of Securities Underlying Unexercised Options					Shares or Units of Stock That Have Not Vested		Equity Incentive Plan Awards	
Name	Grant Year	Exer-ciseable(#)	Unexer-ciseable (#)	Equity Incentive Plan Awards: Number of Securities Underlying Unexercised Unearned Options (#)	Option Exercise Price ($)	Option Expira-tion Date	Number (#)	Market Value ($)(3)	Number of Unearned Shares, Units, or Other Rights That Have Not Vested (#)	Market or Payout Value of Unearned Shares, Units, or Other Rights That Have Not Vested ($)
Constance H. Lau	1999	33,300	—	—	17.63	8/11/09	—	—	—	—
	1999 DE	9,913	—	—	—	8/11/09	—	—	—	—
	2000	40,000	—	—	14.74	4/24/10	—	—	—	—
	2000 DE	11,172	—	—	—	4/24/10	—	—	—	—
	2001	40,000	—	—	17.96	4/23/11	—	—	—	—
	2001 DE	9,409	—	—	—	4/23/11	—	—	—	—
	2002	50,000	—	—	21.68	4/22/12	—	—	—	—
	2002 DE	7,985	—	—	—	4/22/12	—	—	—	—
	2003	50,000	—	—	20.49	4/21/13	—	—	—	—
	2003 DE	5,452	—	—	—	4/21/13	—	—	—	—
	2004	37,500	12,500	—	26.02	4/19/14	—	—	—	—
	2004 DE	3,477	1,159	—	—	4/19/14	—	—	—	—
	2005	—	50,000	—	26.18	4/07/15	—	—	—	—
	2005 DE	—	2,706	—	—	4/07/15	—	—	—	—
	2006	NA	NA	NA	NA	NA	31,000	705,870	—	—
	2007	NA	NA	NA	NA	NA	16,000	364,320	—	—
	Total	298,208	66,365				47,000	1,070,190	—	—
Eric K. Yeaman	2003	20,000	—	—	20.49	4/21/13	—	—	—	—
	2003 DE	1,494	—	—	—	4/21/13	—	—	—	—
	2004	22,500	7,500	—	26.02	4/19/14	—	—	—	—
	2004 DE	2,582	861	—	—	4/19/14	—	—	—	—
	2005	—	30,000	—	26.18	4/07/15	—	—	—	—
	2005 DE	—	4,293	—	—	4/07/15	—	—	—	—
	2006	NA	NA	NA	NA	NA	5,000	113,850	—	—
	2007	NA	NA	NA	NA	NA	5,000	113,850	—	—
	Total	46,576	42,654				10,000	227,700	—	—
T. Michael May	2002	40,000	—	—	21.68	4/22/12	—	—	—	—
	2002 DE	6,388	—	—	—	4/22/12	—	—	—	—
	2003	50,000	—	—	20.49	4/21/13	—	—	—	—
	2003 DE	5,452	—	—	—	4/21/13	—	—	—	—
	2004	37,500	12,500	—	26.02	4/19/14	—	—	—	—
	2004 DE	3,477	1,159	—	—	4/19/14	—	—	—	—
	2005	—	50,000	—	26.18	4/07/15	—	—	—	—
	2005 DE	—	2,706	—	—	4/07/15	—	—	—	—
	2006	NA	NA	NA	NA	NA	8,000	182,160	—	—
	2007	NA	NA	NA	NA	NA	8,000	182,160	—	—
	Total	142,817	66,365				16,000	364,320	—	—
Patricia U. Wong	2003	2,000	—	—	20.49	4/21/13	—	—	—	—
	2003 DE	76	—	—	—	4/21/13	—	—	—	—
	2005	—	24,000	—	26.18	4/07/15	—	—	—	—
	2005 DE	—	1,310	—	—	4/07/15	—	—	—	—
	2006	NA	NA	NA	NA	NA	3,000	68,310	—	—
	2007	NA	NA	NA	NA	NA	3,000	68,310	—	—
	Total	2,076	25,310				6,000	136,620	—	—

Curtis Y. Harada	2002	4,000	—	—	21.68	4/22/12	—	—	—	—
	2002 DE	—	—	—	—	4/22/12	—	—	—	—
	2003	8,000	—	—	20.49	4/21/13	—	—	—	—
	2003 DE	291	—	—	—	4/21/13	—	—	—	—
	2004	7,500	2,500	—	26.02	4/19/14	—	—	—	—
	2004 DE	406	135	—	—	4/19/14	—	—	—	—
	2005	—	10,000	—	26.18	4/07/15	—	—	—	—
	2005 DE	—	541	—	—	4/07/15	—	—	—	—
	2006	NA	NA	NA	NA	NA	2,000	45,540	—	—
	2007	NA	NA	NA	NA	NA	2,000	45,540	—	—
	Total	20,197	13,176				4,000	91,080	—	—

NA
Not applicable
DE
Dividend equivalents

All information presented has been adjusted for the 2-for-1 stock split in June 2004.*(1)*
The 2004 stock appreciation rights grant vests in 25% annual installments and will be fully vested on April 19, 2008 and the 2005 stock appreciation rights grant vests on a cliff basis on April 7, 2009, following a four year vesting period.

(2)
The 2006 restricted stock award becomes unrestricted on May 13, 2010. The 2007 restricted stock award becomes unrestricted on April 12, 2011.

(3)
Market value is based upon the closing price of HEI Common Stock on the New York Stock Exchange of $22.77 as of December 31, 2007.

Option Exercises and Stock Vested

2007 OPTION EXERCISES AND STOCK VESTED

	Option Awards		Stock Awards	
Name	**Number of Shares Acquired on Exercise (#) (1)**	**Value Realized on Exercise ($) (2)**	**Number of Shares Acquired on Vesting (#)**	**Value Realized on Vesting ($)**
Constance H. Lau	29,809	469,454	—	—
Eric K. Yeaman	3,491	91,298	—	—
T. Michael May	19,669	288,486	—	—
Patricia U. Wong	2,397	62,676	—	—
Curtis Y. Harada	1,378	36,035	—	—

(1)
Includes shares acquired with respect to dividend equivalents due to changes made to the provisions for the award of dividend equivalents in light of Section 409A of the Internal Revenue Code: Ms. Lau, 8,072 shares, Mr. Yeaman, 3,491 shares, Mr. May, 8,072 shares, Ms. Wong, 2,397 shares and Mr. Harada, 1,378 shares. Also includes Ms. Lau's exercise of 16,700 nonqualified stock options and 5,037 accompanying dividend equivalents and Mr. May's exercise of 10,000 nonqualified stock options and 1,597 accompanying dividend equivalents.

(2)
Includes the value realized on shares acquired with respect to dividend equivalents due to changes made to the provisions for the award of dividend equivalents in light of Section 409A of the Internal Revenue Code: Ms. Lau, $211,071; Mr. Yeaman, $91,298; Mr. May, $211,071; Ms. Wong, $62,676; and Mr. Harada, $36,035. Also includes value realized on exercise of nonqualified stock options and accompanying dividend equivalents: Ms. Lau, $258,383 and Mr. May, $77,415.

Pension Benefits

The table below shows the present value as of December 31, 2007 of accumulated benefits for each of the named executive officers and the number of years of service credited to each such executive under the applicable pension plan and executive death benefit plan, determined using the interest rate, mortality rate, and other assumptions set out below, which are consistent with those used in HEI's financial statements. (See Note 8 to HEI's Notes to Consolidated Financial Statements Under Item 8 of HEI's Form 10-K for the year ended December 31, 2007.)

2007 PENSION BENEFITS

Name	Plan Name	Number of Years Credited Service (#)	Present Value of Accumulated Benefit ($) (5)	Payments During the Last Fiscal Year ($)
Constance H. Lau	HEI Retirement Plan (1)	16.8	832,197	—
	American Savings Bank Retirement Plan (1)	6.4	127,739	—
	HEI Supplemental Executive Retirement Plan (2)	23.3	4,403,847	—
	HEI Executive Death Benefit (3)	NA	302,266	—
Eric K. Yeaman	HEI Retirement Plan (1)	4.9	97,884	—
	HEI Supplemental Executive Retirement Plan (2)	4.9	83,022	—
	HEI Executive Death Benefit (3)	NA	23,709	—
T. Michael May	HEI Retirement Plan (1)	15.9	946,433	—
	HEI Supplemental Executive Retirement Plan (2)	15.9	1,773,175	—
	HEI Executive Death Benefit (3)	NA	361,758	—
Patricia U. Wong	HEI Retirement Plan (1)	17.6	654,456	—
	HEI Excess Pay Plan (4)	17.6	94,880	—
	HEI Executive Death Benefit (3)	NA	81,245	—
Curtis Y. Harada	HEI Retirement Plan (1)	18.4	608,170	—
	HEI Executive Death Benefit (3)	NA	71,866	—

NA Not applicable*(1)*
Normal retirement benefits under the HEI Retirement Plan are calculated based on a formula of 2.04% × Credited Service (maximum 67%) × Final Average Pay (average monthly base salary for highest thirty-six consecutive months out of the last ten years). Credited service is generally the same as the years of service with HEI or other participating companies (Hawaiian Electric Company, Maui Electric Company, and Hawaii Electric Light Company). Additional credited service of up to eight months is used to calculate benefits for participants who retire at age 55 or later with respect to unused sick leave from the current year and prior two years. Credited service is also granted to disabled participants who are vested at the time of disability for the period of disability. The normal form of benefit is a joint and 50% survivor annuity for married participants and a single life annuity for unmarried participants. Other actuarially equivalent optional forms of benefit are also available. Participants who qualify to receive benefits immediately upon termination may also elect a single sum distribution of up to $50,000 with the remaining benefit payable as an annuity. At early retirement, the single sum distribution option is not actuarially equivalent to the other forms of benefit. Retirement benefits are increased by an amount equal to three percent (3%) of the initial benefit every twenty-four months following retirement. The plan provides benefits at early retirement (prior to age 65), normal retirement (age 65), deferred retirement (over age 65) and death. Early retirement benefits are available for participants who meet the age and service requirements at ages 50-64. Early retirement benefits are reduced for participants who retire prior to age 60, based on the participant's age at the early retirement date. The accrued normal retirement benefit is reduced by an applicable percentage, which ranges from 30% for early retirement at age 50 to 1% at age 59. Accrued or earned benefits are not reduced for eligible

employees who retire at age 60 and above. Ms. Lau, Mr. May, Ms. Wong and Mr. Harada are eligible for early retirement benefits under the HEI Retirement Plan. Mr. Yeaman's benefit became vested upon his completion of five years of service on January 15, 2008. His earliest retirement date is January 15, 2018, when he will meet the age and service requirements for early retirement under the plan, assuming continued employment.

Normal retirement benefits under the American Savings Bank Retirement Plan are calculated based on a formula of 1.5% × Credited Service (maximum 35 years) × Final Average Compensation (averaged over the highest paying five consecutive calendar years out of the last ten calendar years). Compensation is primarily gross earnings but excludes commissions, stock options, long-term incentive plan payments, deferrals to and distributions from the American Savings Bank Select Deferred Compensation Plan, and other "fringe benefits" as defined in the American Savings Bank Retirement Plan. Early retirement benefits are available for participants who meet the age and service requirements at ages 55-64, with a minimum of 10 years of service. Early retirement benefits are reduced for participants who retire prior to age 65, based on the participant's age at the early retirement date. The accrued normal retirement benefit is reduced by an applicable percentage which ranges from 59.8% for early retirement at age 55 to 2% at age 64. Ms. Lau is a participant in the American Savings Bank Retirement Plan. At the time of her promotion to HEI President and Chief Executive Officer on May 2, 2006, her credited service under the American Savings Bank Retirement Plan was frozen and she resumed participation in the HEI Retirement Plan. Ms. Lau is eligible for early retirement under the American Savings Bank Retirement Plan. On December 11, 2007, the HEI Board adopted an amendment to freeze future benefit accruals for all participants under the American Savings Bank Retirement Plan, effective December 31, 2007. Credited service and compensation after December 31, 2007 will not be recognized in calculating retirement benefits under the American Savings Bank Retirement Plan. Effective January 1, 2008, American Savings Bank will be adding matching and profit sharing features for its eligible employees.*(2)*
Benefits under the HEI Supplemental Executive Retirement Plan are determined based on a formula of 2.04% × Credited Service (maximum 60%) × Final Average Compensation (average monthly base salary plus annual executive incentive awards for the three highest calendar years out of the last sixty months prior to retirement). Benefits are reduced by benefits payable by the HEI Retirement Plan, American Savings Bank Retirement Plan and social security, and will not be less than the benefit that would be payable under the HEI Retirement Plan or American Savings Bank Retirement Plan before any Internal Revenue Code limits. Early retirement and death benefits similar to the HEI Retirement Plan are available in the HEI Supplemental Executive Retirement Plan. Ms. Lau, Mr. May and Mr. Yeaman are participants in the HEI Supplemental Executive Retirement Plan. Ms. Lau and Mr. May are eligible for early retirement benefits under the HEI Supplemental Executive Retirement Plan as of December 31, 2007. As of December 31, 2007, Ms. Lau had worked 12 years and 3 months at HEI, 6 years and 5 months at American Savings Bank, and 4 years and 7 months at Hawaiian Electric Company. Her credited years of service under the HEI Supplemental Executive Retirement Plan reflect her actual years of service with all HEI affiliated companies. As of December 31, 2007, Mr. May has 15 years and 11 months of actual service at Hawaiian Electric Company, which are his credited years of service under the HEI Supplemental Executive Retirement Plan. Mr. Yeaman's benefit vested upon completion of five years of service on January 15, 2008. His earliest retirement date is January 15, 2018, when he will meet the age and service requirements for early retirement under the plan, assuming continued employment.

(3)
All named executive officers are covered by the Executive Death Benefit Plan of HEI and Participating Subsidiaries. The plan provides death benefits for participants who terminate after qualifying for immediate commencement of retirement benefits under the HEI Retirement Plan. All of the named executive officers except for Mr. Yeaman are eligible for early retirement benefits under the HEI Retirement Plan as of December 31, 2007. Upon the participant's death following retirement, the benefit payable to the designated beneficiary is equal to one times the participant's base salary prior to retirement, divided by one minus the highest marginal rate of federal income tax on such benefits.

(4)
Benefits under the HEI Excess Pay Plan are determined using the same formula as the HEI Retirement Plan, but are not subject to the Internal Revenue Code limits on the amount of annual compensation that can be used for calculating benefits under qualified retirement plans ($225,000 in 2007). Benefits payable under the HEI Excess Pay Plan are reduced by the benefit payable from the HEI Retirement Plan. Early retirement,

death benefits and vesting provisions are similar to the HEI Retirement Plan. As of December 31, 2007, Ms. Wong is the only named executive officer participating in and is eligible for early retirement benefits under the HEI Excess Pay Plan, immediately upon termination of employment.*(5)*
The present value of accumulated benefits for the named executive officers included in the Pension Benefits table was determined based on the following:

Methodology: The benefits are calculated as of December 31, 2007 based on the service and pay of the named executive officer as of such date.

Assumptions:a.
Discount Rate—The discount rate is the interest rate used to discount future benefit payments in order to reflect the time value of money. The discount rate used in the present value calculations is 6.125% as of December 31, 2007.

b.
Mortality Table—The mortality table is used to discount future pension benefit payments in order to reflect the probability of survival to any given future date. For all benefits, mortality is applied post-retirement only.

c.
Retirement Age—Each named executive officer is assumed to remain in active employment until, and assumed to retire at, the earliest age when unreduced pension benefits would be payable, but no earlier than attained age as of December 31, 2007.

d.
Pre-Retirement Decrements—Pre-retirement decrements refer to events that could occur between the measurement date and the retirement age (such as withdrawal, early retirement, and death) that would impact the present value of benefits. No pre-retirement decrements are assumed in the calculation of pension benefit table present values, although decrements are assumed for financial statement purposes.

e.
Unused Sick Leave—Each named executive officer is assumed to accumulate unused sick leave hours of 1,160 at retirement age.

Nonqualified Deferred Compensation

Named executive officers may elect to participate in the HEI Executives' Deferred Compensation Plan dated February 1, 1985, as amended, which allows an executive to defer compensation from HEI for annual and long-term performance awards. Amounts credited to the plan earn interest quarterly at the prevailing interest rate on three-year certificates of deposit at American Savings Bank. Amounts deferred under the plan are distributed in accordance with the written, irrevocable election of the participant. Payments will commence on the first business day of the calendar year selected by the participant (including any year following a separation from service), but, if a date certain is elected, payments must commence not later than the year following the participant's attainment of age 72 and not earlier than the calendar year which is at least five years after the date of the participant's initial deferral election. No named executive officer is currently participating in this plan.

As Chair and Chief Executive Officer of American Savings Bank, Ms. Lau also participates in the American Savings Bank Select Deferred Compensation Plan, a contributory nonqualified deferred compensation plan. The American Savings Bank Deferred Compensation Plan allows a select group of American Savings Bank management and highly compensated employees to defer up to 100% of current salary, bonus or commissions from current taxation based upon annual elections made prior to the beginning of each deferral year. The deferred amounts are credited with gains/losses of deemed investments chosen by the participant from a select list of 24 publicly traded mutual funds offering a range of investment returns. While the participant is actively employed, the participant can receive an interim distribution of his or her account, but no earlier than the first day of the fourth plan year following the effective date of the initial election to defer. A participant may also request a withdrawal of a certain portion of his or her account to the extent needed to satisfy an emergency, subject to approval by the administrative committee of the plan, whose members are the American Savings Bank

President, Executive Vice President and Chief Administrative Officer, and Vice President/Director of Human Resources. The distribution of accounts from the American Savings Bank Deferred Compensation Plan is triggered by disability, death, or separation from service (including retirement). Upon disability or separation from service other than retirement, the entire account of the participant will be paid out in one lump sum, generally within thirty days according to the participant's distribution elections for each year of deferral. Such elections can provide for payment either in a lump sum or in substantially equal annual payments spread over a period not to exceed fifteen years. With respect to deferrals of income earned after December 31, 2004, distributions to certain key employees (including Ms. Lau) upon separation from service (including through retirement) may not be made earlier than six months after the date of separation (or, if earlier, the date of death of the employee).

2007 NONQUALIFIED DEFERRED COMPENSATION

Name	Executive Contributions in Last FY ($)	Registrant Contributions in Last FY ($)	Aggregate Earnings in Last FY ($)	Aggregate Withdrawals/ Distributions ($)	Aggregate Balance at Last FYE ($)
Constance H. Lau (1)	—	—	24,705	—	256,733
Eric K. Yeaman	NA	NA	NA	NA	NA
T. Michael May	NA	NA	NA	NA	NA
Patricia U. Wong	NA	NA	NA	NA	NA
Curtis Y. Harada	NA	NA	NA	NA	NA

NA Not applicable*(1)*
Ms. Lau did not elect to defer any amounts for 2007. She elected to defer $100,000 each year from bonuses awarded in 2004 and 2005. Earnings were based upon her allocation of deemed investments. Earnings were not considered preferential. Ms. Lau has elected to take distributions upon retirement in 15 annual payments with respect to her current balances.

Potential Payments Upon Termination or Change-in-Control

The tables below reflect the amount of potential payments to each named executive officer in the event of retirement, voluntary termination, termination for cause, termination without cause, and termination following a change-in-control event, assuming termination occurred on December 31, 2007. Named executive officers may receive retirement benefits upon these events, depending on whether they qualify for retirement at the time of termination. The amounts listed are estimates; actual amounts to be paid would depend on the actual date of termination and circumstances existing at that time. Other post-employment benefits, including retiree medical, dental, group life insurance and severance benefits are not listed because they are available to all employees on a non-discriminatory basis.

TERMINATION SUMMARY PAYMENT TABLE

Name/ Benefit Plan or Program	Retirement on 12/31/07 ($) (1)	Voluntary Termination on 12/31/07 ($)	Termination for Cause on 12/31/07 ($) (2)	Termination without Cause on 12/31/07 ($)	Qualifying Termination after Change-in-Control on 12/31/07 ($) (3)
Constance H. Lau					
Long-Term Incentive Plan (4)	982,800	982,800	—	982,800	982,800
Executive Incentive Compensation Plan (5)	—	—	—	—	—
Stock Appreciation Rights (6)	—	—	—	—	—
Restricted Stock (7)	—	—	—	359,828	1,070,190
Preferential interest rate (8)	27,375	—	—	—	—
Change-in-Control Agreement	NA	NA	NA	NA	1,946,929
TOTAL	1,010,175	982,800	—	1,342,628	3,999,919
Eric K. Yeaman					
Long-Term Incentive Plan (4)	236,400	236,400	—	236,400	236,400
Executive Incentive Compensation Plan (5)	—	—	—	—	—
Stock Appreciation Rights (6)	—	—	—	—	—
Restricted Stock (7)	—	—	—	67,792	227,700
Change-in-Control Agreement	NA	NA	NA	NA	1,429,224
TOTAL	236,400	236,400	—	304,192	1,893,324

T. Michael May					
Long-Term Incentive Plan (4)	332,053	332,053	—	332,053	332,053
Executive Incentive Compensation Plan (5)	—	—	—	—	—
Stock Appreciation Rights (6)	—	—	—	—	—
Restricted Stock (7)	—	—	—	108,468	364,320
Change-in-Control Agreement	NA	NA	NA	NA	3,445,527
TOTAL	332,053	332,053	—	440,521	4,141,900
Patricia U. Wong					
Long-Term Incentive Plan (4)	178,800	178,800	—	178,800	178,800
Executive Incentive Compensation Plan (5)	—	—	—	—	—
Stock Appreciation Rights (6)	—	—	—	—	—
Restricted Stock (7)	—	—	—	40,676	136,620
Change-in-Control Agreement	NA	NA	NA	NA	393,667
TOTAL	178,800	178,800	—	219,476	709,087
Curtis Y. Harada					
Long-Term Incentive Plan (4)	82,800	82,800	—	82,800	82,800
Executive Incentive Compensation Plan (5)	—	—	—	—	—
Stock Appreciation Rights (6)	—	—	—	—	—
Restricted Stock (7)	—	—	—	27,116	91,080
Change-in-Control Agreement	NA	NA	NA	NA	889,638
TOTAL	82,800	82,800	—	109,916	1,063,518

NA
Not applicable

Note: All stock-based award amounts were valued using the 2007 year-end closing price of HEI Common Stock of $22.77 per share. Other benefits that are available to all employees on a non-discriminatory basis and perquisites aggregating less than $10,000 in value have not been listed.*(1)*
Retirement Payments & Benefits. In addition to the payments presented above, retired executives are entitled to receive their vested retirement and deferred compensation benefits under all termination scenarios. See Pension Benefits table and Nonqualified Deferred Compensation table and related notes on pages 47-50.

(2)
Termination for Cause Payments & Benefits. If the executive is terminated for cause, he or she could lose any annual or long-term incentives based upon the Compensation Committee's right to amend,

suspend or terminate the incentive awards or any portion of it at any time. "Cause" is defined under the applicable agreements, but generally means willful or intentional conduct that injures HEI such as fraud, a violation of law or Company policy or willful failure to substantially perform Company duties. Termination for cause results in the expiration of all vested nonqualified stock options and stock appreciation rights and related dividend equivalents. Unvested stock appreciation rights and related dividend equivalents and unvested restricted stock would be forfeited as well. The executive's participation in the change-in-control agreement would also end.*(3) Change-in-Control Payments & Benefits.* Maximum lump sum payment consisting of 2.99 times the executive's five-year annual average Internal Revenue Service Form W-2 wages prior to the change-in-control, less additional outplacement fees and benefits, and other accelerated vesting benefits as described below. The executive may also receive benefits and perquisites for two years after the change-in-control, but these would be limited if the payments jeopardize the qualified tax status of any benefit plan. The executive would also receive outplacement service fees, not to exceed 30% of base annual salary at the time of the change-in-control.

(4)
For all termination scenarios, except for termination for cause (see note 2 above), executives would continue to participate in each on-going long-term incentive plan cycle at a pro-rated amount, provided there has been a minimum service of twelve months during the 36 month performance period, with payment to be made at the end of the three-year cycle if performance goals are achieved, using the salary midpoint at the time of termination. The amounts are estimates at target range for goals achievable for all applicable plan years, pro-rated based upon service through December 31, 2007; actual payouts will depend upon performance achieved at the end of the plan cycle.

(5)
For all termination scenarios, except for termination for cause (see note 2 above), executives would continue to participate in the annual incentive compensation plan at a pro-rated amount, provided there has been a minimum service of nine months during the annual performance period, with payment to be made at the end of the annual incentive plan cycle if performance goals are achieved, using the salary midpoint at the time of termination. At December 31, 2007, it was determined that the annual incentive compensation plan goals were not met and accordingly, the amounts shown in the table above are zero.

(6)
The vesting of unvested stock appreciation rights, including related dividend equivalents (accrued to date), would be accelerated upon termination due to retirement or change-in-control. All vested shares must be exercised within a period of three years from the retirement date or within one year from date of termination under a change-in-control or, in any event, within the original grant term, whichever ends first.

Voluntary termination, termination for cause, and termination without cause results in forfeiture of unvested stock appreciation rights, including related dividend equivalents. Vested nonqualified stock options and stock appreciation rights and related dividend equivalents must be exercised within a period of one year from the date of termination or within the original grant term, whichever ends first (other than upon termination for cause). Termination for cause results in the expiration of all vested and unvested nonqualified stock options and stock appreciation rights and related dividend equivalents. As of December 31, 2007, all stock options were fully vested.

The amount that would be shown is the intrinsic ("spread") value of the vested award. The stock appreciation rights had no intrinsic value as of December 31, 2007 because the exercise price was greater than the 2007 year-end closing price.*(7)*
Restricted stock vests at a pro-rated amount (based on service to date compared to the original vesting period) upon termination without cause and becomes fully vested upon a change-in-control. For all other termination events, the unvested restricted stock is forfeited. The amount shown is based on the year-end closing price of vested shares.

(8)
The amount shown is an annual amount calculated as of December 31, 2007. Upon Ms. Lau's retirement, the preferential rate continues. In other termination scenarios, the interest rate would reset to the market rate at the time the loan was funded.

Director Compensation

How is director compensation determined?

The Board believes that a competitive package is necessary to attract and retain individuals with the talent needed for the challenging role of serving as a director of a publicly traded company with a unique blend of highly regulated industries. The Board chooses to compensate nonemployee directors using a mix of cash and HEI Common Stock to allow for an appropriate level of compensation for services, including a level of stock awards that will align the interests of directors with Company shareholders. Only nonemployee directors are compensated for their service as directors.

The Compensation Committee has the responsibility for recommending nonemployee director compensation to the Board. In 2007, the Committee asked Towers Perrin to conduct a review of HEI's nonemployee director compensation practices. Towers Perrin assessed the structures of HEI's nonemployee director compensation program and its value compared to competitive market practices of financial services and utility peer companies, similar to those used in the executive compensation review. The April 2007 analysis took into consideration the duties, scope of role and responsibilities of the corporate and subsidiary board members, in addition to the HEI regulatory structure. The Committee reviewed the analysis in determining its recommendations to the Board concerning the appropriate nonemployee director compensation, including cash retainers, stock awards, and meeting fees. In its meeting on May 3, 2007, the Board approved the Committee's recommendations on director compensation.

Retainer

The following is the retainer schedule for nonemployee directors of HEI and subsidiary companies paid in quarterly installments, effective beginning the second quarter of 2007 and pro-rated for service thereafter. Nonemployee directors of HEI who also serve as directors on subsidiary company boards receive fees for service on such boards or committee as indicated below.

HEI Nonexecutive Chairman of the Board	$	250,000
HEI Director		40,000
HEI Audit Committee Chair		15,000
HEI Compensation Committee Chair		10,000
HEI Nominating and Corporate Governance Chair		5,000
HEI Audit Committee Member		6,000
HEI Compensation Committee Member		4,000
HEI Nominating and Corporate Governance Member		4,000
American Savings Bank Director		25,000
Hawaiian Electric Company Director		25,000
American Savings Bank Audit Committee Chair		12,500
Hawaiian Electric Company Audit Committee Chair		10,000
American Savings Bank Audit Committee Member		5,000
Hawaiian Electric Company Audit Committee Member		4,000
Hawaii Electric Light Company Director		8,000
Maui Electric Company Director		8,000

At its meeting on January 22, 2008, the Board approved the Compensation Committee's recommendation that the $8,000 per year retainer to Hawaii Electric Light Company and Maui Electric Company directors be discontinued. In 2008, Hawaii Electric Light Company and Maui Electric Company directors will receive a meeting fee of $500 per meeting. The Board also approved the Compensation Committee's recommendation that the two nonemployee directors of the newly formed American Savings Bank Compliance Committee will receive a meeting fee of $1,000 per meeting.

Meeting Fees

In addition, the Board also approved the following additional meeting fee schedule earned by a director per extra meeting, after attending the following minimum number of committee meetings during the calendar year:

HEI Audit Committee Member	$1,250 per meeting after 8 meetings
American Savings Bank Audit Committee Member	$1,000 per meeting after 8 meetings
Hawaiian Electric Company Audit Committee Member	$750 per meeting after 8 meetings
HEI Nominating and Corporate Governance Committee Member	$500 per meeting after 6 meetings
HEI Compensation Committee Member	$500 per meeting after 6 meetings

Special Fees

On May 3, 2007 the Board approved the Compensation Committee's recommendations regarding the payment of the following one-time special fees to certain directors (members of the HEI and American Savings Bank Audit Committees) for extraordinary contributions made:

Don E. Carroll	$ 7,500
Shirley J. Daniel	7,500
Thomas B. Fargo	7,500
Richard W. Gushman, II	7,500
Diane J. Plotts	100,000
James K. Scott	7,500
Barry K. Taniguchi	7,500
Jeffrey N. Watanabe	75,000

Stock Awards

For 2007, each HEI nonemployee director received 1,800 shares of HEI Common Stock, which is granted annually for the purpose of further aligning directors' and shareholders' interests in improving shareholder value. Stock grants to existing directors are given during the quarter of HEI's annual meeting. In accordance with the 1990 Nonemployee Director Stock Plan, as amended and restated, a one-time grant of 2,000 shares was also given to Richard W. Gushman, II upon his appointment to the HEI board in June 2007.

Pension and Nonqualified Deferred Compensation

Retirement Benefit. At its meeting 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 upon retirement of the director. Upon their retirement from service as a director, Mr. Myers and Ms. Plotts will each receive an annual amount, paid quarterly, 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). Upon the death of the director, whether retired or not, HEI's obligation to make payments ceases. As of December 31, 2007, the present value of Mr. Myers' and Ms. Plotts' accumulated benefit was $51,623 and $94,168 respectively.

Deferred Compensation. Nonemployee directors may elect to participate in the HEI Nonemployee Directors' Deferred Compensation Plan dated September 9, 1980, as amended, which allows any nonemployee director to defer compensation from HEI for service as a director. The plan allows for either lump sum or installment distributions upon the retirement of the director. Upon the death of the director, the balance of the deferred account will be distributed in a lump sum to a designated beneficiary. Only Mr. Mills currently participates in the plan, but he did not make any deferral elections in 2007. The annual earnings on the plan are paid by HEI based upon the American Savings Bank three-year certificate of deposit rate established on January 1 of each year. As of December 31, 2007, Mr. Mills' deferred compensation balance was $57,601.

All Other Compensation

Perquisites—Discounted Fees and Services. The Board 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 director of American Savings Bank (including American Savings Bank directors who are also nonemployee directors of HEI). Existing preferential rate loans to nonemployee American Savings Bank directors as of June 30, 2006 were grandfathered. The preferential rate loans provided to directors that exceeded $120,000 in the aggregate at any time during 2007 are described under "Other Relationships and Related Person Transactions—Did HEI or any subsidiary provide loans to directors or executive officers?" on page 61 and are reflected in the Director Compensation Table under All Other Compensation on page 57. American Savings Bank continues to offer preferential employee rate loans to its executive officers and employees, as allowed by the amended Federal Reserve Act.

Other Perquisites. Directors, at their election and at their cost, may participate in the group employee medical, vision and dental plans available to all HEI or Hawaiian Electric Company or American Savings Bank employees. Mr. Carroll and Mr. Gushman participate in this program, but since they pay all of the premiums, no aggregate incremental cost is attributed to HEI.

HEI directors who are also nonemployee directors of American Savings Bank may receive other free services such as personal checking and traveler's checks, safe deposit boxes, notary services and stop payment services. American Savings Bank directors may receive these services also if they qualify as Private Banking customers. These services are made in the ordinary course of business and on substantially the same terms, including interest rates and collateral, as those prevailing at the time for comparable transactions with other persons, and do not involve more than the normal risk of collectability or present other unfavorable features.

The following director compensation table shows the annual and long-term compensation of the Board of Directors for 2007:

2007 Director Compensation Table

Name	Fees Earned or Paid in Cash ($) (1)	Stock Awards ($) (2)	Option Awards ($)	Non-Equity Incentive Plan Compensation ($)	Change in Pension Value and Nonqualified Deferred Compensation Earnings ($) (3)	All Other Compensation ($) (4)	Total ($)
Jeffrey N. Watanabe Nonexecutive Chairman of the Board	388,125	42,660	NA	NA	NA	20,846	451,631
Diane J. Plotts Chairman, Audit Committee	206,000	42,660	NA	NA	4,867	13,774	267,301
Bill D. Mills Chairman, Compensation Committee	50,375	42,660	NA	NA	NA	—	93,035
Kelvin H. Taketa Chairman, Nominating and Corporate Governance Committee	66,875	42,660	NA	NA	NA	—	109,535
Don E. Carroll	87,625	42,660	NA	NA	NA	—	130,285
Shirley J. Daniel	81,375	42,660	NA	NA	NA	28,016	152,051
Thomas B. Fargo	85,792	42,660	NA	NA	NA	—	128,452
Richard W. Gushman, II	67,333	89,380	NA	NA	NA	63,835	220,548
Victor H. Li	65,375	42,660	NA	NA	NA	—	108,035
A. Maurice Myers	41,625	42,660	NA	NA	2,543	—	86,828
James K. Scott	81,875	42,660	NA	NA	NA	—	124,535
Barry K. Taniguchi	131,125	42,660	NA	NA	NA	—	173,785

NA
Not applicable

(1)
See detail of cash retainers for Board and committee service below.

(2)
Represents the value of unrestricted HEI Common Stock determined by reference to the average of the high and low sales prices of $23.70 per share on the NYSE on the date of issuance. Each of the HEI nonemployee directors received an annual grant in June 2007 of 1,800 shares of HEI Common Stock with a fair market value of $42,660. HEI directors do not receive any Company restricted stock or stock option awards. Upon his appointment as a nonemployee HEI director, Mr. Gushman received an additional 2,000 shares of unrestricted HEI Common Stock with a fair value of $46,720 determined by reference to the average of the high and low sales prices of $23.36 per share on the NYSE on the date of issuance.

(3)
Represents the change in pension value. Since Ms. Plotts and Mr. Myers no longer earn credited service, the change in present value is solely due to actuarial factors such as change in discount rate and mortality assumptions.

(4)
In 2007, certain American Savings Bank directors continued to have grandfathered preferential rate loans. The difference between the market rate loan interest and the preferential rate loan interest was $28,016 for Dr. Daniel, $63,835 for Mr. Gushman, $13,774 for Ms. Plotts, and $20,846 for Mr. Watanabe.

Details of cash retainers for board and committee service are noted below:

Name	HEI Board Retainer ($)	HEI Comm. Retainer ($)	HEI Chairman of the Board Retainer ($)	HECO Board Retainer ($)	HECO Audit Comm. Retainer ($)	HELCO Board Retainer ($)	MECO Board Retainer ($)	ASB Board Retainer ($)	ASB Audit Comm. Retainer ($)	Meeting Fees ($) (1)	Special Fees ($) (2)	Total ($)
Jeffrey N. Watanabe	38,125	—	237,500	—	—	—	—	23,750	4,750	9,000	75,000	388,125
Diane J. Plotts	38,125	18,000	—	—	—	—	—	23,750	11,875	14,250	100,000	206,000
Bill D. Mills	38,125	11,750	—	—	—	—	—	—	—	500	—	50,375
Kelvin H. Taketa	38,125	5,000	—	23,750	—	—	—	—	—		—	66,875
Don E. Carroll	38,125	3,000	—	—	—	—	—	23,750	4,750	10,500	7,500	87,625
Shirley J. Daniel	38,125	5,750	—	—	—	—	—	23,750	—	6,250	7,500	81,375
Thomas B. Fargo	38,125	7,417	—	23,750	4,000	—	—	—	—	5,000	7,500	85,792
Richard W. Gushman	23,333	—	—	—	—	—	—	23,750	4,750	8,000	7,500	67,333
Victor H. Li	38,125	3,000	—	—	—	—	—	23,750	—	500	—	65,375
A. Maurice Myers	38,125	3,000	—	—	—	—	—	—	—	500	—	41,625
James K. Scott	38,125	8,750	—	23,750	—	—	—	—	—	3,750	7,500	81,875
Barry K. Taniguchi	38,125	5,750	—	23,750	10,000	8,000	8,000	23,750	—	6,250	7,500	131,125

(1)
Per meeting fee paid for each additional committee meeting attended after a minimum number of meetings determined by the Board.

(2)
One-time fee to HEI and American Savings Bank Audit Committee members in recognition of extraordinary contributions made.

Stock Ownership Information

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

The following table shows how many shares of HEI Common Stock were owned as of February 27, 2008 by each director, nominee for director and named executive officer (as listed in the Summary Compensation Table on page 42) 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	14,185				14,185
Shirley J. Daniel	10,706				10,706
Thomas B. Fargo	7,242				7,242
Richard W. Gushman, II	8,402				8,402
Victor H. Li	1,826	11,204	489		13,519
Bill D. Mills	28,229		10		28,239
A. Maurice Myers	29,216	4,018			33,234
Diane J. Plotts	15,080				15,080
James K. Scott	16,902				16,902
Kelvin H. Taketa	13,221				13,221
Barry K. Taniguchi		19,025			19,025
Jeffrey N. Watanabe	19,767		4		19,771
Employee director and Named Executive Officers					
Constance H. Lau	124,852		9,525	311,866	446,243
Other Named Executive Officers					
T. Michael May	53,435			156,476	209,911
Eric K. Yeaman	23,000			54,934	77,934
Patricia U. Wong	20,288			2,075	22,363
Curtis Y. Harada	7,113			22,830	29,943
All directors and executive officers as a group (18 persons)	396,464	34,247	10,028	548,181	988,920 (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 of February 27, 2008 (proxy record date), under the 1987 Stock Option and Incentive Plan.

(4)
As of February 27, 2008, the directors and executive officers of HEI as a group beneficially owned 1.18% of the outstanding HEI Common Stock, no director or officer owned more than 0.6% of such stock and no shares were pledged as security.

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

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

Does HEI have stock ownership guidelines for directors and officers?

In 2003, the Board adopted stock ownership guidelines (last amended on January 22, 2008) 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 Chief Executive Officer of HEI — 2.5 times base salary, (2) executive officers of HEI, the utility President and Chief Executive Officer, the utility Senior Executive Vice President and Chief Operating Officer, and the American Savings Bank President — 1.5 times base salary, (3) members of the Board of Directors of HEI — 5 times annual cash retainer and (4) Chairman of the Board — 1 times Chairman's cash retainer. Stock ownership is measured on January 1 of each year based on the average price of stock on all trading days of the previous calendar year. The directors and officers have until January 1, 2009 to meet the current guidelines, except for Admiral Fargo and Ms. Wong, who have until January 1, 2010 to meet the guidelines; Mr. Gushman, who has until January 1, 2013 to meet the guidelines; and Mr. Yeaman, who has until January 1, 2014 to meet the guidelines in his new role as Hawaiian Electric Company Senior Executive Vice President & Chief Operating Officer.

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

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

Other Relationships and Related Person Transactions

Does HEI have a written related person transaction policy?

The Board of Directors has adopted a written related person transaction policy that is separate from HEI's Corporate Code of Conduct. The related person transaction policy is specific to transactions between related persons such as executive officers and directors and their immediate family members in which the amount involved exceeds $120,000 and in which any related person had or will have a direct or indirect material interest. Under the policy, the Board, acting through the Nominating and Corporate Governance Committee, will approve a related person transaction involving a director if the Board determines in advance that the transaction is not inconsistent with the best interest of the Company and its shareholders. The Board, acting through the Audit Committee, will approve a related person transaction involving an officer if the Board determines in advance that the transaction is not in violation of HEI's Corporate Code of Conduct.

Did HEI enter into any related person transactions with directors or executive officers?

On July 1, 2007, Mr. Watanabe retired from and became honorary Of Counsel to the law firm of Watanabe Ing and Komeiji LLP, which performed legal services for HEI and certain of its subsidiaries during 2007. Fees totaling $235,381.89 were paid to Watanabe Ing and Komeiji LLP in 2007. Mr. Watanabe's retirement benefits from the firm will continue for approximately five years after his retirement date. The amount of these benefits was fixed at the time of retirement and is not subject to adjustment thereafter. Mr. Watanabe's retirement benefits are not tied to the firm's profitability. Mr. Watanabe no longer bills clients for his time and no longer holds an ownership interest in the firm.

Are there any family relationships between any executive officer, director and nominee for director?

There are no family relationships between any executive officer, director and nominee for director.

Did HEI or any subsidiary provide loans to directors or executive officers?

American Savings Bank offers preferential employee rate loans to its executive officers and employees, as allowed by the amended Federal Reserve Act. The HEI Board 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 director of American Savings Bank. Existing preferential rate loans to nonemployee American Savings Bank directors as of June 30, 2006 were grandfathered. Director preferential rate loans that exceeded $120,000 in the aggregate at any time during 2007 are shown below:

Name	Largest Loan Amount Outstanding During 2007	Loan Amount Outstanding on 1/31/08	Amount of Principal Paid in 2007	Amount of Interest Paid in 2007	Type of Transaction	Average Interest Rate Charged(1)
Shirley J. Daniel	1,464,542	1,434,310	27,860	58,075	First Mortgage	4.000%
Richard W. Gushman, II	1,827,985	1,778,391	45,717	58,733	First Mortgage	3.250%
Constance H. Lau	798,299	773,575	22,796	20,682	First Mortgage	2.625%
Constance H. Lau	36,377	32,995	3,118	1,092	Second Mortgage	3.125%
Constance H. Lau (2)	2,203	1,389	4,703	—	Credit Card	12.000%
Victor H. Li	342,499	333,629	8,178	10,163	First Mortgage	3.000%
Diane J. Plotts	434,654	421,360	12,258	11,263	First Mortgage	2.625%
Jeffrey N. Watanabe	539,473	520,215	17,748	19,927	First Mortgage	3.750%

(1)
The first mortgage rate is based on American Savings Bank's policy for employees and directors at the time the loan was made 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%.

(2)
The amount outstanding for Ms. Lau's credit card was for the period ending December 31, 2007.

American Savings Bank made other loans, established lines of credit and issued credit cards to directors and executive officers of HEI, 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 collectability or present other unfavorable features.

Does HEI have Compensation Committee interlocks and insider participation?

Victor Li and Diane Plotts are members of the Compensation Committee and HEI directors who are also members of the American Savings Bank Board. As members of the American Savings Bank Board, they have received preferential rate loans as described above.

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. The Board has determined that the five 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 HEI's financial process on behalf of the Board of Directors. Management has the primary responsibility for HEI'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 six (6) regular and eight (8) special meetings in 2007. 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 professional standards. 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 2007 consolidated financial statements and fees for other professional services billed in 2007 with comparative amounts for 2006:

	2007		2006	
	Fees	%	Fees	%
Audit fees (principally consisted of fees associated with the audit of HEI's, HECO's and ASB's 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)	$ 2,011,500	93.0	$ 2,588,500	95.8
Audit-related fees (principally consisted of fees associated with the audit of the financial statements of certain employee benefit plans)	60,300	2.8	54,000	2.0
Tax fees (tax compliance services with respect to Federal and State taxes)	90,500	4.2	60,500	2.2
All other fees	—	—	—	—
	$ 2,162,300	100.0	$ 2,703,000	100.0

The Audit Committee, pursuant to the terms of its charter, approves all audit services to be performed by the independent registered public accounting firm. In addition, the Audit Committee revised its preapproval policies and procedures for nonaudit services proposed to be performed by HEI's independent registered public accounting firm. Departmental requests for nonaudit services are reviewed by senior management and, once found by management to be acceptable, are sent to the Audit Committee for approval via unanimous written consent or at a meeting of the Audit Committee. 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.

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 2007 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
Barry K. Taniguchi

Other Information

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

HEI pays all expenses of the proxy solicitation. Laurel Hill Advisory Group has been hired to assist in the distribution of proxy materials and solicitation of votes for $6,000 plus reasonable out-of-pocket expenses. In addition, HEI 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 2009 Annual Meeting of Shareholders must notify the Secretary of HEI in writing. The proposal must be received by November 26, 2008.

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 Corporate Secretary of HEI 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 2009, notice must be received by the Secretary of HEI no later than March 7, 2009 nor earlier than February 5, 2009. 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 HEI 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 or nominate a candidate for election?

You can recommend any person as a director of HEI to the Nominating and Corporate Governance Committee by writing to that Committee in care of the Corporate Secretary, Hawaiian Electric Industries, Inc., P. O. Box 730, Honolulu, Hawaii 96808-0730. Recommendations must be received by November 30, 2008 for consideration by the Nominating and Corporate Governance Committee for the 2009 Annual Meeting of Shareholders. The recommendation must include the nominee's qualifications to be a director of HEI 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 7, 2009 nor earlier than February 5, 2009. 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.

What provisions has HEI made for "householding"?

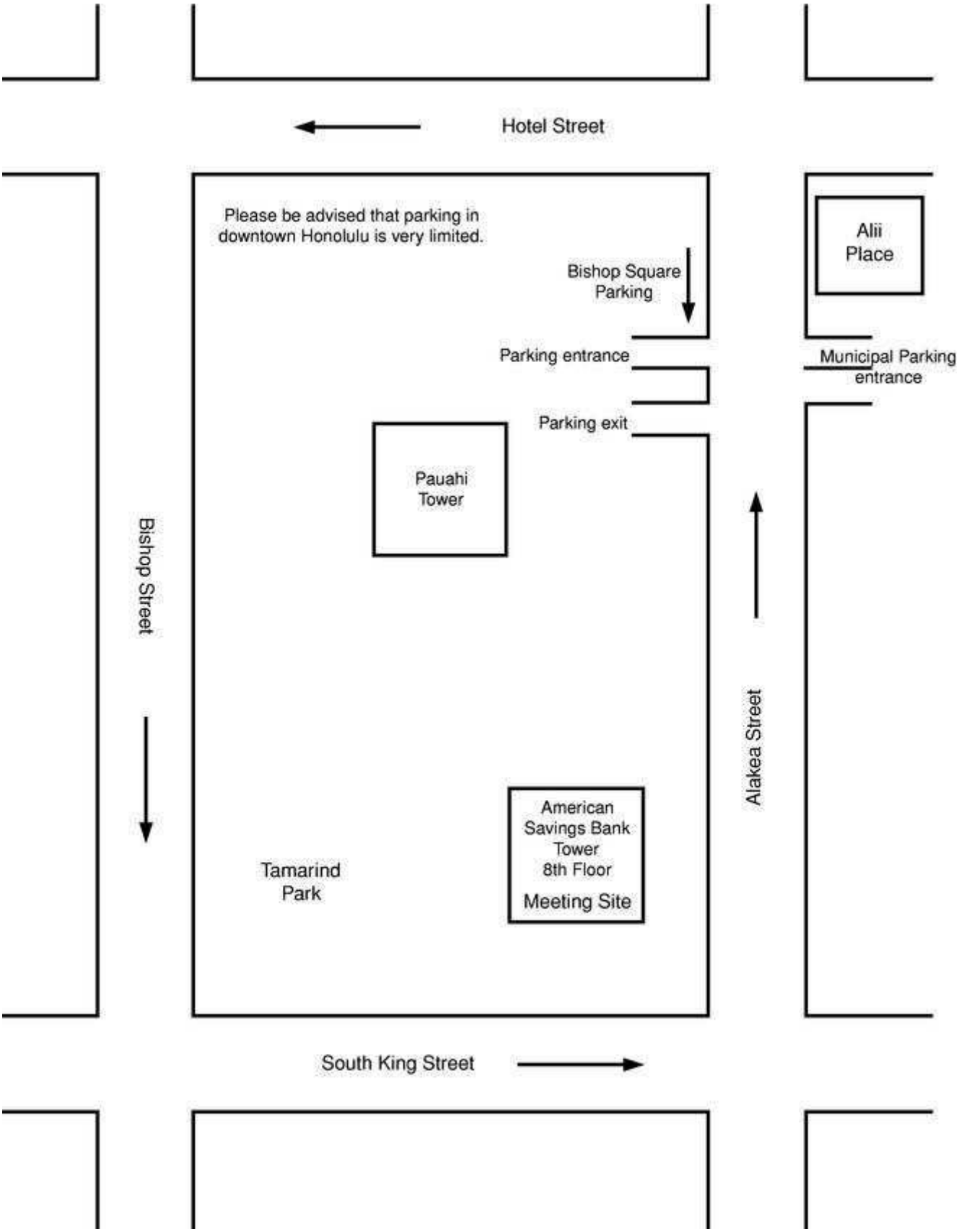
Shareholders of record who share an address can elect to receive only one copy of our annual report to shareholders by consenting thereto in writing. This procedure is referred to as "householding." Each shareholder of record at a householded address continues to receive separate proxy statements and proxy cards, and dividend payments and account statements are not affected. Once you elect householding of the annual report, householding will continue until you are notified otherwise or until you notify us that you wish to receive a separate annual report. You will be removed from the householding program within 30 days of receipt of your notice. If you are a shareholder of record who received a householded annual report this year and you would like to have an additional copy of our annual report mailed to you, we will promptly send an additional copy upon receipt of such request. Record shareholders who wish to commence or to discontinue householding of the annual report, or any record shareholder residing at a householded address who would like to request prompt delivery of a copy of the annual report, should contact us orally or in writing at the following telephone number — toll free at (866)672-5841 or (808)532-5841 between 7:30 a.m. - 3:00 p.m. HST; or at the following address — Hawaiian Electric Industries, Inc., Shareholder Services, P. O. Box 730, Honolulu, HI 96808-0730; or on-line at www.hei.com. If you hold your shares in "street name," please contact your bank, broker or other holder of record to request information about householding.

If other business is properly brought before the Annual Meeting, or at any adjournment thereof, the persons named on the enclosed proxy will vote your stock in accordance with their best judgment. HEI knows of no other business to be presented at the 2008 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 Corporate Secretary

March 26, 2008


Hotel Street
Please be advised that parking in downtown Honolulu is very limited.
Alii Place
Bishop Square Parking
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

HAWAIIAN ELECTRIC INDUSTRIES, INC.

1990 Nonemployee Director Stock Plan

As Amended and Restated: May 6, 2008

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 6, 2008, including provisions formerly memorialized in the Hawaiian Electric Industries, Inc. 1999 Nonemployee Company Director Stock Grant Plan, which is hereby superseded.

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 Compensation 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, including a Nonemployee Director Subcommittee (a subcommittee of nonemployee directors, "nonemployee director" as defined under Rule 16b-3(3)(i) of the Securities Exchange Act of 1934).

(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 eight hundred (1,800) 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 6, 2008. Unless previously terminated by the Board, the Plan will terminate on April 27, 2010.

Appendix C

1987 Stock Option and Incentive Plan of
Hawaiian Electric Industries, Inc.
(as amended and restated effective January 22, 2008)

I. General Provisions

1.1 Purposes of the Plan

The purposes of the 1987 Stock Option and Incentive Plan of Hawaiian Electric Industries, Inc. (the "Company") are to provide a means to attract and retain high caliber personnel and to provide to participating employees long-term incentives for sustained high levels of performance for the Company and its subsidiaries. These purposes may be achieved through the granting of Incentive Awards under the Plan.

1.2 Definitions

(a) "Average Fair Market Value" means, as of any determination date, the average of the daily high and low sales prices of the Common Stock as quoted on the New York Stock Exchange for all trading days during the calendar month preceding the determination date, or if the Common Stock is not admitted to trade on the New York Stock Exchange, the Average Fair Market Value shall be determined by the Committee in such other reasonable manner as the Committee shall decide.

(b) "Board" means the Board of Directors of Hawaiian Electric Industries, Inc.

(c) "Code" means the Internal Revenue Code of 1986, as amended.

(d) "Committee" means the Compensation Committee of the Board of Directors. The Committee shall be composed entirely of members who meet the requirements of Section 1.4(a) hereof.

(e) "Common Stock" means the Common Stock of Hawaiian Electric Industries, Inc.

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

(g) "Employee" means any regular full-time employee of the Company or any of the Company's present or future parent or subsidiary corporations (as defined in Section 424 of the Code), or any successor of such corporation.

(h) "Exchange Act" means the Securities Exchange Act of 1934, as amended.

(i) "Fair Market Value" means, as of any determination date, the average of the daily high and low sales prices of the Common Stock as quoted on the New York Stock Exchange on the date as of which Fair Market Value is to be determined, or if there is no trading of Common Stock on such date, the average of the daily high and low sales prices of the Common Stock as quoted on the New York Stock Exchange on the next preceding date on which there was trading in such shares, or if the Common Stock is not admitted to trade on the New York Stock Exchange, the Fair Market Value shall be determined by the Committee in such other reasonable manner as the Committee shall decide.

(j) "Incentive Award" means a Stock Option, Restricted Stock, Stock Appreciation Right, Stock Payment, Dividend Equivalent, Restricted Stock Unit or Performance Award granted or sold under the Plan.

(k) "Incentive Stock Option" means an incentive stock option, as defined under Section 422 of the Code and the regulations thereunder.

(l) "Nonqualified Stock Option" means a stock option other than an Incentive Stock Option.

(m) "Option" means a right to purchase Common Stock and refers to both Incentive Stock Options and Nonqualified Stock Options.

(n) "Participant" means any Employee or, in the case of death of the Employee, the Employee's beneficiary, selected to receive an Incentive Award pursuant to Section 1.5 hereof.

(o) "Payment Event" means the occurrence of the event or events giving rise to the right to payment of a Performance Award.

(p) "Performance Award" means an award, payable in cash or Common Stock or combination thereof, the value of which is based on the achievement of Performance Goals or such other criteria as may be determined by the Committee.

(q) "Performance Goal" shall mean one or more of the following business criteria applied to a Participant and/or a business unit or the Company and/or a parent or subsidiary of the Company: (1) total return to shareholders; (2) earnings per share of Common Stock; (3) net income (before or after taxes); (4) earnings before all or any interest, taxes, depreciation and/or amortization ("EBIT", "EBITA", or "EBITDA"); (5) gross revenue; (6) return on assets; (7) market share; (8) cost reduction goals; (9) earnings from continuing operations, levels of expense, cost or liability; (10) performance against operational budgets; (11) a Participant's individual operational project goals; (12) return on average common equity; (13) individual performance goals; (14) free cash flow; (15) modified free cash flow (net income plus depreciation and amortization less net capital expenditures); (16) shareholder value added; and (17) any combination of, or a specified increase or decrease of one or more of the foregoing over a specified period, in each case, as applicable, as determined in accordance with generally accepted accounting principles, where applicable.

(r) "Plan" means the Company's 1987 Stock Option and Incentive Plan as amended and restated and set forth herein, as amended from time to time.

(s) "Purchase Price" means the purchase price to be paid by a Participant for Restricted Stock as determined by the Committee.

(t) "Restricted Stock" means Common Stock that the Participant may purchase at a price determined by the Committee, or Common Stock to which the Participant may become entitled without payment of any price upon the lapse of restrictions specified in the restricted stock agreement under which Common Stock is granted, in either case which Common Stock is nontransferable and subject to substantial risk of forfeiture until specific restrictions are satisfied or lapse. Restrictions may be based on continuing employment or achievement of preestablished performance objectives or both.

(u) "Restricted Stock Unit" means the right to receive a share of the Company's Common Stock or the Fair Market Value or Average Fair Market Value thereof in cash (as determined by the Committee) granted pursuant to Section VIII of the Plan.

(v) "Rule 16b-3" means Rule 16b-3 promulgated under Section 16 of the Exchange Act (or any other comparable provisions in effect at the time or times in question).

(w) "Stock Appreciation Right" or "Right" means a right granted pursuant to Section V of the Plan to receive a number of shares of Common Stock, or an amount of cash, or a combination of shares and cash, based on the increase in the Fair Market Value of the share subject to the right.

(x) "Stock Payment" means a payment in shares of the Company's Common Stock (valued at Fair Market Value or Average Fair Market Value, as determined by the Committee) to replace all or any portion of the compensation (other than base salary) that would otherwise become payable to a Participant in cash.

1.3 Shares of Common Stock Subject to the Plan

(a) Subject to the provisions of Section 1.3(c) and Section 9.1 of the Plan, the aggregate number of shares of Common Stock that may be issued pursuant to Incentive Awards under the Plan shall be 4,650,000 shares; provided that of these shares, the 2,000,000 shares that were added to the Plan by amendment effective January 21, 2003, shall not be subject to any Incentive Awards other than Options and Stock Appreciation Rights. Notwithstanding the foregoing, but subject to Section 9.1 of the Plan, (i) commencing with the 2003 calendar year, the aggregate number of shares of Common Stock with respect to which Incentive Awards (including Incentive Awards payable in cash but denominated in Common Stock, *e.g.* , cash-settled Rights or Restricted Stock Units) may be granted to any individual Participant during any calendar year shall not exceed 100,000, and (ii) the total number of shares that may be made subject to awards of Restricted Stock, Stock Payments, or stock-settled Restricted Stock Units granted under the Plan on or after April 22, 2003, shall not exceed 5% of the total number of shares of Common Stock authorized under the Plan as of such date but not subject to an Incentive Award immediately before such date. The grant of any Incentive Award that may be settled only in cash shall not reduce the number of shares of Common Stock with respect to which Incentive Awards may be granted under the Plan.

(b) The Common Stock to be issued under the Plan will be made available, at the discretion of the Board or the Committee, either from authorized but unissued shares of Common Stock or from previously issued shares of Common Stock reacquired by the Company, including shares purchased on the open market.

(c) If any shares of Common Stock subject to an Option (and related Stock Appreciation Right, if any) terminate without being exercised, then shares subject to such Option shall be available again for the grant of Options or other Incentive Awards under the Plan. If any shares subject to a Restricted Stock Award are forfeited, expire or are otherwise cancelled or terminated, then shares subject to such Restricted Stock Award shall be available again for the grant of Restricted Stock Awards or other Incentive Awards under the Plan. Shares of Common Stock with reference to which Stock Appreciation Rights have been granted shall be available for granting of Incentive Awards to the extent the Stock Appreciation Rights are exercised for cash, or, with respect to Stock Appreciation Rights not related to Options, to the extent the Stock Appreciation Rights terminate without being exercised. If any other Incentive Award shall expire or be forfeited, cancelled or terminated for any reason, the shares of Common Stock available under such Incentive Award shall be available again for the granting of Incentive Awards to the maximum extent consistent with Rule 16b-3. To the extent that payment for an Option upon exercise is made with shares of Common Stock or shares of Common Stock are withheld from payment of an Incentive Award in satisfaction of any federal, state or local tax withholding requirements, such shares of Common Stock shall again be available for issuance in connection with future Incentive Awards granted under the Plan.

1.4 Administration of the Plan

(a) The Plan will be administered by the Committee, which will consist of two or more persons who are "non-employee directors" within the meaning of Rule 16b-3 and "outside directors" within the meaning of Section 162(m) of the Code.

(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 as described in the Plan. The Committee has authority in its discretion to determine the Employees to whom, and the time or times at which, Incentive Awards may be granted or sold, the nature of the Incentive Award, the number of shares of Common Stock that make up each Incentive Award, the performance criteria (which need not be identical) utilized to measure the value of Performance Awards, the form of payment (cash or Common Stock or a combination thereof) payable upon the event or events giving rise to payment of an Incentive Award and such other terms and

conditions applicable to each individual Incentive Award as the Committee shall determine. Subject to Section 9.7(c) of the Plan, the Committee may grant at any time new Incentive Awards to a Participant who has previously received Incentive Awards or other grants (including other stock options) whether such prior Incentive Awards or such other grants are still outstanding, have previously been exercised in whole or in part, or are forfeited or otherwise canceled in whole or in part. The purchase price or initial value of the Incentive Awards may be established by the Committee without regard to the existing Incentive Awards or such other grants.

(c) Each Incentive Award will either be evidenced by a written instrument or granted pursuant to a written plan adopted by the Committee and may include any other terms and conditions consistent with the Plan as the Committee may in its discretion determine, including without limitation terms and conditions that would prohibit a Participant from transferring or otherwise disposing of a share of Common Stock issued under an Incentive Award for a period identified in the Incentive Award Agreement or require the forfeiture of a share of Common Stock issued under an Incentive Award if the Participant engages in any conduct that is identified in the Incentive Award agreement. Each Option award agreement shall designate the Option as either an Incentive Stock Option or Nonqualified Stock Option. The Committee may permit a Participant to elect to defer receipt of all or any portion of the cash or shares of Common Stock that are payable under an Incentive Award and provide that such deferred amount shall be credited with an interest rate or such other rate of return as shall be specified by the Committee, all on such terms and conditions as may be established by the Committee.

(d) The Committee in its discretion may condition entitlement to an Incentive Award in whole or in part on the attainment of one or more Performance Goals. The Committee shall establish any such Performance Goal not later than 90 days after the commencement of the period of service to which the Incentive Award relates (or if less, 25% of such period of service), and once granted, the Committee may not have discretion to increase the amount payable under such Award, provided, however, that whether or not an Incentive Award is intended to constitute qualified performance based compensation within the meaning of Section 162(m) of the Code, the Committee shall have the authority to make appropriate adjustments in Performance Goals under an Incentive Award to reflect the impact of extraordinary items not reflected in such Performance Goals. For purposes of the Plan, extraordinary items shall be defined as (1) any profit or loss attributable to acquisitions or dispositions of stock or assets, (2) any changes in accounting standards that may be required or permitted by the Financial Accounting Standards Board or adopted by the Company after the goal is established, (3) all items of gain, loss or expense for the year related to restructuring charges for the Company, (4) all items of gain, loss or expense for the year determined to be extraordinary or unusual in nature or infrequent in occurrence or related to the disposal of a segment of a business, (5) all items of gain, loss or expense for the year related to discontinued operations that do not qualify as a segment of a business as defined in the Statement of Financial Accounting Standards No. 144, (6) such other items as may be prescribed by Section 162(m) of the Code and the Treasury Regulations thereunder as may be in effect from time to time, and any amendments, revisions or successor provisions and any changes thereto, and (7) with respect to Incentive Awards not intended to constitute qualified performance based compensation within the meaning of Section 162(m) of the Code, such other items as the Committee may deem appropriate.

(e) Subject to the express provisions of the Plan, the Committee has the authority to interpret the Plan, to determine the terms and provisions of the Incentive Award agreements, and to make all other determinations necessary or advisable for the administration of the Plan. The Committee has authority to prescribe, amend, and rescind rules and regulations relating to the Plan. 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 or by the unanimous written consent of its members.

(f) No member of the Board or the Committee or designee thereof will be liable for any action, determination or interpretation made in good faith by the Board or the Committee with respect to the Plan or any transaction arising under the Plan, and all members of the Board or the Committee and each and any officer or employee of the Company or other designee acting on their behalf shall, to the extent permitted by law, be fully indemnified and protected by the Company in respect of any such action, determination or interpretation.

1.5 Participation

(a) Such employees of the Company and its subsidiaries as may be selected by the Committee in its discretion are eligible to participate in the Plan. An individual who has been granted or sold an Incentive Award may, if otherwise eligible, be granted or sold additional Incentive Awards if the Committee so determines.

(b) No person who owns (or is deemed to own) immediately before the grant of such Incentive Stock Option, directly or indirectly, stock possessing more than 10% of the total combined voting power of all classes of stock of the Company will be eligible for the grant of an Incentive Stock Option. This restriction does not apply if, at the time such Incentive Stock Option is granted, the Incentive Stock Option exercise price is at least 110% of the Fair Market Value on the date of grant and the Incentive Stock Option by its terms is not exercisable after the expiration of five (5) years from the date of grant.

(c) In no event may any member of the Board who is not an Employee be granted an Incentive Award.

II. Terms and Conditions of Options

2.1 Option Plan

The purchase price of Common Stock under each Incentive Stock Option will be determined by the Committee but may not be less than the Fair Market Value on the date of grant. The purchase price of Common Stock under each Nonqualified Stock Option will be determined by the Committee but may not be less than the lesser of the Fair Market Value or Average Fair Market Value on the date of grant. To the extent that the aggregate Fair Market Value of shares of Common Stock with respect to which Incentive Stock Options are exercisable for the first time by a Participant during any calendar year under the Plan and any other stock option plan of the Company shall exceed $100,000, such Options shall be treated as Nonqualified Stock Options; for such purposes, Fair Market Value shall be determined as of the date on which each such Incentive Stock Option is granted.

2.2 Exercisability

Options granted pursuant to this Plan shall be exercisable at such times and under such conditions as shall be determined by the Committee; provided, however that no Option shall be exercisable after the expiration of ten (10) years from the date the Option is granted. Unless the applicable Option award agreement provides otherwise, upon a Participant's termination of employment for any reason, all of the Participant's Options remaining subject to restrictions on the date of such termination of employment shall be forfeited and shall be available again for grant of Incentive Awards under the Plan.

2.3 Exercise of Option

Options may be exercised by written notice to the Company specifying the number of shares of Common Stock with respect to which the option has been exercised. At the time of exercise of an Option, the purchase price shall be paid in full in cash or its equivalent acceptable to the Committee. To the extent provided by the Option agreement executed by the Participant, the purchase price may be paid by the assignment and delivery to the Company of shares of Common Stock or a combination of

cash and shares of Common Stock equal in value to the exercise price, or in such other manner acceptable to the Committee. Any shares assigned and delivered to the Company in payment or partial payment of the purchase price will be valued at their Fair Market Value on the exercise date. No fractional shares will be issued pursuant to the exercise of an Option, but the Committee in its discretion, may make a cash payment.

III. Terms and Conditions of Performance Awards

3.1 Grant of Performance Awards

The Committee may grant Performance Awards to Employees subject to the provisions of this Section III. The Committee shall determine the Payment Event, which shall be based on the attainment of Performance Goals and such other criteria as the Committee may determine (which need not be identical for each Participant), and the other terms and conditions of such Performance Awards (including without limitation the form and time of payment of Performance Awards). The specific terms and conditions of each Performance Award shall be set forth in a written instrument evidencing the grant of a Performance Award, or in a performance plan adopted by the Committee. Notwithstanding the foregoing, commencing with the 2003 calendar year, (i) no Performance Award may relate to a performance period in excess of three years, (ii) no more than two Performance Awards may be granted to any individual Participant during any calendar year, (iii) with respect to any Performance Award that relates to a performance period of not more than one year, the maximum value of the Performance Award shall not exceed $2,000,000 (to the extent payable in shares of Common Stock, based on either Fair Market Value or Average Fair Market Value at the time of award or payment, as determined by the Committee), and (iv) with respect to any Performance Award that relates to a performance period of more than one year, the maximum value of the Performance Award shall not exceed $2,500,000 (to the extent payable in shares of Common Stock, based on either Fair Market Value or Average Fair Market Value at the time of award or payment, as determined by the Committee).

3.2 Payment of Performance Awards

Payment of Performance Awards may be in cash or in shares of Common Stock valued at Fair Market Value or Average Fair Market Value on the date of payment, or a combination of Common Stock and cash, as the Committee in its discretion may determine. The Committee may impose a limitation on the amount payable upon the occurrence of a Payment Event, which limitation shall be set forth in the written instrument evidencing the grant of a Performance Award.

3.3 Expiration of Performance Awards

If any Participant's employment with the Company is terminated for any reason prior to the occurrence of the Payment Event, all of the Participant's rights under the Performance Award shall expire and terminate unless the applicable performance award agreement or plan provides otherwise.

IV. Restricted Stock

4.1 Award of Restricted Stock

The Committee may grant awards of Restricted Stock to Employees. The Committee shall determine the Purchase Price, the terms of payment of the Purchase Price, the restrictions upon the Restricted Stock, and when such restrictions shall lapse. The Committee may determine that Restricted Stock may be awarded without requiring payment of a Purchase Price. The terms and conditions of the Restricted Stock shall be set forth in a written agreement.

4.2 Conditions of Restricted Stock

All shares of Restricted Stock (including shares received as a result of stock dividends, stock splits or other forms of recapitalization) sold pursuant to the Plan will be subject to the following conditions:

(a) The shares may not be sold, transferred or otherwise alienated or hypothecated until the restrictions are removed or expire.

(b) The Participant shall enter into an escrow agreement (which agreement may be part of the written agreement setting forth the terms and conditions of the Restricted Stock and may specify the Secretary of the Company as escrow holder), providing that the certificates representing the Restricted Stock sold to a Participant pursuant to the Plan will remain in the physical custody of an escrow holder until all restrictions are removed or expire.

(c) Each certificate representing Restricted Stock sold to a Participant pursuant to the Plan will bear a legend making appropriate reference to the restriction imposed.

(d) Such other conditions as the Committee may deem advisable including, without limitation, restrictions designed to facilitate compliance with or exemption from the Exchange Act, the requirements of any stock exchange on which shares of the same class are listed, and with any Blue Sky or securities laws which may be applicable to such shares.

4.3 Lapse of Restrictions

The restrictions imposed upon Restricted Stock under Section 4.2 above will lapse in accordance with such conditions as are determined by the Committee and set forth in a written instrument describing the terms of the sale of the Restricted Stock.

4.4 Rights of Participant

Subject to the provisions of Section 4.2 above, and the restrictions imposed pursuant to Section 4.2, the Committee may determine that the Participant will have all rights of a stockholder with respect to the Restricted Stock sold to the Participant, including the right to vote the shares and receive all dividends and other distributions paid or made with respect thereto. Each Participant who has an outstanding award of Restricted Stock that is subject to restrictions shall deposit with the Company any stock, securities or other property which the Participant is entitled to receive with respect to the Participant's shares of Restricted Stock by reason of an event described in Section 9.1(a) hereof, and such stock, securities or other property will be subject to the restrictions imposed on such Restricted Stock.

4.5 Termination of Employment

Unless the applicable Restricted Stock award agreement provides otherwise, upon a Participant's termination of employment for any reason, all of the Participant's Restricted Stock remaining subject to restrictions on the date of such termination of employment shall be forfeited and shall be available again for grant of Incentive Awards under the Plan.

V. Stock Appreciation Rights

5.1 Granting of Stock Appreciation Rights

The Committee may approve the grant of Stock Appreciation Rights in connection with Options or the grant of Stock Appreciation Rights independent of any Options, subject to the following terms and conditions:

(a) A Stock Appreciation Right that is granted independent of any Option may be granted at any time. A Stock Appreciation Right that is granted in connection with an Option may be granted:

(i) either at the time of grant, or at any time thereafter during the Option term if related to a Nonqualified Stock Option; or

(ii) only at the time of grant if related to an Incentive Stock Option.

(b) A Stock Appreciation Right granted in connection with an Option will entitle the holder of the related Option, upon exercise of the Stock Appreciation Right, to surrender such Option with respect to the number of shares as to which such Stock Appreciation Right is exercised, and to receive payment of an amount computed pursuant to Section 5.1(d). Such Option will, to the extent surrendered, then cease to be exercisable. A Stock Appreciation Right granted in connection with an Option hereunder will be exercisable at such time or times, and only to the extent that a related Option is exercisable, and will not be transferable except to the extent that such related Option may be transferable.

(c) Upon the exercise of a Stock Appreciation Right granted independent of any Option, the holder will be entitled to receive payment of an amount determined by multiplying:

(i) the difference obtained by subtracting the grant price of a share of Common Stock specified in the Stock Appreciation Right award agreement from the Fair Market Value of a share of Common Stock on the date of exercise of such Stock Appreciation Right, by

(ii) the number of shares as to which such Stock Appreciation Right has been exercised.

(d) Upon the exercise of a Stock Appreciation Right granted in connection with an Option, the holder will be entitled to receive payment of an amount determined by multiplying:

(i) the difference obtained by subtracting the purchase price of a share of Common Stock specified in the related Option from the Fair Market Value of a share of Common Stock on the date of exercise of such Stock Appreciation Right, by

(ii) the number of shares as to which such Stock Appreciation Right has been exercised.

(e) Payment of the amount determined under Section 5.1(c) or (d), as the case may be, may be made in whole shares of Common Stock in a number determined at their Fair Market Value (or, in the case of Rights granted independent of any Option or in connection with a Nonqualified Stock Option, Average Fair Market Value), as determined by the Committee, on the date of exercise of the Stock Appreciation Right or, alternatively, at the sole discretion of the Committee, in cash or in a combination of cash and shares as the Committee deems advisable. If the Committee decides to make full payment in shares of Common Stock, and the amount payable results in a fractional share, payment for the fractional share will be made in cash.

VI. Stock Payment

The Committee may approve Stock Payments of the Company's Common Stock (valued at Fair Market Value or Average Fair Market Value at the time of payment, as determined by the Committee)

to an Employee for all or any portion of the compensation (other than base salary) that would otherwise become payable to an Employee in cash.

VII. Dividend Equivalents

A Participant may also be granted at no additional cost "Dividend Equivalents" based on the dividends declared on the Common Stock on record dates during the period between the date an Option or Stock Appreciation Right is granted and the date such Option or Stock Appreciation Right is exercised, or such other period, as determined by the Committee. Such Dividend Equivalents shall be converted to additional shares or cash by such formula as may be determined by the Committee.

Dividend Equivalents shall be computed, as of each dividend record date, both with respect to the number of shares under the Option or Stock Appreciation Right and with respect to the number of Dividend Equivalent shares previously credited to the Participant (or Participant's successor in interest) and not issued during the period prior to the dividend record date.

VIII. Restricted Stock Units

(a) At the time of the grant of Restricted Stock Units, the Committee may impose such restrictions or conditions to the vesting of such Restricted Stock Units as it, in its sole discretion, deems appropriate, to be contained in the award agreement evidencing the grant of the Restricted Stock Units. The Committee may divide such Restricted Stock Units into classes and assign different vesting conditions for each class. Provided that all conditions to the vesting of a Restricted Stock Unit are satisfied, upon the satisfaction of all vesting conditions with respect to a Restricted Stock Unit, such Restricted Stock Unit shall vest. Unless the applicable Restricted Stock Unit award agreement provides otherwise, upon a Participant's termination of employment for any reason, all of the Participant's Restricted Stock Units remaining subject to restrictions on the date of such termination of employment shall be forfeited and shall be available again for grant of Incentive Awards under the Plan.

(b) Upon the vesting of a Restricted Stock Unit, the Participant shall be entitled to receive an amount in cash or Common Stock with a Fair Market Value or Average Fair Market Value, as determined by the Committee, equal to the sum of (1) the Fair Market Value (or Average Fair Market Value, as the case may be) of a share of Common Stock on the date on which such Restricted Stock Unit vests and (2) the aggregate amount of cash dividends paid with respect to a share of Common Stock during the period commencing on the date on which the Restricted Stock Unit was granted and terminating on the date on which such Restricted Stock Unit vests.

IX. Other Provisions

9.1 Adjustment Provisions

(a) Subject to Section 9.1(b) below, 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 property, or if additional shares or new or different shares or other securities or property 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 or other distribution with respect to such shares of Common Stock or other securities, an appropriate and proportionate adjustment shall be made in (i) the maximum number and kind of shares provided in Section 1.3, (ii) the number and kind of shares or other securities or property subject to the outstanding Incentive Awards, and (iii) the price for each share or other unit of any other securities or property subject to outstanding Incentive Awards without material change in the aggregate purchase price or value as to which such Incentive Awards remain exercisable or subject to restrictions.

(b) In addition to the adjustments covered under Section 9.1(a) above, any Incentive Award may contain provisions to the effect that, upon the occurrence of certain events, any outstanding Incentive Awards not theretofore vested, exercisable, payable or free from restrictions, as the case may be, shall either immediately, or upon a further determination made by the Committee at the time of the event, become fully vested, exercisable, payable, or free from restrictions. Except as otherwise provided in an Incentive Award agreement, plan or other written instrument, upon a change in control of the Company (as defined in Section 9.1(d) below), any outstanding Incentive Awards not theretofore vested, exercisable, payable or free from restrictions, as the case may be, shall immediately become fully vested, exercisable, payable, or free from restrictions.

(c) Adjustments and determinations under Section 9.1(a) and 9.1(b) will be made by the Committee, whose determination will be final, binding, and conclusive. No fractional interests will be issued under the Plan resulting from any such adjustments, but the Committee in its discretion may make a cash payment in lieu of fractional shares.

(d) For purposes of Section 9.1(b) above, a "change in control of the Company" shall be deemed to have occurred if the conditions set forth in any one of the following paragraphs shall have been satisfied:

(i) any Person is or becomes the beneficial owner (as defined in Rule 13d-3 under the Exchange Act), directly or indirectly, of securities of the Company (not including in the securities beneficially owned by such Person any securities acquired directly from the Company or any of its affiliates) representing more than 30% of the combined voting power of the Company's then outstanding securities; or

(ii) during any period of two (2) consecutive years (not including any period prior to the grant of the Incentive Award subject to this provision), individuals who at the beginning of such period constitute the Board and any new director (other than a director designated by a Person who has entered into an agreement with the Company to effect a transaction described in clause (i), (iii), or (iv) of this Section 9.1(d) whose election by the Board or nomination for election by the Company's shareholders was approved by a vote of at least two-thirds ($^2/_3$) of the directors then still in office who either were directors at the beginning of the period or whose election or nomination for election was previously so approved) cease for any reason to constitute a majority thereof; or

(iii) the shareholders of the Company approve a merger or consolidation of the Company with any other company, other than (A) a merger or consolidation which would result in the voting securities of the Company outstanding immediately prior thereto continuing to represent (either by remaining outstanding or by being converted into voting securities of the surviving entity), in combination with the ownership of any trustee or other fiduciary holding securities under an employee benefit plan of the Company or any of its affiliates, at least 75% of the combined voting power of the voting securities of the Company or such surviving entity outstanding immediately after such merger or consolidation, or (B) a merger or consolidation effected to implement a recapitalization of the Company (or similar transaction) in which no Person acquires more than 50% of the combined voting power of the Company's then outstanding securities, or

(iv) the shareholders of the Company approve a plan of complete liquidation of the Company or an agreement for the sale or disposition by the Company of all or substantially all of the Company's assets.

For purposes of this Section 9.1(d), "Person" shall have the meaning given in Section 3(a)(9) of the Exchange Act, as modified and used in Sections 13(d) and 14(d) thereof; provided, however, a Person shall not include the Company or any of its subsidiaries, a trustee or other fiduciary holding securities under an employee benefit plan of the Company or any of its subsidiaries, an underwriter temporarily holding securities pursuant to an offering of such securities, or a company owned, directly or indirectly,

by the stockholders of the Company in substantially the same proportions as their ownership of stock of the Company.

9.2 Continuation of Employment

Nothing in the Plan or in any instrument executed pursuant to the Plan will confer upon any Participant any right to continue in the employ of the Company or affect the right of the Company to terminate the employment of any Participant at any time with or without cause.

9.3 Compliance with Government Regulations

No shares of Common Stock will be issued pursuant to an Incentive Award unless and until all applicable requirements imposed by Federal and State securities and other laws, rules and regulations and by any regulatory agencies having jurisdiction and by any stock exchanges upon which the Common Stock may be listed have been fully met. As a condition precedent to the issuance of shares of Common Stock pursuant to an Incentive Award, the Company may require the Participant to take any reasonable action to comply with such requirements. The Company shall be under no obligation to affect the registration pursuant to the Securities Act of 1933, as amended, of any interests in the Plan or any shares of Common Stock to be issued hereunder or to effect similar compliance under any state laws.

9.4 Privileges of Stock Ownership

No Participant and no beneficiary or other person claiming under or through such Participant will have any right, title or interest in or to any shares of Common Stock allocated or reserved under the Plan or subject to any Incentive Award except as to such share of Common Stock, if any, that have been issued to such Participant.

9.5 Withholding

The Company may make such provisions as it deems appropriate to withhold any taxes the Company determines it is required to withhold in connection with any Incentive Award. The Company may require the Participant to satisfy any relevant tax requirements before authorizing any issuance of Common Stock to the Participant. To the extent permitted by the applicable Incentive Award agreement a Participant may satisfy any such withholding tax obligation by any of the following means or by a combination of such means: (a) tendering a cash payment; (b) authorizing the Company to withhold from the Common Stock otherwise issuable to the Participant, a number of shares having a Fair Market Value, as of the date the withholding tax obligations arises, less than or equal to the amount of withholding tax obligations; or (c) delivering to the Company already owned and unencumbered shares of Common Stock having a Fair Market Value, as of the date the withholding tax obligation arises, less than or equal to the amount of the withholding tax obligation.

9.6 Transferability of Incentive Awards

The Committee shall provide that (a) no Option or Right may be exercised during the life of the Participant other than by the Participant or the Participant's duly appointed guardian or personal representative, and (b) no Incentive Award and no Right under the Plan, contingent or otherwise, will be assignable or subject to any encumbrance, pledge, or charge of any nature except that, under such rules as the Committee may establish pursuant to the terms of the Plan, a beneficiary may be designated with respect to an Incentive Award in the event of death of a Participant. If such beneficiary is the executor or administrator of the estate of the Participant, any rights with respect to such Incentive Award may be transferred to the person or persons or entity (including a trust) entitled thereto under the will of the Participant of such Incentive Award. Notwithstanding the foregoing, the Committee may permit transferability of Incentive Awards to the extent permitted by the applicable provisions of Rule 16b-3; provided, however, that the Committee, in its discretion, may impose any restrictions on transferability of Incentive Awards as it deems appropriate.

9.7 Amendment and Termination of Plan; Amendment of Incentive Award

(a) The Board will have the power, in its discretion, to amend, suspend, or terminate the Plan at any time; provided, however, that no amendment to the Plan may be made without approval of the stockholders of the Company to the extent stockholder approval of the amendment is required to comply with the requirements of Rule 16b-3 or, if applicable, Section 162(m) of the Code, and no amendments to the Plan may be made that would impair the rights of a Participant under any Incentive Award theretofore granted without such Participant's consent.

(b) Except as otherwise provided by the applicable Incentive Award agreement or by Section 1.4, the Committee may amend the terms of any Incentive Award theretofore granted, prospectively or retroactively, but, subject to Section 9.1(a) of Plan, no such amendment shall impair the rights of any Participant without his or her consent.

(c) Notwithstanding any other provision of the Plan to the contrary, neither the Plan nor any outstanding Option shall be amended to decrease the purchase price of any outstanding Option unless first approved by the requisite vote of stockholders.

(d) Notwithstanding anything to the contrary contained in the Plan or in any Incentive Award agreement, to the extent the Committee deems it appropriate, the Committee reserves the right to amend or terminate the Plan and/or amend, restructure, terminate or replace an Incentive Award in order to cause the Incentive Award to either not be subject to Section 409A of the Code or to comply with the applicable provisions of such section.

X. Interpretation

The Plan is designed and intended to comply with Rule 16b-3 and, to the extent applicable, Section 409A and Section 162(m) of the Code, and all provisions hereof shall be construed in a manner to so comply. If any provision of the Plan is held to be invalid or unenforceable, the other provisions of the Plan shall not be affected but shall be applied as if the invalid or unenforceable provision had not been included in the Plan. The Plan and all Awards shall be governed by the laws of the State of Hawaii without regard to its principles of conflict of laws.

XI. Duration of Plan

Unless previously terminated by the Board of Directors, the Plan will terminate on January 20, 2013, but Incentive Awards theretofore granted may extend beyond that date.

Appendix D

Towers Perrin Data Bank
General Industry Organizations

A&P
A.G. Edwards
A.T. Cross
AAA of Science
AAI
AARP
Abbott Laboratories
ABC
Accenture
ACH Food
adidas America
Advance Publications
Advance Publications
Advanced Medical Optics
Advanced Micro Devices
Advanta
ADVO
Aegon USA
Aerojet
AES
Aetna
AFLAC
AGL Resources
AIG
Air Products and Chemicals
Alcatel USA
Alcoa
Alcon Laboratories
Allbritton Communications — KATV
Allegheny Energy
Allergan
Allete
Alliance Data Systems
Alliant Techsystems
Allianz
Allstate
Alstom Power
Altana Pharma
Altria Group
Ameren
America Online
American Airlines
American Airlines Publishing
American Chemical Society
American Electric Power
American Express Credit Card
Fifth Third Bancorp
Fireman's Fund Insurance
First Data
FirstEnergy
Fiserv
Fleetwood Enterprises
Fluke
Fluor
Foot Locker
Ford
Forest Laboratories
Fortune Brands
Forum Communications — WDAY
FPL Group
Franklin Resources
Freddie Mac
Freedom Communications
Freedom Communications — KFDM
Freedom Communications — WLAJ
Freedom Communications — WPEC
Freedom Communications — WRGB
Freedom Communications — WTVC
Freedom Communications — WWMT
Freightliner
Fremont Investment & Loan
G&K Services
Gannett
Gap
Gap
Gartner
Gates
GATX
Genentech
General Dynamics
General Mills
General Motors
Genzyme
GEO Group
Georgia Gulf
Gilead Sciences
Omaha Public Power
Omnova Solutions
OneBeacon Insurance
ONEOK
Orange County Teachers' Federal Credit Union
Organon
Osram Sylvania
Otter Tail
Owens Corning
Owens-Illinois
Pacific Gas & Electric
Pacific Life
PacifiCorp
Packaging of America
Panasonic of North America
Papa Johns
Par Pharmaceutical
Parker Hannifin
Parsons
Peabody Energy
Pearson Education
People's Bank
Peoples Energy
Pepco Holdings
PepsiCo
PerkinElmer
Pernod Ricard USA
PetSmart
Pfizer
Pharmion
Phelps Dodge
Philips Electronics North America
Phillips-Van Heusen
Phoenix Companies
Pinnacle West Capital
Pitney Bowes
PJM Interconnection
Plexus
Plymouth Rock Assurance
PMI Group
PNC Financial Services
PNM Resources
Popular
Portland General Electric
PPG Industries

American Family Insurance
American Re
American Standard
American Transmission
American United Life
American Water Works
Ameriprise Financial
Ameriquest Mortgage
Ameritrade
Ameron
AMETEK
Amgen
AmSouth
Anadarko Petroleum
Ann Taylor Stores
APAC
Apache
APL
Apple Computer
Applebee's International
Applied Materials
Aquila
ARAMARK
Arby's Restaurant Group
Arctic Cat
Armstrong World Industries
ArvinMeritor
Ashland
Associated Banc-Corp
Assurant
Assurant Health
AstraZeneca
AT&T
Atmos Energy
Aurora Loan Services
Austin Industries
Auto Club Group
Automatic Data Processing
AutoZone
Avaya
Avery Dennison
Avista
Avnet
AXA Equitable
BAE Systems — CNI Division
Bank North
Bank of America
Bank of the West
Barnes Group
Barrick
Baxter International
Bayer
Bayer CropScience
BB&T
Beckman Coulter
BellSouth

GlaxoSmithKline
GMAC-RFG
Goodrich
Goodyear Tire & Rubber
Gorton's
Great Plains Energy
Great-West Life Annuity
GROWMARK
GTECH
Guardian Life
Guideposts
H&R Block
H.B. Fuller
H.J. Heinz
Haemonetics
Hannaford
Harcourt Education
Harley-Davidson
Harman International Industries
Harris Bank
Harris Enterprises
Harry Winston
Harsco
Hartford Financial Services
Hasbro
Hawaiian Electric
Hawaiian Telecom
HBO
HCA Healthcare
Health Care Services
Health Net
Hearst-Argyle Television
Herbalife International of America
Hercules
Herman Miller
Hershey Foods
Hess
Hewlett-Packard
Hexcel
Hilton Hotels
HNI
HNTB
Hoffmann-La Roche
Honeywell
Horizon Blue Cross Blue Shield of New Jersey
Houghton Mifflin
Hovnanian Enterprises
HSBC North America
Hubbard Broadcasting
Humana
Huntington Bancshares
IAC/InterActive
IBM
ICI Paints North America

PPL
Principal Financial
Prisma Energy
Procter & Gamble
Progress Energy
Progressive
ProQuest
Prudential Financial
Public Service Enterprise
Puget Energy
Pulte Homes
Purdue Pharma
QLT
QUALCOMM
Quest Diagnostics
Quintiles
Qwest Communications
Ralcorp Holdings
Raley's Superstores
Raytheon
RBC Dain Rauscher
Reed Business Information
Reed Elsevier
Reed Exhibitions
Regal-Beloit
Reliant Resources
Reuters America
Revlon
Reynolds American
Reynolds and Reynolds
Rich Products
Rinker Materials
Rio Tinto
RISO
Robert Bosch
Robert Half International
Roche Diagnostics
Roche Palo Alto
Rockwell Automation
Rockwell Collins
Rohm and Haas
Rolls-Royce North America
RSC Equipment Rental
Russell
S.C. Johnson
Sabre
SAFECO
Safety-Kleen Holdco
Safeway
Salt River Project
Sanofi-Aventis
Sarkes Tarzian — KTVN
Sarkes Tarzian — WRCB
SAS Institute
SCANA
Schering-Plough

Belo
Best Buy
BIC
Big Lots
Black & Decker
Blockbuster
Blue Cross Blue Shield of Florida
Bob Evans Farms
Boehringer Ingelheim
Boeing
Boston Scientific
Boy Scouts of America
BP
Bracco Diagnostics
Brady
Bremer Financial
Brinker International
Bristol-Myers Squibb
Bunge
Burlington Northern Santa Fe
BWXT Y-12
C&D Technologies
C.H. Guenther & Son
Cablevision Systems
Cadbury-Schweppes North America
California Independent System Operator
Cameron International
Campbell Soup
Capital Blue Cross
Capital Broadcasting — WRAL
Capital One Financial
Cardinal Health
Cargill
Carpenter Technology
Caterpillar
Catholic Healthcare West
CB Richard Ellis
CDI
Cedar Rapids TV — KCRG
Celestica
Celgene
Cendant
CenterPoint Energy
Cephalon
Ceridian
CH Energy Group
CH2M Hill
Chanel
Charter Communications
CheckFree Holdings
Chemtura
Chevron
Chicago Mercantile Exchange
IDACORP
IDEX
IKON Office Solutions
IMS Health
Independence Blue Cross
IndyMac
ING
Ingersoll-Rand
Intel
InterContinental Hotels
International Flavors & Fragrances
International Paper
International Truck & Engine
Interstate Brands
Invensys
Irvine Company
Irving Oil
Irwin Financial
Itochu International
ITT — Corporate
ITT — Defense
ITT — Motion and Flow Control
J. Crew
J.C. Penney Company
J.M. Smucker
J.R. Simplot
Jack in the Box
Jackson Hewitt
Jacobs Engineering
Jarden
JEA
JM Family
John Crane
John Hancock
Johns-Manville
Johnson & Johnson
Johnson Controls
Joint Commission on Accreditation of Healthcare Organizations
Jostens
Journal Broadcast Group
JSJ
Kaiser Foundation Health Plan
Kaman Industrial Technologies
KB Home
Kellogg
Kennametal
Kerr-McGee
KeyCorp
Kimberly-Clark
Kinder Morgan
Kindred Healthcare
King Pharmaceuticals
Kinross Gold
Kiplinger
Schneider Electric
Schurz — KYTV
Schurz — WAGT
Schwan's
Science Applications International
Scotts Miracle-Gro
Seagate Technology
Sears
Seattle Times
Securian Financial Group
Security Benefit Group of Companies
Sempra Energy
SENCORP
Sensata Technologies
7-Eleven
Shell Oil
Sherwin-Williams
Shriners Hospital for Children
Siemens
Sigma-Aldrich
Sinclair Broadcast Group
Sirius Satellite Radio
Sirius Satellite Radio
SLM
Smurfit-Stone Container
Sodexho
Solvay America
Solvay Pharmaceuticals
Sonoco Products
Sony Electronics
Sony Ericsson Mobile Communications
Southern Company
Southern Union Company
Sovereign Bancorp
Spansion
Sports Authority
Springs Global
Sprint Nextel
St. Jude Medical
St. Lawrence Cement
St. Paul Travelers
Standard Register
Staples
Starbucks
Starwood Hotels & Resorts
State Farm Insurance
State Street
Steelcase
STP Nuclear Operating
String Letter Publishing
SUEZ Energy North America
Sun Life Financial
Sun Microsystems

CHS
CIGNA
Cincinnati Bell
Cingular Wireless
Circle K
CITGO Petroleum
Citigroup
Clarke American Checks
Clear Channel Communications
Cleco
Cleveland Clinic Foundation
Clorox
CMS Energy
CNA
COACH
Cobank
Coca-Cola
Colgate-Palmolive
Colorado Springs Utilities
Columbia Sportswear
Comair
Combe
Comcast Cable Communications
Comerica
Commerce Bancorp
Commerce Bancshares
Compass Bancshares
ConAgra Foods
Connell
ConocoPhillips
Consolidated Edison
Constellation Brands
Constellation Energy
Convergys
Cooper Tire & Rubber
Corn Products
Corporate Express
Countrywide Financial
Covance
Covanta Energy
Cox Enterprises
Crown Castle
Crown Holdings
CSX
Cubic
Cullen/Frost Bankers
CUNA Mutual
Cushman & Wakefield
CVS Pharmacy
Cytec
Dade Behring
Daiichi Sankyo
DaimlerChrysler
Darden Restaurants
Dell
Delphi

Knight Ridder
Koch Industries
Kohler
Kohl's
Kraft Foods
L.L. Bean
L-3 Communications
Lafarge North America
Land O'Lakes
Landmark Communications — WTVF
LaSalle Bank
Lawson Products
Lear
Levi Strauss
LexisNexis
Lexmark International
Liberty Mutual
Limited
Lincoln Center for the Performing Arts
Lincoln Financial
Loews
LOMA
Longs Drug Stores
Lorillard
Louisville Corporate Services
Lower Colorado River Authority
Lucent Technologies
M&T Bank
Magellan Midstream Partners
Makino
Manship Stations — KRGV
Marathon Oil
MarkWest Energy
Marriott International
Marsh & McLennan
Marshall & Ilsley
Martin Marietta Materials
Mary Kay
Masco
Massachusetts Mutual
MasterCard
McClatchy
McDermott
McDonald's
McGraw-Hill
MDC Holdings
MDS Laboratory Service
MDU Resources
MeadWestvaco
Medco Health Solutions
Media General
MedImmune
Medtronic

Sunbeam Television — WHDH
SunGard Data Systems
Sunoco
SunTrust Banks
SVB Financial
Sybron Dental Specialties
Syngenta
Takeda Pharmaceutical
TAP Pharmaceuticals
Targa Resources
Target
Taubman Centers
TDS Telecom
TECO Energy
Tennessee Valley Authority
Terex
Tesoro
Texas Capital Bank
Texas Instruments
Textron
Thomas & Betts
Thomson
Thomson Financial Services
Thomson Learning
Thomson Legal and Regulatory
Thomson Scientific & Healthcare
3M
Thrivent Financial for Lutherans
TIAA-CREF
Time Warner
Time Warner Cable
Timken
Toro
Tower Automotive
Toys 'R' Us
Trans Union
TransCanada
Trex
True Value Hardware
Tupperware
Twin Cities Public Television — TPT
TXU
Tyco Electronics
U.S. Bancorp
UCB
UIL Holdings
Unilever United States
Union Bank of California
Union Pacific
UniSource Energy
Unisource Worldwide
Unisys
United Airlines
United Parcel Service

Dendrite International
Denny's
Dentsply
Devon Energy
Diageo North America
Dial
Discover Financial Services
Discovery Communications
Dispatch Broadcast Group — WBNS
Dominion Resources
Donaldson
Dow Chemical
Dow Jones
DTE Energy
Duke Energy
DuPont
Dynea
Dynegy
E.ON U.S.
E.W. Scripps
Eagle-Picher Industries
Eastman Chemical
Eaton
eBay
Ecolab
Edison International
EDS
El Paso
Elan Pharmaceuticals
Eli Lilly
Elsevier Science
EMC
EMCOR Group
Emdeon
Emerson
Enbridge Energy
EnCana Oil & Gas USA
Energen
Energy East
Energy Northwest
Engelhard
Enron
Entergy
Equifax
Equitable Resources
Equity Office Properties
Erie Insurance
ESRI
Eugene Water & Electric Board
Eugene Water & Electric Board
Evening Post Publishing — KOAA
Exelon
Experian
ExxonMobil

Mellon Financial
Merck
Mercury Insurance
Meredith
Merrill
Merrill Lynch Private Client
Metaldyne
Metavante
Methode Electronics
MetLife
MGE Energy
Microsoft
Middle East Television Network/Alhurra
Milacron
Millennium Pharmaceuticals
Millipore
Mine Safety Appliances
Mirant
Mission Foods
Modine Manufacturing
Molex
Molson Coors Brewing
Monaco Coach
Moody's
Morgan Murphy Stations — WISC
Motorola
MSC Industrial Direct
MSP Communications
Mutual of Omaha
Nalco
NASD
National Enrichment Facility
National Fuel Gas
National Geographic Society
National Semiconductor
National Starch & Chemical
Nationwide
Navy Federal Credit Union
NBC Universal
NCCI Holdings
NCS Pearson
Nestle USA
New York Independent System Operator
New York Life
New York Power Authority
New York Times
Nicor
NIKE
Noranda Aluminum
Norfolk Southern
Nortel Networks
Northrop Grumman
Northwest Airlines

United Rentals
United States Cellular
United States Enrichment
United Stationers
United Technologies
United Water Resources
UnitedHealth
Unitil
Universal Underwriters Group
Univision Communications
UnumProvident
US Investigations Services
USAA
USG
Valero Energy
Vanguard
Vectren
Verizon
Verizon Wireless
Vertex Pharmaceuticals
Viacom
Visa International
Visa USA
Vistar
Visteon
VNU Business Media
Vulcan Materials
W.R. Grace
Wachovia
Walt Disney
Warnaco
Washington Group International
Washington Mutual
Washington Post
Waste Management
Watson Pharmaceuticals
Webster Bank
Wellcare Health Plans
Wellpoint
Wells' Dairy
Wells Fargo
Wendy's International
Westar Energy
Westinghouse Electric
Westinghouse Savannah River
Weyerhaeuser
Whole Foods Market
Williams Companies
Williams-Sonoma
Wisconsin Energy
Wm. Wrigley Jr.
Wolf Creek Nuclear
Wolters Kluwer US
Woodward Communications
World Savings
WPS Resources

Fairchild Controls
Fannie Mae
FANUC Robotics America
Federal Home Loan Bank of San Francisco
Federal Reserve Bank of Cleveland
Federal Reserve Bank of Dallas
Federal Reserve Bank of New York
Federal Reserve Bank of San Francisco
Federal-Mogul
Federated Department Stores
Ferrellgas
Fidelity Investments
NorthWestern Energy
Northwestern Mutual
Novartis
Novartis Consumer Health
Novartis Pharmaceuticals
Novelis
Novo Nordisk Pharmaceuticals
NRG Energy
NSTAR
Nuclear Management
NW Natural
Occidental Petroleum
Office Depot
OGE Energy
Oglethorpe Power
Ohio Casualty
Wray Edwin — KTBS
Wyeth
Xcel Energy
Xerox
Yahoo!
Young Broadcasting — KELO
Young Broadcasting — KLFY
Young Broadcasting — KRON
Young Broadcasting — KWQC
Young Broadcasting — WATE
Young Broadcasting — WKRN
Young Broadcasting — WLNS
Young Broadcasting — WRIC
Young Broadcasting — WTEN
Yum! Brands

HAWAIIAN ELECTRIC COMPANY, INC.

Superseding Revised Sheet No. 2
Effective June 17, 2005

REVISED SHEET NO. 2
Effective June 20, 2008

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HAWAIIAN ELECTRIC COMPANY, INC.

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

RULE NO. 7 (Continued)

Discontinuance and Restoration of Service

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 by 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 $16.00 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 when such field call results in a successful collection of monies. This charge will be added to the customer’s bill.

E. SERVICE ESTABLISHMENT 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 to 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.

Superseding Revised Sheet No. 50
Effective June 1, 2008

REVISED SHEET No. 50
Effective June 20, 2008

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
50.3	Interim Surcharge	June 1, 2008	All Schedules Except Schedule Q
50.4	Interim Rate Increase 2007	June 20, 2008	All Schedules Except Schedule Q
50.5	Test Year 2005 Refund	June 20, 2008	All Schedules Except Schedule Q
51	"R"	June 20, 2008	Residential Service
51A	"R"	June 20, 2008	Residential Service
52	"G"	June 20, 2008	General Service Non-Demand
53	"G"	June 20, 2008	General Service Non-Demand
54	"J"	June 20, 2008	General Service Demand
54A	"J"	June 20, 2008	General Service Demand
54B	"J"	June 20, 2008	General Service Demand
54C	"J"	June 20, 2008	General Service Demand
55	"H"	June 20, 2008	Commercial Cooking, Heating, Air Conditioning & Refrigeration Service
56	"H"	September 1, 1992	Commercial Cooking, Heating, Air Conditioning & Refrigeration Service
57	"PS"	June 20, 2008	Large Power Secondary Voltage Service
58	"PS"	June 20, 2008	Large Power Secondary Voltage Service
58A	"PS"	June 20, 2008	Large Power Secondary Voltage Service
58B	"PP"	June 20, 2008	Large Power Primary Voltage Service
58C	"PP"	June 20, 2008	Large Power Primary Voltage Service
58D	"PP"	June 20, 2008	Large Power Primary Voltage Service
58E	"PT"	June 20, 2008	Large Power Transmission Voltage Service
58F	"PT"	June 20, 2008	Large Power Transmission Voltage Service
58G	"PT"	June 20, 2008	Large Power Transmission Voltage Service

HAWAIIAN ELECTRIC COMPANY, INC.

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

Superseding Revised Sheet No. 50A
Effective June 1, 2001

REVISED SHEET No. 50A
Effective June 20, 2008

RATE SCHEDULES (continued)

Sheet	Schedule	Date Effective	Character of Service
59	"F"	June 20, 2008	Public Street Lighting, Highway Lighting, & Park & Playground Floodlighting
60	"F"	June 20, 2008	Public Street Lighting, Highway Lighting, & Park & Playground Floodlighting
61	"U"	June 20, 2008	Time-of-Use Service
61A	"U"	June 20, 2008	Time-of-Use Service
61B	"U"	June 20, 2008	Time-of-Use Service
62	"E"	June 1, 1996	Electric Service for Employees
63	Energy Cost Adjustment Clause	June 20, 2008	All Schedules Except Schedule Q
63A	Energy Cost Adjustment Clause	June 20, 2008	All Schedules Except Schedule Q
63B	Energy Cost Adjustment Clause	June 20, 2008	All Schedules Except Schedule Q
64	Rider "I"	June 20, 2008	Interruptible Contract Service
65	Rider "M"	June 20, 2008	Off-Peak and Curtailable Service
65A	Rider "M"	June 20, 2008	Off-Peak and Curtailable Service
65B	Rider "M"	June 20, 2008	Off-Peak and Curtailable Service
65C	Rider "M"	June 20, 2008	Off-Peak and Curtailable Service
65D	Rider "M"	June 20, 2008	Off-Peak and Curtailable Service
		(PAGE 66 - NOT ASSIGNED)	
67	Rider "T"	June 20, 2008	Time-of-Day Service
67A	Rider "T"	June 20, 2008	Time-of-Day Service
67B	Rider "T"	June 20, 2008	Time-of-Day Service

HAWAIIAN ELECTRIC COMPANY, INC.

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

Superseding Revised Sheet No. 50B
Effective May 15, 2008

REVISED SHEET NO. 50B
Effective June 20, 2008

RATE SCHEDULES (continued)

Sheet	Schedule	Date Effective	Character of Service
68	IRP Cost Recovery Provision	April 1, 2008	All Schedules Except Schedule Q
68A	IRP Cost Recovery Provision	April 1, 2008	All Schedules Except Schedule Q
69	"SS"	May 15, 2008	Standby Service
69A	"SS"	May 15, 2008	Standby Service
69B	"SS"	May 15, 2008	Standby Service
69C	"SS"	May 15, 2008	Standby Service
69D	"SS"	May 15, 2008	Standby Service
69E	"SS"	May 15, 2008	Standby Service
69F	"SS"	May 15, 2008	Standby Service
69G	"SS"	May 15, 2008	Standby Service
69H	"SS"	May 15, 2008	Standby Service
69I	"SS"	May 15, 2008	Standby Service
69J	"SS"	May 15, 2008	Standby Service
69K	"SS"	May 15, 2008	Standby Service
69L	"SS"	May 15, 2008	Standby Service
69M	"SS"	May 15, 2008	Standby Service
69N	"SS"	May 15, 2008	Standby Service
70	Rider "SSP"	June 30, 2007	SolarSaver Pilot Program
70A	Rider "SSP"	April 4, 2008	SolarSaver Pilot Program
70B	Rider "SSP"	June 30, 2007	SolarSaver Pilot Program
70C	Rider "SSP"	June 30, 2007	SolarSaver Pilot Program
70D	Rider "SSP"	June 30, 2007	SolarSaver Pilot Program
70E	Rider "SSP"	June 30, 2007	SolarSaver Pilot Program
70F	Rider "SSP"	June 30, 2007	SolarSaver Pilot Program
70G	Rider "SSP"	June 30, 2007	SolarSaver Pilot Program
70H	Rider "SSP"	June 30, 2007	SolarSaver Pilot Program
70I	Rider "SSP"	June 30, 2007	SolarSaver Pilot Program
70J	Rider "SSP"	June 30, 2007	SolarSaver Pilot Program
70K	Rider "SSP"	June 30, 2007	SolarSaver Pilot Program
70L	Rider "SSP"	June 30, 2007	SolarSaver Pilot Program
70M	Rider "SSP"	June 30, 2007	SolarSaver Pilot Program

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81	"Q"	June 20, 2008	Purchases From Qualifying Facilities -100 kW or Less

HAWAIIAN ELECTRIC COMPANY, INC.

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

Superseding Revised Sheet No. 50C
Effective June 30, 2007

REVISED SHEET NO. 50C
Effective June 20, 2008

RATE SCHEDULES (continued)

Sheet	Schedule	Date Effective	Character of Service
81A	"Q"	June 20, 2008	Purchases From Qualifying Facilities -100 kW or Less
81B	"Q"	June 20, 2008	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	TOU-C	June 20, 2008	Commercial Time-Of-Use Service
84	TOU-C	June 20, 2008	Commercial Time-Of-Use Service
85	TOU-C	June 20, 2008	Commercial Time-Of-Use Service
85A	TOU-C	June 20, 2008	Commercial Time-Of-Use Service
86	TOU-R	June 20, 2008	Residential Time-Of-Use Service
87	TOU-R	June 20, 2008	Residential Time-Of-Use Service
88	TOU-R	June 20, 2008	Residential Time-Of-Use Service

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HAWAIIAN ELECTRIC COMPANY, INC.

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
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Superseding Revised Sheet No. 50.4 REVISED SHEET NO. 50.4
Effective October 26, 2007 Effective June 20, 2008

INTERIM RATE INCREASE 2007

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
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 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, SolarSaver Adjustment, and Interim Surcharge.

INTERIM RATE INCREASE 2007:

Schedule R/E/TOU-R	7.12 percent
Schedule G/TOU-C Non-Demand	7.05 percent
Schedule J/TOU-C Demand	5.96 percent
Schedule H	7.24 percent
Schedule PS	7.47 percent
Schedule PP	7.61 percent
Schedule PP (Directly served from Substation)	1.84 percent
Schedule PT	6.56 percent
Schedule F	7.23 percent
Schedule U	5.96 percent

The above Interim Rate Increase 2007 is based on an interim increase of $77,867,000 approved by the Public Utilities Commission in its Order granting a Motion to Adjust Interim Increase filed on May 21, 2008 in Docket No. 2006-0386. The revenues collected through this Interim Rate Increase are subject refund with interest in accordance with the Public Utilities Commission's Order Granting Motion to Adjust Interim Increase filed on May 21, 2008.

HAWAIIAN ELECTRIC COMPANY, INC.

Docket No. 2006-0386; Order Granting Motion to Adjust Interim Increase Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

Superseding Revised Sheet No. 51
Effective January 1, 1997

REVISED SHEET NO. 51
Effective June 20, 2008

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)

All kWhr per month - per kWhr	8.2993 ¢/kWhr

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

All kWhr per month - per kWhr	8.8903 ¢/kWhr

Minimum Charge:

Single-Phase Service - per month	$16.00/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:

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

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 June 20, 2008

SCHEDULE G

General Service Non-Demand

Availability:

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

If a customer's usage exceeds 5000 kilowatthours 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	16.4205 ¢/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 0.6%.

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

Superseding Revised Sheet No. 53
Effective September 1, 1992

REVISED SHEET NO. 53
Effective June 20, 2008

SCHEDULE G -(continued)

Primary Supply Voltage Service – continued:

The Primary Supply Voltage Service will be closed to new customers after June 19, 2008.

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 June 20, 2008

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 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 $8.50/kW

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

First	200 kWhr/month/kW of billing demand - per kWhr	13.5915 ¢/kWhr
Next	200 kWhr/month/kW of billing demand - per kWhr	12.4436 ¢/kWhr
All over	400 kWhr/month/kW of billing demand - per kWhr	11.4145 ¢/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 $212.50 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

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

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 June 19, 2008. 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 other 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.

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	3.0%
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 0.6%, 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.

HAWAIIAN ELECTRIC COMPANY, INC.

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

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 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 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 June 20, 2008

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	$25.00
Three phase service - per month	$60.00

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	13.4312 ¢/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

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

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 REVISED SHEET NO. 57
Effective June 1, 2001 Effective June 20, 2008

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	$14.35/kW
Next 1000 kW of billing demand - per kW	$13.85/kW
Over 1500 kW of billing demand - per kW	$12.85/kW

ENERGY CHARGE - ¢ per kWh:

First 200 kWh/month/kW of billing demand - per kWhr	12.2456 ¢/kWhr
Next 200 kWh/month/kW of billing demand - per kWhr	11.4473 ¢/kWhr
Over 400 kWh/month/kW of billing demand - per kWhr	11.1379 ¢/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%.

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

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.

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.

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

Superseding Revised Sheet No. 58A
Effective June 1, 2001

REVISED SHEET NO. 58A
Effective June 20, 2008

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.

HAWAIIAN ELECTRIC COMPANY, INC.

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

Superseding SHEET NO. 58B
Effective June 1, 2001

REVISED SHEET NO. 58B
Effective June 20, 2008

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:	
CUSTOMERS DIRECTLY SERVED FROM SUBSTATION	
First 500 kW of billing demand - per kW	$13.35/kW
Next 1000 kW of billing demand - per kW	$12.85/kW
Over 1500 kW of billing demand - per kW	$11.85/kW
CUSTOMERS NOT DIRECTLY SERVED FROM SUBSTATION	
First 500 kW of billing demand - per kW	$15.11/kW
Next 1000 kW of billing demand - per kW	$14.61/kW
Over 1500 kW of billing demand - per kW	$13.61/kW
ENERGY CHARGE - ¢ per kWh:	
First 200 kWh/month/kW of billing demand - per kWhr	12.1534 ¢/kWhr
Next 200 kWh/month/kW of billing demand - per kWhr	11.3702 ¢/kWhr
Over 400 kWh/month/kW of billing demand - per kWhr	11.0668 ¢/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

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Transmittal Letter dated June 23, 2008.

SCHEDULE PP – (continued)

where the metering point is approved by the Company, a secondary metering adjustment of 0.2142 ¢/kWhr shall be added to the above energy charge.

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.

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 June 20, 2008

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.

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

Superseding SHEET NO. 58E
Effective June 1, 2001

REVISED SHEET NO. 58E
Effective June 20, 2008

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	$14.00/kW
Next 1000 kW of billing demand - per kW	$13.50/kW
Over 1500 kW of billing demand - per kW	$12.50/kW

ENERGY CHARGE - ¢ per kWhr:

First 200 kWh/month/kW of billing demand - per kWhr	11.6037 ¢/kWhr
Next 200 kWh/month/kW of billing demand - per kWhr	10.8318 ¢/kWhr
Over 400 kWh/month/kW of billing demand - per kWhr	10.5326 ¢/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 0.6%.

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

Superseding SHEET NO. 58F
Effective June 1, 2001

REVISED SHEET NO. 58F
Effective June 20, 2008

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.

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 June 20, 2008

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 kWhr:

First	150 kWhr/month/kW of billing demand - per kWhr	18.6161 ¢/kWhr
All over	150 kWhr/month/kW of billing demand - per kWhr	14.6421 ¢/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%.

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Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

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.

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

Superseding Revised Sheet No. 61
Effective January 1, 1995

REVISED SHEET NO. 61
Effective June 20, 2008

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.	5:00 p.m. - 9:00 p.m., Monday through Friday
Mid-Peak.	All On-Peak hours outside of Priority Peak hours
Off-Peak.	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	$18.00/kW
Mid-Peak - per kW of billing demand	$16.00/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.

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

All On-Peak kWhr per month	- per kWhr	13.7277 ¢/kWhr
All Off-Peak kWhr per month	- per kWhr	10.0000 ¢/kWhr

HAWAIIAN ELECTRIC COMPANY, INC.

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

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 - 3.0%
Distribution voltage supplied without further transformation - 2.1%

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

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 0.6%, 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.

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

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.

HAWAIIAN ELECTRIC COMPANY, INC.

Docket No. 7766
Decision and Order No. 14412

Superseding Revised Sheet No. 63
Effective January 1, 1996

REVISED SHEET NO. 63
Effective June 20, 2008

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 the cost of fuel for Company generation (exclusive of company-owned distributed generation(DG)) of 869.64 cents per million Btu for fuel delivered in its service tanks, 14.076 cents per kilowatthour of company-owned DG generation for fuel delivered to the fuel tank at the site used for the company-owned DG, and the cost of purchased energy of 5.568 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 869.64 cents per million Btu, and/or the company-owned DG energy cost is more or less than 14.076 cents per kilowatthour, and/or the purchased energy cost is more or less than 5.568 cents per kilowatthour, a corresponding

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

Energy Cost Adjustment Clause – (continued)

adjustment(Energy Cost Adjustment Factor) to the energy charges shall be made. This adjustment shall be comprised of a Company Generation Component, a DG Generation Component and a Purchased Energy Component.

The Company Generation Component shall be the difference between the current generation cost and the 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 0.011140 million Btu per kilowatthour, weighted by the proportion of current Company generation (exclusive of company-owned DG) to total system net energy in kilowatthours. The base generation cost is the base fuel cost of 869.64 cents per million Btu multiplied by a generation conversion factor of 0.011140 million Btu per kilowatthour, weighted by the proportion of the 2005 test year generation to total system net energy in kilowatthours.

The DG Energy Component shall be the difference between the current cost of DG energy in cents per kilowatthour weighted by the proportion of current company-owned DG energy to total system net energy, and the base DG energy cost of 14.076 cents per kilowatthour weighted by the proportion of the 2005 test year DG energy to total system net energy, adjusted to the sales delivery level and for revenue taxes.

The Purchased Energy Component shall be the difference between the current purchased energy cost weighted by the proportion of current purchased energy to total system net energy, and the base purchased energy cost of 5.568 cents per kilowatthour weighted by the proportion of the 2005 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, the DG Energy 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.

HAWAIIAN ELECTRIC COMPANY, INC.

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

Energy Cost Adjustment Clause -(continued)

This Energy Cost Adjustment Clause is consistent with the terms of the Company's operations, purchased energy contracts, and DGad contracts, and may be revised to reflect any revisions or changes in the Company's operations, purchased energy contracts, and DG 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.

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

Superseding Revised Sheet No. 64
Effective January 1, 1986

REVISED SHEET NO. 64
Effective June 20, 2008

RIDER I

Interruptible Contract Service

Availability:

This Rider is applicable to service supplied and metered at a single voltage and delivery point where 100 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.

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

Superseding Revised Sheet No. 65
Effective June 13, 2008

REVISED SHEET NO. 65
Effective June 20, 2008

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. A customer may utilize this Rider in conjunction with Schedule SS. 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.

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

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.

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

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

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 June 13, 2008

REVISED SHEET NO. 67
Effective June 20, 2008

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. A customer may utilize this Rider in conjunction with Schedule SS.

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.

HAWAIIAN ELECTRIC COMPANY, INC.

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

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 capacity availability

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

Rider T – (continued)

basis. 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 REVISED SHEET NO. 68
Effective August 1, 2007 Effective April 1, 2008

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, Commercial and Industrial Demand-Side Management (DSM) Adjustment, and SolarSaver 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 .....1.0638 ¢/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 $17,583,468 for the 2008 residential program cost and revenue taxes, and the reconciliation of the 2007 program cost recovery, for which recovery has been approved by the Public Utilities Commission.

HAWAIIAN ELECTRIC COMPANY, INC.

Transmittal Letter dated March 31, 2008.

Superseding Revised Sheet No. 68A
Effective February 1, 2008

REVISED SHEET NO. 68A
Effective April 1, 2008

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 .....0.2104 ¢/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 $8,897,596 for the 2008 C&I program costs and revenue taxes, and the reconciliation of the 2007 program cost recovery, for which recovery has been approved by the Public Utilities Commission.

D: SolarSaver Adjustment:

Schedules R and E – per kWh .....0.0046 ¢/kWh

The total monthly bill for Schedules R and E customers shall include the above SolarSaver Adjustment applied to all kWh per month. The above adjustment is based on recovering $50,897 for the 2008 program costs and associated revenue taxes and the reconciliation of the 2007 program cost, including 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, the Commercial and Industrial DSM Adjustment, and SolarSaver 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, the Commercial and Industrial DSM Adjustment and the SolarSaver 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.

SHEET NO. 69
Effective May 15, 2008

SCHEDULE SS
STANDBY SERVICE

A. APPLICABILITY:

Applicable to customers with alternate regular source(s) of energy other than electricity from the Company when such sources are connected to the utility's system and for which the customer relies on the utility for power service when the alternate source is not being operated(hereinafter referred to as "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.

B. DEFINITIONS:

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 (are) not being operated. Standby service refers to power service that the Company provides during both unscheduled outages 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).

C. BILLING ELECTIONS:

Customers must elect either the Regular Rate Schedule Billing Option or the Standby Rate Billing Option. Customers may change billing options after receiving at least 12 billing months of service on the presently selected Billing Option. The rates applicable to each billing option are described below. All other terms and conditions of this Schedule SS apply to both billing options, unless otherwise indicated. Both billing options shall remain in force for at least 10 years from the initial effective date of Schedule SS. The option to elect to change to or from either the Regular Rate Schedule Billing Option or the Standby Rate Billing Option shall remain in force for at least 5 years from the initial effective date of Schedule SS.

Schedule SS customers are eligible for the Company's optional rider tariffs, including, but not limited to, the current Rider M and Rider T, and any riders that may be applicable in the future. The use of a non-utility power source by a Schedule SS customer to reduce its load during the Company's curtailment hours shall be deemed eligible to meet the curtailment requirements of the Company's optional rider tariffs,

SCHEDULE SS - Continued

including, but not limited to, Rider M. If a Schedule SS customer on the Regular Rate Schedule Billing Option elects to participate in an optional rider, the customer's total kW and kWh requirements are subject to billing under the applicable regular rate schedule as adjusted by the optional rider. If a Schedule SS customer on the Standby Rate Billing Option elects to participate in an optional rider, only the customer's Supplemental Service Demand and Supplemental Service Energy are subject to billing under the applicable regular rate schedule as adjusted by the optional rider. All other terms and conditions of this Schedule SS apply to Schedule SS customers utilizing the Company's optional rider tariffs unless otherwise indicated.

Schedule SS customers are not excluded from other programs currently offered by the Company, and as offered by the Company from time to time, provided that they meet the eligibility requirements.

D. REGULAR RATE SCHEDULE BILLING OPTION RATES:

Customers who elect the Regular Rate Schedule Billing Option, including the optional rider tariffs, shall be billed at the rates on their applicable regular rate schedule and/or the rates on their applicable optional rider tariffs, and the measured demand shall reflect the customer's combined standby service and supplemental service requirements served through the regular utility meter. The Determination of Demand provision of the regular rate schedule shall apply with the following exceptions:

1. The determination of measured demand in a billing month shall exclude 15 minute periods where the customer's generating facility was disconnected under certain conditions described in Terms & Conditions #5 and #6 below;

2. New customers to this rate or existing customers with new generation sources shall be permitted a commissioning period for their non-utility generation source(s) that shall not exceed four months from the date that the customer's generating facility commences production of energy in parallel to the utility system, following execution of an interconnection agreement as required under the Company's Rule No. 14H. At the end of this commissioning period, the customer's historical measured demand will be eliminated and re-set for purposes of determining billing demand. A customer

Decision and Order No. 24229, Docket No. 2006-0497.
Transmittal Letter Dated June 6, 2008.

SCHEDULE SS - Continued

may choose to have this billing demand adjustment implemented before the end of the four month period. The Company will make such a billing demand adjustment only once; and

3. The determination of measured demand in a billing month shall exclude 15 minute periods where the customer is on Scheduled Maintenance.

E. STANDBY RATE BILLING OPTION 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 commercial rate schedule. For the purpose of calculating rate adjustments based on kWh, the standby service customer's total kWh in a billing month shall be the sum of the Standby Energy kWh and the Supplemental Service Energy kWh. For the purpose of calculating rate adjustments based on total base rate charges, the Standby Demand Charge and Standby Energy Charge are considered elements of base rate charges.

1. Standby Demand Charge:

The Standby Demand Charge for each month shall be the sum of the Standby Reservation Demand Charge and the Standby Daily Demand Charge.

a. Standby Reservation Demand Charge:

$5.63 per Contract Standby kW, for customers served on Schedule J for Supplemental Service.
$7.26 per Contract Standby kW, for customers served on Schedule PS for Supplemental Service.
$5.12 per Contract Standby kW, for customers served on Schedule PP for Supplemental Service.
$1.69 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

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SCHEDULE SS - Continued

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.

b. Standby Daily Demand Charge:

$0.52 per Standby Billing kW per day, for customers served on Schedule J for Supplemental Service.
$0.66 per Standby Billing kW per day, for customers served on Schedule PS for Supplemental Service.
$0.60 per Standby Billing kW per day, for customers served on Schedule PP for Supplemental Service.
$0.64 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. 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.

The determination of backup demand in a billing month shall exclude 15 minute periods where the customer's generating facility was disconnected under certain conditions described in Terms & Conditions #5 and #6 below.

The Daily Demand Charge will be waived during days of Scheduled Maintenance.

2. Standby Energy Charge:

Standby Energy kWh is the sum of the 15 minute interval Backup Demands (including periods of Scheduled Maintenance) during the month divided by four.

SCHEDULE SS - Continued

a. Standby Energy Charge:

$0.124 per Standby Energy kWh, for customers served on Schedule J for Supplemental Service.
$0.124 per Standby Energy kWh, for customers served on Schedule PS for Supplemental Service.
$0.121 per Standby Energy kWh, for customers served on Schedule PP for Supplemental Service.
$0.120 per Standby Energy kWh, for customers served on Schedule PT for Supplemental Service.

3. Supplemental Service Demand Charge:

The Billing kW for Supplemental Service shall be as follows:

The Billing kW shall be calculated each month as the higher of 1) the measured usage based on the meter readings of the service provided by the Company's generation equipment, less the maximum Backup Demand during the month or 2) the simple average of 1) and the highest Billing kW in the previous 11 months, less the maximum Backup Demand during the month. This Billing kW shall be the kW basis for billing the Supplemental Service Demand and Energy charges under the customer's applicable commercial rate schedule.

The determination of Billing kW for Supplemental Service in a billing month shall exclude 15 minute periods where the customer's generating facility was disconnected under certain conditions described in Terms & Conditions #5 and #6 below.

New customers to this rate or existing customers with new generation sources shall be permitted a commissioning period for their non-utility generation source(s) that shall not exceed four months from the date that the customer's generating facility commences production of energy in parallel to the utility system, following execution of an interconnection agreement as required under the Company's Rule No. 14H. At the end of the four month period, the customer's historical measured demand will be eliminated and re-set for purposes of determining billing demand. A customer may choose to have this billing demand adjustment implemented before the end of the four month period. The Company will make such a billing demand adjustment only once.

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SCHEDULE SS - Continued

4. Supplemental Service Energy Charge:

Supplemental Service Energy kWh shall be based on the meter readings of the service provided by the Company 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.

5. 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.

6. 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 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.

F. TERMS AND CONDITIONS (Applicable to all Schedule SS customers, unless otherwise indicated):

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 the customer requires standby service from the Company.

2. This tariff shall not apply to the customers identified below in items a) through f). However, any of these customers may choose to forego this exception and elect to opt-in to Schedule SS. If a customer elects to be served under the terms and conditions of Schedule SS, such customer must remain on Schedule SS for at least 12 billing months.

   a) Non-utility power sources used exclusively by a customer for emergency service; or

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SCHEDULE SS - Continued

b) 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) Non-utility power sources that are at least fifty percent fueled by non fossil fuel energy, including biodiesel or biofuels, as currently defined in Hawaii Revised Statutes 269-91 or as amended in the future, calculated on an annual fuel energy input basis; or
d) 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
e) Non-utility power sources that are operated for the benefit of customers who have an existing interruptible service contract (Rider I) or curtailable service contract (Rider M, option B) with the utility on the initial effective date of this tariff; or
f) 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. 14H.

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 if the Standby Rate Billing Option is elected, and the initial Scheduled Maintenance Service Periods, if any.

5. The calculation of backup demand and supplemental service billing demand on the Standby Rate Billing Option and the calculation of measured demand under the Regular Rate Schedule Billing Option will exclude 15 minute periods where the customer's generating facility was disconnected, provided the customer's metering and metering parameters have been approved by the Company and the disconnection was caused (a) by voltage or frequency excursions outside of the ranges specified in Rule 14H, Appendix I, #4g and #4h (or as stated in the customer's interconnection agreement) due to events on the utility system or (b) by action of the utility's direct transfer trip equipment, or (c) was requested or required by the utility due to reasons other than problems caused by the customer's generating facility.

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The existence of such excursion or disruption must be recorded by the customer and that recording provided to the utility. The utility, in determining whether such voltage or frequency excursions were due to events on the utility system or the customer's system, shall rely on data recorded in its system operation interruption reports, system frequency archives, power quality monitors installed at substations serving the customer's facility (where available), and information of any incidents on the customer's system that may have caused the excursions. The customer shall, upon request, provide the utility with available information pertaining to customer's electrical and mechanical system operations at the time of the disconnection including, but not limited to, faults on the customer's system, customer equipment damage, and motor starting data.

If the Customer disagrees with the Company's determination of the cause of the disconnection, the Customer may meet with representatives from the Company to discuss the matter. If the parties continue to have a dispute, authorized representatives from the Company and Customer (having full authority to settle the dispute) may meet in person in Hawaii or at some other mutually agreeable location, or by telephone or internet conference, or in some other mutually agreeable fashion, and attempt in good faith to resolve the dispute. If the parties continue to have a dispute, the parties may engage in a form of alternative dispute resolution agreeable to both parties, or a party may request that the Commission resolve the matter by filing a written request with the Commission attaching the relevant information and correspondence, and serving the request on the other party and the Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs of the State of Hawaii.

Customers are not required to exhaust the Company's dispute resolution procedures set forth above before proceeding under provisions applicable to informal or formal complaints or other provisions contained under the Rules of Practice and Procedure before the Public Utilities Commission, currently codified in Title 6, Chapter 61, Subchapter 5 of the Hawaii Administrative Rules, or any other applicable statutes, orders, rules, or regulations. If any such proceeding is initiated, the Customer shall notify the Company in writing that it does not desire to continue with the Company's dispute resolution procedures.

6. A Schedule SS customer has the option, once during each calendar year, to waive the demand that the customer draws from the utility for billing purposes, provided that the demand occurs during an unscheduled outage of the customer's

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generator. The maximum period during which this waiver may apply is no more than the first 72 consecutive hours, even if the unscheduled outage lasts longer than 72 consecutive hours. This waiver is limited to only one billing period. This waiver will be available once during the calendar year beginning with the effective date of the customer's Schedule SS contract. Waivers cannot be carried forward to subsequent years. For billing purposes, for customers on the Regular Rate Schedule Billing Option, implementation of the waiver excludes the waived hours from the calculation of measured demand for the billing month. For billing purposes, for customers on the Standby Service – Standby Rate Billing Option - - implementation of the waiver excludes the waived hours from the calculation of both the Daily Demand Charge and the Supplemental Service Demand Charge. A Schedule SS customer must exercise the waiver within 21 calendar days of the date of the bill for the billing period in which the waiver is exercised via dated written or electronic communication with the utility. Once exercised the waiver cannot be exchanged for another unscheduled outage.

7. 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. This provision is applicable to the Standby Rate Billing Option only.

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. Scheduled Maintenance Service during On-peak hours:

   Maintenance for a customer's non-utility power source(s) is subject to the following terms and conditions:

      a. A non-utility power source cannot be down for on-peak Scheduled Maintenance Service more than 300 hours during the calendar year.

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SCHEDULE SS - Continued

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, which approval shall not be unreasonably withheld, in the Standby Service Contract. The customer shall submit in writing to the Company all subsequent requests for Scheduled Maintenance at least four weeks in advance of the desired maintenance periods. Such requests will be subject to the Company's review and approval, which approval shall not be unreasonably withheld. Where the Company indicates that such periods are not acceptable to the Company based on operating, technical or other similar reasons, the Company and the customer shall work together to determine the Scheduled Maintenance Periods that are reasonable and acceptable to both parties.

b. Scheduled Maintenance Service during Off-peak hours:

Maintenance for a customer's non-utility power source(s) is subject to the following terms and conditions:

(1) 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.

(2) The customer must notify the Company in advance of shutting off and/or starting up its power source that will be maintained under this provision.

(3) 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.

(4) The total off-peak Scheduled Maintenance Periods arranged under Scheduled Maintenance Service shall not be limited, provided that the Company may request the customer to forego a previously scheduled off-peak maintenance period in the event of a system emergency.

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SCHEDULE SS - Continued

9. A non-utility power source or sources may be designated by the customer as producing power only during a limited number of hours per day. Customer shall not be required to provide any advance notice to utility of shutting off or starting up its power source in this situation provided it does not deviate from the previously agreed upon schedule. Customer will be entitled to designate on-peak hours or off-peak hours, if applicable, as Scheduled Maintenance under the terms and conditions described above in Terms and Conditions #8. Customer shall not be required to provide any notification concerning maintenance, as described above in Terms and Conditions #8, if such maintenance is performed entirely within hours during which it does not produce power under the previously agreed upon schedule.

10. 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) are not metered, the customer shall not be eligible for Scheduled Maintenance Service and shall not be eligible for the Standby Rate Billing Option.

11. Except as provided for in Terms and Conditions #12 below, the Company shall install, own, operate, maintain, replace, and read meters on the customer's non-utility power source(s) for billing purposes. The customer shall be responsible for any reasonable costs 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, which approval shall not be unreasonably withheld, 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 reasonable costs 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

SCHEDULE SS - Continued

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.

12. A Schedule SS customer has the option of installing and maintaining a customer-owned or supplied meter to measure the output of the DG unit(s) rather than having the utility install a utility-owned meter as set forth in Section F.11 above. This meter is a revenue meter under the Schedule SS – Standby Rate Option. The customer shall pay for the customer-owned or supplied meter and its installation/removal.

    The customer-owned or supplied meter:

    a. Must be approved by the utility, which approval shall not be unreasonably withheld. The customer shall submit manufacturing specifications and catalog cut sheets for the Company's review. The installation of a meter that is not approved by the Company shall result in the DG unit being considered as not metered.

    b. Along with the metering equipment, the customer-owned or supplied meter must meet UL, EUSEC, NEMA and ANSI standard specifications for metrology accuracy, component tolerances, and physical construction, and be sealed against tampering. Furthermore, the customer must meet all Company electrical grounding standards.

    c. Must provide the billing data required for billing under the Standby Rate Option.

    d. Must have at least a 30 to 60-day data storage capability for the required billing data.

    e. Must be equipped with a modem and be compatible with MV90 for remote interrogation of billing data and have an available telephone line.

    f. Must comply with Company's electrical service installation standards with respect to location, placement, physical clearances, and size of equipment.

    g. Must be available for testing under the conditions and frequency applied to utility-owned meters.

    h. Must not be replaced without notifying the utility in advance of the replacement. The replacement meter is subject to all the above conditions.

SCHEDULE SS - Continued

13. The term of the Schedule SS Service Contract under this Schedule SS 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, unless otherwise mutually agreed to in writing by the parties.

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

SCHEDULE SS - Continued

Schedule SS 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.

Billing Option Elected: _____

If Standby Rate Billing Option selected, items (1) and (2) below must be filled in:

(1) Billing Contract Standby kW _____
(2) Installed kW Capacity of Non-Utility Power Source(s) _____

This contract shall be amended to insert values for items (1) and (2) above at the time the customer selects the Standby Rate Billing Option.

Initial Scheduled Maintenance Periods:
_____
_____

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 SS and is subject to the terms of Rate Schedule SS and any other applicable schedule.

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.

The Customer and the Company identify the following points of contact for all communications related to service under this contract:

Decision and Order No. 24229, Docket No. 2006-0497.
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SCHEDULE SS - Continued

Schedule SS Service Contract Form
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Customer	HECO
_____	_____
Name	Name
_____	_____
Title	Title
_____	_____
Mailing Address	Mailing Address
_____	_____
E-mail Address	E-mail Address
_____	_____
Phone Number	Phone Number

Changes in contact information should be directed to the other party's point of contact in writing and should reference this Schedule SS Service contract.

Authorized Customer Signature:	HECO Representative:
_____|_____	_____|_____
Name Date	Name Date
_____	_____
Title	Title
_____	

RIDER SSP

SOLARSAVER PILOT PROGRAM

AVAILABILITY:

This Rider is available to Participants served under rate Schedule "R" or "E", who install a Residential Efficient Water Heating ("REWH") DSM Program approved retrofit solar water heating ("SWH") system, using a Hawaiian Electric Company, Inc. ("HECO") (hereafter referred to as "Company") REWH DSM Program approved solar water heating contractor, on an existing single-family home or town home. Participants must agree to pay for the solar water heating system under the conditions specified below. This Rider is also available to Participants served under Schedule "R" or "E" at service locations where a solar water heating system has already been installed under this program.

The number of solar water heating systems installed under this Tariff is limited to a total of [300 for HECO] for the entire term of the Pilot Program.

At its sole discretion, the Company shall also determine eligibility for service under this Rider subject to (1) the availability of funds budgeted for this program; (2) the suitability of approved solar water heating systems for the Participant's location and the likelihood that the systems will be used and useful throughout their estimated life; (3) a Participant bill payment history check; (4) existence of electric-resistance water heating equipment;(5) execution and filing of the appropriate SolarSaver Participant Agreement and Short Form SolarSaver Agreement; and (6) the Company's determination that the solar water heating system is estimated to produce sufficient energy savings to offset the total cost of the system; i.e., that the installed price of the solar water heating system (including any applicable taxes, net of the Company's REWH Program DSM rebate) is equal to or below the SWH system price cap.

This Rider is available to solar water heating installations through July 1, 2010, but may be suspended or terminated at any time by order of the Commission. Should the SolarSaver Pilot Program be closed to future participants, this Rider shall continue until terminated by the Commission or the repayment obligation of all Pilot Program Participants has been fulfilled, whichever occurs first.

Docket No. 2006-0425; Decision and Order No. 23531, dated June 29, 2007.
Transmittal Letter Dated July 9, 2007.

Superseding Sheet No. 70A
Effective January 3, 2008

REVISED SHEET NO. 70A
Effective April 4, 2008

RIDER SSP - Continued

RATES:

Each SolarSaver Pilot Program Participant shall pay a monthly SolarSaver Fee ("Fee"). The SolarSaver Fee shall be equal to 80% of the estimated monthly energy bill savings for a family of four at the time that the SolarSaver Fee is set by the utility. The energy bill savings will be estimated by the utility using the most recent REWH Program Impact Evaluation filed with the Hawaii Public Utilities Commission. The SolarSaver Fee shall be constant for the term of the payment period for each Participant unless an accelerated repayment term is requested by the Participant. The payment period in months shall be equal to the solar water heating system price (net of the REWH Program DSM rebate) divided by the SolarSaver Fee.

For the period: April 4 – June 30, 2008

The SolarSaver Fee for new Participants shall be: $36.87/month

The after Utility rebate SWH system price cap
(equal to 144 months times the SolarSaver Fee) shall be: $5,309.00

The Fee and SWH system price cap shall be recalculated on a quarterly (calendar year) basis to incorporate the current Schedule R energy charge, including the base energy charge plus the current energy cost adjustment factor. The recalculated SolarSaver Fee and SWH system price cap shall only be in effect for new Participants enrolled after the Fee recalculation takes place.

The solar water heating system will be owned by the property owner, but installed at the Company's expense and the Participant shall reimburse the Company through a SolarSaver Fee added to the Participant's regular monthly bill. The Fee is an element of the Participant's electric service, and the Participant is liable for payment of the Fee under this Rider under the same conditions as charges under the Participant's regular rate schedule, including, but not limited to, the Participant's service being subject to disconnection for nonpayment in accordance with the Company's rules. Bill payments made by the Participant will first be applied to the electricity use portion of the bill. There is no guarantee that all Participants participating in the SolarSaver Pilot Program will receive lower monthly electric bills.

HAWAIIAN ELECTRIC COMPANY, INC.

Docket No. 2006-0425; Decision and Order No. 23531, dated June 29, 2007.
Transmittal Letter Dated April 4, 2008.

RIDER SSP - Continued

MINIMUM FEE AND TERM OF CONTRACT:

The SolarSaver Participant Agreements (attached) between the utility and Participants will specify the minimum monthly Fee and the term of the payment period. A Participant can choose to accelerate the payment period term by paying a higher Fee or a Participant can choose to pay the remaining balance owed to the Company at any time. A Participant selecting an accelerated payment period term can revert at any time to the minimum monthly Fee available to the Participant. Unless the Participant chooses to accelerate the payment period term, the minimum monthly Fee for the SolarSaver location will not change. However, the SolarSaver Fee for the last month of the payment period shall be equal to the remaining balance.

COMPANY RESPONSIBILITIES

The Company shall arrange to certify that the solar water heating system(s) are properly installed and operating as designed. The Company shall also arrange recordation of the SolarSaver Short Form Customer Agreement with the State Bureau of Conveyances. Upon notification that work is complete, the Company will verify that the solar water heating system(s) have been installed and arrange for payment to the contractor.

At the time of electric service request, the Company will inform all new customers at a location where a SolarSaver solar water heating system has been installed as to the existence of any unbilled Fees remaining under this Rider for that location. If the former Participant received service under an accelerated payment period term, the Company will inform the new Participant that the Participant may revert at any time to the minimum monthly Fee that was available to the former Participant. The Company will also inform these Participants of the general benefits associated with solar water heating systems and their responsibility for the payment of the remaining charges under this Rider and other obligations.

RIDER SSP - Continued

PARTICIPANT RESPONSIBILITIES AS PROPERTY OWNER

In situations where the Participant is the home or property owner and resides at the location where the solar water heating system is installed, or prior to the installation of any solar water heating system, the Participant will be responsible for:

1. Payment of the monthly Fees under this Rider in addition to all other charges on the monthly bill;
2. Taking reasonable steps to prevent damage to such systems;
3. Becoming fully informed concerning the routine operation and maintenance of the solar water heating system installed at the service location; and
4. Allowing access by the Company, at reasonable times, for any inspection of the solar water heating system for the purposes of evaluating the SolarSaver Pilot Program.
5. Execution by the property owner of the SolarSaver Short Form Agreement (and having it notarized) to ensure that a record of the SolarSaver installation has been properly recorded with the State of Hawaii Bureau of Conveyances.

If the Participant is the owner of the premises, the Participant shall inform all prospective purchasers or renters of the location in writing that there is an unexpired obligation under this Rider. Whenever a customer applies for electric service at a location which was the subject of a previous SolarSaver Participant Agreement and SolarSaver Short Form Customer Agreement, payment for which has not been completed, such customer shall become responsible for the remaining balance. If the location was the subject of an accelerated payment term, the new Participant has the option to revert at any time to the minimum monthly Fee that was available to the former Participant. Acceptance of electric service constitutes acceptance of the obligations under this Rider by the new Participant.

PARTICIPANT RESPONSIBILITIES AS RENTER

In situations where the Participant is renting the SolarSaver location, as defined as any tenant who is currently a customer of the Company or any future tenant who shall apply for service from the Company at a SolarSaver location, the renter is responsible for:

1. Receiving written landlord approval to install a SolarSaver SWH system on the rental property;

Docket No. 2006-0425; Decision and Order No. 23531, dated June 29, 2007.
Transmittal Letter Dated July 9, 2007.

RIDER SSP - Continued

2. Paying the monthly SolarSaver Fee for as long as they occupy the property;

3. Allowing access by the Company, at reasonable times, for any inspection of the solar water heating system for the purposes of evaluating the SolarSaver Pilot Program;

SUBJECT TO RULES AND REGULATIONS:

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

RIDER SSP - Continued

SolarSaver Pilot Program
Customer Agreement
(Property Owner)

This agreement is between the _Hawaiian Electric Company, Inc.___ hereafter referred to as "Company" and _(Name of utility customer)____ hereafter referred to as "Customer".

1. The Customer hereby certifies:

   - That I/we are the legal owner(s) of residential property located at

     _____,

   - That I/we are customer(s) of the Company for our residential electric service,
   - That we are replacing an electric resistance water heater with a solar water heating system as part of the SolarSaver Pilot Program.

2. The Company agrees to provide full payment to the customer's selected solar contractor[1] for installing one pre-qualified SolarSaver SWH system at the property address above.

3. The Company agrees to provide full payment of the Residential Efficient Water Heating (REWH) Program Solar Rebate to the customer's selected solar contractor upon successful inspection of the SolarSaver SWH system installed.[2]

4. Customer and Company agree that Customer may select any solar contractor who is approved by the Company for the SolarSaver Pilot Program to install the solar water heating system.

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[1] The Solar Contractor is required to be a Company-approved participant in the Company's Residential Efficient Water Heating Program.

[2] Per REWH Program requirements, a solar rebate will be instantly applied to the Customer's invoice at the time of sale.

Docket No. 2006-0425; Decision and Order No. 23531, dated June 29, 2007.
Transmittal Letter Dated July 9, 2007.

RIDER SSP - Continued

5. Customer agrees to pay the Company a monthly SolarSaver Fee. The monthly Fee is to be collected through the utility bill for the residential electric service attached to the meter for this location to recover the cost of equipment and installation of a solar water heating system installed by a Company-approved contractor of Customer's choice.

6. Customer agrees to sign and notarize the SolarSaver Short Form Customer Agreement (and have it notarized) to be filed by Company with the State of Hawaii Bureau of Conveyances within sixty (60) days of solar water heating system installation.

7. Customer agrees to the following terms of payment to the Company:

_____ Total Cost of System

_____ Less: Instant Utility Rebate from Residential Efficient Water Heating Program

_____ Balance owed by Customer

_____ Customer Monthly SolarSaver Fee

_____ Term (total number of months to pay SolarSaver Fee)

8. Customer agrees to pay the monthly SolarSaver Fee for the period of months listed in this agreement or until:

   a) I/we vacate the residential property address listed in this agreement; or,
   b) The system is paid off earlier in full (upon Customer request);

9. Customer agrees that if I/we sell this residential property prior to full payment of the solar water heating system that I/we will disclose the contents of this SolarSaver Agreement to the buyer, which includes the transfer of payment obligation to the new property owner.

Docket No. 2006-0425; Decision and Order No. 23531, dated June 29, 2007.
Transmittal Letter Dated July 9, 2007.

RIDER SSP - Continued

10. Customer understands and agrees that, with the agreement of the Company, the balance owed on the solar water heating system may be paid in full by the Customer or the Customer may agree to pay a higher monthly fee in order to pay the total balance earlier than the term listed in this agreement.

11. Customer agrees that non-payment of SolarSaver fees will result in the Company collections process and possible disconnection of electrical service. Any fees collected will first be applied to the outstanding balance for electric service before additional funds are applied to the monthly SolarSaver Fee.

12. Customer agrees to notify the SolarSaver Pilot Program Administrator immediately if the installed solar water heating system fails to operate properly. I/we understand that maintenance of the SWH system will be provided through either product warranty, extended warranty insurance or by the utility company during the period that the SolarSaver Fee is being assessed.

13. Customer agrees to payment of the monthly Fees under this Agreement in addition to all other charges on the monthly bill.

14. Customer agrees to take reasonable steps to prevent damage to the SWH system by becoming fully informed concerning the routine operation and maintenance of the solar water heating system installed at the service location.

15. Customer agrees to allow access by the Company, at reasonable times, for any inspection of the solar water heating system for the purposes of evaluating the SolarSaver Pilot Program.

16. The Customer shall inform all prospective purchasers or renters of the location in writing that there is an unexpired obligation under this Agreement. Whenever a customer applies for electric service at a location which was the subject of a previous SolarSaver Agreement, payment for which has not been completed, such customer shall become responsible for the remaining balance. If the location was the subject of an accelerated payment term, the new Participant has the option to revert at any time to the minimum monthly Fee that was available to the former Participant.

Docket No. 2006-0425; Decision and Order No. 23531, dated June 29, 2007.
Transmittal Letter Dated July 9, 2007.

RIDER SSP - Continued

17. Acceptance of electric service constitutes acceptance of the obligations under this Agreement by the new property owner/Participant.

18. The Company agrees that the Customer will no longer be responsible for the monthly SolarSaver Fee if the solar water heating system cannot be repaired, as determined by the utility, other than damage caused by the Customer.

19. Customer agrees that that the solar water heating system being installed is the sole property of the legal owner of the real property.

Executed at _____, Hawaii, this ___ day of _____, 20__.

_____ _____
Customer Customer

_____
Company Representative

RIDER SSP - Continued

SolarSaver Pilot Program
Customer Agreement
(Renter)

This agreement is between the ___Hawaiian Electric Company, Inc. ____ hereafter referred to as Company and ____(Name of utility customer)___ hereafter referred to as Customer.

1. Customer hereby certifies:

   - That I/we are the legal tenant(s) of residential property located at _____,
   - That I/we are customer(s) of the Company for our residential electric service,
   - That I/we are replacing an electric resistance water heater with a solar water heating system as part of the SolarSaver Pilot Program; and,
   - That we have obtained permission for such installation from the legal owner of the property as evidenced by the signed agreement attached as Exhibit 1.

2. The Company agrees to provide full payment to the Customer's selected solar contractor[3] for installing one pre-qualified SolarSaver SWH system at the property address above.

3. The Company agrees to provide full payment of the Residential Efficient Water Heating (REWH) Program Solar Rebate to the customer's selected solar contractor upon successful inspection of the SolarSaver SWH system installed.[4]

4. Customer and Company agree that Customer may select any solar contractor who is approved by the Company for the SolarSaver Pilot Program to install the solar water heating system.

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[3] The Solar Contractor is required to be a Company-approved participant in the Company's Residential Efficient Water Heating Program.

[4] Per REWH Program requirements, a solar rebate will be instantly applied to the Customer's invoice at the time of sale.

RIDER SSP - Continued

5. Customer agrees to pay the Company a monthly SolarSaver Fee. The monthly Fee is to be collected through the utility bill for the residential electric service attached to the meter for this location, to recover the cost of equipment and installation of a solar water heating system installed by a Company-approved contractor of Customer's choice.

6. Customer agrees to the following terms of payment to the Company:

_____ Total Cost of System

_____ Less: Instant Utility Rebate from Residential Efficient Water Heating Program

_____ Balance owed by Customer

_____ Customer Monthly SolarSaver Fee

_____ Term (total number of months to pay SolarSaver Fee)

7. Customer agrees to pay to the monthly SolarSaver Fee for the period of months listed in this agreement or until:

   a) I/we vacate the residential property address listed in this agreement; or,
   b) The system is paid off earlier in full (upon Customer request);

8. Customer agrees that, with the agreement of the Company, the balance owed on the solar water heating system may be paid in full by the Customer or the Customer may agree to pay a higher monthly fee in order to pay the total balance earlier that the term above.

9. Customer agrees that non-payment of SolarSaver Fees will result in the Company collections process and possible disconnection of electrical service. Any delinquent fees collected will first be applied to the outstanding balance for electric service before additional funds are applied to the monthly SolarSaver Fee.

RIDER SSP - Continued

10. Customer agrees that that the solar water heating system being installed is the sole property of the legal owner of the real property and is not owned by the tenant.

11. Customer agrees to notify the SolarSaver Pilot Program Administrator immediately if the installed solar water heating system fails to operate properly and coordinate the scheduling of the repair with the landlord. I/we understand that maintenance of the SWH system will be provided through either product warranty, extended warranty, or by the utility company during the period that the SolarSaver Fee is being assessed.

12. Customer agrees to receive written landlord approval to install a SolarSaver SWH system on the rental property.

13. Customer agrees to pay the monthly SolarSaver Fee for as long as they occupy the property.

14. Customer agrees to allow access by the Company, at reasonable times, for any inspection of the solar water heating system for the purposes of evaluating the SolarSaver Pilot Program.

15. The Company agrees that the Customer will no longer be responsible for the monthly SolarSaver Fee if the solar water heating system cannot be repaired, as determined by the utility, other than damage caused by the Customer.

Executed at _____, Hawaii, this ___ day of _____, 20__.

_____ _____
Customer Customer

_____
Company Representative

Docket No. 2006-0425; Decision and Order No. 23531, dated June 29, 2007.
Transmittal Letter Dated July 9, 2007.

RIDER SSP - Continued

Exhibit 1

SolarSaver Pilot Program
Customer Agreement
(Renter)

LANDLORD APPROVAL FOR RENTAL PROPERTY
SOLARSAVER INSTALLATION

I/We certify that I/we are the legal owner(s) of the residential property located at:
_____,
and that the Tenant in this property has my permission to allow a Company approved Participating Contractor to install the Solar Water Heating (SWH) system described in the attached agreement. As the owner of this property, I/We understand that the system cost will be repaid by the Tenant to Company through a SolarSaver Fee to be assessed on the Tenant's monthly electric bill and any subsequent tenant in this property until the SolarSaver SWH system is paid for in full or until Rider SSP is terminated, whichever occurs first.

As legal owners of the property I/We agree to the installation of the pre-approved SolarSaver Solar Water Heating system, to be the owner of said system, and to notify any subsequent tenants at the same property that the tenant will be required to pay the monthly SolarSaver fee as part of their electric bill or be subject to the Company collections process which may lead to electric service disconnection. Additionally, I/We agree to sign and notarize the SolarSaver Short Form Customer Agreement (and have it notarized) to be filed by Company with the State of Hawaii Bureau of Conveyances within sixty (60) days of solar water heating system installation.

RIDER SSP - Continued

Furthermore, I/We understand that any maintenance or repair of the SWH system during the period that the SolarSaver Fee is being assessed is the responsibility of the utility.

Executed at _____, Hawaii, this ___ day of _____, 20__.

_____
Property Owner

_____
Property Owner

Superseding Revised Sheet No. 81
Effective January 1, 1996

REVISED SHEET NO. 81
Effective June 20, 2008

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	10.63 ¢/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.

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

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 870.43 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 870.40 cents per million Btu multiplied by an on-peak heat rate of 13,382 Btu per net kilowatthour and

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

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.

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

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.

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:

NON-DEMAND SERVICE:

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	21.4205 ¢/kWhr
Mid-Peak Period – per kWhr	18.4205 ¢/kWhr
Off-Peak Period – per kWhr	11.4205 ¢/kWhr

MINIMUM CHARGE:

Single-Phase Service – per month	$30.00/month
Three-Phase Service – per month	$55.00/month

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

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	18.0460 ¢/kWhr
Mid-Peak Period – per kWhr	15.0460 ¢/kWhr
Off-Peak Period – per kWhr	10.0000 ¢/kWhr

DEMAND CHARGE - (To be added to Customer and Energy Charge)

Priority Peak – per kW of billing demand	$15.00/kW
Mid-Peak - per kW of billing demand	$8.50/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 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.

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.

HAWAIIAN ELECTRIC COMPANY, INC.

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

SCHEDULE TOU-C - (continued)

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 -3.0%
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 0.6%, 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: (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.

SCHEDULE TOU-C - (continued)

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 REVISED SHEET NO. 86
Effective May 12, 2003 Effective June 20, 2008

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

TIME-OF-USE ENERGY CHARGE - ¢ per kWh:

Priority Peak Period – per kWhr	22.1896 ¢/kWhr
Mid-Peak Period - per kWhr	19.1896 ¢/kWhr
Off-Peak Period - per kWhr	13.6896 ¢/kWhr

MINIMUM CHARGE:

Single-Phase Service - per month	$17.50/month
Three-Phase Service - per month	$22.50/month

HAWAIIAN ELECTRIC COMPANY, INC.

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

Superseding Sheet No. 87
Effective May 12, 2003

REVISED SHEET NO. 87
Effective June 20, 2008

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.

HAWAIIAN ELECTRIC COMPANY, INC.

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
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Superseding Sheet No. 88
Effective May 12, 2003

REVISED SHEET NO. 88
Effective June 20, 2008

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.

HAWAIIAN ELECTRIC COMPANY, INC.

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

HAWAIIAN ELECTRIC COMPANY, INC.

Superseding Revised Sheet No. 2
Effective June 20, 2008

REVISED SHEET NO. 2
Effective

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HAWAIIAN ELECTRIC COMPANY, INC.

Docket No. 04-0113; Order Approving Revised Tariff Sheets and Rate Schedules, Filed on May 21, 2008.
Transmittal Letter dated June 23, 2008.

RULE NO. 7 (Continued)

Discontinuance and Restoration of Service

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 by 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 when such field call results in a successful collection of monies. This charge will be added to the customer’s bill.

E. SERVICE ESTABLISHMENT 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 to 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.

Superseding Revised Sheet No. 50 REVISED SHEET No. 50
Effective June 20, 2008 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:

Sheet	Schedule	Date Effective	Character of Service
51	"R"		Residential Service
51A	"R"		Residential Service
52	"G"		General Service Non-Demand
53	"G"		General Service Non-Demand
54	"J"		General Service Demand
54A	"J"		General Service Demand
54B	"J"		General Service Demand & Refrigeration Service
		(PAGE 55-56 NOT ASSIGNED)	
57	"DS"		Large Power Directly Served Service
57A	"DS"		Large Power Directly Served Service
58	"P"		Large Power Service
58A	"P"		Large Power Service
58B	"P"		Large Power 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

HAWAIIAN ELECTRIC COMPANY, INC.

Docket No. .

Superseding Revised Sheet No. 50A
Effective June 20, 2008

REVISED SHEET No. 50A
Effective

RATE SCHEDULES (continued)

Sheet	Schedule	Date Effective	Character of Service
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
		(PAGE 66 - NOT ASSIGNED)	
67	Rider "T"		Time-of-Day Service
67A	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
69I	"SS"		Standby Service
69J	"SS"		Standby Service
69K	"SS"		Standby Service
69L	"SS"		Standby Service
69M	"SS"		Standby Service
69N	"SS"		Standby Service

HAWAIIAN ELECTRIC COMPANY, INC.

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Superseding Revised Sheet No. 50B
Effective June 20, 2008

REVISED SHEET NO. 50B
Effective

RATE SCHEDULES (continued)

Sheet	Schedule	Date Effective	Character of Service
70	Rider "SSP"		SolarSaver Pilot Program
70A	Rider "SSP"		SolarSaver Pilot Program
70B	Rider "SSP"		SolarSaver Pilot Program
70C	Rider "SSP"		SolarSaver Pilot Program
70D	Rider "SSP"		SolarSaver Pilot Program
70E	Rider "SSP"		SolarSaver Pilot Program
70F	Rider "SSP"		SolarSaver Pilot Program
70G	Rider "SSP"		SolarSaver Pilot Program
70H	Rider "SSP"		SolarSaver Pilot Program
70I	Rider "SSP"		SolarSaver Pilot Program
70J	Rider "SSP"		SolarSaver Pilot Program
70K	Rider "SSP"		SolarSaver Pilot Program
70L	Rider "SSP"		SolarSaver Pilot Program
70M	Rider "SSP"		SolarSaver Pilot Program
(PAGES 71 - 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	TOU-G		Small Commercial Time-Of-Use Service

Superseding Revised Sheet No. 50C
Effective June 20, 2008

REVISED SHEET NO. 50C
Effective

RATE SCHEDULES (continued)

Sheet	Schedule	Date Effective	Character of Service
83A	TOU-G		Small Commercial Time-Of-Use Service
84	TOU-J		Commercial Time-Of-Use Service
84A	TOU-J		Commercial Time-Of-Use Service
84B	TOU-J		Commercial Time-Of-Use Service
84C	TOU-J		Commercial Time-Of-Use Service
		(PAGE 85 - NOT ASSIGNED)	
86	TOU-R		Residential Time-Of-Use Service
87	TOU-R		Residential Time-Of-Use Service
88	TOU-R		Residential Time-Of-Use Service
		(PAGE 89 NOT ASSIGNED)	

Superseding Revised Sheet No. 51
Effective June 20, 2008

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	$ 9.00/month
Three-Phase Service - per month	$18.00/month

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

First 350 kWhr per month-per kWhr	10.0480 ¢/kWhr
Next 850 kWhr per month-per kWhr	11.2015 ¢/kWhr
All kWhr over 1,200 kWhr per month - per kWhr	12.3335 ¢/kWhr

WAIVER PROVISION:
For customers receiving bill credits under Low Income Home Energy Assistance Program (LIHEAP), the Non-Fuel Energy Charge is 10.0480 ¢/kWhr for all kWhr per month.

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

All kWhr per month - per kWhr 16.1633 ¢/kWhr

Minimum Charge:

Single-Phase Service - per month	$17.00/month
Three-Phase Service - per month	$23.00/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:

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 June 20, 2008

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 kilowatthours per month, and less than or equal to 25 kilowatts, and supplied through a single meter.

If a customer's usage exceeds 5000 kilowatthours 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	$32.00/month
Three-Phase Service - per month	$61.00/month

ENERGY CHARGE: (To be added to Customer Charge)

All kWhr per month - per kWhr	26.2038 ¢/kWhr

Minimum Charge:

Single-Phase Service - per month	$32.00/month
Three-Phase Service - per month	$61.00/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%.

Superseding Revised Sheet No. 53
Effective June 20, 2008

REVISED SHEET NO. 53
Effective

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 June 20, 2008

REVISED SHEET NO. 54
Effective

SCHEDULE J

General Service Demand

Availability:

Applicable to general light and/or power loads which exceed 5000 kilowatthours per month or exceed 25 kilowatts three times within a twelve month period but are less than 300 kilowatts per month, and supplied through a single meter.

Customers who have loads that are less than or equal to 5,000 kilowattshours per month and less than or equal to 25 kilowatts, for 12 consecutive months, will be transferred to Schedule G at the beginning of the next billing period.

Rate:

CUSTOMER CHARGE:

Single-Phase Service - per month	$70.00/month
Three-Phase Service - per month	$100.00/month

DEMAND CHARGE - (To be added to Customer Charge)

All kW of billing demand - per kW per month	$14.00/kW

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

All kwhr per month - per kwhr	20.6269 ¢/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

SCHEDULE J - (continued)

Determination of Demand – Continued

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 25 kW.

This Schedule is closed to new customers with kW demand equal to or greater than 300 kW after June 19, 2008. 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 other 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.

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 "J" (continued)

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.

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 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 shall be subject to the Rules and Regulations of the Company.

HAWAIIAN ELECTRIC COMPANY, INC.

Docket No.

Superseding Revised Sheet No. 57 REVISED SHEET NO. 57
Effective June 20, 2008 Effective

SCHEDULE DS

LARGE POWER DIRECTLY SERVED 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 and served directly from a substation. Customers who are eligible for Schedule DS may elect to be served under any other schedule for which they are eligible.

RATES:

CUSTOMER CHARGE - $ per customer per month: $400.00/month

DEMAND CHARGE – (To be added to Customer Charge)
All kW of billing demand – per kW per month $18.00/month

ENERGY CHARGE - ¢ per kWhr:
All kWhr per month - per kWhr 19.1432 ¢/kWhr

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.

REVISED SHEET NO. 57A
Effective

Schedule DS – (continued)

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.

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, and Power Factor adjustment.

Integrated Resource Planning Surcharge:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, 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. 58 REVISED SHEET NO. 58
Effective June 20, 2008 Effective

SCHEDULE P

LARGE POWER 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. If a Schedule P customer has loads less than 300 kW for 12 consecutive months, the customer will be transferred to Schedule J at the beginning of the next billing month.

RATES:

CUSTOMER CHARGE - $ per customer per month:	$350.00/month
DEMAND CHARGE - $ per kW of billing demand:	
All kW of billing demand - per kW	$22.00/month
ENERGY CHARGE - ¢ per kWh:	
All kWhr per month – per kWhr	$19.9520 ¢/kWhr

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.

HAWAIIAN ELECTRIC COMPANY, INC.

Docket No.

Superseding Revised Sheet No. 58A REVISED SHEET NO. 58A
Effective June 20, 2008 Effective

SCHEDULE P – (continued)

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.

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%.

Superseding Revised Sheet No. 58B REVISED SHEET NO. 58B
Effective June 20, 2008 Effective

SCHEDULE P – (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, Supply Voltage Delivery 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, Supply Voltage Delivery adjustment, 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 Revised Sheet No. 59
Effective June 20, 2008

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 –

$22.00 per month for each point of delivery.

ENERGY CHARGE - ¢ per kWhr:

All kwhr per month - per kwhr 26.3664 ¢/kWhr

Minimum Charge:

$35.00 per month for each point of delivery.

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%.

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 Revised Sheet No. 61 REVISED SHEET NO. 61
Effective June 20, 2008 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:	5:00 p.m. - 9:00 p.m., Monday through Friday
Mid-Peak:	All On-Peak hours outside of Priority Peak hours
Off-Peak:	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	$26.00/kW
Mid-Peak - per kW of billing demand	$23.00/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.

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

All On-Peak kWhr per month	- per kWhr	21.9520 ¢/kWhr
All Off-Peak kWhr per month	- per kWhr	18.0000 ¢/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 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.

HAWAIIAN ELECTRIC COMPANY, INC.

Docket No. .

Superseding Revised Sheet No. 63 REVISED SHEET NO. 63
Effective June 20, 2008 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 DS	- Large Power Directly Served Service
Schedule P	- Large Power 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-G	– Small Commercial Time-of-Use Service
Schedule TOU-J	– Commercial Time-of-Use Service
Schedule SS	- Standby Service

All terms and provisions of Schedules R, E, G, J, DS, P, F, U, SS, TOU-R, TOU-G and TOU-J 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 1,617.81 cents per million Btu for fuel delivered in its service tanks, a purchased energy composite of 9.481 cents per kilowatthour, and a company-owned DG energy composite cost of 24.993 cents per kilwatt 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 1,617.81 cents per million BTU, and/or the Purchased Energy Cost is more or less than 9.481 cents per kilowatthour, and/or the company-owned DG Energy Composite Cost is more or less than 24.993 cents per kilowatt hour, a corresponding adjustment (Energy Cost Adjustment Factor) to the energy charges shall be made.

Superseding Revised Sheet No. 63A
Effective June 20, 2008

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 2009 test-year efficiency factors of 0.011092 million BTU per kilowatthour for low sulfur fuel oil (LSFO), 0.024358 million BTU per kilowatthour for diesel fuel, 0.022909 million BTU per kilowatthour for biodiesel fuel, and 0.011185 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 1,617.81 cents per million BTU weighted by the 2009 Test Year proportion of company-owned central station + other generation to total system net energy, multiplied by the 2009 Test Year efficiency factor of 0.011185 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 total system net energy, and (2) the Base Purchased Energy Composite Cost of 9.481 cents per kilowatthour weighted by the 2009 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 24.993 cents per kilowatthour weighted by the proportion of the 2009 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 sum of the Central Station with Other Generation Component, the Purchased Energy Component and the DG Energy Generation Component.

Superseding Sheet No. 63B
Effective June 20, 2008

REVISED SHEET NO. 63B
Effective

Energy Cost Adjustment Clause -(continued)

The revenue tax requirements 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 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 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 Revised Sheet No. 64
Effective June 20, 2008

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 100 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 _____, 2009.

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.

RIDER M

Off-Peak and Curtailable Service

AVAILABILITY:

This Rider is available to customers served under rate Schedule J, DS, P, whose maximum measured demands prior to any load modifications effected under this rider, exceed 100 and 300 kilowatts, respectively. A customer may utilize this Rider in conjunction with Schedule SS. This Rider cannot be used in conjunction with Rider T, Rider I, Schedule U, and Schedule TOU-J.

RATES:

A. Basic Rates

The rate(s) for service under this Rider shall be as specified under the regular Schedule J, DS, 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, DS, 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)

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 DS, P, 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, DS, 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.

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

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 REVISED SHEET NO. 67
Effective June 20, 2008 Effective

RIDER T
TIME-OF-DAY RIDER

AVAILABILITY:

This rider is available to customers on rate Schedule J, DS, or P but cannot be used in conjunction with the load management Rider M, Rider I, Schedule U, and Schedule TOU-J. A customer may utilize this Rider in conjunction with Schedule SS.

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, DS, 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.

HAWAIIAN ELECTRIC COMPANY, INC.

Transmittal letter dated December 31, 1997.

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 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 REVISED SHEET NO. 68
Effective April 1, 2008 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 DS	- Large Power Directly Served Service
Schedule P	- Large Power 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-G	– Small Commercial Time-of-Use Service
Schedule TOU-J	– Commercial Time-of-Use Service
Schedule SS	- Standby Service

All terms and provisions of Schedules R, E, G, J, DS, P, F, U, SS, TOU-R, TOU-G and TOU-J 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, Commercial and Industrial Demand-Side Management (DSM) Adjustment, and SolarSaver 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, E, TOU-R - per kwh .....1.0638 ¢/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 $17,583,468 for the 2008 residential program cost and revenue taxes, and the reconciliation of the 2007 program cost recovery, for which recovery has been approved by the Public Utilities Commission.

HAWAIIAN ELECTRIC COMPANY, INC.

Docket No. .

Superseding Revised Sheet No. 68A
Effective April 1, 2008

REVISED SHEET NO. 68A
Effective

Integrated Resource Planning Cost Recovery Provision - Continued

C: Commercial and Industrial Demand-Side Management (DSM) Adjustment:

Schedules G, J, DS, P, U, TOU-G, TOU-J, SS - per kWh...0.2104 ¢/kWh

The total monthly bill for Schedules G, J, DS, P, U, TOU-G, TOU-J, and SS customers shall include the above Commercial and Industrial DSM adjustment applied to all kWh per month. The above adjustment is based on recovering $8,897,596 for the 2008 C&I program costs and revenue taxes, and the reconciliation of the 2007 program cost recovery, for which recovery has been approved by the Public Utilities Commission.

D: SolarSaver Adjustment:

Schedules R and E – per kWh .....0.0046 ¢/kWh

The total monthly bill for Schedules R and E customers shall include the above SolarSaver Adjustment applied to all kWh per month. The above adjustment is based on recovering $50,897 for the 2008 program costs and associated revenue taxes and the reconciliation of the 2007 program cost, including 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, the Commercial and Industrial DSM Adjustment, and SolarSaver 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, the Commercial and Industrial DSM Adjustment and the SolarSaver 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.

SCHEDULE SS
STANDBY SERVICE

A. APPLICABILITY:

Applicable to customers with alternate regular source(s) of energy other than electricity from the Company when such sources are connected to the utility's system and for which the customer relies on the utility for power service when the alternate source is not being operated(hereinafter referred to as "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.

B. DEFINITIONS:

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 (are) not being operated. Standby service refers to power service that the Company provides during both unscheduled outages 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).

C. BILLING ELECTIONS:

Customers must elect either the Regular Rate Schedule Billing Option or the Standby Rate Billing Option. Customers may change billing options after receiving at least 12 billing months of service on the presently selected Billing Option. The rates applicable to each billing option are described below. All other terms and conditions of this Schedule SS apply to both billing options, unless otherwise indicated. Both billing options shall remain in force for at least 10 years from the initial effective date of Schedule SS. The option to elect to change to or from either the Regular Rate Schedule Billing Option or the Standby Rate Billing Option shall remain in force for at least 5 years from the initial effective date of Schedule SS.

Schedule SS customers are eligible for the Company's optional rider tariffs, including, but not limited to, the current Rider M and Rider T, and any riders that may be applicable in the future. The use of a non-utility power source by a Schedule SS customer to reduce its load during the Company's curtailment hours shall be deemed eligible to meet the curtailment requirements of the Company's optional rider tariffs,

SCHEDULE SS - Continued

including, but not limited to, Rider M. If a Schedule SS customer on the Regular Rate Schedule Billing Option elects to participate in an optional rider, the customer's total kW and kWh requirements are subject to billing under the applicable regular rate schedule as adjusted by the optional rider. If a Schedule SS customer on the Standby Rate Billing Option elects to participate in an optional rider, only the customer's Supplemental Service Demand and Supplemental Service Energy are subject to billing under the applicable regular rate schedule as adjusted by the optional rider. All other terms and conditions of this Schedule SS apply to Schedule SS customers utilizing the Company's optional rider tariffs unless otherwise indicated.

Schedule SS customers are not excluded from other programs currently offered by the Company, and as offered by the Company from time to time, provided that they meet the eligibility requirements.

D. REGULAR RATE SCHEDULE BILLING OPTION RATES:

Customers who elect the Regular Rate Schedule Billing Option, including the optional rider tariffs, shall be billed at the rates on their applicable regular rate schedule and/or the rates on their applicable optional rider tariffs, and the measured demand shall reflect the customer's combined standby service and supplemental service requirements served through the regular utility meter. The Determination of Demand provision of the regular rate schedule shall apply with the following exceptions:

1. The determination of measured demand in a billing month shall exclude 15 minute periods where the customer's generating facility was disconnected under certain conditions described in Terms & Conditions #5 and #6 below;

2. New customers to this rate or existing customers with new generation sources shall be permitted a commissioning period for their non-utility generation source(s) that shall not exceed four months from the date that the customer's generating facility commences production of energy in parallel to the utility system, following execution of an interconnection agreement as required under the Company's Rule No. 14H. At the end of this commissioning period, the customer's historical measured demand will be eliminated and re-set for purposes of determining billing demand. A customer

SCHEDULE SS - Continued

may choose to have this billing demand adjustment implemented before the end of the four month period. The Company will make such a billing demand adjustment only once; and

3. The determination of measured demand in a billing month shall exclude 15 minute periods where the customer is on Scheduled Maintenance.

E. STANDBY RATE BILLING OPTION 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 commercial rate schedule. For the purpose of calculating rate adjustments based on kWh, the standby service customer's total kWh in a billing month shall be the sum of the Standby Energy kWh and the Supplemental Service Energy kWh. For the purpose of calculating rate adjustments based on total base rate charges, the Standby Demand Charge and Standby Energy Charge are considered elements of base rate charges.

1. Standby Demand Charge:

The Standby Demand Charge for each month shall be the sum of the Standby Reservation Demand Charge and the Standby Daily Demand Charge.

a. Standby Reservation Demand Charge:

$7.04 per Contract Standby kW, for customers served on Schedule J for Supplemental Service.
$7.59 per Contract Standby kW, for customers served on Schedule P for Supplemental Service.
$2.06 per Contract Standby kW, for customers served on Schedule DS 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

SCHEDULE SS - Continued

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.

b. Standby Daily Demand Charge:

$0.57 per Standby Billing kW per day, for customers served on Schedule J for Supplemental Service.
$0.63 per Standby Billing kW per day, for customers served on Schedule P for Supplemental Service.
$0.64 per Standby Billing kW per day, for customers served on Schedule DS 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. 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.

The determination of backup demand in a billing month shall exclude 15 minute periods where the customer's generating facility was disconnected under certain conditions described in Terms & Conditions #5 and #6 below.

The Daily Demand Charge will be waived during days of Scheduled Maintenance.

2. Standby Energy Charge:

Standby Energy kWh is the sum of the 15 minute interval Backup Demands (including periods of Scheduled Maintenance) during the month divided by four.

SCHEDULE SS - Continued

a. Standby Energy Charge:

$0.184 per Standby Energy kWh, for customers served on Schedule J for Supplemental Service.
$0.183 per Standby Energy kWh, for customers served on Schedule P for Supplemental Service.
$0.182 per Standby Energy kWh, for customers served on Schedule DS for Supplemental Service.

3. Supplemental Service Demand Charge:

The Billing kW for Supplemental Service shall be as follows:

The Billing kW shall be calculated each month as the higher of 1) the measured usage based on the meter readings of the service provided by the Company's generation equipment, less the maximum Backup Demand during the month or 2) the simple average of 1) and the highest Billing kW in the previous 11 months, less the maximum Backup Demand during the month. This Billing kW shall be the kW basis for billing the Supplemental Service Demand and Energy charges under the customer's applicable commercial rate schedule.

The determination of Billing kW for Supplemental Service in a billing month shall exclude 15 minute periods where the customer's generating facility was disconnected under certain conditions described in Terms & Conditions #5 and #6 below.

New customers to this rate or existing customers with new generation sources shall be permitted a commissioning period for their non-utility generation source(s) that shall not exceed four months from the date that the customer's generating facility commences production of energy in parallel to the utility system, following execution of an interconnection agreement as required under the Company's Rule No. 14H. At the end of the four month period, the customer's historical measured demand will be eliminated and re-set for purposes of determining billing demand. A customer may choose to have this billing demand adjustment implemented before the end of the four month period. The Company will make such a billing demand adjustment only once.

SCHEDULE SS - Continued

4. Supplemental Service Energy Charge:

Supplemental Service Energy kWh shall be based on the meter readings of the service provided by the Company 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.

5. 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.

6. 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 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.

F. TERMS AND CONDITIONS (Applicable to all Schedule SS customers, unless otherwise indicated):

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 the customer requires standby service from the Company.
2. This tariff shall not apply to the customers identified below in items a) through f). However, any of these customers may choose to forego this exception and elect to opt-in to Schedule SS. If a customer elects to be served under the terms and conditions of Schedule SS, such customer must remain on Schedule SS for at least 12 billing months.

   a) Non-utility power sources used exclusively by a customer for emergency service; or

SCHEDULE SS – Continued

b) 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) Non-utility power sources that are at least fifty percent fueled by non fossil fuel energy, including biodiesel or biofuels, as currently defined in Hawaii Revised Statutes 269-91 or as amended in the future, calculated on an annual fuel energy input basis; or
d) 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
e) Non-utility power sources that are operated for the benefit of customers who have an existing interruptible service contract (Rider I) or curtailable service contract (Rider M, option B) with the utility on the initial effective date of this tariff; or
f) 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. 14H.

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 if the Standby Rate Billing Option is elected, and the initial Scheduled Maintenance Service Periods, if any.

5. The calculation of backup demand and supplemental service billing demand on the Standby Rate Billing Option and the calculation of measured demand under the Regular Rate Schedule Billing Option will exclude 15 minute periods where the customer's generating facility was disconnected, provided the customer's metering and metering parameters have been approved by the Company and the disconnection was caused (a) by voltage or frequency excursions outside of the ranges specified in Rule 14H, Appendix I, #4g and #4h (or as stated in the customer's interconnection agreement) due to events on the utility system or (b) by action of the utility's direct transfer trip equipment, or (c) was requested or required by the utility due to reasons other than problems caused by the customer's generating facility.

SCHEDULE SS - Continued

The existence of such excursion or disruption must be recorded by the customer and that recording provided to the utility. The utility, in determining whether such voltage or frequency excursions were due to events on the utility system or the customer's system, shall rely on data recorded in its system operation interruption reports, system frequency archives, power quality monitors installed at substations serving the customer's facility (where available), and information of any incidents on the customer's system that may have caused the excursions. The customer shall, upon request, provide the utility with available information pertaining to customer's electrical and mechanical system operations at the time of the disconnection including, but not limited to, faults on the customer's system, customer equipment damage, and motor starting data.

If the Customer disagrees with the Company's determination of the cause of the disconnection, the Customer may meet with representatives from the Company to discuss the matter. If the parties continue to have a dispute, authorized representatives from the Company and Customer (having full authority to settle the dispute) may meet in person in Hawaii or at some other mutually agreeable location, or by telephone or internet conference, or in some other mutually agreeable fashion, and attempt in good faith to resolve the dispute. If the parties continue to have a dispute, the parties may engage in a form of alternative dispute resolution agreeable to both parties, or a party may request that the Commission resolve the matter by filing a written request with the Commission attaching the relevant information and correspondence, and serving the request on the other party and the Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs of the State of Hawaii.

Customers are not required to exhaust the Company's dispute resolution procedures set forth above before proceeding under provisions applicable to informal or formal complaints or other provisions contained under the Rules of Practice and Procedure before the Public Utilities Commission, currently codified in Title 6, Chapter 61, Subchapter 5 of the Hawaii Administrative Rules, or any other applicable statutes, orders, rules, or regulations. If any such proceeding is initiated, the Customer shall notify the Company in writing that it does not desire to continue with the Company's dispute resolution procedures.

6. A Schedule SS customer has the option, once during each calendar year, to waive the demand that the customer draws from the utility for billing purposes, provided that the demand occurs during an unscheduled outage of the customer's

SCHEDULE SS - Continued

generator. The maximum period during which this waiver may apply is no more than the first 72 consecutive hours, even if the unscheduled outage lasts longer than 72 consecutive hours. This waiver is limited to only one billing period. This waiver will be available once during the calendar year beginning with the effective date of the customer's Schedule SS contract. Waivers cannot be carried forward to subsequent years. For billing purposes, for customers on the Regular Rate Schedule Billing Option, implementation of the waiver excludes the waived hours from the calculation of measured demand for the billing month. For billing purposes, for customers on the Standby Service – Standby Rate Billing Option - - implementation of the waiver excludes the waived hours from the calculation of both the Daily Demand Charge and the Supplemental Service Demand Charge. A Schedule SS customer must exercise the waiver within 21 calendar days of the date of the bill for the billing period in which the waiver is exercised via dated written or electronic communication with the utility. Once exercised the waiver cannot be exchanged for another unscheduled outage.

7. 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. This provision is applicable to the Standby Rate Billing Option only.

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. Scheduled Maintenance Service during On-peak hours:

   Maintenance for a customer's non-utility power source(s) is subject to the following terms and conditions:

      a. A non-utility power source cannot be down for on-peak Scheduled Maintenance Service more than 300 hours during the calendar year.

SCHEDULE SS - Continued

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, which approval shall not be unreasonably withheld, in the Standby Service Contract. The customer shall submit in writing to the Company all subsequent requests for Scheduled Maintenance at least four weeks in advance of the desired maintenance periods. Such requests will be subject to the Company's review and approval, which approval shall not be unreasonably withheld. Where the Company indicates that such periods are not acceptable to the Company based on operating, technical or other similar reasons, the Company and the customer shall work together to determine the Scheduled Maintenance Periods that are reasonable and acceptable to both parties.

b. Scheduled Maintenance Service during Off-peak hours:

Maintenance for a customer's non-utility power source(s) is subject to the following terms and conditions:

(1) 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.

(2) The customer must notify the Company in advance of shutting off and/or starting up its power source that will be maintained under this provision.

(3) 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.

(4) The total off-peak Scheduled Maintenance Periods arranged under Scheduled Maintenance Service shall not be limited, provided that the Company may request the customer to forego a previously scheduled off-peak maintenance period in the event of a system emergency.

SCHEDULE SS - Continued

9. A non-utility power source or sources may be designated by the customer as producing power only during a limited number of hours per day. Customer shall not be required to provide any advance notice to utility of shutting off or starting up its power source in this situation provided it does not deviate from the previously agreed upon schedule. Customer will be entitled to designate on-peak hours or off-peak hours, if applicable, as Scheduled Maintenance under the terms and conditions described above in Terms and Conditions #8. Customer shall not be required to provide any notification concerning maintenance, as described above in Terms and Conditions #8, if such maintenance is performed entirely within hours during which it does not produce power under the previously agreed upon schedule.

10. 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) are not metered, the customer shall not be eligible for Scheduled Maintenance Service and shall not be eligible for the Standby Rate Billing Option.

11. Except as provided for in Terms and Conditions #12 below, the Company shall install, own, operate, maintain, replace, and read meters on the customer's non-utility power source(s) for billing purposes. The customer shall be responsible for any reasonable costs 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, which approval shall not be unreasonably withheld, 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 reasonable costs 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

SCHEDULE SS - Continued

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.

12. A Schedule SS customer has the option of installing and maintaining a customer-owned or supplied meter to measure the output of the DG unit(s) rather than having the utility install a utility-owned meter as set forth in Section F.11 above. This meter is a revenue meter under the Schedule SS – Standby Rate Option. The customer shall pay for the customer-owned or supplied meter and its installation/removal.

    The customer-owned or supplied meter:

    a. Must be approved by the utility, which approval shall not be unreasonably withheld. The customer shall submit manufacturing specifications and catalog cut sheets for the Company's review. The installation of a meter that is not approved by the Company shall result in the DG unit being considered as not metered.

    b. Along with the metering equipment, the customer-owned or supplied meter must meet UL, EUSEC, NEMA and ANSI standard specifications for metrology accuracy, component tolerances, and physical construction, and be sealed against tampering. Furthermore, the customer must meet all Company electrical grounding standards.

    c. Must provide the billing data required for billing under the Standby Rate Option.

    d. Must have at least a 30 to 60-day data storage capability for the required billing data.

    e. Must be equipped with a modem and be compatible with MV90 for remote interrogation of billing data and have an available telephone line.

    f. Must comply with Company's electrical service installation standards with respect to location, placement, physical clearances, and size of equipment.

    g. Must be available for testing under the conditions and frequency applied to utility-owned meters.

    h. Must not be replaced without notifying the utility in advance of the replacement. The replacement meter is subject to all the above conditions.

SCHEDULE SS - Continued

13. The term of the Schedule SS Service Contract under this Schedule SS 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, unless otherwise mutually agreed to in writing by the parties.

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

Superseding Sheet No. 69M
Effective May 15, 2008

REVISED SHEET NO. 69M
Effective

SCHEDULE SS - Continued

Schedule SS 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.

Billing Option Elected: _____

If Standby Rate Billing Option selected, items (1) and (2) below must be filled in:

(1) Billing Contract Standby kW _____
(2) Installed kW Capacity of Non-Utility Power Source(s) _____

This contract shall be amended to insert values for items (1) and (2) above at the time the customer selects the Standby Rate Billing Option.

Initial Scheduled Maintenance Periods:
_____
_____

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 SS and is subject to the terms of Rate Schedule SS and any other applicable schedule.

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.

The Customer and the Company identify the following points of contact for all communications related to service under this contract:

HAWAIIAN ELECTRIC COMPANY, INC.

Docket No. .

Superseding Sheet No. 69N
Effective May 15, 2008

REVISED SHEET NO. 69N
Effective

SCHEDULE SS - Continued

Schedule SS Service Contract Form

Page 2

Customer	HECO
_____	_____
Name	Name
_____	_____
Title	Title
_____	_____
Mailing Address	Mailing Address
_____	_____
E-mail Address	E-mail Address
_____	_____
Phone Number	Phone Number

Changes in contact information should be directed to the other party's point of contact in writing and should reference this Schedule SS Service contract.

Authorized Customer Signature:	HECO Representative:
_____|_____	_____|_____
Name Date	Name Date
_____	_____
Title	Title
_____	

HAWAIIAN ELECTRIC COMPANY, INC.

Docket No. .

Superseding Sheet No. 70
Effective June 30, 2007

Revised SHEET NO. 70
Effective

RIDER SSP

SOLARSAVER PILOT PROGRAM

AVAILABILITY:

This Rider is available to Participants served under rate Schedule "R" or "E", who install a Residential Efficient Water Heating ("REWH") DSM Program approved retrofit solar water heating ("SWH") system, using a Hawaiian Electric Company, Inc. ("HECO") (hereafter referred to as "Company") REWH DSM Program approved solar water heating contractor, on an existing single-family home or town home. Participants must agree to pay for the solar water heating system under the conditions specified below. This Rider is also available to Participants served under Schedule "R" or "E" at service locations where a solar water heating system has already been installed under this program.

The number of solar water heating systems installed under this Tariff is limited to a total of [300 for HECO] for the entire term of the Pilot Program.

At its sole discretion, the Company shall also determine eligibility for service under this Rider subject to (1) the availability of funds budgeted for this program; (2) the suitability of approved solar water heating systems for the Participant's location and the likelihood that the systems will be used and useful throughout their estimated life; (3) a Participant bill payment history check; (4) existence of electric-resistance water heating equipment;(5) execution and filing of the appropriate SolarSaver Participant Agreement and Short Form SolarSaver Agreement; and (6) the Company's determination that the solar water heating system is estimated to produce sufficient energy savings to offset the total cost of the system; i.e., that the installed price of the solar water heating system (including any applicable taxes, net of the Company's REWH Program DSM rebate) is equal to or below the SWH system price cap.

This Rider is available to solar water heating installations through July 1, 2010, but may be suspended or terminated at any time by order of the Commission. Should the SolarSaver Pilot Program be closed to future participants, this Rider shall continue until terminated by the Commission or the repayment obligation of all Pilot Program Participants has been fulfilled, whichever occurs first.

Superseding Sheet No. 70A
Effective April 4, 2008

REVISED SHEET NO. 70A
Effective

RIDER SSP - Continued

RATES:

Each SolarSaver Pilot Program Participant shall pay a monthly SolarSaver Fee ("Fee"). The SolarSaver Fee shall be equal to 80% of the estimated monthly energy bill savings for a family of four at the time that the SolarSaver Fee is set by the utility. The energy bill savings will be estimated by the utility using the most recent REWH Program Impact Evaluation filed with the Hawaii Public Utilities Commission. The SolarSaver Fee shall be constant for the term of the payment period for each Participant unless an accelerated repayment term is requested by the Participant. The payment period in months shall be equal to the solar water heating system price (net of the REWH Program DSM rebate) divided by the SolarSaver Fee.

For the period: April 4 – June 30, 2008

The SolarSaver Fee for new Participants shall be: $36.87/month

The after Utility rebate SWH system price cap
(equal to 144 months times the SolarSaver Fee) shall be: $5,309.00

The Fee and SWH system price cap shall be recalculated on a quarterly (calendar year) basis to incorporate the current Schedule R energy charge, including the base energy charge plus the current energy cost adjustment factor. The recalculated SolarSaver Fee and SWH system price cap shall only be in effect for new Participants enrolled after the Fee recalculation takes place.

The solar water heating system will be owned by the property owner, but installed at the Company's expense and the Participant shall reimburse the Company through a SolarSaver Fee added to the Participant's regular monthly bill. The Fee is an element of the Participant's electric service, and the Participant is liable for payment of the Fee under this Rider under the same conditions as charges under the Participant's regular rate schedule, including, but not limited to, the Participant's service being subject to disconnection for nonpayment in accordance with the Company's rules. Bill payments made by the Participant will first be applied to the electricity use portion of the bill. There is no guarantee that all Participants participating in the SolarSaver Pilot Program will receive lower monthly electric bills.

Superseding Sheet No. 70B
Effective June 30, 2007

Revised SHEET NO. 70B
Effective

RIDER SSP - Continued

MINIMUM FEE AND TERM OF CONTRACT:

The SolarSaver Participant Agreements (attached) between the utility and Participants will specify the minimum monthly Fee and the term of the payment period. A Participant can choose to accelerate the payment period term by paying a higher Fee or a Participant can choose to pay the remaining balance owed to the Company at any time. A Participant selecting an accelerated payment period term can revert at any time to the minimum monthly Fee available to the Participant. Unless the Participant chooses to accelerate the payment period term, the minimum monthly Fee for the SolarSaver location will not change. However, the SolarSaver Fee for the last month of the payment period shall be equal to the remaining balance.

COMPANY RESPONSIBILITIES

The Company shall arrange to certify that the solar water heating system(s) are properly installed and operating as designed. The Company shall also arrange recordation of the SolarSaver Short Form Customer Agreement with the State Bureau of Conveyances. Upon notification that work is complete, the Company will verify that the solar water heating system(s) have been installed and arrange for payment to the contractor.

At the time of electric service request, the Company will inform all new customers at a location where a SolarSaver solar water heating system has been installed as to the existence of any unbilled Fees remaining under this Rider for that location. If the former Participant received service under an accelerated payment period term, the Company will inform the new Participant that the Participant may revert at any time to the minimum monthly Fee that was available to the former Participant. The Company will also inform these Participants of the general benefits associated with solar water heating systems and their responsibility for the payment of the remaining charges under this Rider and other obligations.

Superseding Sheet No. 70C
Effective June 30, 2007

Revised SHEET NO. 70C
Effective

RIDER SSP - Continued

PARTICIPANT RESPONSIBILITIES AS PROPERTY OWNER

In situations where the Participant is the home or property owner and resides at the location where the solar water heating system is installed, or prior to the installation of any solar water heating system, the Participant will be responsible for:

1. Payment of the monthly Fees under this Rider in addition to all other charges on the monthly bill;
2. Taking reasonable steps to prevent damage to such systems;
3. Becoming fully informed concerning the routine operation and maintenance of the solar water heating system installed at the service location; and
4. Allowing access by the Company, at reasonable times, for any inspection of the solar water heating system for the purposes of evaluating the SolarSaver Pilot Program.
5. Execution by the property owner of the SolarSaver Short Form Agreement (and having it notarized) to ensure that a record of the SolarSaver installation has been properly recorded with the State of Hawaii Bureau of Conveyances.

If the Participant is the owner of the premises, the Participant shall inform all prospective purchasers or renters of the location in writing that there is an unexpired obligation under this Rider. Whenever a customer applies for electric service at a location which was the subject of a previous SolarSaver Participant Agreement and SolarSaver Short Form Customer Agreement, payment for which has not been completed, such customer shall become responsible for the remaining balance. If the location was the subject of an accelerated payment term, the new Participant has the option to revert at any time to the minimum monthly Fee that was available to the former Participant. Acceptance of electric service constitutes acceptance of the obligations under this Rider by the new Participant.

PARTICIPANT RESPONSIBILITIES AS RENTER

In situations where the Participant is renting the SolarSaver location, as defined as any tenant who is currently a customer of the Company or any future tenant who shall apply for service from the Company at a SolarSaver location, the renter is responsible for:

1. Receiving written landlord approval to install a SolarSaver SWH system on the rental property;

Superseding Sheet No. 70D
Effective June 30, 2007

Revised SHEET NO. 70D
Effective

RIDER SSP - Continued

2. Paying the monthly SolarSaver Fee for as long as they occupy the property;

3. Allowing access by the Company, at reasonable times, for any inspection of the solar water heating system for the purposes of evaluating the SolarSaver Pilot Program;

SUBJECT TO RULES AND REGULATIONS:

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

Superseding Sheet No. 70E
Effective June 30, 2007

Revised SHEET NO. 70E
Effective

RIDER SSP - Continued

SolarSaver Pilot Program
Customer Agreement
(Property Owner)

This agreement is between the _Hawaiian Electric Company, Inc.___ hereafter referred to as "Company" and _(Name of utility customer)____ hereafter referred to as "Customer".

1. The Customer hereby certifies:
   - That I/we are the legal owner(s) of residential property located at _____,
   - That I/we are customer(s) of the Company for our residential electric service,
   - That we are replacing an electric resistance water heater with a solar water heating system as part of the SolarSaver Pilot Program.
2. The Company agrees to provide full payment to the customer's selected solar contractor[1] for installing one pre-qualified SolarSaver SWH system at the property address above.
3. The Company agrees to provide full payment of the Residential Efficient Water Heating (REWH) Program Solar Rebate to the customer's selected solar contractor upon successful inspection of the SolarSaver SWH system installed.[2]
4. Customer and Company agree that Customer may select any solar contractor who is approved by the Company for the SolarSaver Pilot Program to install the solar water heating system.

[1] The Solar Contractor is required to be a Company-approved participant in the Company's Residential Efficient Water Heating Program.

[2] Per REWH Program requirements, a solar rebate will be instantly applied to the Customer's invoice at the time of sale.

Superseding Sheet No. 70F
Effective June 30, 2007

Revised SHEET NO. 70F
Effective

RIDER SSP - Continued

5. Customer agrees to pay the Company a monthly SolarSaver Fee. The monthly Fee is to be collected through the utility bill for the residential electric service attached to the meter for this location to recover the cost of equipment and installation of a solar water heating system installed by a Company-approved contractor of Customer's choice.

6. Customer agrees to sign and notarize the SolarSaver Short Form Customer Agreement (and have it notarized) to be filed by Company with the State of Hawaii Bureau of Conveyances within sixty (60) days of solar water heating system installation.

7. Customer agrees to the following terms of payment to the Company:

_____ Total Cost of System

_____ Less: Instant Utility Rebate from Residential Efficient Water Heating Program

_____ Balance owed by Customer

_____ Customer Monthly SolarSaver Fee

_____ Term (total number of months to pay SolarSaver Fee)

8. Customer agrees to pay the monthly SolarSaver Fee for the period of months listed in this agreement or until:

   a) I/we vacate the residential property address listed in this agreement; or,
   b) The system is paid off earlier in full (upon Customer request);

9. Customer agrees that if I/we sell this residential property prior to full payment of the solar water heating system that I/we will disclose the contents of this SolarSaver Agreement to the buyer, which includes the transfer of payment obligation to the new property owner.

Superseding Sheet No. 70G
Effective June 30, 2007

Revised SHEET NO. 70G
Effective

RIDER SSP - Continued

10. Customer understands and agrees that, with the agreement of the Company, the balance owed on the solar water heating system may be paid in full by the Customer or the Customer may agree to pay a higher monthly fee in order to pay the total balance earlier than the term listed in this agreement.

11. Customer agrees that non-payment of SolarSaver fees will result in the Company collections process and possible disconnection of electrical service. Any fees collected will first be applied to the outstanding balance for electric service before additional funds are applied to the monthly SolarSaver Fee.

12. Customer agrees to notify the SolarSaver Pilot Program Administrator immediately if the installed solar water heating system fails to operate properly. I/we understand that maintenance of the SWH system will be provided through either product warranty, extended warranty insurance or by the utility company during the period that the SolarSaver Fee is being assessed.

13. Customer agrees to payment of the monthly Fees under this Agreement in addition to all other charges on the monthly bill.

14. Customer agrees to take reasonable steps to prevent damage to the SWH system by becoming fully informed concerning the routine operation and maintenance of the solar water heating system installed at the service location.

15. Customer agrees to allow access by the Company, at reasonable times, for any inspection of the solar water heating system for the purposes of evaluating the SolarSaver Pilot Program.

16. The Customer shall inform all prospective purchasers or renters of the location in writing that there is an unexpired obligation under this Agreement. Whenever a customer applies for electric service at a location which was the subject of a previous SolarSaver Agreement, payment for which has not been completed, such customer shall become responsible for the remaining balance. If the location was the subject of an accelerated payment term, the new Participant has the option to revert at any time to the minimum monthly Fee that was available to the former Participant.

Superseding Sheet No. 70H
Effective June 30, 2007

Revised SHEET NO. 70H
Effective

RIDER SSP - Continued

17. Acceptance of electric service constitutes acceptance of the obligations under this Agreement by the new property owner/Participant.

18. The Company agrees that the Customer will no longer be responsible for the monthly SolarSaver Fee if the solar water heating system cannot be repaired, as determined by the utility, other than damage caused by the Customer.

19. Customer agrees that that the solar water heating system being installed is the sole property of the legal owner of the real property.

Executed at _____, Hawaii, this ___ day of _____, 20__.

_____
Customer

_____
Customer

_____
Company Representative

Superseding Sheet No. 70I
Effective June 30, 2007

Revised SHEET NO. 70I
Effective

RIDER SSP - Continued

SolarSaver Pilot Program
Customer Agreement
(Renter)

This agreement is between the ___Hawaiian Electric Company, Inc. ____ hereafter referred to as Company and ____(Name of utility customer)___ hereafter referred to as Customer.

1. Customer hereby certifies:

   - That I/we are the legal tenant(s) of residential property located at _____,
   - That I/we are customer(s) of the Company for our residential electric service,
   - That I/we are replacing an electric resistance water heater with a solar water heating system as part of the SolarSaver Pilot Program; and,
   - That we have obtained permission for such installation from the legal owner of the property as evidenced by the signed agreement attached as Exhibit 1.

2. The Company agrees to provide full payment to the Customer's selected solar contractor[3] for installing one pre-qualified SolarSaver SWH system at the property address above.

3. The Company agrees to provide full payment of the Residential Efficient Water Heating (REWH) Program Solar Rebate to the customer's selected solar contractor upon successful inspection of the SolarSaver SWH system installed.[4]

4. Customer and Company agree that Customer may select any solar contractor who is approved by the Company for the SolarSaver Pilot Program to install the solar water heating system.

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[3] The Solar Contractor is required to be a Company-approved participant in the Company's Residential Efficient Water Heating Program.

[4] Per REWH Program requirements, a solar rebate will be instantly applied to the Customer's invoice at the time of sale.

Superseding Sheet No. 70J
Effective June 30, 2007

Revised SHEET NO. 70J
Effective

RIDER SSP - Continued

5. Customer agrees to pay the Company a monthly SolarSaver Fee. The monthly Fee is to be collected through the utility bill for the residential electric service attached to the meter for this location, to recover the cost of equipment and installation of a solar water heating system installed by a Company-approved contractor of Customer's choice.

6. Customer agrees to the following terms of payment to the Company:

_____	Total Cost of System
_____	Less: Instant Utility Rebate from Residential Efficient Water Heating Program
_____	Balance owed by Customer
_____	Customer Monthly SolarSaver Fee
_____	Term (total number of months to pay SolarSaver Fee)

7. Customer agrees to pay to the monthly SolarSaver Fee for the period of months listed in this agreement or until:

   a) I/we vacate the residential property address listed in this agreement; or,
   b) The system is paid off earlier in full (upon Customer request);

8. Customer agrees that, with the agreement of the Company, the balance owed on the solar water heating system may be paid in full by the Customer or the Customer may agree to pay a higher monthly fee in order to pay the total balance earlier that the term above.

9. Customer agrees that non-payment of SolarSaver Fees will result in the Company collections process and possible disconnection of electrical service. Any delinquent fees collected will first be applied to the outstanding balance for electric service before additional funds are applied to the monthly SolarSaver Fee.

Superseding Sheet No. 70K
Effective June 30, 2007

Revised SHEET NO. 70K
Effective

RIDER SSP - Continued

10. Customer agrees that that the solar water heating system being installed is the sole property of the legal owner of the real property and is not owned by the tenant.

11. Customer agrees to notify the SolarSaver Pilot Program Administrator immediately if the installed solar water heating system fails to operate properly and coordinate the scheduling of the repair with the landlord. I/we understand that maintenance of the SWH system will be provided through either product warranty, extended warranty, or by the utility company during the period that the SolarSaver Fee is being assessed.

12. Customer agrees to receive written landlord approval to install a SolarSaver SWH system on the rental property.

13. Customer agrees to pay the monthly SolarSaver Fee for as long as they occupy the property.

14. Customer agrees to allow access by the Company, at reasonable times, for any inspection of the solar water heating system for the purposes of evaluating the SolarSaver Pilot Program.

15. The Company agrees that the Customer will no longer be responsible for the monthly SolarSaver Fee if the solar water heating system cannot be repaired, as determined by the utility, other than damage caused by the Customer.

Executed at _____, Hawaii, this ___ day of _____, 20__.

_____ _____
Customer Customer

_____
Company Representative

Superseding Sheet No. 70L
Effective June 30, 2007

Revised SHEET NO. 70L
Effective

RIDER SSP - Continued

Exhibit 1

SolarSaver Pilot Program
Customer Agreement
(Renter)

LANDLORD APPROVAL FOR RENTAL PROPERTY
SOLARSAVER INSTALLATION

I/We certify that I/we are the legal owner(s) of the residential property located at:
_____,
and that the Tenant in this property has my permission to allow a Company approved Participating Contractor to install the Solar Water Heating (SWH) system described in the attached agreement. As the owner of this property, I/We understand that the system cost will be repaid by the Tenant to Company through a SolarSaver Fee to be assessed on the Tenant's monthly electric bill and any subsequent tenant in this property until the SolarSaver SWH system is paid for in full or until Rider SSP is terminated, whichever occurs first.

As legal owners of the property I/We agree to the installation of the pre-approved SolarSaver Solar Water Heating system, to be the owner of said system, and to notify any subsequent tenants at the same property that the tenant will be required to pay the monthly SolarSaver fee as part of their electric bill or be subject to the Company collections process which may lead to electric service disconnection. Additionally, I/We agree to sign and notarize the SolarSaver Short Form Customer Agreement (and have it notarized) to be filed by Company with the State of Hawaii Bureau of Conveyances within sixty (60) days of solar water heating system installation.

RIDER SSP - Continued

Furthermore, I/We understand that any maintenance or repair of the SWH system during the period that the SolarSaver Fee is being assessed is the responsibility of the utility.

Executed at _____, Hawaii, this ___ day of _____, 20__.

_____
Property Owner

_____
Property Owner

Superseding Revised Sheet No. 81 REVISED SHEET NO. 81
Effective June 20, 2008 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 17.69 ¢/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 June 20, 2008

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 an avoided fuel cost of 19.948 ¢/kWhr on-peak and 14.707 ¢/kWhr off-peak, an avoided O&M cost of 0.170 ¢/kWhr on-peak and 0.011 ¢/kWhr off-peak, and a Power Factor Adjustment of -0.120 ¢/kWhr on-peak and -0.280 ¢/kWhr off-peak. The sum of the on-peak costs are time weighted 14 hours of 24 hours for on-peak and 10 hours of 24 hours for off peak and summed to derive the Schedule Q energy rate.

This Energy Cost Adjustment Clause is consistent with the terms of Decision and Order No. 24086 in Docket No. 7310, and may be revised to reflect further changed, subject to Commission approval.

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.

Superseding Sheet No. 83 REVISED SHEET NO. 83
Effective June 20, 2008 Effective

SCHEDULE TOU-G

SMALL COMMERCIAL TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to general light and/or power loads less than or equal to 5000 kilowatthours per month, and less than or equal to 25 kilowatts, and supplied and metered at a single voltage and delivery point. Customers served under this Schedule who exceed 5,000 kilowatthours per month or 25 kilowatts of demand three times in a twelve month period must transfer to Schedule TOU-J or terminate TOU-G service at the beginning of the next billing period.

TIME-OF-DAY RATING PERIODS:

The time-of-use 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:

CUSTOMER CHARGE:

Single-Phase Service – per month	$32.00/month
Three-Phase Service – per month	$61.00/month

ENERGY CHARGE: (To be added to Customer Charge)

Priority Peak Period – per kWhr	31.2038 ¢/kWhr
Mid-Peak Period – per kWhr	28.2038 ¢/kWhr
Off-Peak Period – per kWhr	21.2038 ¢/kWhr

MINIMUM CHARGE:

Single-Phase Service – per month	$32.00/month
Three-Phase Service – per month	$61.00/month

DETERMINATION OF TIME-OF-USE ENERGY AND DEMAND:

The Company shall install a time-of-use meter to measure the customer's kilowatthour consumption during the time-of-day rating periods.

SCHEDULE TOU-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 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 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 Sheet No. 84 REVISED SHEET NO. 84
Effective June 20, 2008 Effective

SCHEDULE TOU-J

COMMERCIAL TIME-OF-USE SERVICE

AVAILABILITY:

Applicable to general light and/or power loads which exceed 5,000 kilowatthours per month or exceed 25 kW per month three times within a twelve month period and but are less than 300 kW per month and supplied and metered at single voltage and delivery point. This Schedule cannot be used in conjunction with load management Riders M, T, and I. This Schedule may be used in conjunction with Schedule SS.

Customers who have loads that are less than 5,000 kWh and less than 25 kW for 12 consecutive months must either transfer to Schedule TOU-G or terminate Schedule TOU-J service at the beginning of the next billing period.

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:

CUSTOMER CHARGE:

Single-Phase Service – per month	$70.00/month
Three-Phase Service – per month	$100.00/month

DEMAND CHARGE - (To be added to Customer and Energy Charge)

Priority Peak	– per kW of billing demand	$21.00/kW
Mid-Peak	- per kW of billing demand	$14.00/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 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.

SHEET NO. 84A
Effective

SCHEDULE TOU-J - continued

ENERGY CHARGE: (To be added to Customer Charge)

Priority Peak Period	– per kWhr	25.6269 ¢/kWhr
Mid-Peak Period	– per kWhr	22.6269 ¢/kWhr
Off-Peak Period	– per kWhr	18.0000 ¢/kWhr

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. Thekilowatts of demand for the minimum charge calculation each month shall not be less than 25 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 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:

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.

SCHEDULE TOU-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 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, Supply Voltage adjustment, Network Service adjustment, and Power Factor adjustment.

Integrated Resource Planning Cost Recovery Provision:

The Integrated Resource Planning Surcharge shall be added to the Customer, Demand, and Energy charges, Supply 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.

SCHEDULE TOU-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 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. 86 REVISED SHEET NO. 86
Effective June 20, 2008 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	$10.50/month
Three-Phase Service - per month	$18.50/month

ENERGY CHARGES - ¢ per kWh:

TIME-OF-USE CHARGES - ¢ per kWh:

On-Peak Period – per kWhr	43.2113 ¢/kWhr
Off-Peak Period - per kWhr	22.2113 ¢/kWhr

USAGE CHARGES - ¢ per kWh:

All kWhr between 350 – 1,200 kWh per month–	1.0 ¢/kWhr
All kWhr over 1,200 kWh per month-	2.0 ¢/kWhr

MINIMUM CHARGE:

Single-Phase Service - per month	$18.50/month
Three-Phase Service - per month	$23.50/month

SCHEDULE TOU-R – (continued)

TIME-OF-USE RATING PERIODS:

The time-of-use rating periods under this Schedule shall be defined as follows:

On-Peak:	3:00 p.m. - 8:00 p.m., daily
Off-Peak:	8:00 p.m. – 3:00 p.m., daily

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 Revised Sheet No. 88 REVISED SHEET NO. 88
Effective June 20, 2003 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.

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2008-0083
TEST YEAR 2009

SUMMARY OF REVENUES AT PRESENT AND PROPOSED RATES

			PROPOSED INCREASE	
Rate Class	At Present Rates ($000s)	At Proposed With CT-1 Step ($000s)	Amount ($000s)	Percent (%)
Schedule R	$533,570.9	$590,002.7	$56,431.8	10.58%
Schedule G	$105,816.6	$117,062.0	$11,245.4	10.63%
Schedule J	$489,618.6	$536,291.9	$46,673.3	9.53%
Schedule P	$393,959.3	$435,272.6	$41,313.3	10.49%
Schedule DS	$252,991.2	$270,532.7	$17,541.5	6.93%
Schedule F	$9,062.3	$10,017.1	$954.8	10.54%
Total Sales Revenues	$1,785,018.9	$1,959,179.0	$174,160.1	9.76%
Other Operating Revenues	$5,034.0	$5,222.0	$188.0	3.73%
Total Revenues	$1,790,052.9	$1,964,401.0	$174,348.1	9.74%

HAWAIIAN ELECTRIC COMPANY, INC.
DOCKET NO. 2008-0083
TEST YEAR 2009

SUMMARY OF REVENUES AT CURRENT EFFECTIVE AND PROPOSED RATES

			PROPOSED INCREASE	
Rate Class	At Current Effective Rates ($000s)	At Proposed With CT-1 Step ($000s)	Amount ($000s)	Percent (%)
Schedule R	$560,823.9	$590,002.7	$29,178.8	5.20%
Schedule G	$111,272.7	$117,062.0	$5,789.3	5.20%
Schedule J	$509,769.6	$536,291.9	$26,522.3	5.20%
Schedule P	$413,746.2	$435,272.6	$21,526.4	5.20%
Schedule DS	$257,153.5	$270,532.7	$13,379.2	5.20%
Schedule F	$9,521.7	$10,017.1	$495.4	5.20%
Total Sales Revenues	$1,862,287.6	$1,959,179.0	$96,891.4	5.20%
Other Operating Revenues	$5,102.0	$5,222.0	$120.0	2.35%
Total Revenues	$1,867,389.6	$1,964,401.0	$97,011.4	5.20%

Hawaiian Electric Company, Inc.
CIP1 Generating Unit (Full Cost) - Test Year 2009
Results of Operations
($ Thousands)

	Present Rates
Electric Sales Revenue	1,785,019
Other Operating Revenue	4,419
Gain on Sale of Land	615
TOTAL OPERATING REVENUES	1,790,053
Fuel	816,654
Purchased Power	477,055
Production	81,500
Transmission	13,967
Distribution	30,491
Customer Accounts	15,954
Allowance for Uncoll. Accounts	1,283
Customer Service	7,007
Administration & General	76,849
Operation and Maintenance	1,520,760
Depreciation & Amortization	83,183
Amortization of State ITC	(1,462)
Taxes Other Than Income	166,146
Interest on Customer Deposits	471
Income Taxes	(6,109)
TOTAL OPERATING EXPENSES	1,762,989
OPERATING INCOME	27,064
AVERAGE RATE BASE	1,409,547
RATE OF RETURN ON AVERAGE RATE BASE	1.92%

Hawaiian Electric Company, Inc.
CIP1 Generating Unit (Full Cost) at Current Effective Rates - Test Year 2009
Results of Operations
($ Thousands)

	Current Effective Rates
Electric Sales Revenue	1,862,288
Other Operating Revenue	4,487
Gain on Sale of Land	615
TOTAL OPERATING REVENUES	1,867,390
Fuel	816,654
Purchased Power	477,055
Production	81,500
Transmission	13,967
Distribution	30,491
Customer Accounts	15,954
Allowance for Uncoll. Accounts	1,339
Customer Service	7,007
Administration & General	76,849
Operation and Maintenance	1,520,816
Depreciation & Amortization	83,183
Amortization of State ITC	(1,462)
Taxes Other Than Income	173,011
Interest on Customer Deposits	471
Income Taxes	21,290
TOTAL OPERATING EXPENSES	1,797,309
OPERATING INCOME	70,081
AVERAGE RATE BASE	1,408,851
RATE OF RETURN ON AVERAGE RATE BASE	4.97%

HECO T-2
DOCKET NO. 2008-0083

TESTIMONY OF
GEORGE WILLOUGHBY

DIRECTOR
FORECASTS & RESEARCH DIVISION
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Electricity Sales and Customer Forecasts

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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 2009.

TEST YEAR SALES AND CUSTOMERS

Q. What are the test year 2009 estimates for the items in your area of responsibility?

A. The test year 2009 estimates for my area of responsibility are shown in HECO-201 and are summarized below:

	Test year 2009	units
Test Year Electricity Sales	7,657.8	GWh
Average Monthly Number of Customers	296,210	

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 planning purposes. The March 2008 sales update 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 most recent annual forecast is HECO's May 2007 sales and peak forecast.

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 the test year 2009 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 2009,
3) describe the forecast methods used in the derivation of the sales and customer forecasts,
4) discuss the derivation and reasonableness of the 2009 sales forecasts for residential and commercial rate schedules, and
5) discuss the accuracy of previous forecasts.

Forecasting Process for the March 2008 Sales Update

Q. How did HECO develop its March 2008 sales update?

A. Development of the March 2008 update began in early January 2008. HECO undertook an extensive review of recent economic trends and events, and reviewed and updated planned new commercial customer projects and developments, as well as energy efficiency impacts and demand side management

impacts. In addition, 2007 year-end and year-to-date January 2008 actual sales and customers were taken into account.

Econometric models, both short-term monthly and long-term annual models, were then specified for residential use per customer and commercial sales based on the historical data. Customer forecasts were developed separately using trend models. 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 methodology used for the March 2008 update subject to a review process?

A. Yes, it was. The update was reviewed by HECO's Executive Committee.

Q. Is this the same review process an annual sales forecast is subjected to?

A. No. An annual sales forecast, due to its comprehensive nature, is reviewed by an internal working group comprised of middle-level HECO employees prior to review by executive staff. In addition, the methods used to develop the forecast are discussed with an informal technical review group that includes several noted local economists. The purpose of the review is to examine the forecasting approaches and methodology on their technical merits.

Q. Does the lack of a more extensive review process for the March 2008 update mean that the resulting projections are more likely to be inaccurate?

A. No, it does not. The methodological foundation of the March 2008 update is the same as that of the May 2007 forecast. The May 2007 forecast was extensively reviewed by the internal working group, the informal technical review group, and

HECO executives. The March 2008 update focused on incremental changes to the May 2007 forecast based on recent developments. Although the models used in the March 2008 update were re-specified, the basic methodology from the May 2007 forecast was followed.

Q. Was the March 2008 update adopted by the Executive Committee?

A. Yes. The forecast was adopted by the Executive Committee on March 14, 2008.

Q. Why is the March 2008 update being used as the basis for the test year sales and number of customers rather than using the May 2007 forecast?

A. The March 2008 update is the most recent sales update and it incorporates the latest information available at the time the forecast for sales and customers was prepared for this rate proceeding. In particular, economic conditions and expectations have changed significantly since the May 2007 forecast was prepared, as discussed in more detail in the Economic Outlook section of my testimony below. Further, actual sales in 2007 were unexpectedly lower than anticipated in the May 2007 forecast.

<u>Economic Outlook</u>

Q. What is the economic outlook underlying the sales and customer estimates for 2009?

A. Economic forecasts reflecting the worsening U.S. and Hawaii economies were not available when the March 2008 sales update was being developed. However, in the March 2008 sales update, the Forecasts and Research Division elected to adjust the economic variables used for the forecast models downward from levels from the then-current UHERO March 2007 outlook on the expectation that existing economic outlooks were overly optimistic given the emerging economic

conditions. This expectation was shown to be justified when the UHERO annual forecast report was released on March 21.

On March 21, 2008, after the economic outlook for the March 2008 sales update was completed, UHERO issued their report entitled Annual Hawaii Forecast: Economy Grinds To A Halt. UHERO lowered their outlook from their previous forecasts due to the U.S. economy apparently sliding into recession and the continuing national credit market problems. Contributing to this weakness are soft local economic conditions with a faltering visitor industry and a weakening construction industry contributing to anemic job growth. UHERO projected a flat Hawaii economy for the next two years, with growth resuming in 2010.

The discussion that follows is based on materials available when the March 2008 update was prepared and prior to UHERO's March 2008 release, with economists generally still expecting slower but positive growth. In light of more recent forecasts and assessments by local economists, the economic conditions outlined here are probably overly optimistic. These were, however, the prevailing expectations at the time the March 2008 sales update was developed.

The Hawaii economy is expected to grow moderately, but at a much slower rate than in the past few years. Jobs, real personal income and visitor arrivals are all expected to grow and inflation is expected to slow. Hawaii's unemployment rate remains among the lowest in the nation, although it has risen steadily over the last year. All of these measures are positive and reflect what local economists describe as a "soft landing" for the slowing Hawaii economy.

Externally, the U.S. economy is wavering on the brink of a recession, if not already there, fueled by the sub-prime lending crisis. The downturn in the housing market, signs of softness in the labor market and inflationary uncertainty

all contribute to the growing concerns about the U.S. economy. Despite the less than positive outlook, the U.S. economy is still expected to realize year-over-year growth in 2008. The Japanese economy is also expected to grow, although at a slower rate than previously forecast and slower than in previous years.

Q. What is the outlook for tourism?

A. Softness in the tourism industry continues. In 2007, State of Hawaii total visitor arrivals were down 1.2% year-over-year. Domestic arrivals were flat year-over-year, but international arrivals were down 4.7% (see HECO-WP-201, page 21). Various local economists forecast 2008 visitor arrivals to range from an increase of 0.3% to an increase of 1.6% (see HECO-WP-201, page 22). Forecasts for 2008 domestic arrivals range from a decrease of 0.2% to an increase of 1.7%, while international arrivals are forecast to range from a decrease of 0.6% to an increase of 1.2%. Growth was expected to continue into 2009. These forecasts were issued prior to the announcement of the loss of the "Pride of Aloha" cruise ship in the Hawaii market and before the closures of ATA and Aloha Airlines.

Q. What is the outlook for the construction sector?

A. The outlook for the construction industry continues to be positive although slowing from recent record years. New residential construction is expected to continue to slow from its peak in 2005-2006, although the overall industry will receive a boost from private non-residential construction and federal military housing initiatives. Construction also continues to be a major contributor to job growth in the state. Jobs in the construction sector grew almost 5% year-over-year in the third quarter of 2007, although the growth rate was lower than in previous quarters. Construction jobs are expected to peak in 2008 and then decline slightly in 2009. It should be noted that local economists caution that the

slowdown in Hawaii's construction industry could be accelerated by further limitations on credit availability for commercial projects due to the impact of sub-prime loans on U.S. financial markets.

Q. What are the potential risks to the economic outlook?

A. As mentioned earlier, economic conditions and expectations changed rapidly in early 2008 after the economic outlook in the March 2008 update was compiled. Subsequently, UHERO significantly lowered their outlook based on the U.S. economy entering recession and expectations of continuing economic woes. UHERO's Annual Hawaii Forecast was issued on March 21, 2008 and predicted lackluster performance for Hawaii's economy until 2010. The more pessimistic outlook permeates all facets of the local economy in 2008 (see HECO-WP-201, page 23), and carries into 2009.

Risks to the local economy are likely to originate from external economic conditions in the U.S. or Japan. The U.S. economy appears to have entered a recession. Further fallout from sub-prime lending, rising inflation, rapidly slowing economic growth, and an unstable stock market are realistic threats that could further deepen or prolong the U.S. recession. Locally, increased inflation, declining visitor arrivals, and a rapid decline in construction are concerns. Tourism shocks resulting from terrorism, disease outbreaks, or natural disasters always remain possible. Present conditions indicate Hawaii is likely to see an economic slowdown in 2008; however, stable housing prices, less exposure in the sub-prime market, and the bargains available to foreign travelers and investors due to the weak U.S. dollar may help the Hawaii economy avoid a deep and prolonged downturn.

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 test year 2009 sales derived?

A. The 2009 sales were derived in the following manner:

1) The bases for 2009 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, photovoltaic interconnection ("PV") 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 2009 sales forecasts?

A. The estimate of residential sales in 2009 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 2009 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 2009 customer forecasts?

A. The 2009 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 variables, such as personal income or jobs, and other variables, such as temperature, humidity, or 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 that 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. Was there only one type of econometric equation used in the forecast?

A. No. The sales projections for test year 2009 were developed using two types of econometric equations. The first type of equation is a short-term equation developed using recorded monthly data, which was used to estimate residential use and commercial sales for the first year of the forecast horizon (2008). The second type of equation is a long-term equation based on billed annual data, which was used to estimate the annual growth rate applied to the base year (2008) estimate to develop projections for the longer range years in the forecast horizon, including the test year 2009 and beyond.

Q. Why does the forecast use a short-term and a long-term model?

A. The short-term model is used to reflect near term fluctuations in use or sales based on detailed monthly data. The data for this model is available for a short time period and is therefore believed to be more appropriate to capture short-term fluctuations. The long-term equation is used because it better captures the longer range trends in the relationship between use or sales and explanatory variables. The data available for this model covers a longer time period and is more appropriate in capturing the underlying long range change in sales.

Q. Since 2009 is only a few months away, why not use the monthly short-term model for the test year forecast?

A. Short-term monthly econometric models can be very reactive to short-term changes in actual sales, price, economic conditions, and so forth. However, as with any econometric model, the short-term models lose predictive power the further out they are asked to predict. Predicting the full year of monthly sales in 2009 using data available at the time the forecast was developed would require projecting the model over nearly 24 monthly periods into the future. HECO's experience with these models shows that the best results are obtained within the near term, with 12 months being a practical operational upper limit for projections. Similarly, the annual model has greater predictive power in capturing longer range trends than in identifying short range fluctuations. Thus, the short-term model provides a better estimate for 2008, while the long-term annual model provides a better sense of what can be expected in 2009.

Q. How was the residential econometric equation developed?

A. For 2008, the short-term monthly residential econometric equation was specified using recorded monthly use per residential customer in kilowatt-hours ("kWh").

Data for explanatory variables was collected for the period January 1997 through January 2008. The recorded use per customer data was adjusted by adding back the kWh impacts of DSM program measures verified and installed through January 2008. HECO then evaluated numerous hypothetical relationships between use per customer and explanatory variables from this database.

For 2009, the growth rate above 2008 was estimated using the long-term annual residential use econometric equation. The equation was specified in a similar way to the short-term equation except that the annual average billed use per residential customer in kWh was used. The billed use per customer data was adjusted by adding back the DSM impacts installed through 2007.

The residential use per customer econometric equation is discussed in further detail later in my testimony.

Q. How were the commercial econometric equations developed?

A. Similar to the residential equations, for the short-term commercial sales econometric equation, recorded monthly kWh sales, weather, economic and other data were collected for the period January 1997 through January 2008. The recorded sales data was adjusted by adding back DSM kWh impacts verified and installed through January 2008. HECO then evaluated numerous hypothetical relationships between total commercial sales and explanatory variables from this database.

For 2009, the growth rate above 2008 was estimated using the long-term annual commercial sales econometric equation. The equation was specified in a similar way to the short-term equation except that it was based on annual average billed sales. The billed sales were adjusted by adding back the DSM impacts installed through 2007.

The commercial sales econometric equation is discussed in further detail later in my testimony.

Q. How were the econometric equations evaluated?

A. The specification and evaluation of the hypothetical relationships was performed using a proprietary software package, EViews. EViews is a linear regression package, which allows HECO to conduct analyses 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 econometric analyses of sales?

A. As mentioned above, HECO accounted for weather by using weather conditions as explanatory variables in the econometric models. Several weather variables were examined in testing various hypothetical models in the past, including average wet bulb and dry bulb temperatures, heat index, and rainfall.

For 2009, average weather is used in the forecast models, since there is no compelling reason to believe 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, average wet bulb temperature and cooling degree days ("CDD") were identified as the variables with the best explanatory powers. The forecast assumes average wet bulb temperature and CDD derived from monthly averages for 1997 – 2007 and 1978 – 2007, respectively.

Q. Why was the data period January 1997 through January 2008 chosen for the development of the short-term 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. January 2008 represents the last month of data that was available at the time the forecast models were developed.

Q. Why was the data period 1976 – 2007 chosen for the development of the annual long-term econometric equation?

A. The weather station in Honolulu was moved to the Honolulu International Airport from the old Federal Post Office building in downtown Honolulu in 1975. The first full year of consistent weather data, particularly CDD, was compiled in 1976. Average wet bulb temperature was not used as an explanatory variable in the long-term econometric equations because it was not reported by NOAA on a monthly basis until 1997. In addition, because the average annual values have very little variability, the explanatory power of wet bulb temperatures is not very high in an annual model.

Q. Why was the average for wet bulb temperature determined over 1997 – 2007 and the 1978 – 2007 average used for CDD?

A. Monthly wet bulb temperatures were only reported by NOAA from 1997 and 2007 was the last full year of data available. CDD data is available back to 1976, but a 30-year moving average is being used for forecast purposes to be somewhat consistent with NOAA conventions. NOAA uses station "normal" CDD for reporting comparisons based on a three decade average, with the current "normal" CDD calculated over 1971 – 2000. In order to capture the more recent weather

trends, HECO is using a 30-year moving average that maintains the same number of years in the average but captures the years after 2000 in the average.

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. That is, 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-202, pages 1 - 2 and HECO-WP-203, pages 1 - 2) 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 were the results of the forecast model applied?

A. The growth rates from the econometric model results were applied to forecasted 2008 residential use and commercial sales in order to project 2009 use and sales (as shown in HECO-WP-205, page 3 and HECO-WP-206, page 3). Adjustments were also made to the sales forecast to reflect customer-specific project impacts, PV and NEM impacts, and DSM kWh impacts.

Q. What are the customer-specific project impacts in the forecast?

A. The customer-specific project impacts in the forecast are primarily from large construction projects, business closures, and other 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 new timeshare project or the closure of a hotel for renovations. 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 and business closures developed?

A. New large construction projects and business closures 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 impacts of large known customer projects are subtracted from the forecast prior to allocating the sales to rate schedules. Once the allocation factor is 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 recent historical trends and anticipated customer rate schedule transfers. The result is a sales estimate by rate schedule based on the results from the econometric analysis adjusted by the estimated impact on sales of large customer projects.

Q. What DSM programs were included in the 2009 sales estimates?

A. The 2009 sales estimates were adjusted for the future impact of DSM programs ("future DSM"). The estimate of future DSM includes savings from DSM measures installed in 2008 and 2009. The impact of DSM measures installed prior to 2008 ("acquired DSM") was already included in the sales estimates. Future DSM impacts on sales and the transition of the implementation of utility DSM programs to a third party administrator is discussed further by Mr. Hee in HECO T-10.

Q. What was the impact of including future DSM in the 2009 sales estimate?

A. The inclusion of future DSM reduced electricity sales.

<u>2009 Sales Estimates by Rate Schedule</u>

Q. How were the estimated 2009 sales and number of customers by rate schedule derived?

A. The estimated residential and commercial 2009 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 2009 estimates for <u>Schedule R – Residential Service</u> sales and number of customers?

A. The 2009 estimate for Schedule R sales is 2,088.4 GWh and the projected number of customers is 261,899, as shown in HECO-201. The sales projected for this schedule represent a decrease of 0.9% in 2008 below recorded 2007 sales, and a further 1.2% decrease in 2009 below expected 2008 sales of 2,114.7 GWh (see HECO-WP-201, page 15). Residential customers are projected to grow by 0.4% in both 2008 and 2009, as shown in HECO-WP-201, page 37.

Q. How was this sales estimate developed?

A. The 2009 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 2009 estimate of use per customer derived?

A. As discussed earlier, the estimate of residential use per customer is derived from a short-term monthly forecast for 2008, and then projected using the year-over-year percent rate of change from the long-term annual forecast model for 2009, both of which were developed by HECO.

Q. What is the specific form of the residential econometric models for use per customer?

A. The specification for the residential use per customer econometric equations is shown in HECO-202.

The short-term monthly econometric model describes residential electricity use per customer as a function of humidity, electricity price, month-to-month seasonal factors, a time trend, and lagged dependent variable terms (see HECO-202 and HECO-WP-202, page 1). In the short-term, humidity as measured by average wet bulb temperature was found to have a relationship with residential use per customer. The recent changes in residential electricity price was also found to have a relationship with residential use per customer. A time trend variable was included to represent the underlying growth trend in residential use per customer. The lagged dependent variables (similar in function to an autoregressive parameter) strengthen the statistical robustness of the model, as does the monthly dummy variable.

The long-term annual econometric model describes residential electricity use per customer as a function of temperature, electricity price, personal income, and a lagged dependent variable term (see HECO-202 and HECO-WP-202, page 2). In the long-term annual model, temperature as measured by annual cooling degree days was found to have a relationship with residential use per customer. Residential electricity price was again found to have a relationship with residential use per customer. Personal income is included in the equation to represent the impact of general economic conditions on use per customer. And as discussed earlier, the lagged dependent variable term strengthens the statistical robustness of the model.

The dependent and independent variables and forecast assumptions for the independent variables used in the short-term and long-term use per customer econometric equations are shown in HECO-204.

Q. What is the estimated change in use per customer for 2009?

A. The annual average residential use per customer is expected to decrease 1.3% to 8,106 kWh per year in 2008 below 2007, and another 1.6% in 2009 below 2008 to 7,974 kWh per year (see HECO-205 and HECO-WP-201, page 37).

Q. How was the 2009 estimate of the number of customers developed?

A. The number of residential customers was derived using an additive linear trend time series model based on historical residential customer data from January 1980 through April 2006, adjusted for any unusual or out of trend events, such as the Kukui Gardens conversion to Schedule R beginning in 2005 and the addition of customers from the 215 N. King Street condominium beginning in January 2006.

Q. What is the 2009 estimate for the number of Schedule R customers?

A. The estimated 2009 average number of customers is 261,899, an increase of 0.4% over the 2008 average estimate of 260,881. The historical and projected average number of residential customers are shown in HECO-205 and HECO-WP-201, page 37.

Q. What is the resulting 2009 sales estimate for Schedule R?

A. The 2009 Schedule R sales estimate is 2,088.4 GWh, including future DSM, as shown in HECO-205. As discussed earlier, this figure is the result of multiplying the expected Schedule R use per customer of 7,974 kWh per year and the expected number of customers of 261,899.

Q. Why are the 2009 Schedule R estimates reasonable?

A. The Schedule R 2009 estimates are reasonable because they are consistent with the economic outlook for Oahu and with recent historical trends.

In the early part of this decade, HECO saw residential customer growth in the range of about 2,500 per year. As the economy slowed, and the housing market cooled, that number began to decline in 2006, and in 2007 decreased to about 1,100 new residential customer additions per year. A similar level of reduced activity has been seen in the first quarter of 2008 (see HECO-WP-201, page 30). The 2009 estimated average rate of customer growth of about 0.4% is similar to the growth rates seen since the end of 2006. With credit markets in crisis and growing concerns about the local economy, there is no reason to expect higher levels of residential construction activity.

Residential use per customer has dropped steadily since 2004, as shown in HECO-205. Higher electricity prices have almost certainly contributed to this reduction, with customers adopting more energy efficient equipment and

behaviors. For 2009, the main driver of this anticipated decline in use is the assumed higher electricity prices. Rising inflation rates, high housing prices, and projected slow growth in personal income are likely to further erode customers' disposable income. Substantial and rising awareness of the political, economic, and global climate impacts surrounding energy issues are also almost certain to further restrict residential electricity consumption.

Projected 2008 residential sales of 2,114.7 GWh are 0.9% below recorded 2007, as shown in HECO-WP-201, page 37. This is reasonable in light of to the year-to-date April 2008 residential sales decline of 0.7% below recorded sales for the same period in 2007 (see HECO-213). Schedule R 2009 sales are projected to be 1.2% below estimated 2008 sales, as shown in HECO-WP-201, page 37. As shown in HECO-205, Schedule R use per customer has decreased every year since 2004. The forecasted 2009 Schedule R sales decrease is reasonable relative to this trend and the expectation of slower growth in the number of customers than has been seen in the recent past, rising cost of living, and the expectation of a weaker local economy in 2009, particularly the impact of inflation on personal income growth.

Q. What are the 2009 estimates for <u>total commercial sales</u>?

A. The 2009 estimate for commercial sales (Schedules G, J, H, and P) is 5,531.9 GWh as shown in HECO-201. The sales projected for this sector are expected to increase by 0.4% in 2008 over recorded 2007, and by another 0.1% in 2009 over 2008 (see HECO-WP-201, page 15).

Q. How was the commercial sales estimate developed?

A. The 2009 estimate for commercial sales was derived from the results of a short-term monthly econometric equation for 2008, and then projected to 2009 using the

growth rate from a long-term annual econometric equation adjusted for customer-specific project impacts. Future DSM impacts were then applied to the result.

Q. What is the specific form of the econometric model for commercial rate classes?

A. The specification for the commercial sales econometric equations is shown in HECO-203.

The short-term monthly econometric model describes commercial sales as a function of temperature, humidity, non-agricultural job count ("non-ag jobs"), a time trend, 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 time trend was included to represent the underlying growth trend in commercial electricity consumption. The lagged dependent variables strengthen the statistical robustness of the model, as do the dummy variables for specific months.

The long-term annual econometric model describes commercial sales as a function of temperature, electricity price, non-ag job count, a lagged dependent variable term, and a dummy variable for 1996 and beyond. In the long-term, temperature (CDD) and non-ag jobs were again found to have a relationship with commercial sales. Commercial electricity price was also found to have a relationship with commercial electricity use. The lagged dependent variable strengthened the statistical robustness of the model, as does the dummy variable, which indicates a shift in the relationship between sales and economic conditions that occurred around 1996.

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-204.

Q. How was the 2009 estimate of the number of commercial customers developed?

A. The number of commercial customers was derived at a rate schedule level using time series models. Schedules P was based on 1980 – 2007 data, and Schedules G, J, and H were derived from 1986 – 2007 data. In rate schedules G, J, and P, the results 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, the results from an additive exponential trend model were used.

Q. For 2009, how were the forecasts of sales for individual commercial rate schedules developed?

A. As discussed earlier, a rate schedule allocation factor was applied to the total commercial sales estimates. The rate schedule allocation factors used to derive 2009 estimates were based on projected sales by rate schedule from additive exponential trend time series models (see HECO-WP-212, page 7). Once the allocation factor is applied, the projected impacts from large customer specific projects 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 recent historical trends and anticipated customer rate schedule transfers. The result is a sales estimate by rate schedule.

Q. What are the 2009 estimates for <u>Schedule G – General Service (Non-demand)</u> sales and number of customers?

A. The 2009 sales estimate for Schedule G is 383.1 GWh and the estimated average number of customers is 26,277, as shown in HECO-207. The Schedule G sales

are projected to increase 0.8% in 2008 over recorded 2007, and an additional 0.7% in 2009 over estimated 2008 sales of 380.3 GWh. Customers are projected to grow by 0.8% and 1.0% in 2008 and 2009, respectively.

Q. What are the 2009 estimates for Schedule J – General Service (Demand) sales and number of customers?

A. The 2009 sales estimate is 2,086.1 GWh and the estimated average number of customers is 6,707, as shown in HECO-208. The sales in this schedule are projected to increase 0.7% in 2008 over recorded 2007 sales, and then increase 0.8% in 2009 over 2008. Customers are projected to grow by 0.4% in both 2008 and 2009.

Q. What are the 2009 estimates for Schedule H – Commercial Cooking, Air Conditioning, Heating and Refrigeration Service sales and number of customers?

A. The 2009 sales estimate is 33.7 GWh and the estimated average number of customers is 533, as shown in HECO-209. The sales projected for Schedule H represents a decrease of 10.6% in 2008 below recorded 2007 sales, and another decrease of 13.1% in 2009 below 2008. Customers are projected to decrease by 14.9% and 15.0% in 2008 and 2009, respectively. Schedule H sales and customers have decreased steadily since the 1990's. As Mr. Young discusses in HECO T-22, the Company is proposing to eliminate Schedule H in this rate application and move Schedule H customers to other rate schedules as appropriate.

Q. What are the 2009 estimates of sales and number of customers for Schedule P – Large Power Service?

A. The 2009 estimate of sales is 3,029.0 GWh, and the estimated average number of customers is 353, as shown in HECO-210. The sales projected for Schedule P

represents an increase of 0.3% in 2008 over recorded 2007 sales and a decrease of 0.2% in 2009 below 2008. The number of customers is expected to remain relatively stable at 352 in 2008 and 353 in 2009.

Q. Please summarize your testimony on total commercial sales (Schedules G, J, H, and P) for test year 2009.

A. The 2009 estimate for total commercial sales (Schedules G, J, H, and P) is 5,531.9 GWh as shown in HECO-201. This estimate was derived from short-term and long-term econometric equations adjusted for customer-specific project impacts and future DSM impacts. An allocation factor was applied to the total commercial sales estimates to derive rate schedule level forecasts. The number of commercial customers was derived at a rate schedule level using time series models.

Q. Why are the 2009 estimates for the commercial sector reasonable?

A. The 2009 estimates for the commercial sector are reasonable because they are consistent with the economic outlook for Oahu and with recent historical trends.

The economy is projected to continue slowing, and these economic conditions will temper growth in commercial sales. High inflation and slow job growth are likely to impact discretionary spending which in turn will impact commercial activity. The weak national economy threatens to have significant negative impacts on Hawaii's visitor industry. High construction labor and materials costs and a more constrained credit environment may also restrict development of new housing and commercial construction activity.

Higher electricity prices are also likely to have an affect on sales to commercial customers. While commercial customers have less flexibility in responding to higher electricity prices, many commercial customers continue to make energy conservation efforts a higher priority in order to stay within limited

operating budgets. Companies and government entities are instituting energy conservation efforts such as turning off lights and air conditioning when facilities are not occupied.

Projected 2008 commercial sales of 5,524.3 GWh are 0.4% above recorded 2007 (see HECO-WP-212, page 2). This is reasonable relative to the year-to-date April 2008 commercial sales increase of 0.8% (which includes an extra day for leap year) over recorded sales for the same period in 2007 (see HECO-213). Commercial sales in 2009 are projected to be 0.1% above estimated 2008 sales (2008 sales include one extra day of sales due to the leap year). This modest commercial sales increase is reasonable relative to recent sales trends as shown in HECO-206 and the expectation of continued slowing in economic conditions.

Q. What are the 2009 estimates of sales and number of customers for Schedule F – Street Lighting?

A. The 2009 sales estimate is 37.5 GWh, and the estimated 2009 average number of customers is 441, as shown in HECO-211.

Q. How was the sales estimate for Schedule F developed?

A. Schedule F sales are expected to remain flat over the 2008 – 2009 time period, with a slight adjustment for the effect of leap year in 2008. That is, 2008 and 2009 recorded sales for Schedule F are expected to remain at the same level as 2007 Schedule F sales, with an adjustment for leap year in 2008. Schedule F sales have been relatively stable over time, are less sensitive to changes in economic drivers than sales in other rate schedules, and represent less than 0.5% of HECO's sales. Consequently, no attempt was made to develop an econometric approach to forecasting Schedule F sales.

Q. How was the estimate of number of customers for Schedule F developed?

A. In developing the Schedule F number of customers forecast a number of time series models based on 1980 – 2007 data were examined. However, the results of all of the various models showed unrealistically large decreases in the number of Schedule F customers in 2008 before resuming growth. This may have been caused by anomalous monthly data in 2007. Projections were derived instead by assuming a stable number of customers in 2008 followed by forecast increases using the growth rate from an additive linear trend model in 2009.

Q. What are the 2009 estimates for total HECO sales and customers?

A. HECO sales are projected to be 7657.8 GWh in 2009, as shown in HECO-212. Sales are expected to see no change in 2008 as compared to 2007, and then decline slightly by 0.2% in 2009.

The average HECO customer count is expected to be 296,210 in 2009, as also shown in HECO-212. The number of customers is expected to grow by 0.4% in both 2008 and 2009.

<u>Sales Forecast Accuracy</u>

Q. How accurate have past sales forecasts been?

A. In recent forecasts, HECO has consistently overstated expected sales levels. The variances, shown in HECO-214, between recorded 2007 sales and the forecasts developed in 2004, 2005, and 2006 reflect this trend towards overly optimistic sales expectations. Prior to 2005, HECO experienced relatively strong total recorded sales growth for several years. For the period beginning in 2000 and continuing through 2004, HECO's total sales growth averaged 2% per year.

HECO's sales forecasts anticipated that growth would continue, although perhaps at a slower pace in later years.

Instead, total HECO sales have declined each year since 2004. The Company's 2007 recorded sales are at their lowest level since 2003. Further, these year-over-year declines in 2005, 2006, and 2007 occurred during a period of relatively strong economic activity. This decline in sales for three consecutive years is unprecedented in HECO's historical sales data, and was not anticipated in recent sales forecasting efforts. As a result, the forecasts shown in HECO-214 overstated actual 2007 recorded sales by 4.3% on average.

HECO has taken steps to improve its forecast methodology. In particular, the adoption of short-term econometric models was in part driven by a need to be more reactive to rapidly changing current trends and events. HECO believes that the test year forecast of sales and customers is a reasonable projection, taking into account what was known at the time of the forecast. However, given the recent bias towards overstating future sales, the observed unprecedented downward trend in sales, and the current and emerging economic conditions, the possibility remains that the 2009 forecast may be overstated.

SUMMARY

Q. Please summarize your testimony on the test year 2009 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 2009 is based on an update to the annual sales forecast, which was developed through a comprehensive process

involving expert and internal review. The update was built on the methodological foundation of the annual forecast, incorporating the latest available information. As such, it provides a sound and reasonable look at expected sales and customers in 2009.

The 2009 forecasts of sales of 7,657.8 GWh and 296,210 customers are reasonable for ratemaking purposes because they reflect the economic outlook for Oahu, the inclusion of estimated customer specific projects, and recent historical trends.

Q. Does this conclude your testimony?

A. Yes, it does.

Hawaiian Electric Company, Inc.

George A. Willoughby

EDUCATIONAL BACKGROUND AND EXPERIENCE

Business Address:	Hawaiian Electric Company, Inc. 220 South King Street Honolulu, HI 96813
Position:	Director, Forecasts and Research Division
Education:	Ph.D. Social Psychology Northwestern University, 1983 M.A. Experimental Psychology, 1979 Western Kentucky University, 1977
Previous Position:	Vice President, Market Research Hawaii Visitors Bureau Other professional positions with Hawaiian Tel, GTE, Barbara Sunderland and Associates, Research Marketing Systems, and Chicago Citywide Colleges
Other Testimony:	Docket No. 05-0145 – Sales and Peak Forecasts Docket No. 2006-0386 – Electricity Sales and Customer Forecasts

Hawaiian Electric Company, Inc.

TEST YEAR 2009 SALES AND CUSTOMERS

Rate Schedule	2009 Test Year Annual Sales (GWh)	2009 Test Year Average Monthly Number of Customers
R	2,088.4	261,899
G	383.1	26,277
J	2,086.1	6,707
H	33.7	533
P	3,029.0	353
F	37.5	441
Total	7,657.8	296,210
Commercial *	5,531.9	33,870

* Excluding Schedule F

Reference: HECO-WP-201, HECO-WP-212

Hawaiian Electric Co., Inc.

RESIDENTIAL USE PER CUSTOMER FORECAST MODELS

Models

- 2008 forecast: Short-term econometric model
- 2009 forecast: Long-term econometric model growth rate

Data

- 2008 forecast: Short-term econometric model
  - » Monthly recorded residential use per customer
- 2009 forecast: Long-term econometric model growth rate
  - » Annual billed residential use per customer

Dependent Variable

- Residential use per customer
  (kWh per customer)

Explanatory Variables

- 2008 forecast: Short-term econometric model
  - » Monthly wet bulb temperature
  - » Real electricity price (1992$, lagged 3 months)
  - » Lagged (6, 12) dependent variables
  - » Time trend
  - » Month (1) dummy variable

- 2009 forecast: Long-term econometric model growth rate
  - » Annual cooling degree days ("CDD")
  - » Real electricity price (1992$)
  - » Real personal income per capita (1992$)
  - » Lagged (1) dependent variable

Reference: HECO-WP-202

Hawaiian Electric Co., Inc.

COMMERCIAL SALES FORECAST MODELS

Models

- 2008 forecast: Short-term econometric model
- 2009 forecast: Long-term econometric model growth rate

Data

- 2008 forecast: Short-term econometric model
  - » Monthly recorded commercial sales (excluding Schedule F)
- 2009 forecast: Long-term econometric model growth rate
  - » Annual billed commercial sales (excluding Schedule F)

Dependent Variable

- Commercial sales (excluding Schedule F)

Explanatory Variables

- 2008 forecast: Short-term econometric model
  - » Monthly cooling degree days
  - » Monthly wet bulb temperature
  - » Honolulu non-farm jobs (lagged 1 month)
  - » Lagged (1, 4, 12) dependent variables
  - » Time trend
  - » Month (2, 8, 10) dummy variables

- 2009 forecast: Long-term econometric model growth rate
  - » Annual cooling degree days
  - » Real electricity price (1992$)
  - » Honolulu non-farm jobs
  - » Lagged (1) dependent variable
  - » 1996 and thereafter dummy variable

Reference: HECO-WP-203

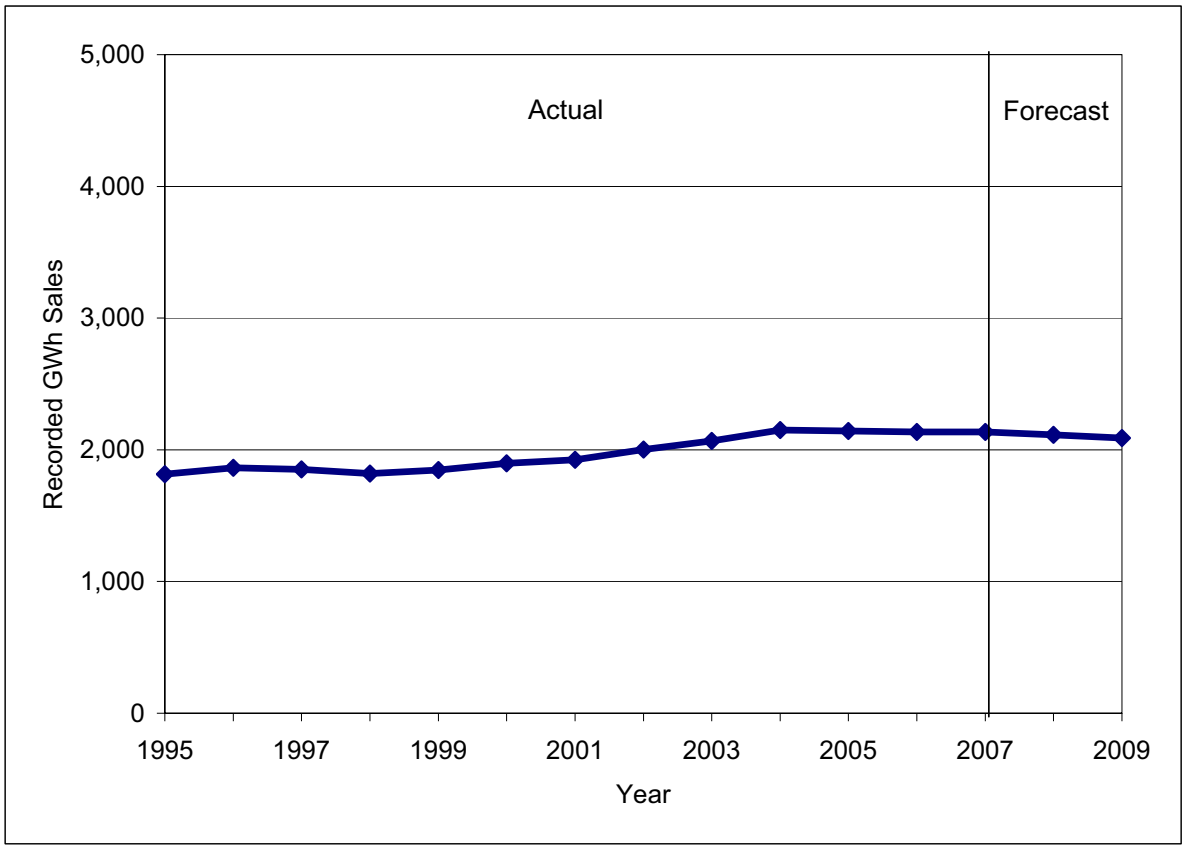
Hawaiian Electric Co., Inc.

FORECAST ASSUMPTIONS

	2007	2008	**2009**	Test Year 2009 Forecast Assumption
Explanatory Variables				
Cooling Degree Days (CDD)	4835	4750	**4750**	Annual, 1978 - 2007 Average by Month
Wet Bulb Temperature	68.9	69.8	**69.8**	Average (by month) annual 1997 - 2007 (used in 2008 short-term models)
Electricity Price				
Nominal (¢/kWh)				February 2008 update of March 2007 electricity price forecast using February 2008 LSFO inventory price. Derived growth rates for 2008-0 applied to 2007 actual billed prices.
Residential	20.37	23.67	**25.23**	
Commercial	16.91	19.65	**20.94**	
Real (¢/kWh) - Res	14.40	16.14	**16.65**	Base year 1992 dollars
Real (¢/kWh) - Comm	11.96	13.40	**13.82**	(1992 CPI-U=155.2)
CPI-U Honolulu	219.5	227.6	**235.2**	March 2007 UHERO Forecast (1982-84 $)
LSFO (nominal $/BBL)	61.73	89.60	**92.59**	February 2008 LSFO inventory price for 2008, 2009 is 2008 price with inflation
Personal Income Per Capita				
Real ($000)	29.5	28.9	**29.1**	UHERO March 2007 personal income, CPI-U and resident population forecasts
Non-Farm Jobs (Honolulu)	460.9	460.9	**464.5**	2008 assumed no growth over 2007 actual as reported in January 2008 with UHERO March 2007 forecast growth rate applied thereafter
Dependent Variables				
Residential Use Per Customer				(Residential kWh with 1996 - 2007 installed DSM added back) ÷ average no. of residential customers
2008 forecast (short-term model)				Recorded monthly data, Jan 1997 - Jan 2008
2009 forecast (long-term model)				Billed annual data, 1976 - 2007
Commercial Sales				Commercial kWh sales with 1996 - 2007 installed DSM added back
2008 forecast (short-term model)				Recorded monthly data, Jan 1997 - Jan 2008
2009 forecast (long-term model)				Billed annual data, 1976 - 2007

Reference: HECO-WP-204

Hawaiian Electric Company, Inc.
SCHEDULE R - RESIDENTIAL SERVICE

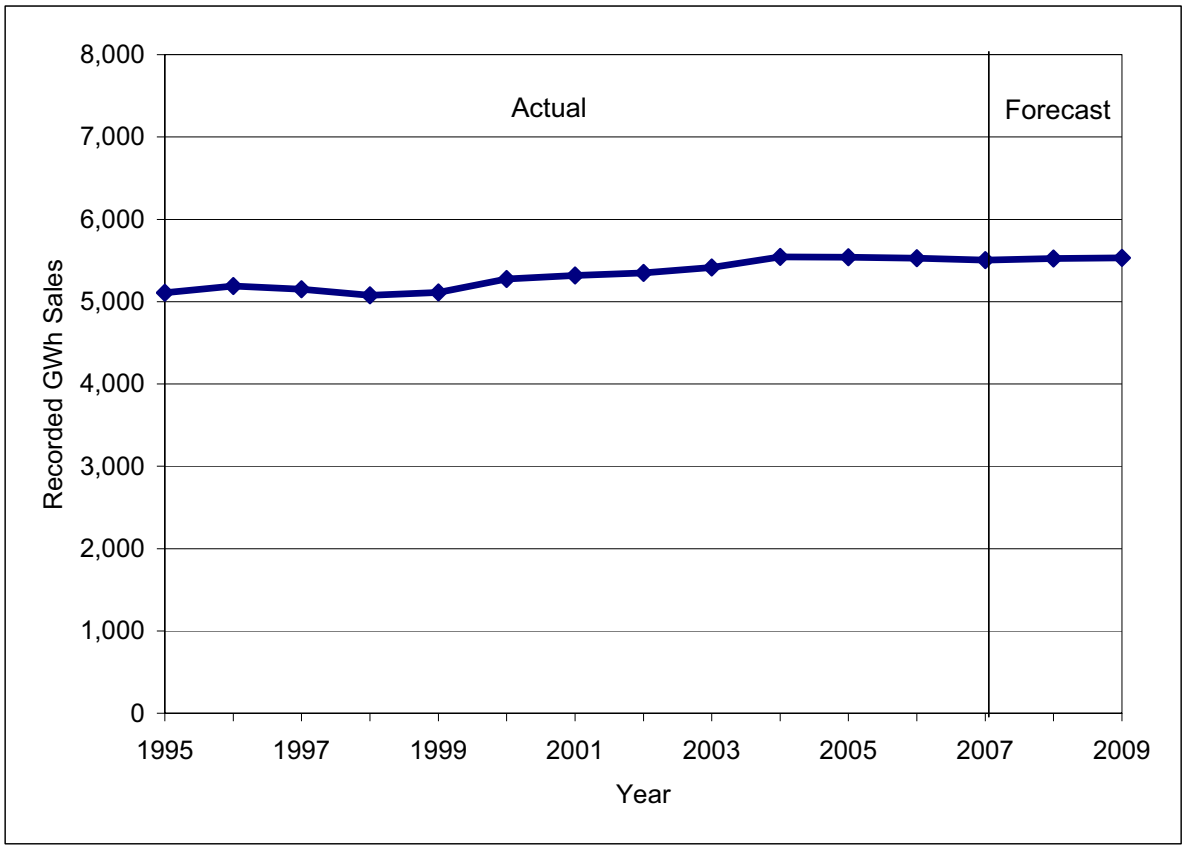


	Year	Recorded GWh Sales *	Customers	Use Per Customer
Recorded	1995	1,815.7	234,832	7,732
	1996	1,863.4	236,849	7,867
	1997	1,852.2	238,269	7,774
	1998	1,820.8	239,487	7,603
	1999	1,846.0	241,167	7,654
	2000	1,897.7	243,511	7,793
	2001	1,924.4	246,226	7,816
	2002	2,002.7	248,765	8,051
	2003	2,066.5	251,248	8,225
	2004	2,151.3	253,670	8,481
	2005	2,142.5	256,269	8,360
	2006	2,134.4	258,793	8,248
	2007	2,134.5	259,860	8,214
Forecast	2008	2,114.7	260,881	8,106
	2009	2,088.4	261,899	7,974

* 1995-2007 are recorded sales. 2008-2009 are forecasted sales assuming average weather.

Reference: HECO-WP-205

Hawaiian Electric Company, Inc.
TOTAL COMMERCIAL

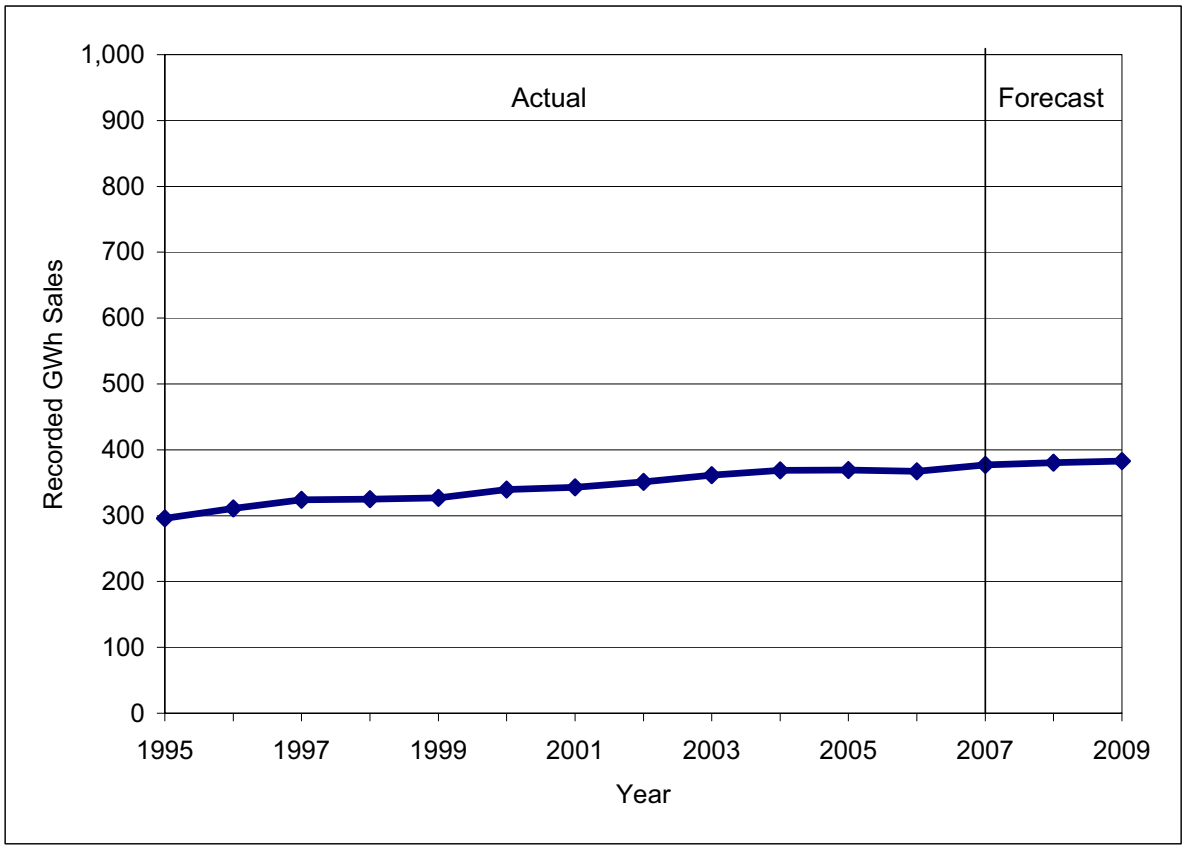


	Year	Recorded GWh Sales *	Customers
Recorded	1995	5,107.4	33,053
	1996	5,188.0	33,093
	1997	5,149.2	32,782
	1998	5,078.7	32,469
	1999	5,113.4	32,447
	2000	5,276.2	32,526
	2001	5,315.9	32,890
	2002	5,349.9	32,724
	2003	5,416.5	32,890
	2004	5,543.9	33,180
	2005	5,541.0	33,356
	2006	5,528.7	33,383
	2007	5,503.4	33,550
Forecast	2008	5,524.3	33,660
	2009	5,531.9	33,870

* 1995-2007 are recorded sales. 2008-2009 are forecasted sales assuming average weather.

Reference: HECO-WP-206

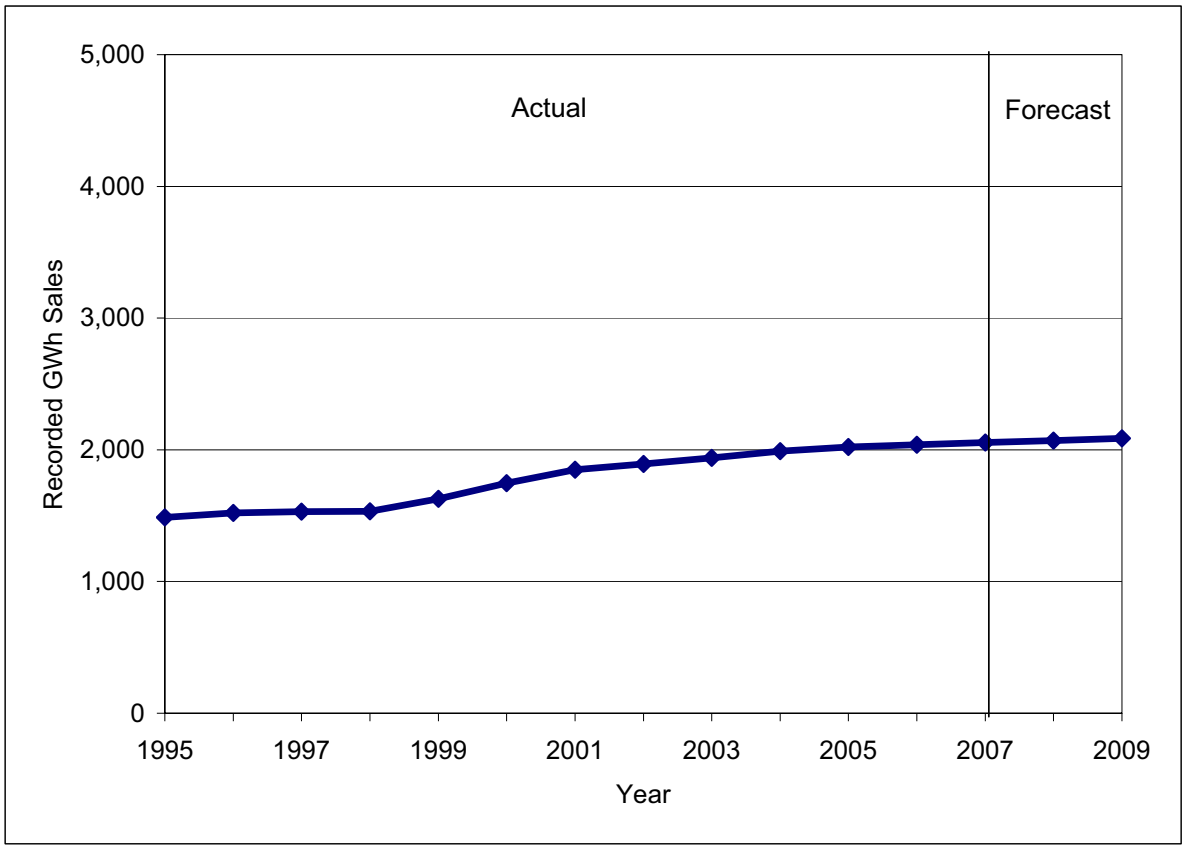
Hawaiian Electric Company, Inc.
SCHEDULE G - GENERAL SERVICE



	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
	2006	367.5	25,590
	2007	377.2	25,806
Forecast	2008	380.3	26,004
	2009	383.1	26,277

* 1995-2007 are recorded sales. 2008-2009 are forecasted sales assuming average weather.

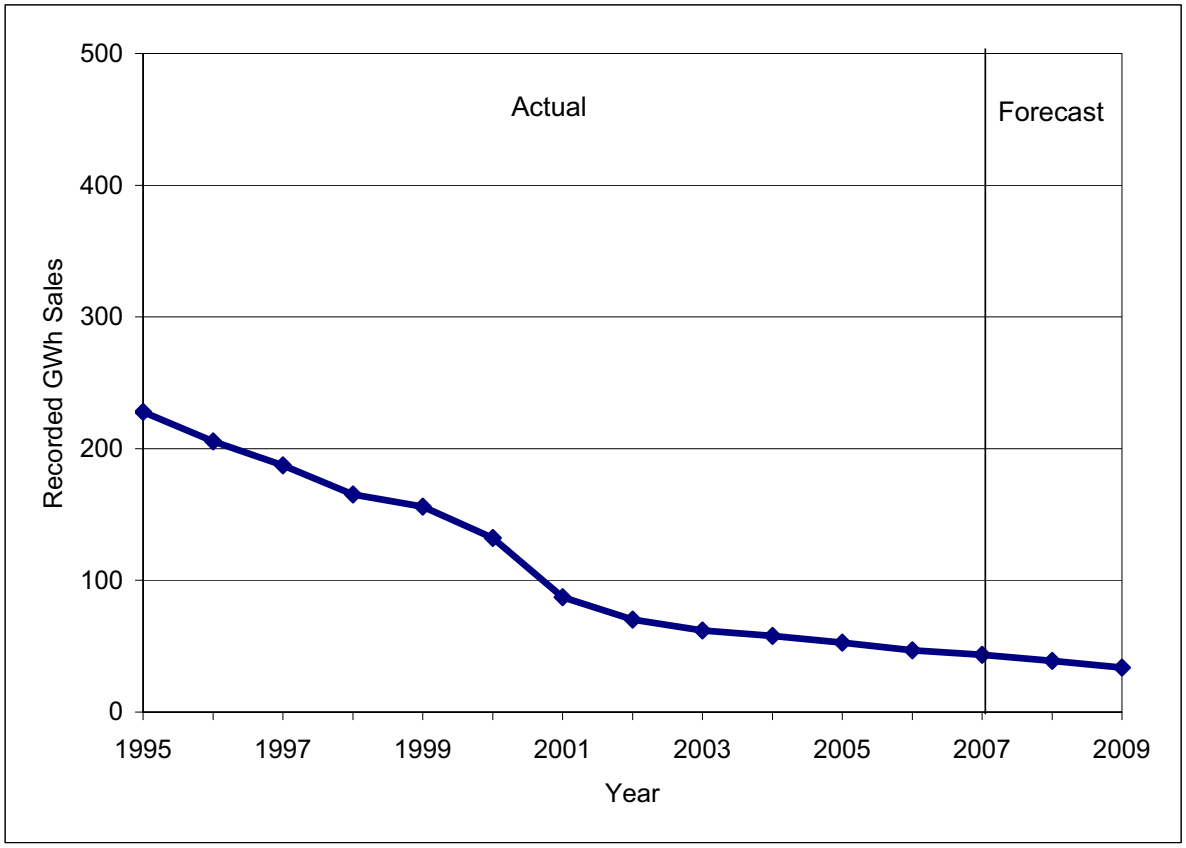
Hawaiian Electric Company, Inc.
SCHEDULE J - GENERAL SERVICE DEMAND



	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	2,020.6	6,536
	2006	2,039.4	6,620
	2007	2,054.8	6,653
Forecast	2008	2,069.4	6,677
	2009	2,086.1	6,707

* 1995-2007 are recorded sales. 2008-2009 are forecasted sales assuming average weather.

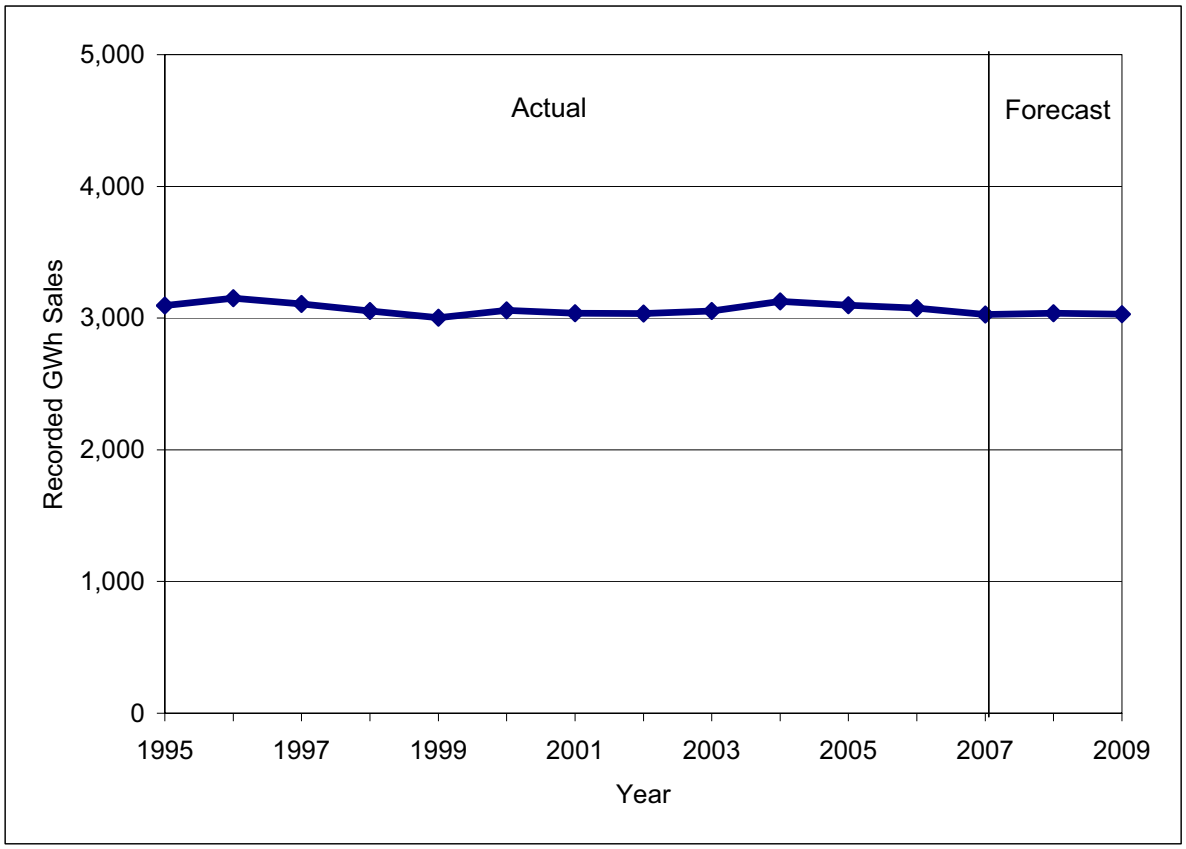
Hawaiian Electric Company, Inc.
SCHEDULE H - COMMERCIAL COOKING, AIR CONDITIONING, HEATING, AND REFRIGERATION SERVICE



	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
	2006	46.9	818
	2007	43.4	737
Forecast	2008	38.8	627
	2009	33.7	533

* 1995-2007 are recorded sales. 2008-2009 are forecasted sales assuming average weather.

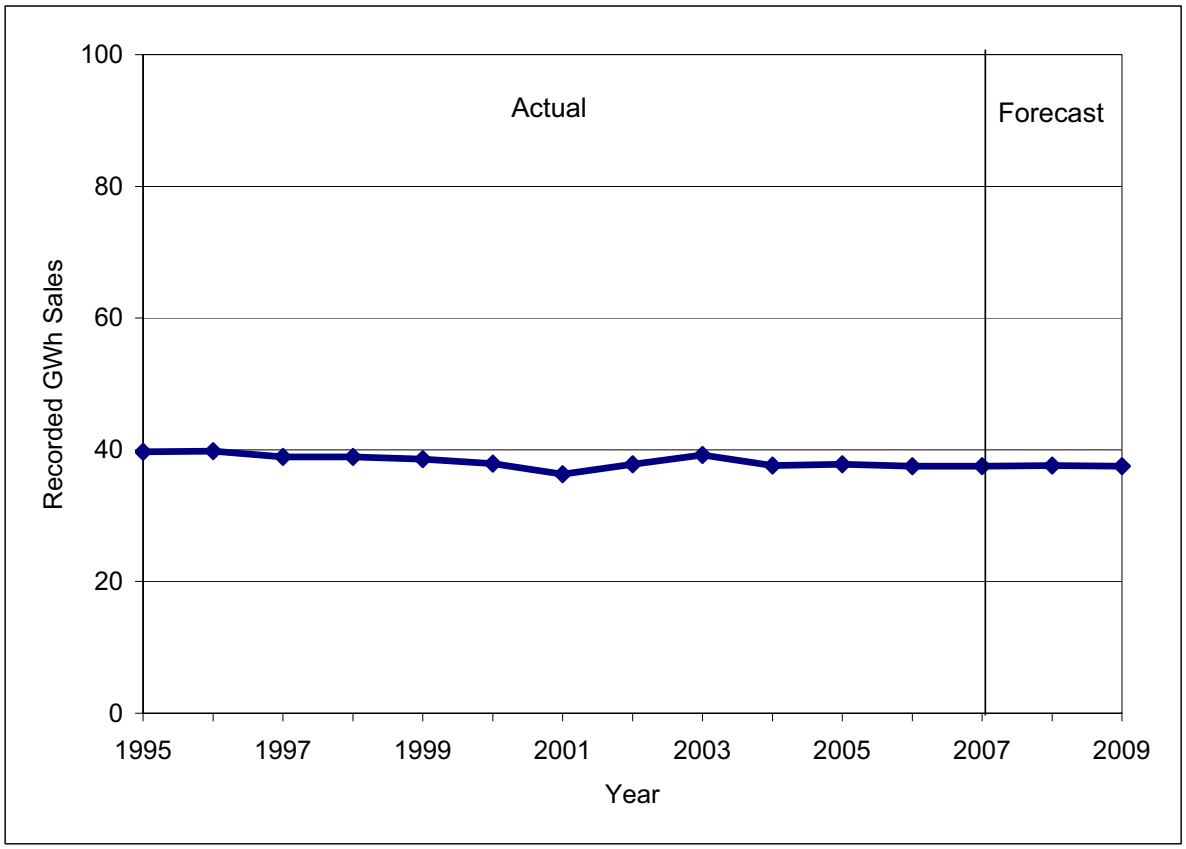
Hawaiian Electric Company, Inc.
SCHEDULE P - LARGE POWER SERVICE



	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
	2006	3,074.8	355
	2007	3,028.0	354
Forecast	2008	3,035.8	352
	2009	3,029.0	353

* 1995-2007 are recorded sales. 2008-2009 are forecasted sales assuming average weather.

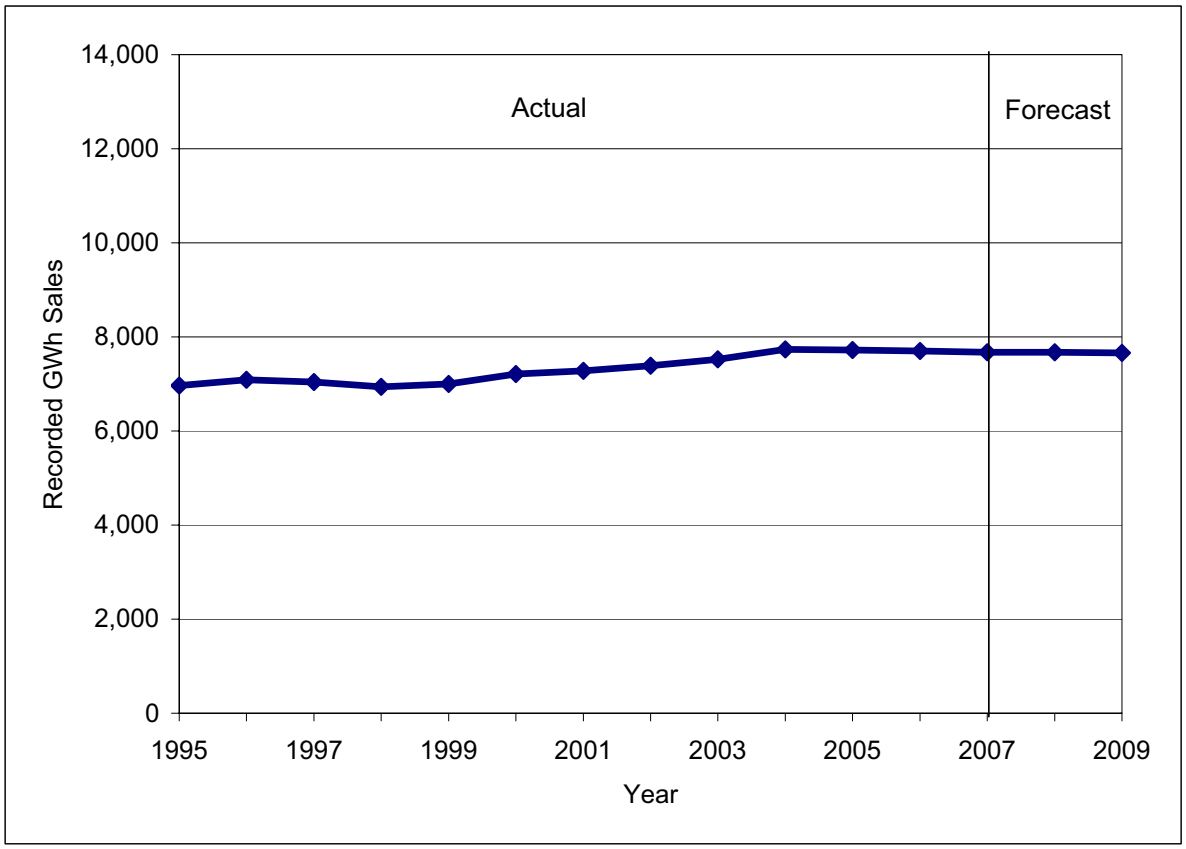
Hawaiian Electric Company, Inc.
SCHEDULE F - STREET LIGHTING



	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
	2006	37.5	439
	2007	37.5	437
Forecast	2008	37.6	437
	2009	37.5	441

* 1995-2007 are recorded sales. 2008-2009 are forecasted sales assuming average weather.

Hawaiian Electric Company, Inc.
TOTAL SYSTEM SALES



	Year	Recorded GWh Sales *	Customers
Recorded	1995	6,962.8	268,225
	1996	7,091.2	270,294
	1997	7,040.3	271,410
	1998	6,938.4	272,315
	1999	6,998.0	273,967
	2000	7,211.8	276,393
	2001	7,276.6	279,482
	2002	7,390.4	281,871
	2003	7,522.2	284,530
	2004	7,732.8	287,257
	2005	7,721.3	290,038
	2006	7,700.6	292,615
	2007	7,675.4	293,847
Forecast	2008	7,676.6	294,978
	2009	7,657.8	296,210

* 1995-2007 are recorded sales. 2008-2009 are forecasted sales assuming average weather.

Reference: HECO-WP-212

Hawaiian Electric Company, Inc.

COMPARISON OF 2008 VS. 2007
APRIL YEAR-TO-DATE
Recorded GWh Sales

Schedule	Apr YTD 2008	Apr YTD 2007	Diff	% Diff
R	668.0	672.5	(4.5)	-0.7%
G	118.2	118.0	0.3	0.2%
J	651.9	640.1	11.8	1.8%
H	12.3	14.2	(1.9)	-13.5%
P	956.8	952.9	3.9	0.4%
F	12.8	12.5	0.3	2.5%
Total	2,420.0	2,410.1	9.9	0.4%
Commercial *	1,739.2	1,725.2	14.1	0.8%

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 not foot due to rounding.

Hawaiian Electric Company, Inc.

COMPARISON OF 2007 SALES TO FORECAST

Rate Schedule	2007 Recorded	June 2004 Update			May 2005 Forecast			August 2006 Forecast		
		2007 Forecast	Recorded - Fcst Diff		2007 Forecast	Recorded - Fcst Diff		2007 Forecast	Recorded - Fcst Diff	
			GWh	%		GWh	%		GWh	%
R	2,134.5	2,167.7	-33.2	-1.5%	2,228.6	-94.1	-4.2%	2,128.9	5.6	0.3%
G	377.2	395.5	-18.3	-4.6%	376.6	0.6	0.2%	371.8	5.4	1.5%
J	2,054.8	2,124.9	-70.1	-3.3%	2,090.7	-35.9	-1.7%	2,068.8	-14.0	-0.7%
H	43.4	54.2	-10.8	-19.9%	53.0	-9.6	-18.1%	40.5	2.9	7.2%
P	3,028.0	3,373.0	-345.0	-10.2%	3,401.7	-373.7	-11.0%	3,073.0	-45.0	-1.5%
F	37.5	41.5	-4.0	-9.6%	37.6	-0.1	-0.3%	37.8	-0.3	-0.8%
Total	7,675.4	8,156.8	-481.4	-5.9%	8,188.2	-512.8	-6.3%	7,720.8	-45.4	-0.6%