BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF HAWAII

In the Matter of the Application of	)	
	)	
HAWAII ELECTRIC LIGHT COMPANY, INC.	)	Docket No. 05-0315
	)	
For Approval of Rate Increases and Revised Rate Schedules and Rules.	)	
	)	

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HELCO

REBUTTAL TESTIMONIES AND EXHIBITS

BOOK 1 OF 2

March 27, 2007

Hawaii Electric Light Company, Inc.

Docket No. 05-0315
Application for Approval of Rate Increases and
Revised Rate Schedules and Rules

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HELCO RT-23	J. D. Makholm
	This witness has no rebuttal testimony or exhibits

HELCO RT-24	G. Meehan
	This witness has no rebuttal testimony or exhibits

HELCO RT-1
DOCKET NO. 05-0315

REBUTTAL TESTIMONY OF
WARREN H. W. LEE

PRESIDENT

HAWAII ELECTRIC LIGHT COMPANY, INC.

Subject: Introductory Statement
Policy Matters

1 INTRODUCTION

2 Q. Please state your name and business address.

3 A. My name is Warren H. W. Lee and my business address is 1200 Kilauea
4 Avenue, Hilo, Hawaii.

5 Q. Have you previously submitted testimony in this proceeding?

6 A. Yes. I submitted written direct testimony in HELCO T-1 and HELCO T-21.

7 Q. What is the scope of your rebuttal testimony in HELCO RT-1?

8 A. My rebuttal testimony in HELCO RT-1 summarizes:

9 1) Hawaii Electric Light Company, Inc.'s ("HELCO" or "Company") rebuttal
10 position in this proceeding;

11 2) Implementation of HELCO's proposed rate increase;

12 3) Results of settlement discussions between HELCO and the Division of
13 Consumer Advocacy ("Consumer Advocate"); and

14 4) The major issues between HELCO and the other party and participant in
15 this proceeding.

16 Q. Did HELCO present a statement at the public hearings held by the Commission?

17 A. Yes. HELCO presented a statement at the public hearings held on June 26, 2006
18 in Hilo and on June 27, 2006 in Kona. HELCO-R-101 provides a copy of
19 HELCO's public hearing statement.

20 Q. Are there any intervenors or participants in this proceeding?

21 A. Yes. In Order No. 22663, issued on August 1, 2006, the Commission granted
22 Keahole Defense Coalition Inc.'s ("KDC") motion to participate, limited to those
23 issues pertinent to HELCO's expansion of the Keahole Generating Station. The
24 order stated that unless the Commission decides otherwise at a future juncture,

1 KDC's participation is limited to responding to any discovery requests, filing a
2 statement of position, and responding to questions at any evidentiary hearing.
3 Order No. 22663 also granted participant status to Rocky Mountain Institute
4 ("RMI"), limited to issues related to tiered rate pricing, time of use pricing,
5 energy cost adjustment charge, net energy metering and the renewable energy
6 and energy efficiency program for affordable homes. The Commission limited
7 RMI's participation to responding to any discovery requests, filing a statement of
8 position, and responding to questions at any evidentiary hearing. On
9 November 29, 2006, RMI filed a notice of withdrawal, which the Commission
10 approved on December 5, 2006 in Order No. 23108.
11 Q. Has HELCO made any changes in its witnesses since the submission of its direct
12 testimonies?
13 A. Yes. Since the Company filed its direct testimonies, Mr. Dan Giovanni (HELCO
14 T-5) left HELCO and became Manager of the Power Supply Operations and
15 Maintenance Department at Hawaiian Electric Company, Inc. ("HECO"). Mr.
16 Norman Verbanic succeeded Mr. Giovanni as Manager of the Production
17 Department at HELCO and has adopted Mr. Giovanni's testimony (HELCO T-5)
18 and is presenting rebuttal testimony (HELCO RT-5) on production operations
19 and maintenance expense and purchased power expense. Mr. Clyde Nagata
20 (HELCO T-14) retired. Mr. Jose Dizon, the current Manager of the Engineering
21 Department at HELCO has adopted HELCO T-14 and provides rebuttal
22 testimony as HELCO RT-14 on plant additions, plant retirements, property held
23 for future use, contributions in aid of construction and customer advances. Mr.
24 Alan Hee, Manager of Energy Services at HECO, has adopted the section on the

Energy Cost Adjustment Clause ("ECAC") in the direct testimony of Mr. Peter Young (HELCO T-3). Since Mr. Hee submitted supplemental testimony on the ECAC as HELCO ST-22, his adoption of Mr. Young's direct testimony on the ECAC will enable one witness to cover this subject area for the Company. Ms. Colleen Miller, Rate Analyst in the Pricing Division at HECO, has adopted the sections on Electric Sales Revenues in Mr. Young's direct testimony (HELCO T-3). The Company has made this change to reallocate witness responsibilities from Mr. Young who is also serving as the Company's witness for Cost of Service and Rate Design, as HECO's witness on Electric Revenues and Other Operating Revenues (HECO T-3) and Cost of Service and Rate Design (HECO T-20) in the HECO 2007 test year rate case (Docket No. 2006-0386) and as Maui Electric Company, Limited's ("MECO") witness on Cost of Service and Rate Design (MECO T-18) in MECO's 2007 test year rate case (Docket No. 2006-0387).

Q. Will any other HELCO witnesses provide rebuttal testimony?

A. Yes. Additional rebuttal witnesses will address various issues on the CT-4 and CT-5 units at the Keahole Generating Station. I will introduce those witnesses in the Keahole CT-4 and CT-5 section of this testimony.

HELCO REBUTTAL POSITION

Q. What is HELCO's rebuttal position?

A. HELCO's rebuttal testimonies and exhibits justify revenue requirements of $348,637,600, as shown in HELCO-R-2101. This amount is based on February 1, 2006 fuel prices, an 8.33% return on average rate base and a 10.7% return on common equity. It reflects a global settlement between HELCO and

1 the Consumer Advocate with respect to all issues impacting revenue
2 requirements, which I will discuss later in this testimony. Given HELCO's
3 estimated revenues at present rates of $324,073,100, HELCO proposes a revenue
4 increase of $24,564,500, or 7.58%, over present rates for a normalized 2006 test
5 year. (See HELCO RT-21 and HELCO-R-2101.)
6 Q. How much of a rate increase did HELCO propose in its Application?
7 A. In its Application, filed on May 5, 2006, the total rate increase HELCO requested
8 was $29,931,100 (based on February 1, 2006 fuel prices), or 9.24%, over
9 revenues at present rates for a normalized 2006 test year.
10 IMPLEMENTATION OF RATE INCREASE
11 Q. How is HELCO requesting that its proposed rate increase be granted?
12 A. As stated in its direct testimony, HELCO requests that the general increase and
13 revisions to its rate schedules be granted in two steps:
14 1) An interim rate increase equal to an increase in rates to which the
15 Commission determines HELCO is "probably entitled" based on the
16 evidentiary record before it, in accordance with Hawaii Revised Statutes
17 ("HRS"), Section 269-16(d). On March 27, 2007, HELCO is filing a
18 statement of probable entitlement which specifies its requested interim
19 increase, based on the evidence before the Commission. To recover the
20 interim rate increase, HELCO proposes that the Commission allow it to
21 implement surcharges to the various classes of service based on a
22 percentage of the customer's bill (exclusive of the energy cost adjustment
23 clause charges and other surcharges). This implementation method was
24 used for HELCO in Docket Nos. 99-0207 and 94-0140, for MECO in

Docket Nos. 94-0345 and 97-0346 and for HECO in Docket No. 04-0113.

2) A final increase when the Commission issues its final decision and order to provide for the amount, if any, of the total requested revenue increase not included in the interim rate increase. HELCO requests that its proposed rate design changes be implemented when the final increase becomes effective. The Company will concurrently terminate the interim rate increase surcharge.

Q. When does HELCO propose that the Commission grant its proposed increase?

A. HELCO proposes that the Commission issue an order granting an interim rate increase as soon as practicable in accordance with HRS 269-16(d) which states:

> 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; provided that in carrying out this mandate, the commission shall require all parties to a proceeding to comply strictly with procedural time schedules that it establishes. If a decision is rendered after the nine-month period, the commission shall report in writing the reasons therefor to the legislature within thirty days after rendering the decision.
>
> Notwithstanding subsection (c), if the commission has not issued its final decision on a public utility's rate application within the nine-month period stated in this section, the commission, within one month after the expiration of the nine-month period, shall render an interim decision allowing the increase in rates, fares and charges, if any, to which the commission, based on the evidentiary record before it, believes the public utility is probably entitled. The commission may postpone its interim rate decision for thirty days if the commission considers the evidentiary hearings incomplete...

The Company filed its application on May 5, 2006.

SETTLEMENT WITH CONSUMER ADVOCATE

Q. What rate increase did the Consumer Advocate propose in its direct testimony in this proceeding?

A. The Consumer Advocate proposed a rate increase of $16.6 million which was $13.3 million less than the $29.9 million revenue increase proposed by HELCO.

Q. Please summarize the results of the Company's settlement discussions with the Consumer Advocate.

A. There were numerous issues of contention between HELCO and the Consumer Advocate in this rate case. With the exception of a few remaining rate design issues, each was resolved through settlement. All issues impacting revenue requirements were resolved. The most significant agreements between HELCO and the Consumer Advocate are as follows:

- write down of $12,898,000 of gross plant in service, less $898,000 of average accumulated depreciation for 2006, (i.e., $12,000,000 of plant in service net of average accumulated depreciation) associated with the CT-4 and CT-5 units at the Keahole generating station, with associated reductions in depreciation expense, accumulated deferred income taxes, unamortized state investment tax credits ("ITC") and amortization of state ITC
- a rate of return on common equity of 10.7% and a composite cost of capital of 8.33%
- establishment of a pension tracking mechanism and an OPEB tracking mechanism
- reduction of $697,000 of Production Operations and Maintenance ("O&M") expenses based on recorded 2006 levels for labor and 2004-2006 recorded levels for certain non-labor materials expenses, and to remove future low pressure turbine ("LPT") turbine replacement overhaul costs
- a reduction of $163,000 of Transmission and Distribution ("T&D") O&M

1 expenses and $131,000 Administrative and General ("A&G") O&M
2 expenses for T&D safety training to reflect a compromise on the Consumer
3 Advocate's proposed "labor cost" adjustment and actual 2006 safety training
4 expenses
5 • agreement to use the results of HELCO's production simulation model to
6 determine the test year amounts for fuel expense, purchase power, fuel
7 inventory, ECAC revenue, ECAC base costs and sales heat rates
8 Various Company witnesses will explain each of the agreements with the
9 Consumer Advocate in their rebuttal testimonies. Although settlements have
10 been reached, HELCO's witnesses may respond to certain arguments or
11 allegations made by the Consumer Advocate in order to establish the Company's
12 viewpoint on the record.
13 With respect to rate design issues, the Consumer Advocate did not object to
14 the Company's proposed three-tier inverted rate design but offered certain
15 revisions. The Parties were also largely in agreement on policy matters related to
16 the Energy Cost Adjustment Clause ("ECAC"). I will discuss these later in my
17 testimony.
18 Q. Will HELCO and the Consumer Advocate execute a settlement letter to
19 document each of the agreements reached?
20 A. Yes. As of the date of the filing of this testimony, the parties have resolved their
21 differences on revenue requirement issues and some of the rate design issues.
22 However, because settlement discussions on revenue requirement issues
23 continued up through March 21, 2007, the parties did not have sufficient time to
24 execute a settlement letter prior to the filing of this testimony. In the coming

days, the Company will be working with the Consumer Advocate on the settlement letter. HELCO and the Consumer Advocate will also resume their settlement discussions to resolve the remaining rate design issues in this rate case and execute a second settlement letter to memorialize these agreements. The Company expects that they will be able to resolve these remaining issues quickly.

In their rebuttal testimonies, the Company's witnesses will describe their understanding of the settlements. Some of the details may change as the parties work on finalizing the settlement letter. As many of the settlements resulted from compromises, the parties reserve the right to revert to their original positions should similar issues arise in other proceedings.

Q. Why did the Company agree to write down $12.9 million of gross plant investment for the Keahole CT-4 and CT-5 generating units?

A. Agreeing to write down that amount of investment was a very difficult decision to make. My understanding is that the Company will have to immediately write down the $12.9 million of gross plant investment. A write down of that magnitude will substantially impact consolidated earnings for an entire quarter for the three Hawaiian Electric utilities. The Company is obviously concerned with how investors will perceive this occurrence and whether there will be any lasting impacts from an investment standpoint.

As reflected in its direct testimonies, the Company's position was that the entire $117 million of gross plant investment for the Keahole CT-4 and CT-5 project should be included in rate base. However, the issue of rate base inclusion of the Keahole CT-4/CT-5 investments was highly contentious, with the

1 Consumer Advocate and especially KDC taking very aggressive positions in this
2 proceeding on excluding significant amounts of this investment from the
3 Company's rate base.
4 Although the Company felt comfortable with the strength of its case, it also
5 recognized that due to a great number of reasons and the passage of
6 approximately fifteen years from the inception of the project, the Keahole
7 CT-4/CT-5 project costs had grown significantly from the original cost estimate.
8 HELCO also recognized that it would be to no one's interest to prosecute
9 this rate case to its conclusion without settlement. Rate cases are inherently a
10 resource drain. The Company's witnesses and support people had worked
11 intensively on this rate case for ten months with little break, in addition to trying
12 to keep up with their regular job functions. An evidentiary hearing on the full
13 case would have involved the appearance of a maximum of 33 witnesses for
14 HELCO, testifying on 54 direct, supplemental and rebuttal testimonies. The
15 preparation effort would have been enormous. The large number of witnesses
16 and testimonies was due in large part to the complexity of the Keahole issues.
17 The Company found it necessary to introduce nine additional Keahole witnesses
18 on rebuttal.
19 Decision making on each Keahole issue would be a difficult and arduous
20 task. It would require a full understanding and unraveling of the history of a
21 project that spanned 15 years and involved law suits and land use and air
22 permitting proceedings in addition to dockets at the Commission. Realistically,
23 such a process would take time and potentially delay timely decision making on
24 the entire rate case.

During settlement discussions, it became clear that the Consumer Advocate would not agree to a global settlement of the revenue requirement issues without a significant write down of Keahole investment. Settlement discussions began on or about March 7 and continued through March 21 when the parties agreed on a global settlement. The parties exchanged proposals and counter-proposals during this period. On March 21, the Consumer Advocate provided a global settlement counter-proposal, indicating it would not be willing to negotiate any further on the terms and that rejection would mean collapse of any chance of a global settlement. HELCO decided that all things considered, it would be best to accept the settlement, bring closure to the Keahole matter and allow HELCO to focus its attention on meeting the challenges of the future and providing efficient, reliable service to its customers.

KDC

Q. What is KDC proposing in this proceeding?

A. KDC is proposing a number of disallowances of costs associated with the CT-4 and CT-5 generating units at the Keahole Generating Station, including exclusion of all amounts relating to CT-5 ($50,181,116) from the Company's rate base. Although KDC's Position Statement itemized certain proposed adjustments, it did not specify a total amount. I will discuss KDC's Position Statement in the section addressing Keahole CT-4 and CT-5.

POLICY MATTERS

Q. What are the major issues that you will address in your testimony?

A. I will address the following major issues:

1) Keahole CT-4 and CT-5

1 2) Rate of return on common equity

2 3) Pension Tracking Mechanism

3 4) ECAC

4 5) Rate Design

5 KEAHOLE CT-4 AND CT-5

6 Q. What was the average depreciated, original cost for CT-4 and CT-5 that was
7 included in HELCO's average rate base for the 2006 test year prior to the
8 settlement?

9 A. The average depreciated, original cost for CT-4 and CT-5 that was included in
10 HELCO's average rate base for the 2006 test year prior to the settlement was
11 $107,280,000. (See HELCO-R-1505, page 1, which is an exhibit to HELCO
12 RT-15.) This amount includes the average depreciated, original cost
13 ($5,896,000) for the $7.57 million that the Commission allowed to be included in
14 rate base in Docket No. 99-0207 (HELCO's 2000 test year rate case) for the
15 three "Pre-PSD" facilities, based on the Commission's estimate of the usefulness
16 of these components to support the needs of the existing Keahole generating
17 station prior to the addition of CT-4 and CT-5, as is discussed below.

18 Q. *Are there other rate base deductions, in addition to Accumulated Depreciation,*
19 associated with the CT-4 and CT-5 costs?

20 A. Yes. Depreciation of the CT-4 and CT-5 costs results in deferred income taxes,
21 as Lorie Ishii explains in HELCO RT-13. Accumulated deferred income taxes
22 ("ADIT") are deducted from rate base. In addition, the project generated state

1 investment tax credits, and unamortized state investment tax credits ("SITC") are
2 deducted from rate base, as Ms. Ishii explains. As a result, the net impact of CT-
3 4 and CT-5 on HELCO's average rate base for the 2006 test year prior to the
4 settlement was $98,829,000, as shown in HELCO-R-1505, page 1.
5 Q. How have the issues between HELCO and the Consumer Advocate with respect
6 to the costs to be included in rate base for CT-4 and CT-5 been resolved by the
7 Parties?
8 A. As I previously stated, the Parties have agreed to a reduction of $12,898,000 of
9 gross plant in service (or $12,000,000 of plant in service net of accumulated
10 depreciation) associated with the CT-4 and CT-5 units at the Keahole generating
11 station, with associated reductions in depreciation expense, accumulated deferred
12 income taxes, unamortized state ITC and amortization of state ITC (the "Keahole
13 adjustment").
14 Q. What is the average depreciated, original cost for CT-4 and CT-5 that is included
15 in HELCO's average rate base for the 2006 test year after the settlement?
16 A. The average depreciated, original cost for CT-4 and CT-5 that is included in
17 HELCO's average rate base for the 2006 test year after the settlement is
18 $95,279,000. (See HELCO-R-1505, page 2, which also is an exhibit to HELCO
19 RT-15.) This amount also includes the average depreciated, original cost
20 ($5,896,000) for the $7.57 million that the Commission allowed to be included
21 in rate base in Docket No. 99-0207 (HELCO's 2000 test year rate case) for the
22 three "Pre-PSD" facilities.

1 Q. What is the net impact of CT-4 and CT-5 on HELCO's average rate base for the
2 2006 test year after the settlement?
3 A. The net impact of CT-4 and CT-5 on HELCO's average rate base for the 2006
4 test year after the settlement is $87,955,000, as shown in HELCO-R-1505, page
5 2.
6 Q. How much have the costs of CT-4 and CT-5 increased since the projects were
7 reviewed by the Commission in Docket Nos. 7048 and 7623?
8 A. The completed cost of CT-4 and CT-5 was approximately two times the original
9 cost estimate for the two generating units.

10 The revised cost estimate for CT-4 provided in Docket No. 7048 was
11 $35,798,200, as shown in Exhibit I to the Keahole Cost Report. The cost
12 estimate was based on an estimated in-service date of November 1994, although
13 HELCO was taking steps to expedite the in-service date, given the urgent need
14 for new generation on the Big Island. (HELCO also recognized the possibility
15 that installation might be delayed beyond November 1994). (See D&O 13050 in
16 Docket No. 7048, page 12.)
17 The revised cost estimate for CT-5 provided in Docket No. 7623 was
18 $24,073,400, as shown in Exhibit I to the Keahole Cost Report. The cost
19 estimate was based on an estimated in service date of September 1995, based on
20 anticipated receipt of the PSD/Covered Source Air permit in November 1994.
21 (The combined cost of CT-5 and ST-7 was estimated to be $62,684,700.) (See
22 D&O 14284 in Docket No. 7623, page 1.)
23 The final cost of CT-4 and CT-5 prior to the settlement was $117,609,535,

including $67,505,579 for CT-4, and $50,103,956 for CT-5, as shown in HELCO-R-1502, page 12. The $117,609,535 million includes the $7.57 million that the Commission allowed to be included in rate base in Docket No. 99-0207 (HELCO's 2000 test year rate case) for the three "Pre-PSD" facilities, including (1) the Shop/Warehouse Building ($972,599) completed in December 1998, (2) the new Fire Protection System ($745,548) completed in September 1999, and (3) the new Water Treatment System ($5,852,005) completed in December 1999, based on the Commission's estimate of the usefulness of these components to support the needs of the existing Keahole generating station prior to the addition of CT-4 and CT-5. (See Decision and Order No. 18365 ("D&O 18365") issued February 8, 2001 in Docket No. 99-0207, pages 27, 29, 31-32.) Revised costs for CT-4 and CT-5, including the costs for the three Pre-PSD facilities placed in service prior to 2000, are provided by Kenneth Fong in exhibits to HELCO RT-15.

Q. Has HELCO explained the reasons for the cost increases?

A. Yes. The cost increase was due to a number of factors, which are described in the Keahole CT-4 and CT-5 Cost Report ("Keahole Cost Report") filed September 7, 2005 in Docket Nos. 7048 and 7623, and are described in detail in Appendix B (Reasons for Cost Increases) and Appendix C (CT-4 and CT-5 Background) to the cost report. Further details have been provided in responses to information requests in this docket. The cost report, and sections of the cost report related to landscaping, noise mitigation measures and construction, are addressed by Kenneth Fong in HELCO RT-15, Barry Nakamoto in HELCO RT-15C, Guy Pasco in HELCO RT-15D, and Anthony Koyamatsu in HELCO RT-

15E. Mr. Nakamoto served as the Keahole Project Manager from 1992 to 2000, Mr. Koyamatsu served as the Keahole Project Manager from 2000 to 2004 and Mr. Fong is currently serving as Project Manager.

Q. What do you mean when you refer to the "Keahole Project"?

A. The term "Keahole Project" generally refers to the phased installation of a nominal 58 megawatt ("MW") (gross) dual-train combined cycle ("DTCC") generating unit at HELCO's existing Keahole generating station site, consisting of (1) two 20 MW simple-cycle combustion turbines ("CTs"), CT-4 and CT-5, (2) two heat recovery steam generators ("HRSGs"), (3) an 18 MW (gross) steam turbine generator ("STG"), ST-7, and (4) auxiliary equipment. As I discuss later, the installation of the HRSGs and the steam turbine generator were deferred due to HELCO's power purchase agreement with Encogen Hawaii, L.P. (now Hamakua Energy Partners, L.P.), and ST-7 is now on track to be in service in 2009. HELCO's application to commit funds for the CT-4 project was the subject of Docket No. 7048, while the remaining CT, HRSGs, and STG were the subject of Docket No. 7623.

Q. What positions did the Consumer Advocate take in its direct testimonies with respect to the costs for the CT-4 and CT-5 projects?

A. The Consumer Advocate recommended that only $7.3 million of AFUDC (of which $1.5 million related to Pre-PSD work already in rate base) be recoverable. The Consumer Advocate's proposed AFUDC adjustment was based on eliminating the accrual of AFUDC prior to January 1994, and stopping the accrual of AFDUC from October 1994 to August 1997. (See CA-T-3, page 69, and response to HELCO/CA-IR-304.)

1 The Consumer Advocate also proposed that 50% of legal costs for land use
2 permitting and related litigation, noise abatement measures, and landscaping be
3 disallowed. (See CA-T-3, pages 93-98.) The average amounts in the 2006 test
4 year rate base for these items are $6,307,961 for legal costs for land use
5 permitting and related litigation, $10,030,048 for noise abatement measures, and
6 $903,404 for landscaping. (See CA-101, Schedule B-8.)
7 In CA-T-3, page 100, Mr. Carver also recommended that "100% of the land
8 rezoning costs be excluded from the installed cost of CT-4 and CT-5." The
9 average amount in the 2006 test year rate base is $1,958,392. (See CA-101,
10 Schedule B-8.)
11 The Consumer Advocate's total proposed adjustment in its direct
12 testimonies for the 2006 test year rate base (taking into account a partially
13 offsetting adjustment to accumulated depreciation on Noise Abatement,
14 Landscaping, and Legal costs, but not Rezoning costs) was $22.4 million. (See
15 CA-101, Schedules B-7 & B-8.)
16 Q. What positions has KDC taken with respect to the costs for the CT-4 and CT-5
17 projects?
18 A. KDC's position in its Position Statement is that the Commission should exclude
19 certain CT-4 and CT-5 costs (approximately $55-60 million) resulting from
20 delays and work stoppages, which it claims flow from decisions with respect to
21 land use and air permitting alleged to have been imprudent. KDC also claims
22 that the Commission should exclude all costs related to CT-5 if CT-5 is not
23 deemed to be used and useful for utility purposes. (See KDC Position Statement,
24 page 43.) KDC's blanket disallowances are arbitrary and unreasonable, and are

not supported by reliable, probative and substantial evidence.

Q. Which witnesses address the contentions with respect to AFUDC?

A. Proposals to disallow AFUDC are rebutted by Michael Adams, Managing Director of the Energy Practice of Navigant Consulting, Inc., in HELCO RT-9B. In addition, in HELCO RT-9A, Patsy Nanbu, HECO's Controller, addresses the accounting policies with respect to AFUDC for HELCO and its affiliate utilities, and background with respect to the Commission's review of a utility's commitment of expenditures pursuant to paragraph 2.3.g.2 of General Order No. 7 ("Rule 2.3.g.2"). Paul Fujioka, in HELCO RT-9, updates the information in the Keahole Cost Report as to the amount of AFUDC foregone by HELCO as a result of stopping the accrual of AFUDC for CT-4 and CT-5 in December 1998.

Q. Which witnesses address contentions with respect to siting CT-4 and CT-5 at Keahole?

A. This should not even be an issue, since the Commission, in its 1994 decision approving the commitment of expenditures for CT-4, found that HELCO had an urgent need for generation in the 1994-1995 time frame, recognized that permitting problems might delay CT-4, and ruled that: "In light of present and foreseeable circumstances, we conclude that the location of CT-4 at Keahole is reasonable." Nonetheless, my rebuttal testimony summarizes HELCO's efforts to obtain another site, and our reasons for returning to the Keahole site. Jose Dizon, who has now joined HELCO as the Manager of its Engineering Department, and who was the Director of Generation Planning for HECO from 1995 to 2000, in HELCO RT-4A, and Lisa Giang, in HELCO RT-4, address the benefits of siting the new generation at Keahole.

1 Q. Which witnesses address contentions regarding the need for CT-4 and CT-5, and
2 HELCO's efforts to expedite installation of CT-4 and CT-5?
3 A. In HELCO RT-4A, Mr. Dizon summarizes the need for CT-4 and CT-5, and
4 HELCO's efforts to expedite installation of CT-4 and CT-5 in light of the
5 urgency of HELCO's generating situation, alternatives considered by HELCO,
6 HELCO's successful efforts to proceed in parallel with the negotiation of a PPA
7 with HEP, while diligently pursuing the installation of CT-4 and CT-5, in order
8 to meet HELCO's growing need for firm capacity, as well as HELCO's
9 successful efforts to maintain service to its customers during the extended period
10 that it took to add new generation. His testimony basically summarizes
11 testimony and information that has been provided to the Commission in earlier
12 dockets. In HELCO RT-4, Ms. Giang rebuts KDC's unsupported claim that CT-
13 5 may not be needed.
14 With respect to HELCO's efforts to expedite the installation of CT-4 and
15 CT-5, Barry Nakamoto rebuts KDC's contentions regarding the "Pre-PSD" work
16 done by HELCO, and generally summarizes his testimony from HELCO's 2000
17 test year rate case on this point.
18 Q. Which witnesses respond to claims that HELCO's efforts to obtain and retain its
19 land use authorization, and its air permit, were unreasonable or imprudent?
20 A. In HELCO RT-15F, Ben Tsukazaki, Esq., of the law firm of Tsukazaki Yeh &
21 Moore, who is a Big Island attorney concentrating in land use law, addresses
22 assertions that HELCO should have pursued reclassification of the Keahole site,
23 followed by rezoning, instead of an Amendment to its Conservation District Use
24 Permit ("CDUP"), as well as the reasonableness of HELCO's extensive efforts to

obtain and retain the land use authorization necessary to install CT-4 and CT-5 at Keahole, and the reasonableness of the legal costs incurred in that effort. I also provide information with respect to HELCO's reasons for requesting a CDUA, and HELCO's expectations with respect to the length of certain delays in the permitting process.

Scott Seu, in HELCO RT-15A, details the reasons and bases for HELCO's air permitting efforts, and HELCO's expectations with respect to the length of certain delays in the permitting process. Jim Clary, President of Jim Clary & Associates, who is a certified consulting meteorologist and provides consulting services and training in air quality, rebuts KDC's contentions regarding air permitting in HELCO RT-15B.

Anthony Koyamatsu, in HELCO RT-15E, addresses steps taken by HELCO to expeditiously complete the construction of CT-4 and CT-5 once HELCO was allowed to proceed with construction.

Q. Which witnesses respond to proposed disallowances of CT-4 and CT-5 project costs for noise mitigation and landscaping?

A. Barry Nakamoto, in HELCO RT-15C, addresses the evolution of the noise standards applicable to the Keahole Generating Station, and rebuts contentions made by KDC that the generating units should have been originally designated to meet a 45/55 dBA standard, and/or that HELCO should have obtained noise easements from surrounding property owners (some of whom were actively opposed to the installation of new generation at Keahole).

Guy Pasco, a Senior Supervising Engineer in HECO's Power Supply Engineering Department, in HELCO RT-15D, addresses the noise mitigation

1 measures employed to meet the 45/55 dBA standard, and rebuts contentions that
2 the cost of those measures would have been substantially lower if incorporated in
3 the CT-4 and CT-5 project designs earlier in the process.
4 Kenneth Fong, in HELCO RT-15, responds to the proposal to disallow 50%
5 of the landscaping costs.
6 Q. Which witness addresses the proposal to exclude costs associated with the
7 recently concluded reclassification/rezoning process from rate base?
8 A. I address this later in my testimony.
9 Q. What is HELCO's response to the-proposed disallowance of accrued AFUDC?
10 A. In HELCO RT-9A, Ms. Nanbu explains that (1) HELCO's policy of accruing
11 AFUDC on project costs is consistent with NARUC, SFAS No. 34 and Federal
12 Power Commission guidelines, (2) HELCO's application of AFUDC for the
13 Keahole project is consistent with HELCO's policy, and (3) although the total
14 amount of AFUDC applied to CT-4 and CT-5 is higher than what one would
15 expect for such a project under a normal construction schedule, the recorded
16 AFUDC was nevertheless actually incurred, and the amount of AFUDC is
17 reasonable given the length of project delays which were externally imposed and
18 were beyond the control of HELCO's management.
19 In HELCO RT-9B, Mr. Adams confirms the reasonableness of HELCO's
20 AFUDC policy, and the implementation of that policy in the case of CT-4 and
21 CT-5. He concludes that the Company should be allowed to include in rate base
22 the full amount of the recorded AFUDC, in the amount of $21,661,087. In
23 addition, he analyzed a number of start/stop scenarios to further test the
24 reasonableness of HELCO's AFUDC policy, and found that results from the

various scenarios demonstrate that the amount of AFUDC that the Company accrued was reasonable. Under the first two scenarios, which he believes to be the most reasonable, the Company would have actually accrued more AFUDC than was actually booked. Even under the most conservative start/stop scenario, the amount of AFUDC which would have been accrued was nearly six times the amount recommended by the KDC. His conclusion is also premised upon the significant amount of CT-4 and CT-5 related AFUDC which the Company has already foregone by virtue of its decision to forego the accrual of AFUDC after November 1998 and to not restart AFUDC once activity on the installation of the units began again in 2003. The amount of foregone AFUDC ranges from $8.1 million to over $52 million.

Both Mr. Adams and Ms. Nanbu stress that AFUDC is a cost actually incurred in the construction of plant facilities, and is just as much a cost of construction as are labor and material costs. Investor supplied funds have been used and invested in the Keahole project, and investors expect and deserve a return on the funds prudently applied by HELCO.

Q. What is HELCO's response to the proposed disallowance of other CT-4 and CT-5 costs?

A. From HELCO's perspective, the proposed disallowances appear to be based on speculation that these costs would not have been incurred if alternative actions had been taken (such as siting CT-4 and CT-5 at an unspecified alternative site, or seeking reclassification/rezoning instead of another Amendment to its CDUP (a "CDUA") , or not seeking to expedite the installation of new generation) and, implicitly, on claims that it was imprudent for HELCO not to have taken these

1 alternative actions. However, HELCO's decision to site the generation at
2 Keahole, to request a CDUA, and to attempt to expedite the addition of
3 generation were previously reviewed by the Commission. For example, the
4 Commission, in its 1994 decision approving the commitment of expenditures for
5 CT-4, found that HELCO had an urgent need for generation in the 1994-1995
6 time frame, recognized that permitting problems might delay CT-4, and still
7 concluded, in light of present and foreseeable circumstances, that the location of
8 CT-4 at Keahole was reasonable.
9 Q. What is HELCO's position with respect to the proposed exclusion of land
10 rezoning costs?
11 A. The rezoning costs are listed as a separate component of rate base, and are not
12 listed as part of the installed cost of CT-4 and CT-5. Filing for rezoning was a
13 condition of the CDUA extension and of the settlement agreement that allowed
14 CT-4 and CT-5 to be completed. Now that rezoning is complete, the costs are
15 properly included in rate base. If the costs are not included in rate base at this
16 time on the theory that they exclusively relate to ST-7, then the costs should
17 accrue AFUDC until ST-7 goes into service.
18 <u>The Need for CT-4 and CT-5</u>
19 Q. When did HELCO initiate its efforts to install CT-4 and CT-5?
20 A. In 1991, HELCO initiated efforts to install the next increment of new generating
21 capacity after the installation of Combustion Turbine No. 3 ("CT-3") at Puna.
22 The drivers for this new installment of generating capacity included supporting
23 system load requirements by having capacity installed on the west side of the Big
24 Island, and allowing for the retirement of aging existing generators on the

HELCO system. Based on HELCO's capacity planning criteria, it was initially determined that HELCO needed additional increments of capacity in 1994-1995 (20 MW), 1996 (20 MW) and 1997 (18 MW) due to forecast load growth and planned retirements of older generating units (as well as other considerations).

Q. Which witness addresses the need for CT-4 and CT-5?

A. Mr. Dizon, in HELCO RT-4A, covers the original determination of need for CT-4 and CT-5, and the continuing need for new generation after HELCO entered into a power purchase agreement ("PPA") with Encogen Hawaii, L.P. (whose successor in interest is Hamakua Energy Partners, L.P., or "HEP"). Ms. Giang, in HELCO RT-4, rebuts KDC's claim that CT-5 may not be needed.

Q. Did the Commission recognize the need for new generation?

A. Yes. There was no issue in Docket No. 7048, in which the Commission approved the commitment of expenditures for CT-4, regarding HELCO's need for capacity. The Commission stated that: "All parties agree that HELCO requires additional capacity to meet its future load requirements. The Consumer Advocate agrees with HELCO that there is an immediate need for additional generation in West Hawaii." (Decision and Order No. 13050 ("D&O 13050"), issued January 21, 1994 in Docket No. 7048, page 3.) The D&O concluded that HELCO required additional generation in the West Hawaii area in the 1994-1995 time frame, that none of the parties to the docket disputed the need for capacity, and that the other parties had not presented any viable alternatives to CT-4. Therefore, the Commission also found that "CT-4 is the only alternative with the possibility of fruition in the 1994-1995 timeframe." (D&O 13050, page 8.)

Q. When was CT-4 needed?

1 A. HELCO determined in 1991 that CT-4 was needed in 1994. The original need
2 date was determined based on the assumption that the 25 MW committed by
3 Puna Geothermal Venture ("PGV") would be available. However, PGV's project
4 was substantially delayed, which increased the urgency of adding CT-4. PGV's
5 capacity finally became available on a firm basis at the end of June 1993.
6 Q. Did the Commission approve the commitment of funds for CT-4?
7 A. Yes. The Commission approved HELCO's commitment of funds for CT-4 in
8 Docket No. 7048, in which it found that "HELCO's proposed [CT-4] project is
9 reasonable and in the public interest." (D&O 13050, page 14.).
10 Q. Did the Commission recognize the need for generation in addition to that to be
11 provided by CT-4?
12 A. Yes. As was explained in Docket No. 7048, the CT-4 project was designed to
13 include facilities and equipment to facilitate the possible future incorporation of
14 CT-4 into a 56 MW DTCC unit. The Commission concluded that "it is prudent
15 and reasonable for HELCO to include in the CT-4 project some of the costs
16 needed to upgrade CT-4." (D&O 13050, page 13.) The Commission also
17 determined that "the need for additional capacity on the Big Island is such that
18 HELCO must continue parallel planning for additional generation in the event
19 that non-utility generators do not deliver energy as promised. Should it become
20 necessary for HELCO to build CT-5, the provisions made in CT-4 for conversion
21 will help expedite the installation of CT-5." (D&O 13050, page 14.)
22 Q. When was CT-5 needed?
23 A. HELCO initially determined that CT-5 would be needed in 1996 (and that ST-7
24 would be needed in 1997). However, HELCO had to accelerate the installation

1 date for CT-5 as part of a contingency plan to address the delays and problems
2 experienced by PGV from 1991 to 1993 in adding its 25 MW of committed
3 power, and the uncertainties associated with the continued supply of power by
4 the sugar companies providing firm capacity to HELCO, including Hamakua
5 Sugar Company (10 MW) and Hilo Coast Processing Company ("HCPC")
6 (18 MW).
7 Q. When did HELCO file its application for the approval of CT-5 and ST-7?
8 A. HELCO filed its application in Docket No. 7623 on February 26, 1993.
9 Q. What did the Commission find with respect to the need for additional generation
10 in Docket No. 7623?
11 A. The Commission issued its final decision in the CT-5/ST-7 docket, Docket
12 No. 7623, on September 22, 1995. (Decision and Order No. 14284
13 (September 22, 1995) ("D&O 14284").) The Commission concurred that
14 HELCO requires plant additions (beyond the capacity to be provided by CT-4) in
15 the "reasonably near future", and that CT-5 and ST-7 are the appropriate type
16 and size generating units for HELCO to meet its probable future requirements.
17 (D&O 14284, page 6.)
18 Q. Was the need for additional generation addressed in Integrated Resource
19 Planning ("IRP")?
20 A. Yes. In Docket No. 7259, the Commission approved HELCO's supply-side
21 resource plan, which included 56 MW (net) of generating capacity to be added
22 by the end of 1997, with additional generation to be added in subsequent years.
23 (Decision and Order No. 14708 (May 29, 1996), Docket No. 7259.)
24 Q. Why was the need for new generation considered to be urgent?

1 A. As is indicated above, HELCO determined in 1991 that CT-4 was needed in
2 1994. The original need date was determined based on the assumption that the
3 25 MW committed by PGV would be available. However, PGV's project was
4 substantially delayed, which increased the urgency of adding CT-4. PGV's
5 capacity finally became available on a firm basis at the end of June 1993, but
6 other independent power producers ("IPPs") were having financial difficulties
7 and their continued availability was in substantial doubt as Mr. Dizon explains in
8 HELCO RT-4A. In addition, load was continuing to grow on HELCO's system.
9 Q. Did the Commission recognize the urgency of proceeding with CT-4?
10 A. Yes. For example, one of the questions at the conclusion of the evidentiary
11 hearings in Docket No. 7049 in July 1992 was what actions HELCO could take
12 to accelerate the installation of CT-4. (HELCO RT-1 at 30.) HELCO identified
13 doing pre-PSD work as an important strategy to accelerate CT-4's installation,
14 and did so in 1992.
15 The Commission also continued to urge HELCO on a number of occasions
16 to "maximize, rather than minimize, its strategies to meet the demand for
17 electricity." (See D&O 14030.) In Order No. 14502 (January 26, 1996) (page 4)
18 in Docket No. 7956, and in Decision and Order No. 15053 (October 4, 1996)
19 (page 31) in Docket No. 94-0079, the Commission reminded HELCO that its
20 primary consideration was to have the next generation unit on line as quickly as
21 possible.
22 IPP Alternatives
23 Q. What did the Commission find in Docket No. 7048 with respect to whether IPP
24 proposals were an alternative to CT-4?

A. The Commission explicitly reviewed the issue of whether IPP proposals were an alternative to CT-4, and found that "HELCO's proposed [CT-4] project is the only viable project with the likelihood of being able to provide critically needed generation in the 1994-1995 time frame". (D&O 13050, page 14.) The Commission also found that, while permitting problems might delay the CT-4 project, intervenor Waimana Enterprise, Inc. ("Waimana"), had not "presented any viable alternatives to CT-4". (D&O 13050, page 8.)

Q. What was Waimana's "interest" in the proceeding?

A. In the early 1990's, Waimana formed a partnership with Diamond Energy, Kawaihae Cogeneration Partners ("KCP"), to develop a 58 MW fossil-fueled cogeneration power plant on land to be leased by Waimana as a native Hawaiian corporation from the Department of Hawaiian Home Lands ("DHHL") at Kawaihae. Waimana was unsuccessful in negotiating a PPA (for reasons addressed at length in Docket No. 7956, including its extremely high price relative to other options). Waimana's strategy was to oppose HELCO's efforts to develop its own generation (and to enlist and/or finance other opponents), so that HELCO would have no option but to contract with KCP. Ultimately, Waimana's lease at Kawaihae was invalidated as a result of the lack of an Environmental Impact Statement ("EIS"), and Diamond Energy (the partner providing the financing for KCP) discontinued its business in the United States. However, even its own inability to do a project did not prevent it from continuing to oppose and appeal every permit approval obtained by HELCO.

Q. Did the Commission address IPP alternatives in the CT-5/ST-7 proceeding?

A. Yes. The Commission further found that, "[w]hile the need for the next unit is

acute, HELCO may not be able to install CT-5 and ST-7 within the time frame it contemplates." At the same time, the Commission noted that the issue of when Intervenors Enserch Development Corporation ("Enserch") and Waimana/ KCP's "respective facilities can actually be installed is far from settled." (D&O 14284, page 12.)

Q. What did the Commission conclude with respect to CT-5?

A. With respect to CT-5, the Commission concluded:

> "Thus, in this docket, we will continue to leave open the option of HELCO obtaining additional generation through its own facility. We will allow HELCO to continue to pursue construction of its own facility and to commit funds for such purpose, except as reserved in part D below. This authorization is subject to the condition that HELCO, in parallel with its efforts to construct its own facility, negotiate in good faith with Enserch, Waimana/KCP, and any other party that may propose a power purchase contract, to the end that the generating unit that can be most expeditiously put into service at allowable cost, whether constructed by HELCO, Enserch, Waimana/KCP, or any other person, will constitute the next unit to be added to HELCO's system." (D&O 14284, pages 12-13.)

Q. What was Enserch's "interest" in the CT-5/ST-7 docket?

A. Enserch (whose project entity was Encogen Hawaii, L.P., or "Encogen") was the developer of a second proposed IPP project. Enserch proposed to install a 60 MW combined cycle facility to be located at the old Haina Mill site.

<u>Parallel Plan</u>

Q. How did HELCO respond to the directive in D&O 14284?

A. In parallel with its efforts to expeditiously add needed generation at Keahole, HELCO engaged in extensive negotiations for possible PPAs with KCP and Enserch. HELCO successfully reached agreement with the Encogen project developers and a PPA was negotiated in 1997 and approved by the Commission

in 1999. (At that time, the PPA was assigned to HEP.) HEP's facility commenced commercial operation in two phases in 2000, as was addressed in HELCO's 2000 test year rate case, Docket No. 99-0207.

Q. When did HELCO determine that it would be prudent to continue to install CT-4 and CT-5, while still contracting with Encogen (subject to Commission approval) to purchase firm capacity?

A. HELCO determined in early 1997 that it would be prudent to proceed with the installation of generation at Keahole (i.e., to complete the installation of CT-4 and CT-5), while at the same time entering into a PPA with Encogen. At the same time, in order to reduce the rate impact to the customers, HELCO deferred the planned installation of ST-7, and planned to put some of its own capacity (at that time, its Puna steam unit) on cold standby reserve status until additional generation was needed. (HELCO also stopped accruing AFUDC on CT-4 and CT-5 in December 1998.)

Q. When did the Encogen project become a viable option?

A. Encogen did not become a viable option from a price standpoint until 1997 – <u>after</u> the Third Circuit Court confirmed HELCO's default entitlement. HELCO and Encogen finalized the price, terms and conditions of their PPA in June 1997.

Q. Did HELCO provide the Commission and the Consumer Advocate with the reasons for the parallel plan?

A. The reasons for proceeding in parallel with the installations of CT-4, CT-5 and the Encogen (now HEP) facility were addressed in a number of dockets, and are addressed by Mr. Dizon in this docket. In short, the parallel plan allowed HELCO (1) to increase its opportunity to install generation as soon as possible,

1 (2) to address the possibility that the Encogen facility or HELCO's Keahole
2 additions might be further delayed, (3) to meet the continuing need for
3 generation after the "next" increment of generation was added to HELCO's
4 system, (4) to add generation in West Hawaii (and, ultimately, to complete an
5 efficient DTCC unit at Keahole), given the imbalance between the amount of
6 HELCO's system load in West Hawaii and the small amount of generating
7 capacity that HELCO had in the region, and (5) to obtain the benefits from
8 HELCO's planned unit additions at Keahole for which most of the expenditures
9 already had been incurred.
10 Q. What do you mean by the continuing need for generation after the "next"
11 increment of generation was added to HELCO's system?
12 A. As Mr. Dizon has explained in other dockets, HELCO's generation expansion
13 plans also included the need for subsequent increments of generation (of 20 MW
14 or more), generally in the 1999 and 2001 timeframes. For example, HELCO's
15 biennial Electric Utility System Cost Data filing (July 1, 1996) showed the
16 addition of CTs in 1999 and 2001 after the completion of a DTCC facility. In
17 addition, HELCO's need for additional generation in the 1999 timeframe, even if
18 a dual train combined cycle unit was completed at either Keahole or at Hamakua,
19 was shown in the generation expansion plans filed by HELCO (1) in the dockets
20 arising out of its request for approval to commit funds for the Keahole generation
21 additions, (2) the dockets commenced at the request of qualifying facilities
22 seeking to enter into power purchase agreements with HELCO, (3) HELCO's
23 proceeding, and (4) the contingency planning docket, Docket No. 94-0140. Mr.
24 Dizon addresses HELCO's resource plan in more detail in HELCO RT-4A.

1 Q. Did entering into the PPA with Encogen/HEP decrease the urgency with respect
2 to CT-4 and CT-5?
3 A. No, the urgency with respect to Keahole generation did not end when HELCO
4 reached agreement on a PPA with Encogen, although it increased the probability
5 that generation would be added. At that time, the Keahole additions appeared to
6 be much further along and were expected to be in service sooner than the
7 Encogen facility, and there was still substantial uncertainty as to the timing of the
8 Encogen facility, as was explained at the time agreement was reached with
9 Encogen and when approval of the Encogen PPA was requested. As HELCO
10 indicated in numerous filings with the Commission, the in-service dates for the
11 two phases of the Encogen facility were uncertain, even after HELCO signed its
12 PPA with Encogen. At the time that HELCO and Encogen finalized the price,
13 terms and conditions of their PPA in 1997, there were three principal factors that
14 could delay Encogen's in-service date – receipt of its financing commitment, its
15 final air permit, and a final, non-appealable Commission approval of the PPA.
16 Q. Was HELCO encouraged to maximize its opportunities to install generation as
17 soon as possible?
18 A. Yes. The Commission has stated on numerous occasions that, under the
19 circumstances, "HELCO must obviously maximize, rather than minimize, its
20 strategies to meet the demand for additional capacity." (D&O 14030, page 25.)
21 In Order No. 14502, issued January 26, 1996 in Docket No. 7956 ("Order
22 14502") the Commission reiterated that: "HELCO's critical need for additional
23 capacity to meet its load requirements is unquestioned, and clearly, the primary
24 consideration is to have the next generation unit on line as quickly as possible."

(Order 14502, page 4.) Also, in Decision and Order No. 15053, issued October 4, 1996 in Docket No. 94-0079, the Commission stated that:

> "In seeking to fulfill the Big Island's acute generation needs, we remind HELCO that its primary consideration is to have the next generation unit on line as quickly as possible. To this end, HELCO may decide to pursue its own generation at Keahole; but, at the same time, it must in good faith negotiate with EDC, KCP, and any other independent power producer that proposes to build capacity and provide energy to HELCO. In this respect, we emphasize our full expectation that HELCO, in its dealings with EDC and other QFs proposing projects, will fulfill its obligations with in the intent and spirit of PURPA." (D&O 15053, page 31.)

Q. Had HELCO successfully pursued the strategy of expediting the installation of its own generation, while planning in parallel for the addition of purchased power, on a prior occasion?

A. Yes. For example, HELCO filed its application for the commitment of funds for CT-3 on February 16, 1990, and HELCO subsequently committed to the purchase of the CT in order to meet a schedule for the installation of the unit in 1992 if the provision of power by PGV continued to be delayed. HELCO was able to install the unit and have it operational in July 1992, as a result of which it averted the need for further rolling blackouts on HELCO's system despite the continued absence of PGV for another year. The Commission's decision and order in Docket No. 6643 was issued on March 23, 1992. Had HELCO waited until the decision and order was issued to commit to the purchase of the combustion turbine, HELCO would not have been able to complete installation of the unit until approximately 1994. The impact on HELCO's system reliability and on its customers would have been severe, particularly in the period preceding the availability of power from PGV beginning in June 1993.

Q. Has the importance of parallel planning and parallel plans been recognized in

other Commission proceedings?

A. Yes. In the recent Competitive Bidding Docket, the Consumer Advocate asked the Commission to explicitly recognize a utility's obligation to do parallel planning pursuant to its obligation to serve. In Decision and Order No. 23121 ("D&O 23121") (page 13), issued December 8, 2006 in Docket No. 03-0372, the Commission found that its Competitive Bidding Framework "does not relieve the electric utility from its obligation to provide safe and reliable electric service *to its customers, including the obligation to resolve reliability problems, both* short- and long-term, and that the Framework's provisions do not implicitly relieve the utility from this basic, underlying obligation to serve."

The Competitive Bidding Framework attached to D&O 23121 explicitly recognizes the importance of parallel planning. For example, Section II.D.2 states that: "In consideration of the isolated nature of the island utility systems, the utility may use a Parallel Plan option to mitigate the risk that an IPP's option may fail. Under this Parallel Plan option, the utility may continue to proceed with its Parallel Plan until it is reasonably certain that the awarded IPP project will reach commercial operation, or until such action can no longer be justified to be reasonable." As a result, Section VII.B provides that: "The costs that an electric utility incurs in taking reasonable and prudent steps to implement Parallel Plans and Contingency Plans are recoverable through the utility's rates, to the extent reasonable and prudent, as part of the cost of providing reliable service to customers."

Q. Has the Commission also recognized that utilities must be assured a fair

opportunity to earn a reasonable return on the capital prudently committed to the business?

A. Yes. In addition to the language in the general public utilities law (HRS§ 269-16(b)(3)), the recovery of costs prudently incurred by a utility in meeting its obligation to service is based in large part on the "long-standing regulatory compact", which the Commission has described as follows:

> The regulatory compact has two aspects: (1) in return for a monopoly franchise, utilities accept the obligation to serve all comers; and (2) in return for agreeing to commit capital necessary to allow the utilities to meet the obligation, utilities are assured a fair opportunity to earn a reasonable return on the capital prudently committed to the business. In Wash. Util. And Trans. Comm'n v. Puget Sound Power & Light Co., 62 P.U.R.45th 557, 581 (1984), the Washington Commission explained the regulatory compact in this fashion:
>
> "The social and economic compact of utility regulation begins with the premise that a regulated utility has an obligation to serve the public. [A] utility possesses an unending obligation to provide service to anyone within the service territory of that utility who demands service in accordance with approved tariffs.
>
> However, in order for the social duty to serve to be viable, the compact must also provide for a utility to recover expenses it prudently undertakes to meet the obligation."

(See Re Citizens Utilities Company, Kauai Electric Division, Docket Nos. 94-0097 & 94-0308, Decision and Order No. 14859 (August 7, 1996) (page 13).)

Steps Taken To Add Generation At Keahole Given The Urgency

Q. KDC, with the advantage of 20/20 hindsight, contends that HELCO should not have attempted to expedite the installation of new generation by issuing equipment orders prior to receiving land use and/or air permits. KDC's position is that $18.6 million of AFUDC should be excluded because, allegedly, "The Company's projects were not lawfully permitted within a reasonable time [and

1 sic] were not built in accordance with a reasonable timetable. Nor could the
2 projects be characterized as being planned, permitted and built on a 'planned
3 progressive basis.'" (KDC Position Statement, pages 42-43.) What is HELCO's
4 response to these contentions?
5 A. HELCO would prefer to have Commission approval for the commitment of
6 expenditures before incurring substantial commitments. However, that is not a
7 requirement under General Order No. 7 ("GO 7") project reviews, as Ms. Nanbu
8 explains in HELCO RT-9A, and such a requirement could preclude the Company
9 from meeting its obligation to serve under circumstances where project reviews
10 exceed the intended 90 days (which is almost always the case for major projects).
11 In this case, the Commission recognized that the generation situation was
12 urgent, and was urging the Company to expedite the addition of new generation
13 and address the uncertainties created by IPP bankruptcies and delays. Thus,
14 HELCO took those steps that were available to it to expedite the addition of new
15 generation, as it had done before in the case of CT-3.
16 Q. Given the urgency, what steps did HELCO take to add CT-4?
17 A. Given the urgency of the need, HELCO acted as expeditiously as possible to
18 obtain the needed permits and equipment for CT-4: (1) The Commission
19 application was filed in July 1991 (and was amended in September 1992 to
20 reflect the change to the Keahole site); (2) The application for a CDUA was
21 filed with the Department of Land and Natural Resources in August 1992; (3)
22 The application for the air permit was filed with the Department of Health in
23 January 1993; and (4) A letter of intent for the purchase of the combustion
24 turbine was sent on October 31, 1991 (subject to cancellation without penalty

before June 1, 1992).

Q. When did HELCO commit to the purchase of the combustion turbine for CT-5?

A. HELCO "committed" to the purchase of the combustion turbine by letter dated May 7, 1993 ("Notice to Proceed"). A conditional letter-of-intent dated February 1, 1993 was issued to Stewart & Stevenson Services, Inc. ("S&S") for the procurement for CT-5, subject to cancellation without charge if HELCO elected not to issue a notice to proceed to S&S by May 1, 1993. The cancellation date was extended to May 7, 1993 by oral agreement.

Issuing the Notice to Proceed enabled HELCO to (1) ensure that the CT-5 unit would be available for installation in accordance with HELCO's schedule, (2) avoid a price increase on the CT-5 engine, and (3) reduce shipping and handling costs by shipping both CT-4 and CT-5 at the same time. As a result, HELCO determined that, on a net present value basis, there was no economic penalty to adding CT-5 in 1995 instead of delaying the addition to 1996.

Q. Why was the letter-of-intent issued to S&S?

A. The CT-5 conditional letter-of-intent was issued in February 1993 because of HELCO's decision to accelerate the installation of CT-5. HELCO was able to reserve the only remaining slot in the production schedule for an early 1994 shipment, which would allow CT-5 to be completed and shipped to HELCO in time for commercial operation by late 1994. The letter-of-intent also enabled HELCO to secure the advantage of the pricing offered by S&S.

Q. Why did HELCO accelerate the scheduled installation date for CT-5?

A. As was addressed in Docket No. 7623, HELCO accelerated the schedule for CT-5 based on the "HELCO Contingency Plan Analysis", dated February 19, 1993,

which examined the impact of the inability of PGV to meet its commitment date for the provision of 25 MW of firm capacity, and the apparent inability of Hamakua Sugar Company ("Hamakua") to continue to provide firm capacity to HELCO.

As Mr. Dizon addresses in HELCO RT-4A, prior to issuing the Notice to Proceed in May 1993, HELCO reviewed (1) the status of PGV, Hamakua, and HCPC, (2) the benefits of proceeding with the retirements of its older, less efficient generating units, and (3) the benefits and economics of adding CT-5 in 1995 (even if it were not required on the basis of HELCO's capacity planning criteria until 1996). At that time, PGV still had not demonstrated that it would be able to solve its problems or that it would be able to meet its firm power commitment to HELCO. HELCO also was faced with significant uncertainty regarding the ability of its existing firm capacity producers, Hamakua (whose discontinuance of operations after the fall of 1994 appeared relatively certain) and HCPC (whose status beyond the Fall of 1994 was also uncertain), to continue to meet their firm power commitments.

<u>Siting CT-4 and CT-5 at Keahole</u>

Q. Did the Consumer Advocate question the reasonableness of the decision to site CT-4 and CT-5 at Keahole, despite the Commission's explicit finding in 1994 that it was reasonable to site CT-4 at Keahole?

A. No. At page 51, Mr. Carver stated that the Consumer Advocate was <u>not</u> contesting HELCO's decision to add generation in West Hawaii. (Response to HELCO/CA-IR-318.) However, he did pose the following questions: (1) "Could HELCO have avoided the extensive noise abatement and landscaping

costs at a different location . . . ?" (2) "Had HELCO chosen an alternate site for CT-4 (and CT-5), could the units have been completed and brought on-line sooner even though HELCO did not own property at the time?" (CA-T-3 page 95.) Mr .Carver also referred to a "different location" for CT-4 (and CT-5) and, on pages 95 to 97, he referred to "an alternate site for CT-4 (and CT-5)". (CA-T-3, pages 95-97.) In response to the direct question of whether the Consumer Advocate took the position that HELCO should have pursued a different generation option at an alternate site, instead of locating CT-4 and/or CT-5 at Keahole, the response was that: "It is not the Consumer Advocate's position that HELCO should not have located CT-4 and CT-5 at Keahole."

Q. What matters were addressed in Docket No. 7048 with respect to the siting of CT-4?

A. In Docket No. 7048, HELCO's decision to site new generation in West Hawaii, HELCO's extensive efforts to obtain a new generating station site for up to 200 MW of generation in West Hawaii, and the suitability of the Keahole Power Plant site for the addition of the combined cycle facility, were addressed at length. (See D&O 13050, pages 10-12.) In brief, the power plant was a permitted use at the Keahole site, and a generating plant already existed at Keahole. In addition, there was adequate undeveloped area at the Keahole Power Plant site to site the full combined cycle facility. Concerns expressed in the 1988 West Hawaii Site Study regarding siting a 200 MW West Hawaii generating facility at Keahole (to which the Consumer Advocate and KDC refer), generally were <u>not</u> applicable to the proposed siting of a 58 MW (gross) unit, and HELCO addressed those concerns that might be applicable to the combined

1 cycle unit. HELCO's testimony in Docket No. 7048 also summarized the efforts
2 undertaken by HELCO to address concerns at Keahole such as visual impact and
3 noise.
4 Q. Was HELCO somehow imprudent in expecting that it would obtain the permits
5 necessary to install additional generation at Keahole?
6 A. HELCO's judgment that the necessary permits and approvals would be obtained
7 despite the opposition was ultimately borne out. HELCO obtained the land use
8 authorization it needed to install new generation in 1996, although it was not
9 confirmed until 1997. After that, the only remaining permit needed for the
10 installation of generation at Keahole was the air permit. The delays encountered
11 in obtaining the final air permit were extraordinary, and were well beyond
12 HELCO's reasonable control. HELCO took diligent and prudent steps to obtain
13 the PSD air permit, and HELCO could not have reasonably anticipated the
14 substantial delays in the PSD air permit process.
15 Q. Why do you describe the delays as extraordinary?
16 A. The delays experienced in obtaining the necessary permits and approvals were
17 unprecedented in Hawaii for a generation project. Part of the reason for that was
18 the unprecedented efforts of an IPP to oppose HELCO's efforts, in an attempt to
19 leave HELCO with no option but to accept its proposal. Waimana/KCP
20 sponsored testimony at one of HELCO's air permit hearings, appealed the air
21 permit to the Environmental Appeals Board, helped fund KDC's participation in
22 the CDUA proceedings and litigations, and directly opposed the Keahole CDUA
23 in numerous administrative proceedings and litigations.
24 Q. Was HELCO's decision to site CT-4 at Keahole an explicitly stated issue in

1 Docket No. 7048?

2 A. Yes. HELCO's decision to site CT-4 at Keahole was an explicitly stated issue in
3 Docket No. 7048. The third issue in Stipulated Prehearing Order No. 11903,
4 filed on October 7, 1992, was as follows: "Whether the location of HELCO's
5 CT-4 is reasonable in light of present and foreseeable circumstances." (See
6 D&O 13050, page 2.)

7 Q. What did the Commission find with respect to this issue?

8 A. With respect to this issue, the Commission concluded that the Keahole site is
9 large enough to encompass not just CT-4 but also CT-5, if HELCO decides to
10 pursue that option. "In light of present and foreseeable circumstances, we
11 conclude that the location of CT-4 at Keahole is reasonable." (D&O 13050,
12 page 12.)

13 Q. Was HELCO aware that there would be opposition to siting additional
14 generation at Keahole?

15 A. HELCO was aware that there would be opposition to siting additional
16 generation, and to siting such generation at Keahole. The fact that there was
17 opposition was discussed at length in Docket No. 7048. As a result of the
18 expected opposition, HELCO did not undertake the task of obtaining the
19 necessary approvals and permits lightly, or without obtaining expert assistance.
20 For example, HELCO retained CH2M Hill, which provided extensive testimony
21 in Docket No. 7048, to handle the land use permitting.

22 Q. Did HELCO anticipate the degree of opposition that it faced in the Keahole
23 permitting processes?

24 A. As indicated above, HELCO anticipated community opposition, and took steps

to address the anticipated concerns. However, the degree of opposition experienced by HELCO in the 1993-1994 timeframe (and continuing until a settlement was reached in 2003) with respect to CT-4 and CT-5 was unexpected, as the community reaction to CT-4 and CT-5 was significantly greater than HELCO experienced with CT-3, and the prior experience of other utilities installing generation in the islands. The last significant generation additions were the two 180 MW power plants that were put in by Kalaeloa and AES-BP in the late 1991-1992 timeframe, both with little or no resistance. Community and utility attitudes and perceptions were different back in the early 1990s versus today. Since the early 1990s, communities' willingness to accept significant infrastructure projects has changed from the time when most communities accepted the intrusions and burdens that could result from the siting of infrastructure facilities (i.e., power plants, landfills) in their area as a fact of life, although they were not necessarily happy about the projects. Now, communities have become much more resistant to accepting additional infrastructure.

Q. The Consumer Advocate and KDC point to various statements in documents indicating that there would be opposition to siting additional generation at Keahole. (See, for example, CA-T-3, pages 88-92.) What is HELCO's response?

A. The matters referred to generally occurred prior to the Commission's finding in D&O 13050. The Commission was aware that there would be opposition. Nonetheless, its finding was based on all of the evidence before it, and not just the few matters cited taken in isolation.

Documents indicating that installing new generation at Keahole would

encounter opposition do not show (just as there was no showing in Docket No. 7048, where the issue was litigated) that the decision to site new generation at Keahole was imprudent, or that another option would have been preferable. The mere fact that there may have been alternative options that could have been pursued does not make or show that the selected option was imprudent. Similarly, the fact that the selected option may have been "contentious" does not render selection of the option imprudent.

Q. KDC refers to CH2M Hill's August 1988, West Hawaii Site Study. (See KDC Position Statement, page 18.) What is the significance of this study?

A. This study was provided and discussed in the proceedings reviewing the commitments of expenditures for CT-4 and CT-5/ST-7. It documents HELCO's efforts to obtain another site in West Hawaii for a new generating station (to locate up to 200 MW of generation). As a result of the study, HELCO undertook extensive efforts to obtain another site, as documented in those proceedings. The study does not indicate that efforts to site a 56 MW generating unit at the existing Keahole generating station would incur the extended land use and air permitting delays that ensued. Nor does it indicate that other sites would not be subject to permitting challenges and opposition, as was the case at Kawaihae.

Concerns expressed in the 1988 West Hawaii Site Study regarding siting a 200 MW West Hawaii generating facility at Keahole generally were not applicable to the proposed siting of a 58 MW (gross) unit, and HELCO addressed those concerns that might be applicable to the combined cycle unit. HELCO's testimony in Docket No. 7048 also summarized the efforts undertaken by HELCO to address concerns at Keahole such as visual impact and noise.

1 Q. KDC states that "[w]hen the Company installed CT-2 at the Station in 1988, it
2 informed the State Board of Land and Natural Resources (the "Board" or
3 "BLNR"), which regulated the Conservation district in which the Station was
4 located, that it would not expand the Station further." (KDC Position Statement,
5 page 5, citing DLNR Staff Report, September 23, 1988, page 6; June 1988
6 conditional use permit application, pages 17-18; and DLNR Staff Report,
7 January 21, 1993, page 2, 3-4.) Did HELCO intend to install further generation
8 at Keahole?
9 A. At that time, HELCO did not intend to install further generation at Keahole. The
10 long term plan in the time frame in which HELCO obtained the CDUA for CT-2
11 was to rely on geothermal power. However, as HELCO established in the CT-5
12 docket, the DLNR did not impose any conditions on HELCO that prohibited the
13 Company from applying for further expansion at Keahole. (See Transcript of
14 Proceedings held July 18, 1994 at 590 (Lyman), Docket No. 7623.) In addition,
15 HELCO took extensive steps to obtain another site in West Hawaii, before
16 determining that additional generation should be added at Keahole due to the
17 exigent circumstances.
18 Q. Did the Commission consider these factors in Docket No. 7048?
19 A. Yes, and the Commission described the siting issue at length in D&O 13050
20 (pages 10-12) before concluding that the location of CT-4 at Keahole is
21 reasonable. As the Consumer Advocate stated in its testimony: "Even though it
22 was recognized that HELCO may still experience permitting problems, the
23 Commission ultimately approved the commitment of funds to construct CT-4 at
24 Keahole in January 1994, generally due to the difficulty of acquiring land at the

other sites and Keahole being the only alternative site to possibly meet HELCO's generation needs in 1994." (CA-T-3, page 94.)

The issue of whether it was reasonable for HELCO to site new generation at Keahole after HELCO was unable to obtain a site for a new generating station in West Hawaii was fully litigated in Docket No. 7048, and the Commission explicitly found that the decision was reasonable. The factors for and against the decision to site generation at Keahole were extensively considered in a contested case proceeding. Any attempt to relitigate this matter, after there was a full and fair opportunity to litigate the issue at the time the decision was made, would be unfair and inappropriate.

Q. What is the best way to ensure that 20/20 hindsight is avoided?

A. It is always possible to speculate after-the-fact as to what could have been done differently. However, the question of what should have been done must be addressed based on the facts and circumstances as they existed at the time decisions were made. The best way to decide whether a decision is prudent without relying on 20/20 hindsight is to evaluate the decision at the time it is made. That is exactly what the Commission did in Docket No. 7048.

Alternate Sites

Q. In its direct testimonies, the Consumer Advocate proposed that the Commission disallow certain CT-4 and CT-5 costs, based on the claim that certain costs might have been avoidable if CT-4 (and CT-5) had been located at another site, or if HELCO had selected another, unspecified option. (See CA-T-3, pages 95-96.) Did HELCO attempt to obtain another site in West Hawaii?

A. Yes. The intention was to have CT-4 be the first generating unit at HELCO's

1 proposed new 200 MW West Hawaii generating facility. A site at Kawaihae
2 initially was selected based on a site selection study commissioned by HELCO
3 in the late 1980s. This 1988 West Hawaii Site Study prepared by consultant
4 CH2M Hill had identified a Kawaihae site located about a mile north of the
5 Harbor area as a preferred site based on a variety of evaluation factors and input
6 from a broad cross-section of community advisors. However, HELCO's efforts
7 to acquire a site at Kawaihae from DHHL were unsuccessful.
8 HELCO then attempted to procure a site at Puu Anahulu, owned by the
9 State of Hawaii. This area was also on the list of preferred sites identified in the
10 1988 West Hawaii Site Study. Efforts to acquire the site from the State of
11 Hawaii were also unsuccessful.
12 Q. Why did HELCO then decide to locate the new generation at its existing Keahole
13 generating station?
14 A. In late 1992, with the need date for additional generating capacity approaching,
15 HELCO evaluated its options and determined that installing CT-4 at its existing
16 Keahole Power Plant and separating the next generation addition from the
17 longer-term efforts to acquire a new West Hawaii site was prudent. Accordingly,
18 in August 1992 HELCO applied for an amendment to its existing CDUP at
19 Keahole and in September 1992, HELCO filed an amendment to its Commission
20 application identifying the Keahole site as the location for the CT-4 unit.
21 Q. Why was a Kawaihae site unavailable to HELCO?
22 A. HELCO's efforts to obtain a Kawaihae site for CT-4 were detailed in Docket No.
23 7049, in which the Commission found that siting CT-4 at Keahole was
24 reasonable. HELCO discussed with the DHHL how it could qualify as a lessee

or sublessee for the Kawaihae Site. However, DHHL adopted a preference to award the lease to a native Hawaiian corporation. If no native Hawaiian corporation was selected, then HELCO and other non-native Hawaiian bidders might have an opportunity to be considered. (See response to CA-IR-500(c).)

Benefits of Keahole Site

Q. Why is it beneficial to site new generation in West Hawaii?

A. It is beneficial to site new generation in West Hawaii because most of HELCO's generation is on the East side of the Big Island, including its base-loaded Hill steam units and PGV's geothermal unit. However, the demand for electric power is evenly divided between East and West Hawaii. The installation of generation at Keahole has provided needed generation in West Hawaii for area reliability and voltage support, and reduces transmission losses. If generation had been sited at another location, substantial improvements to the transmission system would have been required (depending on the location of the hypothetical site.)

Q. Which witnesses address the general benefits of siting generation in West Hawaii, and the specific benefits of having CT-4 and CT-5 at Keahole?

A. Ms. Giang in HELCO RT-4, and Mr. Dizon in HELCO RT-4A, discuss the general benefits of siting generation in West Hawaii, and the specific benefits of having CT-4 and CT-5 at Keahole. Mr. Verbanic, who is adopting the testimony in HELCO T-5, also discusses the benefits of having CT-4 and CT-5 at Keahole from his perspective as HELCO's Production Manager in HELCO RT-5.

CDUA

Q. Why was an amendment to HELCO's existing CDUP required?

1 A CT-4 and CT-5 are located at HELCO's existing Keahole Generating Station.
2 Because the Keahole site is in a Conservation District, expansion plans
3 necessitated obtaining an amendment to HELCO's existing CDUA from the
4 State BLNR. That permit had originally been obtained in 1973 and had been
5 amended subsequently on three occasions as additional generating units were
6 added at the site.
7 Q. When did HELCO apply for the CDUA?
8 A. HELCO filed its CDUA application for an amendment to its CDUP ("CDUA")
9 in August 1992. The history of HELCO's ultimately successful efforts to obtain
10 the land use authorization is summarized in Appendix C to the Keahole Cost
11 Report, and a more detailed chronology (based on the monthly status reports
12 submitted in Docket No. 7623) is attached as HELCO-R-102. The Commission
13 and Consumer Advocate were kept apprised of the status on a monthly basis by
14 the reports filed pursuant to D&O 14284 in the CT-5/ST-7 docket.
15 Q. Was an Environmental Impact Statement ("EIS") required?
16 A. Yes, the application triggered the need for an EIS, a draft of which was
17 submitted to the DLNR in late 1992. At that time, a relatively short time was
18 anticipated for BLNR approval (as a contested case hearing was not required
19 unless requested by an interested party with standing) and for acceptance of the
20 EIS, and outside legal representation for these activities had not been forecast as
21 necessary.
22 Q. What complications did HELCO encounter with respect to obtaining an EIS?
23 A. An accepted Final EIS is a prerequisite to the completion of a CDUA
24 application. HELCO's Final EIS (filed in June 1993) was denied during its 30-

1 day acceptance period because it did not reflect the generation contribution of
2 PGV, an independent power producer which had finally come on line after the
3 draft EIS was submitted. A Revised Draft EIS was submitted in July 1993 and
4 the DLNR accepted HELCO's Revised Final EIS in January 1994.
5 Q. Was a contested case hearing requested?
6 A At the public hearing held by BLNR in January 1993, many project opponents
7 testified against the application and two individuals residing in the neighboring
8 agricultural park, Peggy Ratliff ("Ratliff") and Mahi Cooper ("Cooper"),
9 verbally requested a contested case hearing. At that point, outside counsel was
10 retained. There were several complications and delays in scheduling a contested
11 case hearing and in obtaining acceptance of the EIS, as well as addressing
12 numerous lawsuits and administrative proceedings related to those steps, all of
13 which contributed to HELCO incurring unanticipated legal fees as well as other
14 costs.
15 Q. How did HELCO obtain its land use entitlement?
16 A. BLNR's inability to garner enough votes (four out of the six members of the
17 board) to either approve or deny the CDUA resulted in the circumstance of
18 HELCO obtaining in 1996, in lieu of an approved permit, a "default entitlement"
19 enabling it, by operation of law, to put its property to the use applied for. The
20 validity of and terms and conditions inherent to a default entitlement triggered
21 many more lawsuits and administrative proceedings over the next nine years
22 attributable to aggressive opposition to the project. As a result, there were
23 several lengthy delays to construction and increasing legal and other costs
24 incurred. Finally, with the Supreme Court's affirming (six years after the

1 original ruling) of a lower court judgment regarding the default entitlement, as
2 well as a negotiated settlement in 2003 aimed at resolving other pending
3 litigation and disputes, the project was finally able to be completed.
4 Q. In September 2000, the Third Circuit Court granted a post-judgment motion by
5 opponents and ruled that a 3-year construction deadline condition applied and
6 that, absent an extension from BLNR, the 3-year construction deadline had
7 already expired as of April 1999 (three years after the default entitlement arose).
8 What is your response to KDC's contention that "the Company knew that the
9 Board's standard 3-year construction deadline would apply to the Projects" in
10 1996? (KDC Position Statement, page 22.)
11 A. Prior to September 2000, HELCO had a reasonable basis to conclude that the
12 deadline did not apply to a default entitlement. For example, the DLNR had
13 issued a letter to HELCO in January 1998 specifically stating that the condition
14 did not apply, and Orders and judgments had been entered in various related
15 proceedings that lent credibility to DLNR's representations to HELCO.
16 Furthermore, by the time the court made its ruling, the deadline had expired and,
17 therefore, HELCO could not have applied for an extension prior to the expiration
18 of the deadline since that had already occurred.
19 Q. How did HELCO respond to the circuit court's September 2000 ruling?
20 A. In October 2000, HELCO requested an extension from the BLNR. A contested
21 case hearing on the matter was requested by opponents to the project and,
22 although arguably not required, was granted in January 2001. In March 2002,
23 the BLNR approved HELCO's request for a construction deadline extension
24 based on the favorable recommendation of the hearing officer. Accordingly, the

1 circuit court lifted the stay on construction in April 2002 and HELCO proceeded
2 to obtain the necessary County of Hawaii building and construction permits to
3 proceed with PSD related construction.
4 Q. How long did construction continue after the circuit court lifted the stay?
5 A. Project opponents challenged the BLNR's construction deadline extension,
6 arguing that BLNR had no authority to grant an extension for a deadline that had
7 already expired. In September 2002, the Third Circuit Court agreed and reversed
8 the March 2002 BLNR extension and all construction work was once again
9 stopped. HELCO appealed this decision to the Supreme Court in November
10 2002.
11 Q. Did HELCO take steps to reach a settlement with the opponents on this issue?
12 A. Yes. While mediation efforts were ongoing, in July 2003 (after over five years
13 on appeal) the Supreme Court affirmed the February 1998 final judgment
14 upholding HELCO's default entitlement. Following this decision, settlement
15 discussions escalated, the parties reached an agreement in principle, and
16 eventually a Settlement Agreement was executed on or about November 6, 2003
17 and provided, subject to satisfaction of several conditions, that HELCO would be
18 permitted to proceed with installation of CT-4 and CT-5, and, in the future, ST-7.
19 The Settlement Agreement was executed by HELCO, KDC, Ratliff, Cooper,
20 DHHL, DOH, BLNR and DLNR. In October 2003, the BLNR conditionally
21 approved a 19-month extension of the previous December 31, 2003 construction
22 deadline (i.e., to July 31, 2005), but subject to court action allowing construction
23 to proceed.
24 Q. Was HELCO able to comply with BLNR's new construction deadline?

A. Yes. Following a remand of the pending appeal by the Supreme Court, in October 2003, a motion to vacate the November 2002 Final Judgment (which was suspending construction) was filed in the Third Circuit Court by KDC and DHHL and was granted in November 2003. On November 17, 2003, HELCO resumed construction of CT-4 and CT-5. CT-4 and CT-5 were installed and were put into limited commercial operation in May and June 2004, respectively. The BLNR's extended construction deadline of July 31, 2005 has been met.

Q. Why did Mr. Carver take the position that accrual of AFUDC should have been suspended in September 1994?

A. Mr. Carver maintained that: "[S]ignificant facts were known in the September 1994 time frame that consistently signaled further delays in the permitting and construction schedule. At that time, HELCO knew or should have known that limited physical construction would be allowed for a potentially protracted period, which should have reasonably resulted in a decision to suspend AFUDC capitalization until the necessary permits were received allowing construction activities to proceed on a reasonably planned an progressive schedule of activities." (CA-T-3, pages 73-74.)

Q. What are the factual circumstances to which he referred?

A. One of two factual circumstances at the time that Mr. Carver cited relates to the CDUA process:

> "In May 1994, HELCO appeared before BLNR regarding its CDUA application, without a contested case hearing being held. Although BLNR was unable to cast enough votes to approve or deny the application, HELCO obtained a 'default entitlement' by operation of law, due to the statutory time limit in the CDUA having expired a few days after the hearing. However, HELCO was unable to commence construction because the air permit had

> not yet been granted. Project opponents challenged the 'default entitlement,' with the Third Circuit Court granting a stay on HELCO's ability to proceed with construction. In November 1994 in response to the default entitlement challenge, the Circuit Court remanded HELCO's CDUA application back to DLNR for a contested case hearing. Although the combustion turbines and other major equipment had already been delivered and placed in storage, HELCO's ability to initiate pre-PSD related construction was delayed pending the contested case hearing."

(CA-T-3, pages 72-73.) The other factual circumstance relates to air permitting, which is addressed by Mr. Seu in HELCO RT-15A and Mr. Clary in HELCO RT-15B

Q. Did HELCO expect a "protracted period of delay" as a result of the Third Circuit Court's stay order, which was filed on July 29, 1994, or the Third Circuit Court's remand order in November 1994?

A. No. On June 24, 1994, the Third Circuit Court granted the stay, which was entered on July 29, 1994. It is notable that the court entered a second order on July 29, 1994 establishing a schedule for briefing and oral argument for the agency appeal. In addition, the contested case proceeding on remand should not have taken as long as it did, given that the Final EIS had already been accepted, and there was a limited time frame within which the BLNR was required to act on the application. In the remand order, the court provided that BLNR was to hold the contested case hearing and reach a decision within 49 days of the order, subject to permissible extension by BLNR. On November 29, 1994, the chair of BLNR called for a one-year extension, with an extended decision deadline of December 28, 1995. Even though the process took longer than expected due to circumstances beyond HELCO's reasonable control, the Third Circuit Court ultimately ruled that HELCO had validly obtained a default entitlement as of

1 April 1996, although the court's amended ruling confirming that default
2 entitlement was not issued until July 1997.
3 Rezoning versus CDUA
4 Q. KDC asserts that the Commission should exclude HELCO's escalation costs
5 because, according to KDC, these costs could have been avoided "[h]ad the
6 company rezoned the Station site . . . and proposed to use SCR at the outset . . .
7 ." (KDC Position Statement, page 30.) Similarly, KDC claims that the cost of
8 Land Use Permitting Services from CH2M Hill should be excluded because,
9 allegedly, "the Company could have avoided these cost increases if it had
10 rezoned the Station site." (KDC Position Statement, page 38.) Why did HELCO
11 seek another amendment to its CDUP, rather than seek reclassification, followed
12 by rezoning, of the Keahole site?
13 A. As stated in our response to CA-IR-500(d), HELCO did not pursue the
14 reclassification of the Keahole Generator Station site from the State
15 Conservation District to the State Urban District and from the County Open
16 Zoning District to the County Industrial Zoning District as part of its original
17 proposal to install CT-4/5 at the Keahole Generator Station. HELCO had
18 previously been granted a CDUP for its power plant at the Keahole site, and was
19 subsequently granted three CDUP amendments for installing additional
20 generating units. The amount of time estimated for rezoning the site from
21 conservation to industrial was thought to be too lengthy at the time to have the
22 necessary generating capacity installed when HELCO needed it. Based on this,
23 HELCO decided to proceed as it had previously done successfully on its CDUP
24 amendments and would consider evaluating rezoning the Keahole property after

the installation of the CT-4/CT-5/ST-7 project was completed. (See letter dated December 8, 1993 from Warren Lee to Keith Ahue, Chairperson, DLNR, which is included in the Revised Final EIS for the Keahole Generating Station Expansion, dated December 1993 and accepted on January 7, 1994 by DLNR; Prefiled Direct Testimony of Albert L. Lyman, filed November 17, 1995 in CDUA No. HA-487A, pages 25-27.)

Q. Why was the amount of time to obtain rezoning thought to be too lengthy?

A. In 1992, HELCO estimated that reclassification and rezoning of the Keahole site would have taken more than 3 years and delayed the project beyond 1995 when generating capacity was required. Reclassification of the Keahole site from the State of Hawaii Conservation District to the Urban District required an accepted EIS and approval by the State Land Use Commission. After reclassification was obtained, the change in the Hawaii County zoning from Open ("O") to General Industrial ("MG") required approval by the County Council and Mayor after review by the County Planning Department and Planning Commission. HELCO estimated at the time that each of these discretionary approval processes would take years and at least one to two years for the reclassification and anywhere up to five years or more for the rezoning process. (See response to CA-SIR-53(a).)

Q. Was the time required to reclassify and rezone the property following the November 2003 settlement indicative of what would have happened in 1992?

A. No. The successful rezoning followed a settlement that resolved outstanding litigations contesting the right to add generation at Keahole. That settlement occurred only after the Hawaii Supreme Court confirmed HELCO's default entitlement to add generation at Keahole. All of the opponents to the project,

1 except Waimana (which was ultimately found to be without standing), entered
2 into the settlement agreement.
3 Q. Is there reason to believe that the opponents of the project would not have
4 opposed reclassification/rezoning of the site?
5 A. No. There were two categories of opponents to adding further generation at
6 Keahole. One group, including KDC, opposed the addition of any further
7 generation, and even attacked the Company's right to maintain its existing
8 generation at Keahole. The second group, including Waimana, opposed all
9 efforts by HELCO to add its own generation, at least prior to addition of
10 generation by KCP at Kawaihae. There is no basis to assume that the opposition
11 by either group would have disappeared or even lessened if HELCO had sought
12 reclassification/rezoning of the Keahole site, instead of a CDUA. What is clear
13 is that the opponents would have had three bites at the apple if HELCO had
14 sought reclassification/rezoning of the Keahole site – once before the Land Use
15 Commission, a second time before the County Council, and a third time through
16 the Mayor (through his veto power).
17 Q. KDC claims that "[t]he Company knowingly rejected the obvious advantages of
18 rezoning", and "assumed the obvious disadvantages of a CDUP . . . ." (KDC
19 Position Statement, page 7.) Which witnesses address the reasons for requesting
20 another CDUA, and the substantial risks inherent in the reclassification/rezoning
21 process?
22 A. I address the reasons for requesting the CDUA. In HELCO RT-15F, Mr.
23 Tsukazaki confirms the reasonableness of that approach, and discusses the very
24 real and substantial risks of the reclassification/rezoning process.

1 Q. What did KDC assume with respect to conditions under its hypothetical
2 reclassification/rezoning process?
3 A. KDC apparently takes the position that conditions would not have been imposed,
4 although KDC would undoubtedly have pushed for such conditions. For
5 example, KDC asserts that the Commission should exclude HELCO's escalation
6 costs because, according to KDC, these costs could have been avoided "[h]ad the
7 company rezoned the Station site . . . and had it proposed to use SCR at the
8 outset . . . ." Similarly, KDC claims that Land Use Permitting Services from
9 CH2M Hill should be excluded because, allegedly, "the Company could have
10 avoided these cost increases if it had rezoned the Station site." (KDC Position
11 Statement, pages 30, 38.)
12 Q. Would HELCO have been able to avoid conditions on its use of the property if it
13 had sought rezoning of the site in 1992?
14 A. Assuming HELCO had been successful, conditions could still have been applied,
15 as Mr. Tsukasaki testifies in HELCO RT-15F.
16 Proposed Disallowances of Non-AFUDC Costs
17 Q. As noted above, KDC opposes the recovery of land use permitting costs. (The
18 Consumer Advocate also proposed that 50% of legal costs for land use
19 permitting and related litigation, noise abatement measures, and landscaping be
20 disallowed. See CA-T-3, pages 93-98;CA-101, Schedule B-8.) Please
21 summarize HELCO's response.
22 A. HELCO strongly objects to the proposed disallowances. The CT-4 and CT-5
23 projects have been completed and are providing essential generation services to
24 customers. There is no question as to whether they are actually used or useful

for public utility purposes, and HELCO is entitled to a reasonable opportunity to earn a fair return on its prudent investment in these facilities. From HELCO's perspective, the proposed disallowances appear to be based on speculation that these costs would have been reduced or eliminated if alternative actions had been taken (such as siting CT-4 and CT-5 at an unspecified alternative site, or seeking reclassification/rezoning instead of another CDUA, or not seeking to expedite the installation of new generation) and, implicitly, on claims that it was imprudent for HELCO not to have taken these alternative actions. However, HELCO's decision to site the generation at Keahole, to request a CDUA, and to attempt to expedite the addition of generation were previously reviewed by the Commission. For example, the Commission, in its 1994 decision approving the commitment of expenditures for CT-4, found that HELCO had an urgent need for generation in the 1994-1995 time frame, recognized that permitting problems might delay CT-4, and still concluded, in light of present and foreseeable circumstances, that the location of CT-4 at Keahole was reasonable.

There was no demonstration that the legal fees and other costs incurred for land use permitting were unreasonable in amount, in view of the administrative proceedings to obtain and extend the land use authorization, and the numerous appeals brought by legal actions initiated by project opponents in the Third Circuit in Kona, and in the Hawaii Supreme Court. (These proceedings are briefly summarized in Appendix C of the Keahole Cost Report, and are detailed in the Monthly Status Reports.) Nor has there been a demonstration that the costs were "imprudently" incurred.

If a different expansion option had been selected, all costs would have been

1 different. (Some would have been substantially higher.) That is not a basis for
2 disallowing the costs associated with the selected expansion option.
3 Q. Which witnesses address claims related to the noise mitigation costs?
4 A. These claims are rebutted by Mr. Nakamoto and Mr. Pasco.
5 Q. In CA-T-3, page 100, Mr. Carver also recommended that "100% of the land
6 rezoning costs be excluded from the installed cost of CT-4 and CT-5." The
7 average amount in the 2006 test year rate base is $979,196. (See CA-101,
8 Schedule B-8.) Mr. Carver took the position that the recovery of such costs
9 would have been more appropriately addressed upon HELCO's application to
10 include the costs of ST-7 in rate base. (CA-T-3, page 100.) Please summarize
11 HELCO's response.
12 A. The rezoning costs are listed as a separate component of rate base, and are not
13 listed as part of the installed cost of CT-4 and CT-5. Filing for rezoning was a
14 condition of the CDUA extension and of the settlement agreement that allowed
15 CT-4 and CT-5 to be completed. Now that rezoning is complete, the costs are
16 properly included in rate base.
17 Q. If the costs are not included in rate base at this time on the theory that they
18 exclusively relate to ST-7, should the costs accrue AFUDC until ST-7 goes into
19 service?
20 A. Yes. In its IR responses, the Consumer Advocate stated that "[t]o the extent
21 HELCO believes that the rezoning costs are reasonably attributable to ST-7, the
22 Company could have included those costs in the ST-7 project and capitalized
23 AFUDC during periods of progressive physical construction activity." (CA
24 Response to HELCO/CA-IR-325.)

1 Q. How are the rezoning costs treated in the settlement?

2 A. They are included in rate base. All of the issues raised by the Consumer
3 Advocate with respect to Keahole costs were resolved by the Keahole
4 adjustment.

5 RATE OF RETURN ON COMMON EQUITY

6 Q. What was HELCO's proposed rate of return on common equity?

7 A. HELCO's proposed return on common equity was 11.25%.

8 Q. What was the Consumer Advocate's proposal on HELCO's return on common
9 equity?

10 A. The Consumer Advocate provided a range on its proposed return on common
11 equity of 9.5% to 10.25%, with a mid-point of 9.88% (CA-101, Schedule D).

12 Q. Why is a sufficient return on equity needed?

13 A. The return on equity must be sufficient to assure investor confidence in the
14 financial integrity of HELCO. This will enable the Company to maintain its
15 credit and capital-attracting ability. Financial integrity and financial strength are
16 important considerations in determining a fair rate of return on rate base and on
17 common equity for the Company.

18 Q. What else should be considered when determining a reasonable allowed rate of
19 return on common equity for HELCO?

20 A. A reasonable allowed rate of return on common equity must reflect the risks
21 associated with the Company's business. Dr. Roger Morin testified in HELCO
22 T-17 that HELCO's business risks and regulatory risks are comparable to those
23 of other electric utilities while its financial risks exceed those of other electric
24 utilities primarily on account of its small size and debt-equivalent purchased

1 power contracts.

2 Ms. Sekimura also points out that many of the factors that adversely impact
3 HELCO's risks have been recognized by the Commission in prior rate case
4 decisions and continue to apply in this case. They include: (1) HELCO's
5 service territory is geographically isolated; (2) HELCO lacks interties, which
6 precludes the Company from having other utility systems provide reliable
7 backup generation sources; (3) there is a scarcity of generation sites in HELCO's
8 service territory, (4) HELCO purchases a substantial percentage of its power
9 through firm capacity contracts, which impacts HELCO's financial condition;
10 (5) HELCO's service territory is significantly dependent upon tourism;
11 (6) HELCO is significantly dependent on oil for electric generation; and
12 (7) HELCO is a very small company. Since the overall risks for HELCO are
13 greater than for the comparable companies, an upward adjustment to the rate of
14 return on common equity is appropriate. Timely decisions, including the upward
15 adjustment made to the rate of return on common equity, will be important
16 factors in helping HELCO maintain its credit and adequately compensate
17 investors.

18 Dr. Morin (HELCO RT-18) and Ms. Sekimura (HELCO RT-17) address at
19 length the other aspects of Mr. David Parcell's testimony (CA-T-4), upon which
20 the Consumer Advocate's position in direct testimony was based.

21 Q What is the rate of return on common equity ("ROE") that is used to determine the
22 Company's rate of return on rate base in the settlement with the Consumer
23 Advocate?

24 A. The compromise ROE accepted by both parties in the settlement is 10.7%.

1 PENSION TRACKING MECHANISM

2 Q. What is the Consumer Advocate's position on the Company's test year estimates
3 of pension expense (i.e., net periodic pension cost or "NPPC") and the inclusion
4 of the pension asset into rate base?

5 A. As discussed by Ms. Julie Price in HELCO RT-10, the Consumer Advocate
6 accepts the Company's test year pension expense estimate. In HELCO RT-9, Mr.
7 Paul Fujioka explains that the Consumer Advocate accepts the pension asset in
8 rate base, although the Company does not agree with the Consumer Advocate's
9 method to determine when it is appropriate to include the pension asset in rate
10 base.

11 Q. Please describe the agreement with respect the Consumer Advocate's proposed
12 pension tracking mechanism.

13 A. The Consumer Advocate proposed, and the Company accepted, the use of a
14 pension tracking mechanism, which is intended to smooth the impact on
15 ratepayers of potential fluctuations in pension costs, and generally would require
16 that the Company make fund contributions at the actuarially calculated net
17 periodic pension cost ("NPPC") if allowed without penalty by the tax laws. The
18 agreed upon pension tracking mechanism includes certain modifications proposed
19 by the Company to allow greater flexibility for funding more than NPPC for
20 certain specified reasons, as well as language to clarify how the tracking
21 mechanism will be implemented. As a result of agreeing to implement the
22 pension tracking mechanism, HELCO proposed and the Consumer Advocate
23 accepted, after certain modifications, a tracking mechanism for Postretirement
24 Benefits Other Than Pensions ("OPEB"), which mirrors the pension tracking

1 mechanism. The Consumer Advocate's proposed pension tracking mechanism,
2 and the pension and OPEB tracking mechanisms agreed to by both parties in the
3 settlement agreement, are addressed by Ms. Tayne Sekimura in HELCO RT-18.
4 Q. What is your understanding of how the pension tracking mechanism would work?
5 A. If the mechanism is approved by the Commission, in each future rate case, the
6 cumulative amount of pension cost in rates since the last rate change will be
7 compared to the cumulative amount of contributions to the pension fund since the
8 rate change, and the difference will be included as a reduction to rate base (if
9 positive) or an addition to rate base (if negative). The test year ending pension
10 balance in rate base will then be amortized over 5 years.
11 Q. When will the agreed upon pension and OPEB tracking mechanisms become
12 effective?
13 A. The proposed mechanisms are subject to Commission approval. If approved, the
14 pension and OPEB tracking mechanisms will apply prospectively from the date
15 that the Commission issues an order which (1) approves the adoption of the
16 pension and OPEB tracking mechanisms and (2) establishes new rates that
17 explicitly incorporate the provisions of the mechanism in the new rates. If the
18 Commission's interim rate order in this docket includes (1) approval to adopt the
19 mechanisms and (2) interim rates that explicitly incorporate the test year NPPC of
20 $2,744,000 and the test year net periodic benefit costs ("NPBC") of $1,530,400,
21 and amortization of the pension asset of $2,554,000 (there is no corresponding
22 "OPEB asset" to be amortized), then the tracking mechanisms would be adopted
23 as of the date of the interim rate order.
24 Q. Do the revenue requirements filed in this rebuttal testimony assume that the

1 pension tracking mechanism is adopted?

2 A. Yes. The revenue requirements filed in this rebuttal testimony reflect adoption of
3 the pension tracking mechanism. The revenue requirements include $2,554,000,
4 which is the amortization of the ending pension asset balance, in addition to the
5 test year NPPC of $2,744,000. These amounts are reflected in the testimonies of
6 Mr. Fujioka in HELCO RT-9 and Ms. Price in HELCO RT-10.

7 ENERGY COST ADJUSTMENT CLAUSE

8 Q. What is the Consumer Advocate's policy position on the ECAC?

9 A. The Consumer Advocate agrees that the ECAC should continue to be employed
10 and does not recommend any structural changes to the current ECAC other than
11 those that the Company has proposed. The Consumer Advocate agrees that it is
12 reasonable to include propane fuel costs and a distributed generation ("DG")
13 component in the ECAC and to use a three-part sales heat rate for HELCO's
14 central station units and HELCO's wind and hydro units. The Consumer
15 Advocate also does not oppose at this time the Company's proposal not to subject
16 DG units to a fixed efficiency factor. The Consumer Advocate's position is
17 discussed by Mr. Alan Hee in HELCO RT-22.

18

19 RATE DESIGN

20 Q. Does the Consumer Advocate support implementation of inclining block rates for
21 residential customers?

22 A. Yes. The Consumer Advocate states that the proposed inclining block rates are
23 appropriate as it will help mitigate the impact of rate increases to customers with
24 smaller homes and kilowatt usage and provide pricing cues to large users that may

1 stimulate conservation investment among customers most likely to be financially
2 positioned to afford such investments.
3 Q. Does the Consumer Advocate recommend any changes to the proposed inclining
4 block rate structure?
5 A. Yes. The Consumer Advocate recommends that usage in the first two energy
6 blocks of Schedule R, up to 1000 kWh per month, should receive the average
7 percentage revenue increase ultimately ordered for the residential class.
8 Q. What is the Company's response to the Consumer Advocate's proposal to assign
9 the average Schedule R class increase to the first two rate blocks of the proposed
10 Schedule R inclining block design?
11 A. The Company's rate design rate proposals for the three proposed residential
12 energy blocks create meaningful bill impact differences and should be approved.
13 The merit of HELCO's proposed inclining rate block design include mitigation of
14 the rate impact on the smallest users of the system, as shown in Schedule R bill
15 comparisons in HELCO-R-2016 in the rebuttal testimony of Mr. Peter Young
16 (HELCO RT-20). That differentiation in bill impact is not achieved if the same
17 percentage increase is applied to both the first and second tier blocks up to 1000
18 kWh per month as the Consumer Advocate suggests.
19 Q. What is the Company's response to the Consumer Advocate's proposal to reject
20 the Company's proposed change to the Schedule R minimum bill provision?
21 A. The Company originally proposed a revision to the minimum bill to recover a
22 greater contribution towards the fixed costs of serving residential customers
23 through a steady monthly fee based on a fraction of the customer's maximum use
24 of the electrical system. The Consumer Advocate does not agree with HELCO's

1 proposal based on considerations of tariff complexity, ratepayer equity, and
2 customer resistance. The Company is willing to agree to the Consumer
3 Advocate's proposal and withdraw the proposed modification to the Schedule R
4 minimum bill in order to minimize the issues in this proceeding.
5 Q. What is the Company's response to the Consumer Advocate's proposal to modify
6 miscellaneous service charges for service establishment, same day service,
7 returned payment, and field collection to the levels agreed upon in settlement in
8 HECO's Docket No. 04-0113?
9 A. The Company accepts the Consumer Advocate's proposal.
10 Q. *What is the Company's response to the Consumer Advocate's proposal to not*
11 include the Company's proposed Renewable Energy and Energy Efficiency
12 Program for Affordable Homes ("REEEPAH") clause?
13 A. As agreed in settlement discussions with the Consumer Advocate, the Company
14 will remove the REEEPAH dollars from the revenue requirement and withdraw
15 the proposed REEEPAH clause. HELCO will include a proposal for renewable
16 energy programs in its IRP-3, and will seek cost recovery through the IRP cost
17 recovery provision. HELCO proposes to modify the current IRP cost recovery
18 provision to include a "Renewable Energy Programs Adjustment", as shown in
19 HELCO-R-2015 in Mr. Young's rebuttal testimony (HELCO RT-20). The
20 Renewable Energy Programs Adjustment will recover the costs associated with
21 renewable energy programs that are proposed within the HELCO IRP process and
22 approved by the Commission.
23 SUMMARY
24 Q. Please summarize your testimony.

A. HELCO's total requested increase in revenues is $24,564,500, or 7.58%, over revenues at present rates for the normalized 2006 test year (based on February 1, 2006 fuel oil prices) for revenue requirements of $348,637,600. The requested rate increase is intended to give HELCO a reasonable opportunity to earn an 8.33% return on an average test year rate base of $357,238,100 and a 10.7% return on common equity. HELCO proposes to implement this requested rate increase in two steps, an interim rate increase and a final increase. The interim rate increase would be structured as surcharges to the various classes based on a percentage of the customer's bill (exclusive of energy cost adjustment charges and other surcharges). HELCO proposes to implement the final increase with the rates and charges that it has proposed in this proceeding.

HELCO also requests the Commission to approve (1) the adoption of the pension and OPEB tracking mechanisms in its interim decision and order in this proceeding and (2) interim rates that incorporate the test year NPPC of $2,744,000 and the test year NPBC of $1,530,400, and amortization of the pension asset of $2,554,000 (there is no corresponding "OPEB asset" to be amortized). With such approval, the tracking mechanisms would be adopted as of the date of the interim decision and order.

Q. Does this conclude your testimony?

A. Yes, it does.

Hawaii Electric Light Company

Public Hearing Statement
Docket No. 05-0315
HELCO Application for a Rate Increase

June 26 & 27, 2006
Hilo High School Cafeteria
Kealakehe Intermediate School Cafeteria

Introduction

Good evening Chairman Caliboso, Commissioner Kawelo and members of the audience. My name is Warren Lee and I am president of Hawaii Electric Light Company.

First, I would like to thank our customers who are here this evening. We appreciate your attendance and we want to hear your comments on the Company's proposal. My staff and I will also be around after the hearing and will be available to talk with you then.

We understand that higher prices are hard on our customers so asking for a rate increase was not an easy decision. Our challenge is to balance the cost of electricity with reliable service and to meet the growing customer demands for Big Island families and businesses.

Tonight, I will briefly cover how much of an increase we are asking for, what the increase will be used for, and how it will affect customer bills. In particular, I want to explain the innovative new rate structures we are proposing to help minimize the impact on lower income families and those who conserve energy.

How much of an increase is HELCO requesting and how will it be structured?

HELCO is requesting an overall net increase of 9.2% or $29.9 million in base revenues. However, we have proposed opportunities for customers to save money and to fairly shift the rate responsibility to those who contribute the most to high electricity costs.

First, we are asking the PUC to approve Hawaii's first residential tiered rate structure so those who use less electricity will pay lower rates. Under this plan, the majority of Big Island residents will see smaller monthly increases in their electric bill, in the range of 2.6% to 7.6%. These are customers who use 500 kilowatt-hours a month or less. Those who use a lot of electricity will see larger increases in their monthly bill, for example, up to nearly 15% for a residence using 5,000 kWh. This new tiered system encourages energy conservation and efficiency and rewards customers who use energy wisely. We hope to be the first utility in Hawaii to implement such a rate structure.

Second, we recognize that some low-income households have multiple families under the same roof and thus have higher electricity use, so we also propose that households that confirm participation in designated low income home energy programs have their rates capped to those in the lowest usage tier. This means a rate increase of no more than about 5% for these customers.

Third, we have asked for a revised minimum bill provision, which will fairly place more of the cost burden on part-time residents whose large homes and

intermittent high energy use necessitate larger capacity in HELCO's systems and higher electricity costs.

Finally, we have proposed a Renewable Energy and Energy Efficiency Program for Affordable Homes which is planned to include a residential solar water heating grant program, a customer assistance program that provides photovoltaic system installation and consultation to customers wishing to participate in HELCO's net energy metering program.

Why is a rate increase needed?

We know that a rate increase is tough for everyone and we held off asking for one as long as possible. HELCO's last rate increase was in 2000, and the proposed rate increase is to help pay for additions made to improve electric service and reliability on the Big Island since that time. The rate increase will recover costs for improvements already made since 2001. Some of these improvements that have been made and are in service include the addition of two new combustion turbines at the Keahole plant which went into commercial operation in 2004 as well as transmission and distribution line improvements across the island.

The Keahole plant in particular has stabilized power for the whole island. Before completion of the Keahole units, 75% of the island's power generation was located in East Hawaii while 50% of the demand was on the West side. The Keahole units have placed electrical generation closer to customers in West Hawaii thereby decreasing load on our transmission facilities and improving system reliability.

As I have said before, Keahole should be the last fossil fuel power plant on our island. Going forward, we anticipate that any new generation will come from renewable energy resources such as geothermal, solar, wind, biomass, pumped storage hydro, distributed generation and even garbage-to-energy.

In 2005, about 22% of the electricity sold on this island came from renewable sources, making the Big Island a national leader in renewable use and HELCO is committed to making renewable energy, energy efficiency and conservation the basis for our energy future on the Big Island.

What is the effect of the rate increase on customer bills?

What most of our customers will want to know is "how will this increase affect my electric bill?" If approved, HELCO's tiered-rate structure would provide smaller percentage increases for those who use less electricity. If the full request of 9.2% were approved, a "typical" residential customer using 500 kWh a month would pay $11.46 more, or a 7.6% increase resulting in a bill of $162.17.

Again, the tiered system we are proposing is intended to encourage conservation and lessen the impact on residential customers who use smaller amounts of electricity. If approved, we anticipate the rate increase to take effect sometime in early 2007.

Conclusion

Thank you for this opportunity to briefly describe our rate increase application. As I mentioned earlier, my staff and I will be available after the public hearing to answer your questions and concerns.

CDUA Chronology

Prior CDUP and amendments ((1973-1988)

In 1973, BLNR approved CDUP No. HA-487 for a new electric generation and switching station at Keahole. In 1984, BLNR approved the first amendment to existing CDUP No. HA-487, allowing installation of two additional 2.75 MW diesel generators and associated facilities and equipment. In 1987, BLNR approved the second amendment to the CDUP, allowing installation of one additional 2.75 MW diesel generator and associated facilities and equipment. In 1988, BLNR approved the third amendment to the CDUP, allowing installation of a combustion turbine (CT-2) and associated facilities and equipment.

HELCO files application for fourth amendment to CDUP (August 1992)

In August 1992, HELCO filed its application for a fourth amendment to the existing CDUP, asking for approval to install CT-4, CT-5 and ST-7.

Request for contested case hearing (1993)

In January 1993, the BLNR held a public hearing on HELCO's CDUA application. A contested case hearing was requested by several parties including individuals living in the neighboring Agricultural Park. Outside legal counsel was retained to handle the contested case. BLNR approved the request for a contested case in April 1993 and at that time Waimana petitioned to be a party to the contested case. In February 1994 (after acceptance of HELCO's EIS, a prerequisite to having a complete application), the DLNR attempted to schedule the contested case hearing for March 1994 and appointed the first hearings officer. There were a number of disputes and resulting delays connected with trying to schedule the hearing. Waimana filed to have the hearing date postponed, and in March the parties stipulated to a new date; HELCO conditionally agreed to extend the BLNR's deadline from May 18, 1994 to July 2, 1994, provided that the hearing begin by May 2, 1994. The first hearing officer assigned recused himself in March due to challenges by the other parties. A second hearing officer was appointed in April but fell seriously ill before a hearing could take place, and withdrew. On April 22, 1994, BLNR informed the parties that the hearing was postponed indefinitely and that it was unable to find a hearings officer in time for a May 2, 1994 hearing date. Considering the BLNR deadline of May 18, 1994 and the need for new generation capacity for the Big Island, HELCO elected to proceed with requesting approval of its CDUA by the BLNR even though DLNR had not been able to successfully schedule a contested case hearing.

Delays in processing HELCO's EIS (1993-1994)

An accepted EIS is a prerequisite to a CDUA application being deemed complete and ripe for action, and therefore any unforeseeable delays in processing the EIS impact the timing of consideration of the application. HELCO first filed its Draft EIS in December 1992 and a Final EIS in June 1993. That Final EIS was denied due to changes in the operational status of an independent power producer, PGV, during the 30-day acceptance period. After many years of not being able to produce power in accordance with its contact with HELCO, PGV finally came on-line. As a result, the information in HELCO's EIS did not reflect PGV's contribution to the system generation grid the DLNR rejected HELCO's EIS in order to allow HELCO to resubmit it with more current information. A Revised Draft EIS was submitted in July 1993 and a Revised Final EIS was submitted in December 1993. The Revised Final EIS was subsequently accepted in January 1994 and the DLNR then attempted to schedule the contested case hearing that had been requested by project opponents.

Effect of BLNR action is a default entitlement, which is challenged (1994)

HELCO appeared before BLNR in May 1994, without the benefit of a contested case hearing having been held. The BLNR was not able to cast enough votes to approve or deny HELCO's CDUA application. (The DLNR staff report had recommended denying the application without prejudice.) After the statutory time limit expired a few days after the hearing, HELCO obtained a "default entitlement" by operation of law, entitling it to put the property to the use set forth in its application.

At the time the default entitlement arose, the air permit had still not been obtained. HELCO requested and obtained DOE and EPA approval for construction activities not directly related to the proposed emission sources that can provide benefit to the existing plant facilities ("pre-PSD" construction). HELCO was not able to begin even pre-PSD construction, however, since project opponents filed a challenge to the "default entitlement" in May 1994, and the Third Circuit Court granted a stay on HELCO's ability to proceed with construction. In May, HELCO attempted to get DLNR to approve its construction plans, but DLNR returned the plans, citing the ongoing review of the CDUA status.

Circuit Court Remand of HELCO's CDUA Application to BLNR for Contested Case Hearing (1994)

In response to the default entitlement challenge, on November 9, 1994, the circuit court remanded HELCO's CDUA application back to the BLNR for a contested case hearing. BLNR was to hold the hearing and reach a decision within 49 days of the order, subject

to permissible extensions. BLNR later that month extended the deadline for the hearing and decision by one year, to December 28, 1995.

HELCO's plans to initiate allowable pre-PSD related construction were delayed accordingly while the contested case hearing was pending. By the time of the remand the combustion turbines and other major equipment had already been procured and delivered on-site and had to be stored for what turned out to be an extended period of time

Contested Case Hearing; BLNR action leads to default entitlement; attempts to clarify HELCO's rights (1995-1996)

BLNR appointed a hearings officer in March 1995, but Waimana and Ratliff objected to that individual. Four months later, retired Justice Frank Padgett was selected as the hearings officer. The contested case hearing was held in November of 1995. Just prior to the hearing, in October 1995, DHHL had consummated a land exchange by selecting the parcel of land to the north of the Keahole plant site and, accordingly, became a party to the hearing. The hearing officer issued his findings of facts and conclusions of law to the BLNR in December 1995 and recommended denial of HELCO's CDUA due to non-conformance with the open space requirements in the standard land use conditions.

After five extensions of the BLNR deadline by the chairman (resulting in a deadline of April 26, 1996), the matter came before the BLNR in April 1996. BLNR failed to garner enough votes to approve accepting the Hearing Officer's recommendations and also failed to approve or deny HELCO's CDUA application. Based on this "no action" result, a default entitlement again arose, allowing HELCO to put its land to the use applied for by operation of law. The initial minute order issued by BLNR on April 24 stated that they were denying the application, but an amended minute order on May 10 replaced that language with language stating that BLNR "will not issue a permit with respect to CDUA HA-487A."

HELCO attempted to have DLNR approve its construction plans at that point, but DLNR refused in light of the confusion as to the effect of the BLNR's "non-action." In May and June of 1996, HELCO filed first a Notice of Protective Agency Appeal of Amended Minute Order No. 11, then a Complaint for Declaratory Judgment asking the Third Circuit Court to affirm HELCO's default entitlement and direct the DLNR to process HELCO's construction drawings for approval. Meanwhile, project opponents again brought lawsuits challenging the default entitlement, and the actions were consolidated.

Circuit Court Allows Construction to Proceed and Pre-PSD Construction is Started; attempts are made to clarify applicable conditions; KDC brings another lawsuit (1997-1998)

In January 1997, the Third Circuit Court issued a decision that HELCO "may automatically put its land to the uses requested in its CDUA." Because of disputes between the parties as to the language in the ruling, in particular with regard to applicable conditions, the circuit court stated that it would revisit its findings to determine whether all issues had been disposed of or whether an amended order was needed.

About this time, in February 1997, KDC and other individuals filed a complaint for declaratory judgment in Civ. No. 97-017K against DOH, DLNR, BLNR and HELCO alleging breach of conditions in HELCO's CDUP, air permit, and land patent and alleging that HELCO cannot comply with the conditions applicable to the default entitlement. In addition, in May 1997 KDC and Ratliff filed a Motion for Reconsideration of the January 1997 order and cited the Engelstad case there (a case cited for the proposition that the three-year construction deadline applies even in the case of a default entitlement), which HELCO then responded to in its Memorandum in Opposition in June 1997.

The court confirmed and clarified its January ruling in July 1997, adding to its earlier order that, "The DLNR conditions set forth in HAR 13-2-20 do not apply inasmuch as the conditions are incompatible with Haw. Rev. Stat. 183-41." The court did not cite Engelstad and did not provide that the three-year construction deadline applied to HELCO.

Only then could HELCO proceed to obtain grading and building permits from the County of Hawaii for pre-PSD construction, and that pre-PSD work began in August 1997. While HELCO had encountered considerable delays in its attempts to initiate construction, at that time it was anticipated that the critical path air permit would be issued in time to allow a smooth transition from pre-PSD to post-PSD construction.[1]

At a hearing in December 1997 in the 97-017K case, the court clarified its July 1997 Amended Order by revising relevant language regarding conditions to read, "The DLNR conditions set forth in HAR 13-2-21, as referred to in HAR 13-2-20, do not apply to the extent that [instead of "inasmuch as"] the conditions are incompatible with Haw. Rev. Stat. 183-41." On January 30, 1998, the DLNR issued a letter to HELCO determining, in the context of the Circuit Court's rulings, the conditions applicable to the default entitlement and finding that "Conditions 6 and 15 [3-year deadline] do not apply." A final judgment was issued by the circuit court in February 1998 and was appealed to the Supreme Court by project opponents.

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[1] In November 1997, the EPA granted HELCO its air permit. The air permit was almost immediately challenged by the project opponents with appeals to the Environmental Appeals Board ("EAB") which automatically stayed the permit. HELCO continued with pre-PSD construction while working with the Department of Health and EPA Region 9 to defend the air permit to the EAB.

Administrative clarification of conditions (1998-2000)

The parties continued in various ways to attempt to clarify the conditions applicable to HELCO's default entitlement. The January 1998 DLNR letter to HELCO was challenged in court by Ratliff, who filed a complaint in March 1998. In March 1999, the court denied the request to declare the letter invalid and stated that determining the applicable conditions is a ministerial function. The written Order was issued in April 2001.

In August 1998 (before the April 1999 date eventually found by the Court to be the construction deadline), KDC filed a petition with BLNR requesting, in part, that the Board determine that: a. HELCO violated the terms of its existing CDUP and the conditions applicable to its default entitlement; b. the existing CDUP was null and void; and c. HELCO be enjoined from using the property under its default entitlement. Petitioners, in the course of ongoing litigation in the Circuit Court, complained to the Court about the lack of action on the petition and in September 1999 the Court orally directed BLNR to act on the petition and to inform the parties of the conditions applicable to HELCO's default entitlement and that a stay would take effect on November 30, 1999 if the Board failed to act by that time. In November 1999 (after the April 1999 date), BLNR ruled on the petition, stating:

a. All fifteen (15) conditions in section13-2-21, HAR, are applicable to the default entitlement. . .[and] are not inconsistent with section 183-41, HRS.
b. . . .the conditions in the prior permits may have independent prospective application but not as to the default entitlement awarded to HELCO.
c. The BLNR declines at this time to rule on the effect on the default entitlement of HELCO's violations of its air quality permits.

While "a" appeared to be clear on its face, no further guidance was given as to the commencement date or deadline for condition 15, the three-year rule. There was no declaration in the ruling, or indication through enforcement or otherwise subsequent to the ruling, that BLNR considered the default entitlement to have lapsed because of the three-year deadline. The meaning and implications of "b" and "c" were unclear.

In that context, KDC and Ratliff returned to BLNR in February 2000 with a Request to Nullify the default entitlement on various grounds, including that the three-year construction period starting January 3, 1997 (using the date of the first Circuit Court ruling confirming the default entitlement, rather than the April 26, 1996 date which was the deadline for BLNR action on the CDUA) had expired. At a hearing that month, BLNR orally denied the request to nullify. On or about August 15, 2000, BLNR issued a written letter documenting the ruling and stating that "[n]ullification of the default entitlement for reasons of abandonment by HELCO is unwarranted and is therefore denied." No mention was made in either the oral ruling or in the letter as to the commencement or expiration dates of the three-year construction period under condition 15.

Circuit Court rules that construction deadline applied and had expired (2000)

In September 2000, the Third Circuit Court granted a post-judgment motion by opponents and ruled that a 3-year construction deadline condition applied and that, absent an extension from BLNR, the 3-year construction deadline had already expired as of April 1999 (three years after the default entitlement arose). Prior to that time, as detailed herein, HELCO had a reasonable basis to conclude that the deadline did not apply to a default entitlement for the Keahole project, including that:

1. The condition by its terms applies to permits granted by BLNR; in this case, BLNR specifically stated in 1996 that it would not issue a permit.

2. The DLNR had issued a letter to HELCO in January 1998 specifically stating that the condition did not apply.

3. Orders and judgments had been entered in various related proceedings that lent credibility to DLNR's representations to HELCO.

Furthermore, by the time the court made its ruling, the deadline had expired and, therefore, HELCO could not have applied for an extension prior to the expiration of the deadline since that had already occurred.

BLNR considers and grants extension of construction deadline (2000-2002)

As a result of the court ruling, pre-PSD construction was stopped. In October 2000, HELCO requested an extension from the BLNR. The court granted a stay on construction until BLNR acted on the request for extension. A contested case hearing on the matter was requested by opponents to the project and, although arguably not required, was granted in January 2001. The contested case hearing was held in September 2001 and in November 2001 the hearing officer submitted his findings of facts and conclusions of law and recommended granting the extension to HELCO. In March 2002, the BLNR approved HELCO's request for a construction deadline extension, to December 2003, based on the favorable recommendation of the hearing officer. Accordingly, the circuit court lifted the stay on construction in April 2002 and HELCO proceeded to obtain the necessary County of Hawaii building and construction permits to proceed with PSD related construction.[2]

[2] Meanwhile, the air permit had become effective in November 2001.

Third Circuit Court Reverses BLNR Construction Deadline Extension (2002)

Project opponents challenged the BLNR's construction deadline extension, arguing that BLNR had no authority to grant an extension for a deadline that had already expired. In September 2002, the Third Circuit Court agreed and reversed the March 2002 BLNR extension and all construction work was once again stopped. HELCO appealed this decision to the Supreme Court in November 2002. The pending litigation halted construction until the settlement agreement was reached

Mediation and Settlement; Remand to Circuit Court; Vacatur of BLNR Extension Reversal; Further BLNR Extension of Deadline (2003)

In April 2003 the Circuit Court granted HELCO's Motion to Compel Alternative Dispute Resolution. Discussions among the parties (other than Waimana, which refused to participate) were ongoing throughout the year but escalated when the Supreme Court affirmed the Circuit Court's default entitlement judgment in July 2003. A Settlement Agreement involving HELCO, KDC, Ratliff, Cooper, DHHL, DOH, BLNR and DLNR was executed in November 2003. In anticipation of a settlement, in September 2003 HELCO filed with the Supreme Court a motion for remand of S. C. 25446 (HELCO's appeal of the November 2002 judgment reversing the BLNR's March 2002 extension of the construction deadline), which was granted. KDC then filed with the Circuit Court a Motion to Vacate Order Reversing BLNR's 3/25/02 Decision, which was granted in November 2003. In October 2003, HELCO had obtained from BLNR a further extension to July 2005, conditioned upon the remand and vacatur. In late 2003 and early 2004, the parties worked together to either move or stipulate to dismissal of pending litigation.

Reclassification of Land from Conservation to Urban; Rezoning to General Industrial (2003-2006)

As a condition of the first BLNR extension (March 2002) and also of the second BLNR extension (October 2003) and of the Settlement Agreement (November 2003), HELCO was required to submit a petition for boundary amendment to the State Land Use Commission ("LUC") in order to have the Keahole site reclassified from Conservation to Urban. That petition was filed in November 2003, the EIS was accepted by the LUC in February 2005 and the final decision and order approving the reclassification was issued in November 2005. At that time, an application was filed with the County of Hawaii to rezone the site, and the ordinance approving the rezoning was signed in May 2006.

Each of the boundary amendment petition, the related EIS and the rezoning application resulted in significant costs being incurred. The costs incurred to have the site reclassified and rezoned are not included in the costs for CT-4 and CT-5.

HELCO RT-2
DOCKET NO. 05-0315

REBUTTAL TESTIMONY OF
CURTIS A. BECK

MANAGER
ENERGY SERVICES DEPARTMENT
HAWAII ELECTRIC LIGHT COMPANY, INC.

Subject: Electricity Sales and Customers

INTRODUCTION

Q. Please state your name and business address.

A. My name is Curtis A. Beck and my business address is 1200 Kilauea Avenue, Hilo, Hawaii.

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

A. I am employed by Hawaii Electric Light Company, Inc. ("HELCO") as Manager of the Energy Services Department. My experience and educational background are listed in HELCO-200 in my direct testimony.

Q. What is the scope of this testimony?

A. My rebuttal testimony in HELCO RT-2 covers the sales forecast and average number of customers for test year 2006.

TEST YEAR ELECTRICITY SALES

Q. What is HELCO's forecast of 2006 test year electricity sales?

A. Total electricity sales for the 2006 test year were estimated to be 1,148.0 gigawatt-hours ("GWH"), as shown on HELCO-201 in my direct testimony.

Q. What is the Consumer Advocate's position with respect to test year 2006 electricity sales?

A. The Consumer Advocate accepts HELCO's test year 2006 electricity sales forecast. See CA-T-1, page 18.

Q. What were HELCO's actual 2006 total electricity sales?

A. Actual total electricity sales for 2006 were 1,144.7 GWH, as shown in HELCO's response to CA-SIR-3.1. Actual 2006 total electricity sales were lower than HELCO's forecasted amount. However, for purposes of this rate case, HELCO will use its forecasted 2006 test year electricity sales and is not proposing a change in its rebuttal testimony.

1 TEST YEAR AVERAGE NUMBER OF CUSTOMERS

2 Q. What is HELCO's forecast of 2006 test year average number of customers?

3 A. Average number of customers for the 2006 test year was estimated to be 74,174, as
4 shown on HELCO-206 in my direct testimony.

5 Q. What is the Consumer Advocate's position with respect to test year 2006 average
6 number of customers?

7 A. The Consumer Advocate accepts HELCO's test year 2006 estimate of average
8 number of customers. See CA-T-1, page 18.

9 SUMMARY

10 Q. Please summarize your rebuttal testimony on test year 2006 electricity sales and
11 average number of customers.

12 A. HELCO and the Consumer Advocate agree that the test year 2006 forecast of
13 electricity sales is 1,148.0 GWH, as shown in HELCO-201. HELCO and the
14 Consumer Advocate also agree that test year 2006 forecast of average number of
15 customers is 74,174, as shown in HELCO-206.

16 Q. Does this conclude your rebuttal testimony?

17 A. Yes, it does.

Witness HELCO RT-2

has no rebuttal exhibits.

HELCO RT-3
DOCKET NO. 05-0315

REBUTTAL TESTIMONY OF
COLLEEN M. MILLER

RATE ANALYST, PRICING DIVISION
ENERGY SERVICES DEPARTMENT
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Electric Revenues

INTRODUCTION

Q. Please state your name and business address.

A. My name is Colleen M. Miller and my business address is 220 South King Street, Suite 1201, Honolulu, Hawaii.

Q. By whom are you employed, and in what position?

A. I am a Rate Analyst with the Pricing Division of the Energy Services Department at the Hawaiian Electric Company, Inc. My experience and educational background are listed in HELCO-R-300.

Q. Have you sponsored other written testimony in this docket?

A. No. I am adopting the sections on Electric Sales Revenue in Mr. Peter Young's direct testimony (HELCO T-3). As discussed in Mr. Warren Lee's rebuttal testimony (HELCO RT-1), this change was made to reallocate witness responsibilities from Mr. Young who is also serving as a witness in other Commission proceedings.

Q. What do you cover in HELCO RT-3?

A. My rebuttal testimony in HELCO RT-3 covers the following:

1) Hawaii Electric Light Company, Inc.'s ("HELCO") test year 2006 estimate of electric revenues based on pre-settlement positions with the Consumer Advocate (the electric revenues at proposed rates are based on a pre-settlement revenue requirements analysis that took into account some of the agreements reached with the Consumer Advocate, but not all of the agreements as, due to timing considerations, the analysis was done before all of the agreements were finalized with the Consumer Advocate; the pre-settlement revenue requirements analysis is further discussed by Mr. Lee in HELCO RT-21);

2) A comparison with HELCO's direct testimony electric revenues, and

3) A comparison with the Consumer Advocate's electric revenues estimates.

ELECTRIC REVENUES

Q. What is HELCO's estimate of test year 2006 electric sales revenues at present and proposed rates before taking into consideration the agreements reached with the Consumer Advocate?

A. HELCO's estimate of test year 2006 electric sales revenues (pre-settlement) at present rates and proposed rates are $323,147,700 and $350,024,200, respectively, as shown in HELCO-R-301, page 1. The pre-settlement proposed electric sales revenues for test year 2006 reflect an increase of $26,876,500 or 8.32 % above the estimated electric sales revenues at present rates. (This is based on the pre-settlement position that ties to Mr. Young's Cost of Service Testimony (HELCO RT-20).) Subsequent to this filing, the Company will submit revised cost of service, revenues and rate design exhibits and workpapers to reflect the settlement agreement between the Company and the Consumer Advocate.

Q. What are the electric sales revenues for test year 2006, based on the settlement discussions with the Consumer Advocate?

A. Based on the settlement discussions with the Consumer Advocate, the electric sales revenues at present rates for test year 2006 are $323,147,700, and the electric sales revenues at proposed rates are $347,541,100. HELCO-R-2101.

Q. How is the revised allocation of revenues at proposed rates determined?

A. The determination of the revised allocation of revenues at proposed rates, reflected in HELCO-R-301 and HELCO-R-302, is discussed in the cost-of-service and rate design testimony in HELCO RT-20.

Q. Are any issues with the Consumer Advocate addressed in your testimony?

A. No, HELCO and the Consumer Advocate do not have any issues relating to electric sales revenues.

Comparison with HELCO's Direct Testimony Electric Revenues

Q. How does HELCO's pre-settlement test year electric sales revenue estimate at present rates compare with that presented in its direct testimony?

A. HELCO's pre-settlement estimate of electric sales revenues at present rates is $36,500 lower than the estimate provided in its direct testimony. A comparison by rate class is presented in HELCO-R-301, page 2.

Q. Why is the pre-settlement testimony estimate of electric sales revenue at present rates different than the direct testimony estimate?

A. The pre-settlement testimony estimate of electric sales revenues at present rates is different from the direct testimony estimate because of the following:

1) A revised estimate of the Energy Cost Adjustment Factor,

2) A revised estimate of Rider Adjustments for customers on Rider M.

Q. What is the rebuttal estimate of the Energy Cost Adjustment Factor?

A. The rebuttal estimate of the Energy Cost Adjustment Factor at present rates is 8.998 cents per kWh, which compares to the 9.003 cents per kWh used in direct testimony. The revised estimate of the Energy Cost Adjustment Factor at present rates is discussed by Mr. Alan Hee in HELCO RT-22.

Q. What are the rebuttal estimates of Rider Adjustments for customers on Rider M?

A. The revised estimate of Rider Adjustments for customers on Rider M at present rates and proposed rates are presented in the adjustments to revenues on rate Schedules J and P shown in HELCO-RWP-302, pages 43 and 127.

1 Q. Why is the estimate of Rider Adjustments for customers on Rider M being
2 revised?
3 A. The estimate of Rider Adjustments for customers on Rider M is being revised for
4 the addition of one Schedule P account and one Schedule J account and the
5 termination of one Schedule P account.
6 Q. Why are additional rider customers being added?
7 A. HELCO is including two Rider M customers that signed Rider M contracts in
8 2006, but were not previously identified in direct testimony or in the response to
9 CA-IR-447.
10 Q. What is the dollar amount of the revenue adjustment at present rates for the two
11 Rider M customers being added?
12 A. The total dollar amount of the revenue adjustment at present rates for the two rider
13 customers being added is - $49,400. This includes the one Schedule P rider
14 account dollar amount of - $37,800 and the one Schedule J rider dollar amount of
15 - $11,600.
16 Q. Why is one rider customer being terminated?
17 A. HELCO is excluding one Rider M customer that was disconnected in 2006, but
18 was not previously identified in direct testimony or in the response to CA-IR-447.
19 Q. What is the dollar amount of the revenue adjustment at present rates for the one
20 rider customer being terminated?
21 A. The dollar amount of the revenue adjustment at present rates for the one rider
22 customer being terminated is - $70,100.
23 Q. What is the net impact for the revised Rider adjustments at present rates?
24 A. The net impact for the revised Rider adjustments is to increase the estimate of
25 revenues at present rates by $20,700. This includes subtraction of the adjustment

for the termination of one rider customer (-$70,100) and the addition of the adjustment for two rider customers added (-$49,400) or [$20,700 = - (-$70,100) + (-$49,400)].

Q. How does HELCO's pre-settlement test year electric sales revenue estimate at proposed rates compare with that presented in its direct testimony?

A. HELCO's pre-settlement estimate of electric sales revenues at proposed rates is $3,040,300 lower than the estimate provided in its direct testimony. A comparison by rate class is presented in HELCO-R-301, page 3.

Q. Why is the pre-settlement testimony estimate of electric sales revenue at proposed rates different than the direct testimony estimate?

A. The Company revised its pre-settlement test year 2006 estimates of electric sales revenue at proposed rates for changes in items included in revenue requirements. The reasons for these changes between direct testimony and rebuttal testimony are discussed by the other HELCO witnesses in the case.

Comparison with Consumer Advocate's Electric Revenue Estimates

Q. Were there differences between HELCO and the Consumer Advocate with respect to the test year estimates of electric sales revenue at present rates?

A. Yes. HELCO and the Consumer Advocate differed with respect to the test year estimates of electric sales revenue at present rates due to differences in the Energy Cost Adjustment Factor assumption and assumptions for Rider M customers.

Q. How did the Company and the Consumer Advocate differ on the Energy Cost Adjustment Factor?

A. The Company used 8.998 ¢/kWh for the Energy Cost Adjustment Factor in rebuttal testimony. The Consumer Advocate used 8.621 ¢/kWh for the Energy

Cost Adjustment Factor, as shown in CA-T-1, CA-101, Schedule C-2. Mr. Hee discusses the Energy Cost Adjustment Factor in HELCO RT-22.

Q. What were the differences for Rider M customers?

A. The differences for Rider M customers included the addition of two customers and the termination of one customer for a net impact at present rates of $20,700.

Q. Have the Company and the Consumer Advocate reached an agreement on assumptions for present revenues?

A. Yes. In order to minimize issues in this proceeding, the Consumer Advocate and Company have agreed to use the Energy Cost Adjustment Factor of 8.998 ¢/kWh and adjust for updates in Rider M customers for an estimated revenues at present rates of $323,147,700.

SUMMARY

Q. Please summarize your testimony.

A. HELCO's pre-settlement estimate of test year 2006 electric sales revenues at present rates and proposed rates are $323,147,700 and $350,024,200, respectively. The pre-settlement proposed electric sales revenues for test year 2006 reflect an increase of $26,876,500 or 8.32 % above the estimated test year electric sales revenues at present rates.

Additional Rider adjustments for current rider customers are included in the pre-settlement estimate of revenues. A review of rider customers added since HELCO's direct testimony shows that HELCO gained two new rider customers and terminated one customer and the net effect of their associated Rider M adjustments increases revenues at present rates by $20,700.

Q. Does this conclude your testimony?

A. Yes.

COLLEEN M. MILLER

EDUCATIONAL BACKGROUND AND EXPERIENCE

BUSINESS ADDRESS:	Hawaiian Electric Company P.O. Box 2750 Honolulu, Hawaii 96840
CURRENT POSITION:	Rate Analyst, Pricing Division, Energy Services Department
YEARS OF SERVICE:	10 Years
EDUCATION:	University of Hawaii at Manoa Master of Business Administration Bachelor of Arts - Economics
OTHER CURRICULUM:	NERA Marginal Cost Course for Electric Utilities – Redondo Beach, CA Basics of Rate Design Course – New Mexico State University

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315 TEST-YEAR 2006
TEST YEAR 2006 REBUTTAL

ELECTRIC SALES REVENUES
($ Thousands)

Rate Class	At Present Rates	At Proposed Rates	Proposed Increase	% Change
Schedule R	$ 129,555.8	$ 140,331.1	$ 10,775.3	8.32%
Schedule G	33,904.1	36,723.9	2,819.8	8.32%
Schedule J	95,497.8	104,623.3	9,125.5	9.56%
Schedule H	4,804.9	5,204.5	399.6	8.32%
Schedule P	58,135.4	61,761.8	3,626.4	6.24%
Schedule F	1,249.7	1,379.6	129.9	10.39%
HELCO Total	$ 323,147.7	$ 350,024.2	$ 26,876.5	8.32%

Source: HELCO-R-302

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
TEST YEAR 2006 REBUTTAL

ELECTRIC SALES REVENUES
COMPARISON OF DIRECT TESTIMONY AND REBUTTAL TESTIMONY ESTIMATES
AT PRESENT RATES

($ Thousands)

Rate Class	Direct Testimony	Rebuttal Testimony	Difference	Change (%)
Schedule R	$ 129,577.5	$ 129,555.8	$ (21.7)	-0.02%
Schedule G	33,909.0	33,904.1	(4.9)	-0.01%
Schedule J	95,527.2	95,497.8	(29.4)	-0.03%
Schedule H	4,805.7	4,804.9	(0.8)	-0.02%
Schedule P	58,114.9	58,135.4	20.5	0.04%
Schedule F	1,249.9	1,249.7	(0.2)	-0.02%
Total Electric Revenue	$ 323,184.2	$ 323,147.7	$ (36.5)	-0.01%

Source: HELCO-R-302, HELCO-301.

HAWAII ELECTRIC LIGHT COMPANY, INC.
DOCKET NO. 05-0315
TEST YEAR 2006 REBUTTAL

ELECTRIC SALES REVENUES
COMPARISON OF DIRECT TESTIMONY AND REBUTTAL TESTIMONY ESTIMATES
AT PROPOSED RATES

($ Thousands)

Rate Class	Direct Testimony	Rebuttal Testimony	Difference	Change (%)
Schedule R	$ 141,557.6	$ 140,331.1	$ (1,226.5)	-0.87%
Schedule G	37,044.1	36,723.9	(320.2)	-0.86%
Schedule J	105,672.6	104,623.3	(1,049.3)	-0.99%
Schedule H	5,250.0	5,204.5	(45.5)	-0.87%
Schedule P	62,146.6	61,761.8	(384.8)	-0.62%
Schedule F	1,393.6	1,379.6	(14.0)	-1.00%
Total Electric Revenue	$ 353,064.5	$ 350,024.2	$ (3,040.3)	-0.86%

Source: HELCO-R-302, HELCO-301.

HAWAII ELECTRIC LIGHT COMPANY, INC.
SCHEDULE R - RESIDENTIAL SERVICE
DOCKET NO. 05-0315 TEST-YEAR 2006

ESTIMATE OF TEST-YEAR REVENUES

		PRESENT RATES		PROPOSED RATES	
	BILLING UNITS (MWH)	UNIT PRICE ¢/KWH	REVENUES $1000s	UNIT PRICE ¢/KWH	REVENUES $1000s
ENERGY CHARGE:					
NON-FUEL ENERGY CHG.	435400	11.5238	50,174.6		
BASE FUEL CHG.	435400	7.6132	33,147.9		
SUBTOTAL ENERGY			83,322.5		
ENERGY CHARGE:					
BASE FUEL CHG.	435400			16.7455	72,909.9
NON-FUEL ENERGY CHG.					
0 - 300 kWh	198136			12.5244	24,815.3
300 - 1000 kWh	191119			14.6349	27,970.1
Over 1000 kWh	46145	435400		15.4656	7,136.6
SUBTOTAL ENERGY					132,831.9
CUSTOMER CHARGE:	BILLS	$/MONTH		$/MONTH	
Single Phase Svc.	736167	10.00	7,361.7	10.00	7,361.7
Three Phase Svc.	309	14.50	4.5	14.50	4.5
SUBTOTAL CUSTOMER			7,366.2		7,366.2
SUBTOTAL ENERGY + CUSTOMER CHARGES			90,688.7		140,198.1
ADJUSTMENTS:					
RENEWABLE CREDIT					189.6
EMPLOYEE DISC.			(342.7)		(188.0)
10% APT-HSE.			(86.2)		(86.4)
LIHEAP ADJ.			0.0		(72.9)
MINIMUM ADJ.			118.7		290.7
SUBTOTAL			(310.2)		133.0
UNADJUSTED BASE REV.:			90,378.5		140,331.1
	(MWH)				
FOA, CENTS/KWH	435400	8.99800	39,177.3	0.000	0.0
TOTAL SALES REVENUES			129,555.8		140,331.1
FCS, %			0.0	0.000	0.0
TOTAL REVENUES			129,555.8		140,331.1

Source: HELCO-RWP-302

HAWAII ELECTRIC LIGHT COMPANY, INC.
SCHEDULE G - GENERAL SERVICE NON-DEMAND
DOCKET NO. 05-0315 TEST-YEAR 2006

ESTIMATE OF TEST-YEAR REVENUES

	BILLING UNITS MWH	PRESENT RATES UNIT PRICE ¢/KWH	PRESENT RATES REVENUES $1000S	PROPOSED RATES UNIT PRICE ¢/KWH	PROPOSED RATES REVENUES $1000S
ENERGY CHARGE:	98,000.0	21.3604	20,933.2	32.2535	31,608.4
	BILLS	$/BILL		$/BILL	
CUSTOMER CHARGE:					
1 PHASE	103,078	28.00	2,886.2	35.00	3,607.7
3 PHASE	26,390	48.00	1,266.7	57.00	1,504.2
SUBTOTAL	129,468		4,152.9		5,111.9
POWER FACTOR ADJ.			0		0.0
MINIMUM BILL ADJ.			0		0.0
SCHEDULE E ADJ.					-39.1
RENEWABLE CREDIT					42.7
Other Base Adj.			0.0		0.0
SUBTOTAL			0.0		3.6
Total Base Rev.			25,086.1		36,723.9
FCS, %		0	0.0	0	0.0
Other % Adj.					
SUBTOTAL			0		0
FOA, ¢/KWH	98000	8.9980	8,818.0	0.0000	0.0
Other ¢/KWH Adj					
SUBTOTAL			8,818.0		0.0
TOTAL REVENUES			33,904.1		36,723.9

Source: HELCO-RWP-302

HAWAII ELECTRIC LIGHT COMPANY, INC.
SCHEDULE J - GENERAL SERVICE DEMAND
DOCKET NO. 05-0315 TEST-YEAR 2006

ESTIMATE OF TEST-YEAR REVENUES

	PRESENT RATES			PROPOSED RATES		
	BILLING UNITS MWH	UNIT PRICE ¢/KWH	REVENUES $1000S	BILLING UNITS MWH	UNIT PRICE ¢/KWH	REVENUES $1000S
ENERGY CHARGE:						
0 - 200 KWH/KW	211,908.4	16.4579	34,875.7	217,081.1	26.1538	56,775.0
201 - 400 KWH/KW	112,450.2	14.2407	16,013.7	107,147.6	23.9367	25,647.6
> 400 KWH/KW	30,541.4	13.2397	4,043.6	30,671.3	22.9357	7,034.7
SUBTOTAL	354,900.0		54,933.0	354,900.0		89,457.3
	BILLS	$/BILL		BILLS	$/BILL	
CUSTOMER CHARGE:						
1 PHASE	2,679	33.00	88.4	2,679	39.00	104.5
3 PHASE	16,029	56.00	897.6	16,029	65.00	1,041.9
SUBTOTAL	18,708		986.0	18,708		1,146.4
DEMAND CHARGE:	1,211,882.0	7.00	8,483.2	1,245,222.0	12.00	14,942.7
ADJUSTMENTS:						
TRANS VOLT ADJ (TP)			0.0			0.0
PRI VOLT ADJ (DP)			(266.4)			(221.8)
PRI VOLT ADJ (DS)			(12.2)			(3.0)
PF ADJ			(16.9)			(18.4)
MINIMUM BILL ADJ.			0.0			0.0
RENEWABLE CREDIT						154.6
SCHEDULE E ADJ.			0.0			(90.5)
Rider Adj.			(542.8)			(744.0)
SUBTOTAL			(838.3)			(923.1)
Total Base Revenue:			63,563.9			104,623.3
FIRM CAP. SURCHRG. %		0.000	0.0		0.000	0.0
Other % Adj.						
	MWH			MWH		
FOA, ¢/KWH	354,900.0	8.998	31,933.9	354,900.0	0.000	0.0
Other ¢/KWH Adj.						
Total Rev. Adj.			31,933.9			0.0
Other Adj.						
TOTAL SALES REV.			95,497.8			104,623.3

Source: HELCO-RWP-302

HAWAII ELECTRIC LIGHT COMPANY, INC.
SCHEDULE H - COMMERCIAL COOKING, HEATING,
AIR CONDITIONING & REFRIGERATION SERVICE
DOCKET NO. 05-0315 TEST-YEAR 2006

ESTIMATE OF TEST-YEAR REVENUES

	BILLING	PRESENT RATES		PROPOSED RATES	
	UNITS	UNIT PRICE	REVENUES	UNIT PRICE	REVENUES
	MWH	CENTS/KWH	$1000s	CENTS/KWH	$1000s
ENERGY CHARGE:	17200	15.9189	2,738.1	26.4183	4,543.9
	KW	$/KW		$/KW	
CAPACITY CHARGE:	57,328	7.00	401.3	9.00	516.0
CUSTOMER CHARGE:	BILLS	$/BILL/MO		$/BILL/MO	
1 PHASE	1,456	28.00	40.8	34.00	49.5
3 PHASE	1,712	45.00	77.0	54.00	92.4
SUBTOTAL	3,168		117.8		141.9
UNADJUSTED BASE REV.			3,257.2		5201.8
ADJUSTMENTS:	MWH				
FOA, Cents/kwh	17200	8.998	1,547.7	0	0.0
SUBTOTAL			1547.7		0.0
SCHEDULE E ADJ.			0.0		-4.8
RENEWABLE CREDIT					7.5
UNADJ. TOTAL REV.			4,804.9		5204.5
FCS, %		0	0.0	0	0.0
TOTAL REVENUES			4,804.9		5,204.5

Source: HELCO-RWP-302

HAWAII ELECTRIC LIGHT COMPANY, INC.
SCHEDULE P - LARGE POWER SERVICE
ESTIMATE OF TEST-YEAR REVENUES
DOCKET NO. 05-0315 TEST-YEAR 2006

		PRESENT RATES		PROPOSED RATES	
	BILLING UNITS	UNIT PRICE	REVENUES $1000S	UNIT PRICE	REVENUES $1000S
ENERGY CHARGE:	(MWH)	CENTS/KWH		CENTS/KWH	
0 - 200 KWH/KW	97,978	15.2290	14,921.1	24.0599	23,573.4
201 - 400 KWH/KW	93,216	13.0488	12,163.6	21.8797	20,395.4
> 400 KWH/KW	46,906	12.0458	5,650.2	20.8767	9,792.4
SUBTOTAL	238,100		32,734.9		53,761.2
DEMAND CHARGE:	(KW)	$/KW		$/KW	
0 - 500 KW	318,134	11.25	3,579.0	19.50	6,203.6
> 500 KW	176,093	10.75	1,893.0	19.00	3,345.8
SUBTOTAL	494,227		5,472.0		9,549.4
	BILLS	$/BILL		$/BILL	
CUSTOMER CHARGE:	732	375.00	274.5	500.00	366.0
ADJUSTMENTS:					
PF			(515.8)		(854.7)
TP			0.0		0.0
DP			(1,113.6)		(922.6)
DS			(31.8)		(7.9)
RIDER T			0		0
RIDER M			(109.0)		(188.0)
Schedule U			0		0.0
RENEWABLE CREDIT					103.7
SCHEDULE E ADJ.			0.0		(45.4)
SUBTOTAL			(1,770.2)		(1,914.9)
Base Revenue:			36,711.2		61,761.7
FCS ADJ.		0	0.0	0	0.0
FUEL OIL ADJ.	238100	8.998	21,424.2	0.000	0.0
SUBTOTAL			21,424.2		0.0
TOTAL REVENUES			58,135.4		61,761.7

Source: HELCO-RWP-302

HAWAII ELECTRIC LIGHT COMPANY, INC.
SCHEDULE F - STREET LIGHTING SERVICE
DOCKET NO. 05-0315 TEST-YEAR 2006

ESTIMATE OF TEST-YEAR REVENUES

	BILLING UNITS (MWH)	PRESENT RATES UNIT PRICE ¢/KWH	PRESENT RATES REVENUES $1000S	PROPOSED RATES UNIT PRICE ¢/KWH	PROPOSED RATES REVENUES $1000S
ENERGY CHARGE:					
0 - 150 KWH/KW	1,922.6	22.7311	437.0	34.689	666.9
> 150 KWH/KW	2,477.4	16.5301	409.5	28.488	705.8
SUBTOTAL	4,400.0		846.5		1,372.7
ADJUSTMENTS:					
MINIMUM CHARGE:			7.3		6.5
RENEWABLE CREDIT					1.9
UNADJUSTED TOTAL REV.:			853.8		1,381.1
FUEL OIL ADJ.:	4,400.0	8.998	395.9	0.000	0.0
SUBTOTAL			395.9		0.0
EMP. DISC ADJ.			0.0		-1.5
FIRM CAP. SURCHRG. %		0.000	0	0.000	0
TOTAL REVENUES			1,249.7		1,379.6

Source: HELCO-RWP-302

HELCO RT-4
DOCKET NO. 05-0315

REBUTTAL TESTIMONY OF

LISA K. K. GIANG, P.E.

SENIOR PLANNING ENGINEER
GENERATION PLANNING DIVISION
POWER SUPPLY SERVICES DEPARTMENT
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: Fuel Oil Expense,
Fuel Related Expense,
Generation Efficiency,
Fuel Inventory, and
Generation Capacity Issues

INTRODUCTION

Q. Please state your name and business address.

A. My name is Lisa Giang and my business address is 820 Ward Avenue, Honolulu, Hawaii.

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

A. I am a Senior Planning Engineer in the Generation Planning Division in the Power Supply Services Department at Hawaiian Electric Company, Inc. ("HECO"). I am submitting testimony on behalf of Hawaii Electric Light Company, Inc. ("HELCO").

Q. Have you sponsored testimony in this proceeding?

A. Yes. I submitted written direct testimony, exhibits, and supporting workpapers as HELCO T-4.

Q. What areas will your rebuttal testimony cover?

A. My rebuttal testimony will:

1) provide updated, final 2006 test year estimates for fuel oil expense, fuel related expense, generation efficiency factor, and fuel inventory;
2) describe the process by which HELCO and the Consumer Advocate reached agreement on the final 2006 test year estimates for fuel oil expense, fuel related expense, generation efficiency factor, and fuel inventory;
3) describe the adjustments made in the production simulation to arrive at the final 2006 test year estimates for fuel oil expense, fuel related expense, generation efficiency factor, and fuel inventory; and
4) address generation capacity issues raised by the Position Statement of the Keahole Defense Coalition ("KDC") relevant to the 2000 to present timeframe.

1 UPDATED 2006 TEST YEAR ESTIMATES

2 Q. What are the updated, final normalized 2006 test year estimates for the items in
3 your area of responsibility?

4 A. The updated, final normalized test year estimates in my area of responsibility are:

Test Year 2006		Units
1) Fuel Expense	78,583,400	$
a) Fuel Oil Expense	78,090,700	$
b) Fuel Related Expense	492,800	$
2) Fuel Price		
a) HELCO Shipman/Hill Industrial Fuel Oil	57.0902	$/BBL
b) HELCO Puna Industrial Fuel Oil	58.3389	$/BBL
c) HELCO Puna Diesel Fuel	86.7656	$/BBL
d) HELCO Kanoelehua Diesel Fuel	86.7252	$/BBL
e) HELCO Waimea Diesel Fuel	87.7341	$/BBL
f) HELCO Keahole Diesel Fuel	88.0456	$/BBL
g) Distributed Generators Diesel Fuel	94.0338	$/BBL
3) Purchased Energy Forecast	709.256	GWH
a) HEP	419.745	GWH
b) PGV	221.944	GWH
c) AEC Wind	4.841	GWH
d) HRD Wind	34.225	GWH
e) Wailuku River Hydro	27.496	GWH
f) Other IPP Hydro	1.008	GWH
4) Efficiency Factor (Sales Heat Rate)	MBTU / KWH SALES	
a) Steam	0.015615	
b) Diesel	0.013526	
c) Wind/Hydro	0.014826	
5) Fuel Inventory	8,240,900	$

30 Q. Which exhibits and workpapers provide the details of these test year estimates?

31 A. The exhibits that provide the details for these test year estimates can be found on
32 HELCO-R-401 to 404 for fuel oil expenses, HELCO-R-405 for fuel related
33 expenses, HELCO-R-406 for test year fuel efficiency, and HELCO-R-408 for

fuel oil inventory. The exhibits reference the appropriate workpapers that contain detailed calculations of the test year estimates.

Q. How were the updated, final normalized 2006 test year estimates for fuel oil expense, fuel related expense, fuel inventory, purchased energy forecast, and efficiency factor determined?

A. The updated, final normalized 2006 test year estimates for these items were determined by performing a computer production simulation for the test year using updated inputs that were provided (to the extent they were available) in HELCO T-4's response to CA-IR-447 and CA-IR-448 and other updated inputs that are described later in my testimony under the section titled "Adjustments to the Production Simulation."

PROCESS TO REACH AGREEMENT ON THE FINAL 2006 TEST YEAR ESTIMATES

Q. Does the Consumer Advocate agree with the final 2006 test year estimates for fuel oil expense, fuel related expense, generation efficiency factor, and fuel inventory as shown above?

A. Yes, they do. In a settlement discussion held between HECO/HELCO and the Consumer Advocate on March 15, 2007, the Consumer Advocate agreed to accept HELCO's final 2006 test year values shown above in the interest of reducing the number of areas of disagreement in this proceeding.

Q. Please describe the process by which HELCO and the Consumer Advocate reached agreement on the final 2006 test year estimates for fuel oil expense, fuel related expense, generation efficiency factor, and fuel inventory.

A. HELCO submitted its initial 2006 test year estimates for fuel oil expense, fuel related expense, generation efficiency factor, and fuel inventory in its direct testimony in HELCO T-4 on May 5, 2006. In response to Consumer Advocate

Information Requests, HELCO submitted, among other things, (1) its input and output data used in its production simulation, (2) relevant historical costs and calculations to support its results, and (3) updated information (in particular, that provided in response to CA-IR-447 and -448). This information submitted by HELCO was either (a) used to determine test year fuel oil expense, fuel related expense, generation efficiency factor, and fuel inventory, or (b) going to be used in an updated production simulation run or in updated calculations for its rebuttal testimony. Using the information provided by HELCO and using its own production simulation model (which is different from the P-Month model used by HELCO), the Consumer Advocate prepared its own estimates of test year fuel oil expense, fuel related expense, generation efficiency factor, and fuel inventory. The Consumer Advocate provided its results in its direct testimony on February 21, 2007. A comparison of HELCO's direct testimony values and the Consumer Advocate's direct testimony values is shown in HELCO-R-401. To help determine the reasons for differences between HELCO's and the Consumer Advocate's results, HELCO submitted Information Requests to the Consumer Advocate and, in the process, also provided additional information that became available since HELCO submitted its responses to the Consumer Advocate's Information Requests. The Consumer Advocate submitted its responses and the information requested by HELCO on March 6-7, 2007. On March 12, 2007, HECO/HELCO and the Consumer Advocate held a settlement conference to discuss the reasons for the differences between HELCO's and the Consumer Advocates test year estimates. Among the reasons for the differences were (i) HELCO's and the Consumer Advocate's use of different production simulation models, which can produce different results even with identical inputs, (ii) the

Consumer Advocate had not yet incorporated some of the updated information into its production simulation (for example, the corrections and updates to some of the as-available generation provided by HELCO T-4 in response to CA-IR-448) and (iii) minor errors discovered in both HELCO's and the Consumer Advocate's production simulation runs. HELCO ran a production simulation using the updated information (which the Consumer Advocate agreed with, as I explain later in my testimony) and arrived at the updated 2006 test year estimates for fuel oil expense, fuel related expense, generation efficiency factor, and fuel inventory. These results were provided to the Consumer Advocate. On March 15, 2007, HECO/HELCO and the Consumer Advocate held another settlement conference and discussed the production simulation results. At this conference, the Consumer Advocate agreed to accept HELCO's updated test year values shown above because the differences were relatively small and agreement would be in the interest of reducing the number of areas of disagreement in this proceeding.

HELCO's final test year estimates are shown in HELCO-R-401, under the column titled "Rebuttal (Settlement)."

Q. What was the extent of the differences between HELCO's final test year estimates and the Consumer Advocate's test year estimates?

A. HELCO's final test year estimate for fuel oil expense is $78,090,700. The Consumer Advocate's estimate for test year fuel oil expense was $77,449,800, which was $640,900, or 0.82% lower than HELCO's estimate.

HELCO's final test year estimate for fuel related expense is $492,800. The Consumer Advocate's estimate for test year fuel related expense was $425,900, which was $66,900, or 13.57% lower than HELCO's estimate.

HELCO's final test year estimate for fuel inventory is $8,240,900. The Consumer Advocate's estimate for test year fuel inventory was $8,230,758, which was $10,142, or 0.12% lower than HELCO's estimate.

ADJUSTMENTS TO THE PRODUCTION SIMULATION

Q. What adjustments have been made in the production simulation in your rebuttal testimony?

A. Adjustments have been made in the production simulation to account for the following:

1) revised hourly pattern files for Shipman 3 and Shipman 4 operation;
2) revised minimum ratings for Hamakua Energy Partners, L.P. ("HEP");
3) revised hourly variable O&M costs for CT3, CT4, and CT5;
4) revised generating unit "heat rate constants" for CT3;
5) updated energy production for certain non-firm units;
6) updated start-up costs for Shipman propane;
7) revised usable and unusable fuel tank capacities;
8) inclusion of Ocean Cargo Insurance in fuel related expenses;
9) updated start-up costs for Hill propane;
10) updated fuel additives and Petrospect costs; and
11) updated ignitor diesel fuel costs.

Hourly Pattern File for Shipman Operation

Q. What change was made to hourly pattern file used by the production simulation to model the operation of the Shipman 3 and Shipman 4 units?

A. The Shipman 3 and Shipman 4 hourly pattern file was corrected so that the production simulation model would operate these units during the hours from 7:00 am to 9:00 pm as indicated in HELCO T-4's response to CA-IR-448. In the

production simulation used for the direct testimony, Shipman 3 and Shipman 4 were incorrectly operating only until 8:00 pm.

Minimum Ratings for HEP

Q. What change was made to the minimum ratings of HEP?

A. The minimum rating of HEP with one CT operating in simple cycle mode was changed to 5 MW from 6 MW as identified in HELCO T-4's response to CA-IR-448. The minimum rating of HEP with two CTs operating in combined cycle mode was changed to 16 MW from 12 MW as identified in HELCO's response to CA-SIR-30. The corrections are shown on HELCO-RWP-404, page 97 and a comparison of HELCO's direct and rebuttal positions are shown in the table below.

HEP Minimum Rating	Direct Testimony	Rebuttal Testimony
1 CT simple cycle	6 MW	5 MW
2 CT combined cycle	12 MW	16 MW

Hourly Variable O&M Costs

Q. What change was made to the hourly variable O&M costs?

A. The variable O&M costs ($/hour) for Puna CT3, Keahole CT4, and Keahole CT5 were corrected as indicated in HELCO T-4's response to CA-IR-448 and is shown on HELCO-RWP-404, page 98. The corrected variable O&M costs for these units are 122.738332, 117.275518, and 117.275518, respectively, and a comparison of HELCO's direct and rebuttal positions are shown below.

Variable O&M ($/hour)	Direct Testimony	Rebuttal Testimony
Puna CT3	115.738332	122.738332

Variable O&M ($/hour)	Direct Testimony	Rebuttal Testimony
Keahole CT4	110.275518	117.275518
Keahole CT5	110.275518	117.275518

Generating Unit "Heat Rate Constants"

Q. What change was made to generating unit "heat rate constants"?

A. The heat rate constants for Puna CT3 were revised as shown in HELCO-RWP-404, page 97. The correct A, B and C coefficients are 49.384232, 7.6807581 and 0.0309678, respectively.

Heat Rate Constants	Direct Testimony	Rebuttal Testimony
A	50.860532	49.384232
B	8.5793772	7.6807581
C	0.0088151	0.0309678

Q. Why were the heat rate constants for Puna CT-3 revised?

A. HELCO conducted efficiency tests on Puna CT-3 in December 2005 and January 2006. The heat rate constants were revised to best fit the curve. The revised heat rate constants were inadvertently not included in the production simulation used for the direct testimony. The correct heat rate constants for Puna CT-3 were provided in HELCO's response to CA-IR-38.

Updated Energy Production for Certain Non-firm Units

Q. What change was made to the energy production of the non-firm units?

A. The energy production of the Lalamilo wind farm, Waiau hydro, Wailuku River Hydro, and other IPP Hydro were updated. The energy production of the other non-firm units were not changed.

Q. Why was the energy production for these units updated?

A. At the time the production simulation for my direct testimony was filed in May 2006, HELCO had only complete calendar year data for 2005 for these non-firm units. At the time HELCO T-4 filed its response to CA-IR-447 on December 1, 2006, HELCO had additional actual data covering the period January to October 2006. HELCO T-4 provided that data in response to CA-IR-447. At the present time, HELCO has complete data for these non-firm units covering the 2006 calendar year and HELCO has updated the production simulation to incorporate the additional year of data. New five-year (2002-2006) averages were calculated. The updated energy production for these units are 1,437 MWH for Lalamilo wind farm, 3,846 MWH for Waiau Hydro, 27,496 MWH for Wailuku River Hydro, and 1,008 MWH for other IPP Hydro, as shown on HELCO-RWP-404, pages 103, 105, and 107.

Test Year Generation (MWH)	Direct Testimony	Rebuttal Testimony
Lalamilo Wind Farm	1,691	1,437
Waiau Hydro	3,550	3,846
Wailuku River Hydro	27,475	27,496
Other IPP Hydro	1,021	1,008

Q. Did the Consumer Advocate object to these changes?

A. No. In response to HELCO/CA-IR-210, part b., the Consumer Advocate stated they did not object to these changes.

Q. Why weren't the energy productions for other non-firm units, such as Apollo Energy Corporation ("AEC") wind farm and Hawi Renewable Development ("HRD") updated?

A. The energy productions for these units were not updated because HRD was installed in March 2006 and does not have a complete year of data, and AEC shutdown their existing operation in August 2006 to begin construction of repowering their wind farm.

Updated Start-up Costs for Shipman Propane

Q. What changes were made to the start-up costs for Shipman Propane?

A. After HELCO T-4 provided responses to CA-IR-447 and CA-IR-448, and after reviewing the actual fuel related expenses for 2006, an error was discovered regarding the Shipman propane expense. The production simulation model was counting all the starts for Shipman 3 and Shipman 4 as "cold" starts. In reality, only the starts after shutdowns exceeding 12 hours should be counted as cold starts and all other starts should be "warm" starts. The production simulation model has been revised to account for the starts correctly. Based on the actual 2006 propane expense and total number of starts, the typical fuel requirement per start is approximately 17.7 MBTU. The production simulation was updated with the 17.7 MBTU fuel requirement per start (for both cold and warm starts) and the total number of starts for Shipman 3 and Shipman 4 remained at 524 starts. The resulting Shipman propane amount for the test year is $92,800, as shown on HELCO-RWP-405, page 1. A comparison of HELCO's direct and rebuttal positions are shown below:

Propane Costs ($)	Direct Testimony	Rebuttal Testimony
Shipman	$228,900	$92,800

Q. Did the Consumer Advocate object to these changes?

A. No. In response to HELCO/CA-IR-218, part c., the Consumer Advocate stated they did not object to these changes.

Revised Fuel Tank Capacities

Q. What changes were made to the fuel tank capacities?

A. As indicated in HELCO T-4's response to CA-IR-448, corrections were made to the unusable and usable tank capacities for Shipman/Waiakea Tank No. 3, Keahole Tank No. 3, and Keahole Tank No. 4. The corrected fuel tank capacities are shown on HELCO-RWP-408, pages 1-2. The changes are shown in the table below:

Heel or Unusable (BBL)	Direct Testimony	Rebuttal Testimony
Shipman/Waiakea Tank No. 3	1,428	1,372
Shipman/Waiakea Subtotal	2,128	2,072
IFO Grand Total	13,536	15,480
Keahole Tank No. 3	350	550
Keahole Tank No. 4	350	550
Keahole Subtotal	1,429	1,829
Diesel Grand Total	2,773	3,173

Usable Capacity (BBL)	Direct Testimony	Rebuttal Testimony
Shipman/Waiakea Tank No. 3	3,374	3,430
Shipman/Waiakea Subtotal	4,249	4,305
IFO Grand Total	52,319	52,375
Keahole Tank No. 3	13,400	13,200
Keahole Tank No. 4	13,400	13,200

Keahole Subtotal	34,671	34,271
Diesel Grand Total	48,542	48,142

Q. Why were the changes made?

A. These changes were made to correct the inadvertent error in the amounts used in the direct testimony.

Q. Did the Consumer Advocate object to these changes?

A. No. In response to HELCO/CA-IR-216, the Consumer Advocate stated they did not object to these changes.

Ocean Cargo Insurance

Q. What is ocean cargo insurance?

A. Ocean cargo insurance is paid by HELCO for the transportation of fuel from Oahu. This cost item was inadvertently omitted from the Fuel Related Expense as indicated in HELCO T-4's response to CA-IR-448.

Q. How is the ocean cargo insurance being incorporated into the fuel related expense?

A. As indicated in HELCO T-4's response to CA-IR-448, the ocean cargo insurance should have been 0.1175% of the fuel oil expense. The ocean cargo insurance rate changed in December 2006 from 0.1175% to 0.1000%. HELCO has calculated the ocean cargo insurance expense for the 2006 test year by using the 0.1175% of fuel expense for January thru November and 0.1000% of fuel expense for December and is shown on HELCO-RWP-405, page 3. The resulting ocean cargo insurance amount for the test year is $90,627.

	Direct Testimony	Rebuttal Testimony
Ocean Cargo Insurance Cost ($)	$0	$90,627

Q. Did the Consumer Advocate object to these changes?

A. No. In response to HELCO/CA-IR-218, part b., the Consumer Advocate stated they did not object to these changes.

Updated Start-up Costs for Hill Propane

Q. What change was made to the start-up costs for Hill propane?

A. The start-up costs for Hill propane in the direct testimony was calculated based on a 5-year average using the years 2001-2005. HELCO has acquired complete data for the 2006 calendar year and has updated the 5-year average using the years 2002-2006. The updated start-up costs for Hill propane is $3,389, as shown on HELCO-RWP-405, page 1 and a comparison of HELCO's direct and rebuttal positions are shown below.

Propane Costs ($)	Direct Testimony	Rebuttal Testimony
Hill	$3,278	$3,389

Q. Did the Consumer Advocate object to these changes?

A. No. In response to HELCO/CA-IR-218, part d., the Consumer Advocate stated they did not object to these changes.

Updated Fuel Additives and Petrospect Costs

Q. What change was made to the Fuel Additives cost?

A. The Fuel Additives for the 2006 test year have been updated to reflect the actual expenses incurred in 2006. The fuel additive cost for 2006 was substantially higher than in prior years because HELCO purchased two different fuel additives, one for the Puna steam unit (SDR) and one for the Hill units (MH1000). The SDR fuel additive for Puna was initially being tested free of charge prior to 2006 in an agreement with the supplier. Since the additive proved useful by

maintaining the tubular air heater exit gas temperatures (and thereby reducing the gas' fouling effects), HELCO began purchasing the fuel additive for continued use at Puna with the potential of eliminating the need to blow soot. The updated Fuel Additives cost for the test year is $230,913, as shown on HELCO-RWP-405, page 2. A comparison of HELCO's direct and rebuttal positions are shown below.

	Direct Testimony	Rebuttal Testimony
Fuel Additive	$121,306	$230,913

Q. What change was made to the Petrospect cost?

A. The Petrospect cost for the 2006 test year has been updated to reflect the actual expenses incurred in 2006. The updated Petrospect cost for the test year is $75,055, as shown on HELCO-RWP-405, page 2. A comparison of HELCO's direct and rebuttal positions are shown below.

	Direct Testimony	Rebuttal Testimony
Petrospect	$71,256	$75,055

Q. Did the Consumer Advocate object to the changes to either the Fuel Additive cost or the Petrospect cost?

A. No. In response to HELCO/CA-IR-218, part d., the Consumer Advocate stated they did not object to these changes.

<u>Updated Ignitor Diesel Fuel Amounts</u>

Q. What change was made to the Ignitor Diesel Fuel amounts?

A. The Ignitor Diesel Fuel amounts in the direct testimony were calculated based on a 5-year average using the years 2001-2005. HELCO has complete data for the

2006 calendar year and updated the 5-year average using the years 2002-2006. The updated Ignitor Diesel Fuel amount is 826 barrels, as shown on HELCO-RWP-408, page 4.

Ignitor Diesel Fuel Consumption (Barrels)	Direct Testimony	Rebuttal Testimony
Hill Plant	562	523
Puna Plant	274	303

Q. Did the Consumer Advocate object to these changes?

A. No. In response to HELCO/CA-IR-218, part d., the Consumer Advocate stated they did not object to these changes.

HELCO's CAPACITY SITUATION

Q. What will you be covering in this section of your rebuttal testimony?

A. In this section of my rebuttal testimony, I will be covering HELCO's generation capacity situation from 2000 to present. Mr. Jose Dizon covers HELCO's capacity situation from the early 1990s to 2000 in HELCO RT-4A. More specifically, I will cover for the period 2000 to present:

1) the need for Keahole CT-5,
2) the steps to accelerate the installation of CT-5,
3) alternatives to CT-5, and
4) the benefits of CT-5.

Need for Keahole CT-5

Q. In your direct testimony, you described the changes to HELCO's generating system since HELCO's previous rate case in Docket No. 99-0207 (HELCO Test Year 2000 Rate Case). Among the changes to the generating system were the

additions of Keahole CT-4 and CT-5 on May 25, 2004 and June 30, 2004, respectively. What is the Consumer Advocate's position with respect to the need for Keahole CT-4 and CT-5?

A. The Consumer Advocate does not take issue with the need for Keahole CT-4 and CT-5. In CA-T-3, page 51, lines 4 to 9, Mr. Carver stated:

> Q. In this proceeding, is the Consumer Advocate contesting HELCO's decision to add generation in West Hawaii or any asserted need to add generation capacity in order to meet growing demand for electricity?
>
> A. No.

Q. What is KDC's position with respect to the need for Keahole CT-4 and CT-5?

A. KDC did not assert in its Position Statement, dated February 18, 2007, in this docket that CT-4 was not needed. However, with respect to the need for CT-5, KDC's position is not clear. KDC asserted in its Position Statement, on page 1, "KDC objects to [the] cost of CT-5 and its related facilities to the extent that CT-5 is not used and useful for utility purposes." KDC claimed on page 2 that CT-5 represented "unnecessary capacity," contending that HELCO "[a]dded CT-5 to the Station even though there was no evidence that CT-5's additional capacity was or is warranted or that CT-5 would be or is used or useful." KDC further contended on page 46 that, "The Commission should determine that CT-5 is not used and useful for utility purposes and the Commission should exclude the cost items referred to above from the Company's rate base for reasons stated above." However, in responding to HELCO/KDC-IR-125(b), KDC seemed to retreat from its Position Statement. HELCO asked whether, "In KDC's estimation, is CT-5 'used and useful for utility purposes'?" KDC avoided answering the question directly and responded, "KDC has left that determination to the Commission as the Commission stated in Order 14284, Docket No. 7623." KDC

avoided answering a similar inquiry in HELCO/KDC-IR-137(a) by simply referring to its response to HELCO/KDC-IR-125.

Q. What is HELCO's response to KDC's assertion that the additional capacity provided by CT-5 was or is not needed?

A. Keahole CT-5 was and is needed to maintain an adequate generation reserve margin for the HELCO system. Moreover, the availability of CT-5 provides additional benefits that are and will need to be utilized by HELCO because of its location at Keahole including, (1) helping to mitigate potential transmission line overloads in the event of outages of certain transmission lines, (2) helping to reduce the need to install an additional cross-island transmission line to carry power from East Hawaii, where most of the generating resources are located, to West Hawaii, where about one-half of the electrical power on the island is consumed, (3) reducing fuel costs by reducing the amount of transmission system losses and by providing more efficient generation at Keahole that is used to mitigate potential transmission line overloads, (4) facilitating the reconductoring of certain transmission lines, and (5) helping to accommodate renewable energy on the system.

<u>CT-5 Helps Maintain an Adequate Reserve Margin</u>

Q. What is "reserve margin"?

A. Reserve margin is the amount of reserve capacity on the system over and above the system peak. Reserve margin may be expressed in MW or as a percentage of the system peak. For example, if the system peak demand is 200 MW and the total installed capacity is 240 MW, then the reserve margin is 40 MW, or 40 MW / 200 MW = 20%.

Q. Why is an adequate reserve margin necessary for any generating system?

A. An adequate reserve margin is necessary for several reasons. These include:

1) the need to allow generating units to be taken out of service for routine maintenance or overhauls;

2) the need to allow for the unexpected outages of generating units that occur from time to time. These unexpected outages are called forced outages;

3) The need to allow for growth in demand over time. It is impractical and not economical to install a generating unit every year to accommodate each year's growth in demand. Therefore, there needs to be sufficient generating capacity on the system to accommodate several years of demand growth; and

4) the need to account for the possibility that peak demand may be higher than expected.

Q. How does HELCO determine the adequacy of its reserve margin?

A. HELCO determines the adequacy of its reserve margin through the application of its capacity planning criteria. HELCO's capacity planning criteria call for having a sufficient amount of reserve capacity to be able to serve the expected system peak demand even if the largest available unit is unexpectedly lost from service and a unit is already unavailable due to planned maintenance. (See Exhibit HELCO-R-410 for a copy of HELCO's capacity planning criteria.)

HELCO's planning criteria also include a consideration of maintaining a minimum reserve margin of approximately 20%. The 20% value is a guideline and may be higher depending on the conditions on the system. As stated in HELCO's 2007 Adequacy of Supply report, filed with the Commission on January 30, 2007, footnote 3 on page 2 states, "HELCO is evaluating whether and to what extent reserve margins higher than those produced by the application of

the capacity planning criteria should be targeted based on factors (such as unit availabilities and the need to account for fluctuations in intermittent generation on the system) not explicitly considered by the criteria." One example of when a reserve margin higher than 20% would be warranted is when there is a higher than normal expectation of multiple generating unit outages. In other words, the capacity planning criteria account for the loss of the largest unit during the system peak. However, there may be a higher probability that multiple units (having an aggregate capacity greater than that of the largest unit) will be forced out of service during the system peak. In this case, a higher reserve margin would be warranted.

Furthermore, the actual reserve margin on the system is a value calculated from the capacity on the system. Capacity may be added to the system for reasons other than to meet the capacity planning criteria. HELCO's capacity planning criteria document further states:

> "The actual commercial operation date for the next unit to be added shall be determined using these rules as guides, with due consideration given to short-term operating conditions, equipment procurement, construction, regulatory approvals, financial and other constraints, etc."

HELCO-R-410, page 2.

Q. Has the Commission recognized the need to consider factors other than those contained in generation planning criteria?

A. Yes. The Commission has recognized that the timing of generation additions cannot be determined solely through application of the generation planning criteria, because the criteria do not consider a number of factors. The Commission's decision in Docket No. 7623 recognized the need to consider factors other than those explicitly considered in the generation planning criteria,

such as power purchase uncertainties in generation planning, and specifically noted the problems associated with HELCO's power purchases from non-utility generators, including Hamakua Sugar, HCPC, and PGV. (Decision and Order No. 14282 (September 22, 1995), pages 8-9.) The Commission also recognized in Docket No. 6643, in which it approved HELCO's commitment of funds for CT-3, that unit need may be based on uncertainty with respect to the addition of QF capacity (in that case, PGV), as well as application of the generation capacity expansion criteria. (Decision and Order No. 11556 (March 23, 1992), pages 5-6.)

Q. Has HELCO incorporated these considerations into its Integrated Resource Planning?

A. Yes. HELCO's IRP-2 report, filed with the Commission on September 1, 1998, in Docket No. 97-0349, stated on page 5-1:

> "It should be noted that the Generation Addition Rule[1] is applicable to long-range generation expansion studies. HELCO does not determine the need for new generation based solely on the application of this Rule. As capacity needs become imminent, it is essential that HELCO broaden its consideration to ensure timely installation of generation capacity necessary to meet its customers' energy needs."

As stated in the IRP-2 report on page 5-1, near-term considerations for adding capacity may include:

- the current condition and rated capacity of existing units,
- the preferred mix of generation resources to meet varying daily and seasonal demand patterns at the lowest reasonable capital and operating cost,
- the forecasted minimum demand,

[1] Refers to Rule 1 in HELCO's capacity planning criteria (HELCO-R-410).

- required power purchase obligations and contract terminations,
- the unpredictable output of supplemental resources,
- the uncertainties surrounding Non-utility generation (NUG) resources,
- transmission system considerations, and
- system stability considerations for HELCO's isolated system.

Q. Please explain how CT-5 helps maintain an adequate reserve margin.

A. The presence of CT-5 on the system helps maintain a sufficient amount of reserve margin to be able to serve the expected peak demand even with a unit unavailable due to planned maintenance and with the largest available unit forced out of service due to an unexpected problem. CT-5 also helps maintain generating system reliability in the event small to large increments of generating capacity are lost from service for extended periods of time, as has happened with the Puna Geothermal Venture ("PGV") 30 MW geothermal unit and the Hamakua Energy Partners, L.P. ("HEP") 60 MW combined cycle unit. I will explain this in further detail later in my testimony.

In HELCO's 2007 Adequacy of Supply report, filed with the Commission on January 30, 2007, HELCO reported a reserve margin of 32.4% over the 2006 system peak based on a total installed capacity of 266.6 MW-net[2] and a peak demand of 201.3 MW-net. Without the 22 MW from CT-5, HELCO's reserve margin would have been 22% over the 2006 system peak. This is very near HELCO's 20% minimum reserve margin guideline. By 2009, HELCO's system peak is forecast to be 215.5 MW-net. Even assuming PGV at its rating of 30 MW (despite it being frequently below 30 MW), HELCO's reserve margin in

[2] PGV's normal rating is 30 MW. In July 2006, PGV began experiencing problems with well production. At the time of the system peak, PGV's output was 24.7 MW.

2009 would be 16%, or below the 20% minimum reserve margin guideline, without 22 MW from CT-5 and before the addition of 16 MW from Keahole ST-7. Having CT-5 will help maintain an adequate reserve margin until ST-7 can be installed.

Q. Would it have been better from a capacity planning standpoint for HELCO to have kept HCPC on the system, acquired additional capacity from PGV, or purchased capacity from another Independent Power Producer to maintain the necessary reserve margin, as KDC appears to contend?

A. No. I will explain the problems with such an approach later in my testimony in the section titled "Alternatives to CT-5."

Q. Please explain how CT-4 and CT-5 help maintain generating system reliability in the event large increments of generating capacity are lost from service for extended periods of time.

A. As I indicated earlier, HELCO has actually experienced several instances when small to large increments of generating capacity from PGV were unavailable. For example, in April 2002, the output of the PGV plant was derated to an average of 5.6 MW for at least 8 months due a problem with one of their supply wells. This was a significant loss of 24.4 MW of generation for an extended period of time. (This is greater than the rating of CT-4 or CT-5, which have a normal top load rating of 22 MW-net.)

HELCO has also experienced the loss of small to large increments of generating capacity from the HEP 60 MW combined cycle unit. For example, in the period from January 9, 2006 to January 17, 2006, HEP experienced an unexpected outage of its steam unit. The steam unit was scheduled for an outage of five days from January 9, but it experienced a forced outage and was not

returned until January 18. HEP was able to produce only approximately 40 MW of its 60 MW output with two combustion turbines operating in simple cycle mode. However, the cost of operating HEP in simple cycle CT mode is higher than operating CT-4, CT-5, and most of HELCO's existing units. Therefore, although HEP was available to produce 40 MW, due to economic dispatch HEP was operated at approximately 20 MW with one combustion turbine in simple cycle operation. Both Keahole CT-4 and CT-5 were operating to serve the system load economically.

It appears that these significant deratings of PGV and HEP are not uncommon. Having CT-5 on the system provides a "cushion" of reserve margin to maintain generating system reliability during events like these.

<u>CT-5 Helps Mitigate Potential Transmission Line Overloads</u>

Q. Please explain how CT-5 helps mitigate potential transmission line overloads.

A. As I explained in my direct testimony, in HELCO T-4, page 23, line 19 to page 25, line 11, and in response to CA-SIR-3, CT-4 or CT-5 is operated for more hours, at higher output levels, and generate more energy than it otherwise would under economic dispatch in order to mitigate the potential for line overloads of certain transmission lines under contingency situations where certain other transmission lines are unexpectedly lost from service. CT-4 alone cannot serve this function as it must sometimes be taken out of service for routine maintenance, or at times, the unit may be forced out of service due to an unexpected problem. CT-4 and CT-5 share this duty to mitigate potential transmission line overloads.

CT-5 Helps to Reduce the Need to Install Additional Cross-Island Transmission Lines

Q. Please explain how CT-5 helps to reduce the need to install additional cross-island transmission lines.

A. Currently, there are four cross-island transmission lines that carry power from the east side of the island, where most of the generation is situated, to the west side, where about one-half of the island's demand is. As the imbalance between demand and generation on the west side increases, these cross-island transmission lines may reach the limit that they can safely and reliably carry power. Once they reach their limit, additional east-to-west (i.e., cross-island) transmission capacity would need to be installed. Alternatively, locating generating capacity in the west side of the island (i.e., at Keahole), reduces the imbalance between demand and generation which reduces the need to export power from east to west and therefore helps to reduce the need to install additional cross-island transmission capacity.

As Mr. Jose Dizon stated in HELCO's previous rate case, Test Year 2000, Docket No. 99-0207, HELCO RT-4A, page 16, lines 8-11, "Locating future power generation on the West side will allow HELCO to postpone construction of additional east-west transmission lines, minimize transmission line losses, and provide greater system stability during power disturbances."

CT-5 Helps Reduce Fuel Costs

Q. Please explain how CT-5 helps reduce fuel costs.

A. CT-5 helps reduce fuel costs in two ways. First, by providing generation on the west side of the island since 2004, it is estimated that system transmission losses have been reduced by 0.5%, saving about $1.0 million per year.

Second, had CT-5 (and CT-4) been located on the east side of the island, less efficient existing generation at Keahole (i.e., Keahole CT-2) would need to be run for more hours and generate more energy than it otherwise would under economic dispatch in order to mitigate the potential for overloading certain transmission lines under contingency situations where certain other transmission lines are unexpectedly lost from service. For example, the heat rate of Keahole CT-2 is about 14,700 Btu/kWh-net at full load. By comparison, the heat rate of CT-5 (or CT-4) is about 12,200 Btu/kWh-net at full load. It is estimated that running CT-5 (or CT-4) instead of CT-2 saves about $1.9 million per year.

Furthermore, these cost savings will increase when CT-4 and CT-5 are converted to a dual train combined cycle unit with the addition of ST-7 in 2009. This is because the units will be in baseload operation and further reduce transmission losses and heat rate.

<u>CT-5 Will Facilitate the Reconductoring of the 6800, 7200 and 7300 Transmission Lines</u>

Q. What are the 6800, 7200 and 7300 transmission lines?

A. The 69 kilovolt ("kV") transmission line that runs from Keamuku to Keahole is designated as the 6800 line. The 69 kV line that runs from Waimea to Keamuku is designated as the 7200 line. The 69 kV line that runs from Waimea to Ouli is designated as the 7300 line. These lines are located in the northwestern part of the island and, as I explained in my direct testimony on page 24 and in response to CA-SIR-3, may become overloaded under certain situations. Therefore, HELCO plans to "reconductor" these lines, i.e., replace the existing conductors with new conductors with higher power carrying capacity, in the coming years.

Q. How will the presence of CT-5 facilitate the reconductoring of these transmission lines?

A. The reconductoring work on the 6800, 7200 and 7300 lines will be done sequentially. While the reconductoring work is in progress, Keahole CT-5, along with Keahole Units CT-2, CT-4 and diesel units D21 to 23, may be called upon to aide in minimizing the line loadings such that the remaining in-service transmission lines are within their continuous rating depending on the system load.

As shown in Attachment 1 in response to CA-IR-61 provided pursuant to Protective Order No. 22593, dated June 30, 2006, it is estimated that about 40 MW of Keahole generation is expected to be required, depending on the system load, to keep the temperature of the 7200 and 7300 lines low enough to give the HELCO system operator sufficient time to respond, should one of these in-service transmission lines unexpectedly trip out of service. In the event of the trip of one of these lines, the system operator would need time to either ramp up generation at Keahole, if it is possible, or systematically shed load from the system. Without CT-5, if CT-4 is on maintenance, HELCO would have only about 20 MW of generation. As such, HELCO would not have adequate generation to meet the 40 MW requirement.

<u>CT-5 Helps to Accommodate Renewable Energy</u>

Q. Please explain how CT-5 helps to accommodate renewable energy.

A. CT-5 helps to accommodate renewable energy by providing voltage regulation and load following capability, which as-available renewable generating resources (and sometimes even firm renewable resources) are unable to provide. In addition, because CT-5 can be turned off during the off-peak periods, more

renewable energy, either as-available or firm, can be accepted by the system during this period.

Steps to Accelerate the Installation of CT-4 and CT-5

Q. In November 2002, the Third Circuit Court issued a "stop work" order such that no further installation or construction activity at Keahole on CT-4 or CT-5 could continue. When did installation work on CT-4 and CT-5 resume?

A. On November 12, 2003, the Third Circuit Court vacated the stop work order following its acceptance of a settlement agreement between HELCO, KDC, the Department of Hawaiian Homelands, and other stakeholders. This settlement agreement was reached through a mediation process that helped solve the complicated legal disputes surrounding Keahole. Work to install CT-4 and CT-5 resumed shortly after the stop work order was vacated.

Q. Did HELCO then pursue an accelerated schedule to install CT-4 and CT-5?

A. Yes, it did.

Q. Why did HELCO pursue an accelerated schedule to install CT-4 and CT-5?

A. First, let me set some context. When the CT-4 and CT-5 project was halted, it was approximately 85% complete. Therefore, once construction was allowed to resume, it was prudent to complete the remaining 15% of the work without delay, and both CT-4 and CT-5 became operational within approximately 6 months. Even after the settlement, one of the project opponents that did not participate in the settlement discussions (Waimana Enterprises, Inc.) continued to pursue ways to block the installation of the units. HELCO did not want to take the risk that the project would somehow be further delayed even though 95% or 99% complete. HELCO therefore took the opportunity to complete the installation of west-side generation, something for which it had vigorously fought for over 10 years.

Q. What was the situation with respect to HELCO's short-term PPA with Hilo Coast Power Company ("HCPC") which KDC refers to on page 31 of its Position Statement?

A. As stated in my direct testimony HELCO T-4, given HELCO's capacity situation at the time, HELCO negotiated a short-term power purchase agreement ("PPA") with HCPC in 1999 so that HCPC would provide capacity during the period in which the installation of CT-4 and CT-5 was delayed. The Second Amended and Restated PPA ("Second Amended PPA") had a term "from January 1, 2000 to and including December 31, 2004", and would be continued for one-year periods "unless either party gives written notice of termination by May 30 of the year of termination." (Section XIV, paragraph A, page 20 of the Second Amended PPA.)

Since there was considerable uncertainty as to when CT-4 and CT-5 would actually be on line and how long the capacity from HCPC would be needed, the Second Amended PPA contained a section on HELCO's right to early termination. The Second Amended PPA stated, "HELCO may choose to terminate this Contract as of January 1, 2002, 2003 or 2004, by giving HCPC written notice of such termination no later than May 30 of the previous year." (Section XIV, paragraph B, page 21 of the Second Amended PPA.)

These provisions in the Second Amended PPA set some milestones as to when decisions needed to be made relative to termination of the contract, depending on the status of the installation of CT-4 and CT-5. For example, if there was reasonable assurance that the installation of CT-4 and CT-5 could be completed by May 30th of a particular year, then the written notice of termination could be issued to HCPC such that the Second Amended PPA would be terminated by January 1st of the subsequent year. If there was not a reasonable

assurance that the installation of CT-4 and CT-5 could be completed by May 30th of a particular year, then the Second Amended PPA would need to continue for an additional year, at a cost of $5,082,000 ($231/kW-year) per contract year.

Therefore, it was beneficial for HELCO to accelerate the installation of CT-4 and CT-5 and to complete it as soon as practicable in order to avoid (1) additional delays from potential legal actions by Waimana or other opponents of the project and (2) incurring additional capacity payment costs from HCPC at a cost of $5,082,000 ($231/kW-yr) per contract year.

Q. When were CT-4 and CT-5 first started up for testing?

A. CT-4 was first fired up on March 18, 2004. It was synchronized to the grid on March 22, 2004. It reached full load on March 26, 2004. It was declared in commercial operation on May 25, 2004.

CT-5 was first fired up on June 1, 2004. It was synchronized to the grid on June 2, 2004. It reached full load on June 7, 2004. It was declared in commercial operation on June 30, 2004.

Q. When was written notice of termination given to HCPC?

A. Written notice of termination was given to HCPC on May 27, 2004. By that date, CT-4 was already in commercial operation and HELCO had reasonable assurance that CT-5 would be commercial operation within the next few weeks. With the written notice, the HCPC Agreement was terminated on January 1, 2005. The capacity from HCPC was not needed at that point and $5,082,000 in annual capacity payments to HCPC were avoided.

<u>Alternatives to CT-5</u>

Q. Should HELCO have kept HCPC on the system and done without CT-5?

A. No, it would have been undesirable for HELCO to have kept HCPC on the system and done without CT-5 for several reasons. First, CT-5 is needed instead

of HCPC because generation is needed on the west side of the island since there is an existing imbalance between the location of load and generation, and most of the load growth is in that part of the island. HELCO has consistently stated since the late 1980s that installation of generation on the west side of the island would mitigate the need to export power from the east side of the island to the west side and reduce the need for additional transmission capacity to carry this power from east to west. HELCO's long-term resource plans in IRP-1[3] and IRP-2[4] called for the installation of three combined cycle units in West Hawaii. As stated earlier in my testimony, HELCO pursued only a short-term contract with HCPC so that HCPC would provide capacity during the period in which the installation of CT-4 and CT-5 was delayed. HCPC is on the east side of the island and output from the plant would exacerbate, not mitigate, the potential for transmission line overloads. CT-5, as I explained in my direct testimony, helps mitigate potential line overloads.

Second, HCPC was contractually bound by several operating constraints, which hampered the flexibility in operating the system. These constraints included fixed dispatch during "Priority Periods," which were 14 hours per day for five consecutive days (Monday through Friday) at a minimum average load level of 18,000 kW and a "Minimum Purchase Obligation" of 60,480,000 kWh during Priority Periods (Section III.A.1 of Second Amended and Restated PPA). In general, HCPC was dispatched at 18 MW from 7:00 am, increased to 22 MW from about 6:00 pm then lowered to 18 MW from 8:00 pm with the plant being shutdown by 10:00 pm. Fixed dispatch meant that the HCPC plant needed to be

[3] Filed on October 15, 1993 in Docket No. 7259.
[4] Filed on September 1, 1998 in Docket No. 97-0349.

operated at the given outputs at the given times. The plant was not allowed to ramp up or down in output to help meet increases or decreases in system demand. This meant that the plant could not contribute to offsetting fluctuations in output from the as-available windfarms and run-of-river hydro plants. Therefore, the burden and wear-and-tear of balancing system supply and demand fell on HELCO's generating units.

Furthermore, if HELCO needed to dispatch HCPC outside of the Priority Periods, adequate notification and scheduling was required for these "Emergency Periods" (Section III.A.2 of Second Amended and Restated PPA.)

Third, the HCPC unit (which was installed in the early 1970s) was becoming more prone to forced outages, given the constant cycling of the unit in recent years, and the lower maintenance expenditures in recent years based on the expectation of a 2004 end-of-service date.

Fourth, the continued operation of HCPC under the terms of the short-term agreement after the HRD wind farm was added in 2005 and the Apollo wind farm is repowered in 2007 also would have constrained HELCO's ability to accept as-available renewable energy from these new facilities. Having CT-5 instead of HCPC enables HELCO to accommodate this type of renewable energy. HCPC had a fixed dispatch. The minimum purchase obligation of the HCPC contract would have eliminated that block of energy from being provided by existing or future renewable energy producers. HELCO's ability to dispatch CT-5 instead of HCPC also allows HELCO to accept renewable energy by also providing frequency and voltage regulation and load following (which the HCPC facility did not) for other resources on the system that do not provide those functions.

In summary, having new, fully dispatchable, generation at Keahole is beneficial from a generating and grid system reliability standpoint. In contrast, HCPC's facility was subject to substantial constraints with respect to its availability and dispatchability, and was located on the grid where it contributed to transmission system concerns rather than helped alleviate them.

Q. Should HELCO have negotiated for additional capacity from PGV and done without CT-4 and CT-5?

A. HELCO did, in fact, acquire an additional 5 MW from PGV in 1996. The Commission approved the purchase of the additional 5 MW in Decision and Order No. 14840, in Docket No. 96-0042, dated August 2, 1996.

Notwithstanding the purchase of this additional capacity from PGV, it would not have been prudent to purchase an additional large increment of capacity from PGV as a substitute for the capacity from CT-5 for three primary reasons. First, similar to HCPC, PGV is located on the east side of the island and would not help mitigate potential line overloads.

Second, since 2002 PGV has experienced significant difficulties in providing the 30 MW of contracted capacity, as summarized below:

1) From April 2002 through the end of 2002, the normal top load rating of PGV averaged only 5.6 MW, a reduction of 24.4 MW from its normal rating of 30 MW, due to a blockage of a source well.

2) PGV was able to gradually restore the output of the plant to about 27 MW by the end of 2003. Its average rating for 2003 was 21 MW.

3) In 2004, PGV generally exported between 25 MW and 26 MW, between 5 and 6 MW less than its contracted capacity.

4) In 2005, PGV redrilled an existing well, then drilled a new production well and new injection well. As a result, PGV was able to export 30 MW with all wells in service and all ten of the Ormat Energy Converters (OEC) in service.

5) In July 2006, PGV began experiencing problems with well production. From July 2006 through the end of 2006, PGV generally exported between 19 MW and 25 MW. PGV has represented that it expects to be restored to the contract export of 30 MW by April 2007.

Third, PGV does not provide dispatchable generation, which CT-4 and CT-5 do. PGV must operate at steady output and generally cannot vary its output to follow increasing or decreasing demand on the system. PGV cannot help offset wind farm power fluctuations, which CT-4 and CT-5 do. PGV does not help regulate system frequency or voltage, which CT-4 and CT-5 do.

Q. Should HELCO have purchased capacity from Kawaihae Cogeneration Partners ("KCP") instead of installing CT-5?

A. No. As explained by Mr. Jose Dizon in HELCO RT-4A, in the section titled "IPP Alternatives," HELCO did not purchase capacity from KCP because KCP did not offer a viable project. As Mr. Dizon stated, the Commission found that, while permitting problems might delay the CT 4 project, Waimana, the developer of the Kawaihae Cogeneration Partners ("KCP") project, had not "presented any viable alternatives to CT 4." (D&O 13050, page 8.)

Furthermore, the estimated cost to interconnect a 60 MW dual train combined cycle unit (the type KCP was proposing) at Kawaihae was approximately $20.1 million (1996-$) for the addition of a new line or

approximately $16.8 million (1996-$) for a reconductoring option[5]. This is a cost HELCO would not have incurred to add CT-5 to the system.

Benefits of CT-5

Q. What are the benefits of having CT-5 on the system?

A. As I explained earlier in my rebuttal testimony, CT-5 (1) helps maintain an adequate generation reserve margin for the HELCO system, (2) helps mitigate potential transmission line overloads in the event of outages of certain transmission lines, (3) helps reduce the need to install an additional cross-island transmission line to carry power from East Hawaii to West Hawaii, where about one-half of the electrical power on the island is consumed, (4) reduces fuel costs by reducing the amount of transmission system losses and by providing more efficient generation at Keahole that is used to mitigate potential transmission line overloads, (5) facilitates the reconductoring of certain transmission lines, and (6) helps to accommodate renewable energy on the system.

Q. Is CT-5 used and useful for utility purposes?

A. Yes, it is. In 2006, CT-5 ran for 4,052 hours and produced 57,700,090 kWh. CT-5 provides needed reserve capacity to enable other units to be taken out of service for planned maintenance. CT-5 also provides reserve capacity in the event other units are forced out of service or if other power plants, such as PGV, are significantly derated for long periods of time. CT-5 also provides the frequency and voltage regulation and load following benefits that I described earlier in my rebuttal testimony.

In the case of CT-5, there is no question but that it is both actually used and useful, and is critical to providing reliable service to customers on the Big Island.

[5] Docket No. 7623, HECO RT-3B, page 6.

Moreover, there would be no basis for a finding that any of HELCO's less used generation is somehow "excessive" now that CT-5 (and CT-4) are available and HELCO's reserve margin has been restored to an acceptable level. It is not feasible for a utility to exactly time the addition of new generation with load growth, since plans for new generation must be based on forecasts and take into account uncertainties, and implementation must be commenced years in advance of the forecast need. I am not aware of any instance in which the Commission has denied the inclusion in rate base of new or existing generating units where (1) the utility had taken prudent steps to meet the future needs of its customers in adding new generation, and (2) the generation challenged as being excess was actually being used. A proposal to exclude the cost of such generation would ignore not only the public service obligation of utilities, but also the realities of resource planning and the adverse financial consequences that would inevitably ensure for the utility and its ratepayers.

SUMMARY

Q. Please summarize your testimony with respect to fuel expense, purchased energy and fuel inventory.

A. The testimony presented supports the reasonableness of the following values for the 2006 test year:

Test Year 2006		Units
1) Fuel Expense	78,583,400	$
a) Fuel Oil Expense	78,090,700	$
b) Fuel Related Expense	492,800	$
2) Fuel Price		
h) HELCO Shipman/Hill Industrial Fuel Oil	57.0902	$/BBL
i) HELCO Puna Industrial Fuel Oil	58.3389	$/BBL
j) HELCO Puna Diesel Fuel	86.7656	$/BBL
k) HELCO Kanoelehua Diesel Fuel	86.7252	$/BBL

l) HELCO Waimea Diesel Fuel	87.7341	$/BBL
m) HELCO Keahole Diesel Fuel	88.0456	$/BBL
n) Distributed Generators Diesel Fuel	94.0338	$/BBL
3) Purchased Energy Forecast	709.256	GWH
g) HEP	419.745	GWH
h) PGV	221.944	GWH
i) AEC Wind	4.841	GWH
j) HRD Wind	34.225	GWH
k) Wailuku River Hydro	27.496	GWH
l) Other IPP Hydro	1.008	GWH
4) Efficiency Factor (Sales Heat Rate)	MBTU / KWH SALES	
d) Steam	0.015615	
e) Diesel	0.013526	
f) Wind/Hydro	0.014826	
5) Fuel Inventory	8,240,900	$

The above items were determined by detailed analyses and methodologies, are consistent with historical values considering known and expected conditions, and are consistent with all items in this case as they relate to each other.

Q. Does this conclude your testimony?

A. Yes, it does.

Hawaii Electric Light Company, Inc.

SUMMARY OF RESULTS

	HELCO Direct Testimony (A)	HELCO Pre-Settlement (B)	Consumer Advocate Direct Testimony (C)	Consumer Advocate Direct Testimony (3/6/07) (D)	Rebuttal (Settlement) (E)
Total Fuel Oil Expense ($000)	$ 78,400.3	$ 78,090.7	$ 74,762.2	$ 77,449.8	$ 78,090.7
Total Fuel Related Expense ($000)	$ 424.7	$ 492.8	$ 425.9	$ 425.9	$ 492.8
Propane Expense	$ 232.2	$ 96.2	$ 233.3	$ 233.3	$ 96.2
Fuel Additive Expense	$ 121.3	$ 230.9	$ 121.3	$ 121.3	$ 230.9
Petrospect Expense	$ 71.3	$ 75.1	$ 71.3	$ 71.3	$ 75.1
Ocean Cargo Insurance Expense	$ -	$ 90.6	$ -	$ -	$ 90.6
Total Fuel Expense ($000)	$ 78,825.0	$ 78,583.4	$ 75,188.0	$ 77,876.0	$ 78,583.4
Fuel Prices ($/BBL)					
Shipman/Hill IFO	57.0902	57.0902	57.0902	57.0902	57.0902
Puna IFO	58.3389	58.3389	58.3389	58.3389	58.3389
Puna Diesel	86.7656	86.7656	86.7656	86.7656	86.7656
Waimea Diesel	87.7341	87.7341	87.7341	87.7341	87.7341
Kanoelehua Diesel	86.7252	86.7252	86.7252	86.7252	86.7252
Keahole Diesel	88.0456	88.0456	88.0456	88.0456	88.0456
DG Diesel	94.0338	94.0338	94.0338	94.0338	94.0338
Test Year Sales (GWH)	1148.0	1148.0	1148.0	1148.0	1148.0
Test Year No Charge (GWH)	1.7	1.7	1.7	1.7	1.7
Test Year Losses (GWH)	101.8	101.8	101.8	101.8	101.8
Net-to-System Input (GWH)	1251.4	1251.4	1251.4	1251.4	1251.4
Purchased Power (GWH)	710.1	709.3	711.0	711.4	709.3
Net HELCO (GWH)	541.3	542.1	540.4	540.0	542.1
Central Station	514.5	515.3	513.6	512.0	515.3
DG	0.1	0.1	0.1	1.4	0.1
Wind/Hydro	26.7	26.7	26.7	26.7	26.7
Total Central Station Net Heat Rate (BTU/Net KWH)	13,644	13,600	13,646	13,554	13,600
Steam Net Heat Rate (BTU/Net KWH)	14,347	14,324	14,342	14,488	14,324
Diesel Net Heat Rate (BTU/Net KWH)	12,500	12,407	12,013	12,053	12,407
Total Central Station Sales Heat Rate (BTU/KWH Sales)	0.014874	0.014826	0.014872	0.014773	0.014826
Steam Sales Heat Rate (BTU/KWH Sales)	0.015640	0.015615	0.015631	0.015792	0.015615
Diesel Sales Heat Rate (BTU/KWH Sales)	0.013627	0.013526	0.013089	0.013144	0.013526
Wind/Hydro Sales Heat Rate (BTU/ KWH Sales)	0.014874	0.014826	0.014803	0.014705	0.014826
Total Fuel Inventory ($)	$ 8,266,075	$ 8,243,502	$ 7,161,382	$ 8,230,758	$8,240,900
IFO Fuel Inventory	$ 4,155,094	$ 4,175,090	$ 4,536,555	$ 4,122,796	$4,175,090
Diesel Fuel Inventory	$ 4,109,336	$ 4,066,938	$ 2,622,580	$ 4,086,219	$4,064,336
DG Fuel Inventory	$ 1,645	$ 1,474	$ 2,247	$ 22,743	$ 1,474
Total Fuel Inventory (BBL)	119,168	119,028	108,897	118,554	118,998
IFO Fuel Inventory	72,355	72,705	79,000	71,773	72,705
Diesel Fuel Inventory	46,796	46,307	29,873	46,550	46,277
DG Fuel Inventory	17	16	24	231	16

Column B: Information used for pre-settlement revenue requirement calculation.
Column D: Information from files (05-0315 Exhibits 3-6-07.xls and 05-0315 Workpapers 3-6-07.xls) provided in Consumer Advocate's response to HELCO/CA-IR-208.

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Hawaii Electric Light Company, Inc.

TEST YEAR 2006 FUEL OIL PRICES

Rebuttal Testimony

Line		Delivered-to-plant Weighted Fuel Price ($/BBL)
1	Shipman (IFO)	57.0902
2	Hill (IFO)	57.0902
3	Puna (IFO)	58.3389
4	Waimea (Diesel)	87.7341
5	Kanoelehua (Diesel)	86.7252
6	Keahole (Diesel)	88.0456
7	Puna CT-3 (Diesel)	86.7656
8	Distributed Generators (Diesel)	94.0338

Reference:
HELCO-RWP-402, page 1

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Hawaii Electric Light Company, Inc.

TEST YEAR 2006 NET GENERATION
Rebuttal Testimony

Line		(A) Energy (GWH)	(B) Percent of Net System Input
1	Test Year Sales	1,148.0	
2	+ No Charge (@ 1653 MWH)	1.7	
3	Sales + No Charge	1,149.7	
4	+ Losses (@ 8.14%)	101.8	
5	Net-To-System Input	1,251.4	100.00%
6	- Purchase Power	709.3	56.68%
7	Net HELCO	542.1	43.32%
7a	Central Station	515.3	41.18%
7b	Distributed Generators	0.1	0.01%
7c	Wind/Hydro	26.7	2.14%

Reference:
Line 1: HELCO-RWP-403, page 1
Line 2: HELCO-RWP-403, page 2
Line 4: HELCO-RWP-403, page 3
Line 6: HELCO-RWP-404, page 3
Line 7a: HELCO-RWP-404, page 3
Line 7b: HELCO-RWP-404, page 3
Line 7c: HELCO-RWP-404, page 3

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Hawaii Electric Light Company, Inc.

TEST YEAR 2006 FUEL OIL EXPENSE SUMMARY
Rebuttal Testimony

Line	Plant	(A) Fuel Consumption (BBLs)	(B) Fuel Prices ($/BBL)	(C) = (A) x (B) Fuel Expense ($000)
1	Shipman	100,218	57.0902	5,721.4
2	Hill	431,736	57.0902	24,647.9
3	Puna	197,186	58.3389	11,503.6
4	IFO Subtotal	729,140		41,872.9
5	Waimea	1,147	87.7341	100.7
6	Kanoelehua	6,540	86.7252	567.2
7	Keahole	352,088	88.0456	30,999.8
8	Puna CT3	52,234	86.7656	4,532.1
9	Diesel Subtotal	412,010		36,199.8
10	Central Station Total	1,141,149		78,072.7
11	Distributed Generators	191	94.0338	17.9
12	HELCO GRAND TOTAL	1,141,340		78,090.7

Reference:
Column A: HELCO-RWP-404, page 2
Column B: HELCO-R-402

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Hawaii Electric Light Company, Inc.

TEST YEAR 2006 FUEL RELATED EXPENSES
($000)
Rebuttal Testimony

Line		Dollars ($000)
1	Propane Expenses	96.2
2	Fuel Additives Expenses	230.9
3	Petrospect Expenses	75.1
4	Ocean Cargo Insurance Expense	90.6
5	Total	492.8

Reference:
Line 1: HELCO-RWP-405, page 1
Line 2: HELCO-RWP-405, page 2
Line 3: HELCO-RWP-405, page 2
Line 4: HELCO-RWP-405, page 3

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Hawaii Electric Light Company, Inc.

TEST YEAR 2006 FUEL EFFICIENCY
Rebuttal Testimony

Line			
1	Cental Station Generated Energy	(Net GWH)	515.3
2	Steam Generated Energy	(Net GWH)	320.7
3	Diesel Generated Energy	(Net GWH)	194.6
4	Test Year Sales	(GWH)	1,148.0
5	Total Central Station Fuel Consumed	(000 BBLs)	1,141
6		(000 MBTUs)	7,008
7	Steam Fuel Consumed	(000 BBLs)	729
8		(000 MBTUs)	4,594
9	Diesel Fuel Consumed	(000 BBLs)	412
10		(000 MBTUs)	2,414
11	Total Central Station Net Heat Rate	(BTU / Net KWH)	13,600
12		(Net KWH / BBL)	452
13	Steam Net Heat Rate	(BTU / Net KWH)	14,324
14		(Net KWH / BBL)	440
15	Diesel Net Heat Rate	(BTU / Net KWH)	12,407
16		(Net KWH / BBL)	472
17	Central Station with Wind/Hydro Sales Heat Rate	(MBTU / KWH Sales)	0.014826
18	Steam Sales Heat Rate	(MBTU / KWH Sales)	0.015615
19	Diesel Sales Heat Rate	(MBTU / KWH Sales)	0.013526
20	Wind/Hydro Sales Heat Rate	(MBTU / KWH Sales)	0.014826

Reference
Lines 1 - 10: HELCO-RWP-406, page 1; Excludes Company wind and hydro
Line 4: HELCO-RWP-403, page 1
Line 11: Line 6 ÷ Line 1
Line 12: Line 1 ÷ Line 5
Line 13: Line 8 ÷ Line 2
Line 14: Line 2 ÷ Line 7
Line 15: Line 10 ÷ Line 3
Line 16: Line 3 ÷ Line 9
Line 17: HELCO-RWP-406, page 1
Line 18: HELCO-RWP-406, page 1
Line 19: HELCO-RWP-406, page 2
Line 20: HELCO-RWP-406, page 2

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Hawaii Electric Light Company, Inc.

HISTORICAL FUEL EFFICIENCY (Net Heat Rate)
Rebuttal Testimony

Line		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		Recorded						Rebuttal Test Year	Rebuttal TY vs. 2006 recorded	
		2001	2002	2003	2004	2005	2006	2006	Diff	%
1	Helco Net Heat Rate (BTU / KWH)	13,524	13,552	13,758	13,136	13,167	13,234	13,600	366	2.8
2	Steam Net Heat Rate (BTU / KWH)	14,393	14,492	14,277	13,780	14,019	14,457	14,324	-133	-0.9
3	Diesel Net Heat Rate (BTU / KWH)	13,636	12,609	12,933	12,962	12,464	12,507	12,407	-100	-0.8

Reference:
Columns A - F: HELCO-RWP-407.
Column G: HELCO-R-406, line 11
Column H: Column G - Column F
Column I: Column H ÷ Column F
Line 1: HELCO-RWP-407, line 8; Includes Company wind and hydro
Line 2: HELCO-RWP-407, line 10; Excludes Company wind and hydro
Line 3: HELCO-RWP-407, line 11; Excludes Company wind and hydro

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Hawaii Electric Light Company, Inc.

DERIVATION OF FUEL INVENTORY
TEST YEAR 2006
Rebuttal Testimony

Line		Pre-Settlement (A) Fuel Inventory (BBLs)	Pre-Settlement (B) Fuel Inventory ($)	Rebuttal (Settlement) (C) Fuel Inventory (BBLs)	Rebuttal (Settlement) (D) Fuel Inventory ($)
	Industrial Fuel Oil Inventory				
1	Shipman/Hill	53,215	$ 3,038,032	53,215	$ 3,038,032
2	Puna	19,491	$ 1,137,058	19,491	$ 1,137,058
3	TOTAL INDUSTRIAL FUEL OIL INVENTORY	72,705	$ 4,175,090	72,705	$ 4,175,090
	Diesel Fuel Inventory				
4	Puna	6,626	$ 574,902	6,626	$ 574,902
5	Waimea	659	$ 57,850	659	$ 57,850
6	Kanoelehua	1,161	$ 100,653	1,131	$ 98,051
7	Keahole	37,861	$ 3,333,533	37,861	$ 3,333,533
8	TOTAL CENTRAL STATION DIESEL FUEL INVENTORY	46,307	$ 4,066,938	46,277	$ 4,064,336
9	Distributed Generators	16	$ 1,474	16	$ 1,474
10	TOTAL HELCO	119,028	$ 8,243,502	118,998	$ 8,240,900

Reference:
Line 1: HELCO-R-408, page 2
Line 2: HELCO-R-408, page 3
Line 4: HELCO-R-408, page 4
Line 5: HELCO-R-408, page 5
Line 6: HELCO-R-408, page 6
Line 7: HELCO-R-408, page 7
Line 9: HELCO-R-408, page 8

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Hawaii Electric Light Company, Inc.

DERIVATION OF SHIPMAN/HILL INDUSTRIAL FUEL OIL INVENTORY
TEST YEAR 2006
Rebuttal Testimony

Line			Test Year 2006	
1	Test Year Shipman/Hill Burn Rate		1,745	BBL / Day
2	24 Day Inventory (Line 1 x 24 Days)		41,887	BBLs
3	+ Dead Storage		11,328	BBLs
4	Total Industrial Fuel Oil BBL Inventory (Line 2 + Line 3)		53,215	BBLs
5	Fuel Price	$	57.0902	/ BBL
6	Industrial Fuel Oil Inventory (Line 4 x Line 5)	$	3,038,032	

Reference:
Line 1: HELCO-RWP-408, page 5
Line 3: HELCO-RWP-408, page 1
Line 5: HELCO-R-402, page 1

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Hawaii Electric Light Company, Inc.

DERIVATION OF PUNA INDUSTRIAL FUEL OIL INVENTORY
TEST YEAR 2006
Rebuttal Testimony

Line			Test Year 2006	
1	Test Year Puna Burn Rate		639	BBL / Day
2	24 Day Inventory (Line 1 x 24 Days)		15,339	BBLs
3	+ Dead Storage		4,152	BBLs
4	Total Industrial Fuel Oil BBL Inventory (Line 2 + Line 3)		19,491	BBLs
5	Fuel Price	$	58.3389	/ BBL
6	Industrial Fuel Oil Inventory (Line 4 x Line 5)	$	1,137,058	

Reference:
Line 1: HELCO-RWP-408, page 5
Line 3: HELCO-RWP-408, page 1
Line 5: HELCO-R-402, page 1

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Hawaii Electric Light Company, Inc.

DERIVATION OF PUNA DIESEL FUEL INVENTORY
TEST YEAR 2006
Rebuttal Testimony

Line		Pre-Settlement Test Year 2006			**Rebuttal (Settlement) Test Year 2006**		
1	Test Year Ignitor Diesel Fuel Consumption		274	BBLs		**303**	**BBLs**
2	+ Days Per Year		365	Days		**365**	**Days**
3	Ignitor Diesel Burn Rate (Line 1 + Line 2)		1	BBL / Day		**1**	**BBL / Day**
4	Test Year Puna Diesel Burn Rate		206	BBL / Day		**206**	**BBL / Day**
5	Total Puna Diesel Burn Rate		207	BBL / Day		**207**	**BBL / Day**
6	30 Day Inventory (Line 5 x 30 Days)		6,211	BBLs		**6,211**	**BBLs**
7	+ Dead Storage		415	BBLs		**415**	**BBLs**
8	Total Diesel Fuel BBL Inventory (Line 6 + Line 7)		6,626	BBLs		**6,626**	**BBLs**
9	Fuel Price	$	86.7656	/ BBL	**$**	**86.7656**	**/ BBL**
10	Diesel Fuel Inventory (Line 8 x Line 9)	$	574,902		**$**	**574,902**	

Reference:
Line 1: HELCO-RWP-408, page 4
Line 4: HELCO-RWP-408, page 6
Line 7: HELCO-RWP-408, page 2
Line 9: HELCO-R-402, page 1

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Hawaii Electric Light Company, Inc.

DERIVATION OF WAIMEA DIESEL FUEL INVENTORY
TEST YEAR 2006
Rebuttal Testimony

Line			Test Year 2006	
1	Test Year Waimea Burn Rate		5	BBL / Day
2	30 Day Inventory (Line 1 x 30 Days)		135	BBLs
3	+ Dead Storage		524	BBLs
4	Total Diesel Fuel BBL Inventory (Line 2 + Line 3)		659	BBLs
5	Fuel Price	$	87.7341	/ BBL
6	Diesel Fuel Inventory (Line 4 x Line 5)	$	57,850	

Reference:
Line 1: HELCO-RWP-408, page 6
Line 3: HELCO-RWP-408, page 2
Line 5: HELCO-R-402, page 1

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Hawaii Electric Light Company, Inc.

DERIVATION OF KANOELEHUA DIESEL FUEL INVENTORY
TEST YEAR 2006
Rebuttal Testimony

Line		Pre-Settlement Test Year 2006		**Rebuttal (Settlement) Test Year 2006**	
1	Test Year Ignitor Diesel Fuel Consumption	562	BBLs	**523**	**BBLs**
2	+ Days Per Year	365	Days	**365**	**Days**
3	Ignitor Diesel Burn Rate (Line 1 ÷ Line 2)	2	BBL / Day	**1**	**BBL / Day**
4	Test Year Kanoelehua Diesel Burn Rate	23	BBL / Day	**23**	**BBL / Day**
5	Total Kanoelehua Diesel Burn Rate	25	BBL / Day	**24**	**BBL / Day**
6	30 Day Inventory (Line 5 x 30 Days)	756	BBLs	**726**	**BBLs**
7	+ Dead Storage	405	BBLs	**405**	**BBLs**
8	Total Diesel Fuel BBL Inventory (Line 6 + Line 7)	1,161	BBLs	**1,131**	**BBLs**
9	Fuel Price	$ 86.7252	/ BBL	**$ 86.7252**	**/ BBL**
10	Diesel Fuel Inventory (Line 8 x Line 9)	$ 100,653		**$ 98,051**	

Reference:
Line 1: HELCO-RWP-408, page 4
Line 4: HELCO-RWP-408, page 6
Line 7: HELCO-RWP-408, page 2
Line 9: HELCO-R-402, page 1

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Hawaii Electric Light Company, Inc.

DERIVATION OF KEAHOLE DIESEL FUEL INVENTORY
TEST YEAR 2006
Rebuttal Testimony

Line		Test Year 2006	
1	Test Year Keahole Burn Rate	1,201	BBL / Day
2	30 Day Inventory (Line 1 x 30 Days)	36,032	BBLs
3	+ Dead Storage	1,829	BBLs
4	Total Diesel Fuel BBL Inventory (Line 2 + Line 3)	37,861	BBLs
5	Fuel Price	$ 88.0456	/ BBL
6	Diesel Fuel Inventory (Line 4 x Line 5)	$ 3,333,533	

Reference:
Line 1: HELCO-RWP-408, page 6
Line 3: HELCO-RWP-408, page 2
Line 5: HELCO-R-402, page 1

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Hawaii Electric Light Company, Inc.

DERIVATION OF DISTRIBUTED GENERATORS DIESEL FUEL INVENTORY
TEST YEAR 2006
Rebuttal Testimony

Line			Test Year 2006	
1	Test Year Diesel Fuel Consumption		191	BBLs
2	÷ Days Per Year		365	Days
3	Burn Rate (Line 1 ÷ Line 2)		1	BBL / Day
4	30 Day Inventory (Line 3 x 30 Days)		16	BBLs
5	+ Dead Storage		0	BBLs
6	Total Diesel Fuel BBL Inventory (Line 4 + Line 5)		16	BBLs
7	Fuel Price	$	94.0338	/ BBL
8	Diesel Fuel Inventory (Line 6 x Line 7)	$	1,474	

Reference:
Line 1: HELCO-R-404, page 1
Line 5: HELCO-RWP-408, page 2
Line 7: HELCO-R-402, page 1

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Hawaii Electric Light Company, Inc.

HISTORICAL AVERAGE FUEL INVENTORY
(Barrels)
Rebuttal Testimony

		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		Recorded						Rebuttal Test Year	Rebuttal TY vs. 2006 Recorded	
Line		2001	2002	2003	2004	2005	2006	2006	Diff	%
	Industrial Fuel Oil									
1	Avg Inventory	61,401	62,503	69,422	67,127	75,756	68,460	72,705	4,246	6.2
2	Avg No. of Days	32	33	39	42	38	30	24		
	Diesel Fuel									
3	Avg Inventory	32,467	27,201	33,707	37,843	42,857	49,059	46,307	-2,752	-5.6
4	Avg No. of Days	65	30	47	45	38	38	30		

Reference:
Columns A - F: HELCO-RWP-409, pages 1-6
Column G: HELCO-R-408, pages 2-7
Column H: Column G - Column F
Column I: Column H + Column F

Note:
Column G, lines 2 and 4 are based on the average of the highest three monthly consumption rates in the test year as explained in the direct testimony. The average days of supply based on the annual average consumption rate in the test year is 37 and 41 for IFO and diesel fuel, respectively.

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Hawaii Electric Light Company, Inc.

HISTORICAL DISTRIBUTED GENERATORS FUEL CONSUMPTION
Rebuttal Testimony

Line		(A)	(B)	(C)	(D)	(E)	(F)	(G)	(H)	(I)
		Recorded						Rebuttal Test Year	Rebuttal TY vs. 2006 Recorded	
		2001	2002	2003	2004	2005	2006	2006	Diff	%
1	Fuel Consumption (Barrels)	813	1,894	535	279	187	187	191	3	1.8
2	Fuel Expense ($)	50,334	104,093	30,822	18,057	15,001	15,001	17,939	2,938	19.6

Reference:
Columns A - F: HELCO-RWP-404, pages 108-113
Column G: HELCO-R-404
Column H: Column G - Column F
Column I: Column H ÷ Column F

NOTE: TOTALS MAY NOT ADD EXACTLY DUE TO ROUNDING

Hawaiian Electric Company
Engineering Standard Practices Manual
POWER SUPPLY/Planning & Engineering
Section 10. Planning & Engineering Department, Subsec. B. Part 14.1
Revised January 22, 1997

Capacity Planning Criteria for Addition of Generation HELCO Long-Range Expansion Studies

Introduction

The following specifies how various generating unit kilowatt ratings are to be used in long-range generation expansion studies for determining the requirement dates for generation additions to the HELCO system. The latest approved load forecast will be used.

Generating Unit Rating Definitions

Generating units shall be given the following kilowatt ratings, where applicable, for use in determining generation addition requirement dates. None of these ratings will exceed the generator nameplate maximum kva rating at rated power factor, under any condition.

1. Normal Top Load Rating: (A1, A2, A3 . . . AN)
   a. For steam turbines, this is the maximum load the unit is capable of carrying continuously on a normal day-to-day basis with valves wide open, normal pressure, normal temperature, and all feed water heaters in service. This is the maximum load to which the unit is normally dispatched.
   b. For combustion turbines, this is the base temperature control capability, which is the maximum load the unit is capable of carrying continuously on a day-to-day basis.
   c. For diesel units, this is the maximum design capability, which is determined by the manufacturers recommendations and operating conditions.
2. Reserve Rating: (B1, B2, B3 . . . BN)
   a. For applicable steam turbines this is the maximum load the unit is capable of carrying continuously on a day-to-day basis with valves wide open, 5 percent overpressure, normal temperature, and all feed water heaters in service.
   b. For combustion turbines this is the base temperature control capability, which is the maximum load the unit is capable of carrying continuously on a day-to-day basis.
   c. For diesel units less than 2.5 MW normal top load rating, the reserve rating will be the same as the normal top load rating. For diesel units, 2.5 MW and larger, this is the two hour, 10 percent overload capability.
3. Emergency Rating: (C1, C2, C3 . . . CN)
   a. For applicable steam turbines, this is the maximum load the unit is capable of carrying (if all possible steps are taken to increase the unit's capability) with valves wide open, 5 percent overpressure, normal temperature, and top feed water heater out of service.
   b. For combustion turbines, this is the peak reserve temperature control capability, which is the maximum rating at which the unit can be operated, generally for a limited period of time with increased maintenance costs.
   c. For diesel units this is the same as the reserve rating.

When HELCO purchases Non-Utility Generation firm capacity, these sources may be represented as generating units with Normal Top Load, Reserve, and Emergency ratings determined to be at reasonable levels which are consistent with the intent of these definitions and consistent with the purchase power contracts.

Generation Addition Rule

New generation will be added to prevent the violation of the rule listed below where "available units" means all operable units and firm capacity suppliers physically connected to the system which are not on scheduled maintenance.

The sum of the reserve of all available units, with a unit on maintenance, less the reserve rating of the largest available unit must be equal to or greater than the system peak load to be supplied.

$$\sum_{i=1}^{N} B_i > \text{Load}$$

In addition, consideration will be given to maintaining a reserve margin of approximately 20 percent based on Reserve Ratings.

The application of this rule in long-range generation expansion studies must consider the effects of interruptible loads, Demand Side Management and the agreements for firm power and firm standby power.

The preceding rules apply to capacity planning in long-range generation expansion studies. The actual commercial operation date for the next unit to be added shall also be determined using these rules as guides, with due consideration given to short-term operating conditions, equipment procurement, construction, regulatory approvals, financial and other constraints, etc.

Operating Rule

One HELCO unit will normally be running at all times.

Load Shedding

Automatic load shedding is an operating reserve and is not to be considered as a resource reserve in generation planning studies.

Future Changes to Generation Addition Guidelines

At some future date it may be desirable to change the rules set forth above to provide additional reserves. This change will be dependent on actual operating conditions, financial restraints, and other constraints.

The rules below provide for additional reserves as compared to the rules above:

1. Spinning Reserve
   a. There must be enough generation running so that upon the tripout of any one unit the remaining units will have sufficient capacity to restore system frequency to 60 Hz.
   b. There must be enough generation running in economic dispatch so that upon the tripout of any one unit the remaining units will have sufficient quick-load pickup

capability to restore system frequency to at least 58.5 Hz within 3 seconds after tripout.

2. Loss of Load Probability

Capacity planning analysis will include a calculation of risk (Loss of Load Probability) in years per day for each year of each plan of the long-range expansion study

REBUTTAL TESTIMONY OF

JOSE S. DIZON

MANAGER

ENGINEERING DEPARTMENT

HAWAII ELECTRIC LIGHT COMPANY, INC.

Subject: Keahole Issues

INTRODUCTION

Q. Please state your name and business address.

A. My name is Jose Dizon and my business address is 54 Halekauila Street, Hilo, Hawaii.

Q. What is your present position at Hawaii Electric Light Company?

A. On February 5, 2007 I became the new Manager of the Engineering Department of Hawaii Electric Light Company, Inc. ("HELCO"), replacing Clyde Nagata who retired in December 2006.

BACKGROUND AND EXPERIENCE

Q. What is your background and experience?

A. Prior to my new role as manager of the HELCO Engineering Department, I was the Director of Corporate Communications/Company Spokesperson for Hawaiian Electric Company, Inc. ("HECO"), the HECO Operating Superintendent for the Power Supply Operations and Maintenance Department, and the HECO Director of Generation Planning. As the former Director of Generation Planning, the following work has either been performed directly by me or under my direct supervision for the HECO, HELCO and MECO electric utility systems: (1) generation expansion studies; (2) contingency planning; (3) integrated resource planning, specifically in the area of integration analysis; (4) avoided cost calculations; (5) Biennial Electric System Cost Data ("PURPA") filings; and (6) Adequacy of Supply Reports. In addition, I have personally submitted testimony before this Commission or prepared testimony on behalf of witnesses in the following HELCO cases: (1) HELCO's TY 2000 Rate Case (Docket No. 99-0207), (2) CT-5/ST-7 (Docket No. 7623), (3) Integrated Resource Planning (Docket Nos. 7259 & 97-0349), (4) Kawaihae Cogeneration Partners, L.P. (Docket No. 7956); (5) Enserch Development Corp. Complaint (Docket No.

94-0079); (6) HELCO-Encogen PPA (Docket No. 98-0013); (7) HCPC (Docket No. 97-0102); (8) HELCO's TY 1996 Rate Case (Docket No. 94-0140), and (9) HELCO's TY 1999 Rate Case (Docket No. 97-0420); (10) HELCO Contingency Plan Docket (Docket No. 96-0029). Please refer to my biography in HELCO-R-4A00 for other previous testimony and my educational background.

Q. What areas are you covering in your rebuttal testimony?

A. In this rebuttal testimony, I will discuss the following:

1) the need for generation in West Hawaii;
2) the urgency of the generation situation;
3) the steps taken by HELCO to accelerate the addition of generation;
4) generation siting in West Hawaii
5) the alternatives to Keahole, including IPP alternatives;
6) proceeding in parallel with Encogen Hawaii, L.P. (now Hamakua Energy Partners, "HEP");
7) the benefits of siting generation at Keahole; and,
8) the steps taken to maintain reliability in spite of the delays.

THE NEED FOR GENERATION IN WEST HAWAII

Q. When did HELCO determine that CT-4 was needed?

A. In 1991, HELCO initiated efforts to install the next increment of new generating capacity after the installation of Combustion Turbine No. 3 ("CT-3") at Puna. The drivers for this new installment of generating capacity included supporting system load requirements by having capacity installed on the west side of the Big Island, and allowing for the retirement of aging existing generators on the HELCO system. Based on HELCO's capacity planning criteria, it was initially determined that HELCO needed additional increments of capacity in 1994-1995 (20 MW),

1996 (20 MW) and 1997 (18 MW) due to forecast load growth and planned retirements of older generating units (as well as other considerations).

In the May 1991 Hawaii Electric Light Company Unit Type and Size Study, HELCO identified the need for additional generation in the April 1994 time frame. This need was based on meeting HELCO's generation planning criteria given the anticipated load growth projected in the May 16, 1990 sales and peak load forecast, and the retirement of existing units upon reaching their expected service lives. The need for additional generation in 1994 also took into account the benefits of increasing HELCO's generation reserve margin to improve HELCO's generation reliability, uncertainties regarding the continued availability of firm capacity from non-utility generators ("NUGs") and limits on the near-term potential peak load savings from demand-side management ("DSM") programs.

HELCO's generation expansion plans also included the need for subsequent increments of generation (of 20 MW or more), generally in the 1999 and 2001 timeframes. For example, HELCO's biennial Electric Utility System Cost Data filing (July 1, 1996) showed the addition of CTs in 1999 and 2001 after the completion of a DTCC facility. In addition, HELCO's need for additional generation in the 1999 timeframe, even if a dual train combined cycle unit was completed at either Keahole or at Hamakua, was shown in the generation expansion plans filed by HELCO (1) in the dockets arising out of its request for approval to commit funds for the Keahole generation additions, (2) the dockets commenced at the request of qualifying facilities seeking to enter into power purchase agreements with HELCO, (3) HELCO's Integrated Resource Planning ("IRP") proceeding, and (4) the contingency planning docket, Docket No. 94 0140.

Q. Did HELCO explore other alternatives to CT-4?

A. Yes. HELCO explored a number of possible alternatives for the first 20 MW increment of capacity, but HELCO determined, and the Commission agreed, that CT-4 was the only alternative with the possibility of fruition in the 1994-1995 timeframe. (D&O 13050, page 8.)

In Docket No. 7048, the Commission recognized HELCO's need for additional capacity in the 1994 to 1995 timeframe. (Decision and Order No. 13050 (January 21, 1994), ("D&O 13050"), Docket No. 7048.) In Docket No. 7623, the Commission recognized the need for additional generation in the 1996 to 1997 timeframe. (Decision and Order No. 14284 (September 22, 1995), ("D&O 14284"), Docket No. 7623.) In addition, in Docket No. 7259, the Commission approved HELCO's supply side resource plan, which included 56 MW (net) of generating capacity to be added by the end of 1997, with additional generation to be added in subsequent years. (Decision and Order No. 14708 (May 29, 1996), Docket No. 7259.)

There was no issue in Docket No. 7048 regarding HELCO's need for capacity. The Commission stated that: "All parties agree that HELCO requires additional capacity to meet its future load requirements. The Consumer Advocate agrees with HELCO that there is an immediate need for additional generation in West Hawaii." (D&O 13050, page 3.) The Commission was also in agreement with HELCO that DSM programs could not defer the need for additional capacity: "Despite HELCO's efforts to encourage DSM programs, the programs will not eliminate or shift sufficient load to obviate the need for additional generation. They will not be sufficient to reduce enough load in the near term to defer HELCO's proposed unit addition in 1994." The D&O concluded that HELCO required additional generation in the West Hawaii area in the 1994 1995 time frame, that none of the parties to the docket disputed the need for capacity, and

that neither the Consumer Advocate nor the intervenor presented any viable alternatives to CT-4. Therefore, CT-4 was the only alternative deemed viable in the 1994-1995 time frame. The Commission found that "HELCO's proposed project is reasonable and in the public interest." (D&O 13050, page 14.)

THE URGENCY OF THE GENERATION SITUATION

Q. What happened to increase the urgency of CT-4?

A. The original need date was determined based on the assumption that the 25 MW committed by PGV would be available. However, PGV's project was substantially delayed, which increased the urgency of adding CT-4. (PGV's capacity finally became available on a firm basis at the end of June 1993.)

Q. Did the Commission recognize the urgency of the generation situation?

A. Yes it did. The Commission explicitly recognized the urgency of proceeding with CT-4. For example, one of the questions at the conclusion of the evidentiary hearings in Docket No. 7049 in July 1992 was what actions HELCO could take to accelerate the installation of CT-4.

The Commission also continued to urge HELCO on a number of occasions to "maximize, rather than minimize, its strategies to meet the demand for electricity," reminding HELCO that its primary consideration was to have the next generation unit on line as quickly as possible.

The urgency with respect to Keahole generation did not end when HELCO reached agreement on a PPA with Encogen Hawaii, L.P. ("Encogen") in 1997. The Keahole additions were much further along and were expected to be in service sooner than the Encogen facility, and there was still substantial uncertainty as to the timing of the Encogen facility, as was explained at the time agreement was reached with Encogen and when approval of the Encogen PPA was requested.

For this and other reasons, HELCO proceeded in parallel with the Encogen PPA and the additions of CT-4 and CT-5.

THE STEPS TAKEN BY HELCO TO ACCELERATE THE ADDITION OF GENERATION

Q. What steps did HELCO take to accelerate the addition of CT-4?

A. Given the urgency of the need, HELCO acted as expeditiously as possible to obtain the needed permits and equipment for CT-4: (1) The Commission application was filed in July 1991 (and was amended in September 1992 to reflect the change to the Keahole site); (2) The application for an amendment to its Keahole Conservation District Use Permit ("CDUP") was filed with the Department of Land and Natural Resources in August 1992; (3) The application for the air permit was filed with the Department of Health in January 1993; and (4) A letter of intent for the purchase of the combustion turbine was sent on October 31, 1991 (subject to cancellation without penalty before June 1, 1992).

Q. Why did HELCO place the order for the combustion turbine for CT-4 before obtaining the CDUP Amendment ("CDUA"), air permit and/or Commission approval for the commitment of expenditures?

A. Due to the long lead time for the combustion turbine generator, HELCO elected to exercise an option for the procurement of the CT-4 generating unit from the equipment packager, Stewart & Stevenson. This option existed during the procurement process for the CT-3 unit and the Maalaea 14 and 16 units at MECO. The Commission was notified of this decision via letter dated November 20, 1991 in Docket No. 7048. In addition to the combustion turbine, Stone & Webster began design and procurement processes for the balance of plant equipment.

The Company would prefer to have all permits and approvals in hand before placing equipment orders. Waiting to place orders for long lead time items until all permits have been received can result in substantial delays in completing a

time-critical project, because the order date determines the purchaser's place in the manufacturing queue, and it also takes time to manufacture and ship major generating unit components. Installation of the generating unit cannot begin until it is on site.

Q. Why did HELCO accelerate its commitment for CT-5?

A. The Commission approved HELCO's commitment of funds for CT-4 in Docket No. 7048, and allowed HELCO to continue to pursue construction of its own facility and to commit funds for such purpose in Docket No. 7623. As HELCO explained in other dockets, such as Docket No. 7623, HELCO purchased CT-5 in order (1) to have the unit available when needed for installation, and (2) to lock in a lower purchase price for the unit and to take advantage of the economics of shipping CT-5 with CT-4.

Q. When did HELCO commit to the purchase of the combustion turbine for CT-5?

A. HELCO "committed" to the purchase of the combustion turbine for CT-5 by letter dated May 7, 1993 ("Notice to Proceed"). A conditional Letter Of Intent dated February 1, 1993, was issued to Stewart & Stevenson Services, Inc. ("S&S") for the procurement for CT-5, subject to cancellation without charge if HELCO elected not to issue as notice to proceed to S&S by May 1, 1993. The cancellation date was extended to May 7, 1993 by oral agreement.

Q. Why was the letter-of-intent issued to S&S?

A. The CT-5 conditional letter of intent was issued in February 1993 because of HELCO's decision to accelerate the installation of CT-5. HELCO was able to reserve the only remaining slot in the production schedule for an early 1994 shipment, which would allow CT-5 to be completed and shipped to HELCO in time for commercial operation by late 1994. The Letter Of Intent also enabled HELCO to secure the advantage of the pricing offered by S&S.

Q. Why did HELCO accelerate the scheduled installation date for CT-5?

A. As was addressed in Docket No. 7623, HELCO accelerated the schedule for CT-5 based on the "HELCO Contingency Plan Analysis", dated February 19, 1993, which examined the impact of the inability of Puna Geothermal Venture ("PGV") to meet its commitment date for the provision of 25 MW of firm capacity, and the apparent inability of Hamakua Sugar Company ("Hamakua") to continue to provide firm capacity to HELCO.

Prior to issuing the Notice to Proceed, HELCO reviewed (1) the status of PGV, Hamakua and HCPC (which then was providing 18 MW firm capacity to HELCO), (2) the benefits of proceeding with retirement of its older, less efficient generating units, and (3) the benefits of adding CT-5 in 1995 (even if it were not required on the basis of HELCO's capacity planning criteria until 1996). At that time, PGV still had not demonstrated that it would be able to solve its problems or that it would be able to meet its firm power commitment to HELCO. HELCO also was faced with significant uncertainty regarding the ability of its existing firm capacity producers, Hamakua (who's discontinuance of operations after the Fall of 1994 appeared relatively certain) and HCPC (who's status beyond the Fall of 1994 was also uncertain), to continue to meet their firm power commitments.

Issuing the Notice to Proceed enabled HELCO to (1) avoid a price increase on the CT-5 engine (2) ensure that the CT-5 unit would be available for installation in accordance with HELCO's schedule and (3) reduce shipping and handling cost by shipping both CT-4 and CT-5 at the same time. As a result, HELCO determined that, on a net present value basis, there was no economic penalty to adding CT-5 in 1995 instead of delaying the addition to 1996.

Q. Did HELCO have a reasonable basis for ordering the combustion turbines while simultaneously seeking the permits and approvals necessary to install the generating units?

A. Yes. Ordering the equipment was a necessary step in meeting the need date for CT-4, and was a prudent step in addressing the uncertainty with respect to the viability of the IPP power upon which HELCO was relying for a major part of its firm capacity. HELCO (and the Commission) recognized that there could be delays in obtaining the CDUA (or the air permit). The possibility of such delays made it even more critical to have the combustion turbines on site when the permits were obtained – so that any permitting delay would not be compounded by delays in obtaining the combustion turbines.

Q. Did HELCO take other steps to shorten the installation time?

A. Yes. As Mr. Barry Nakamoto (HELCO RT-15C) has addressed in other dockets, after HELCO had to return to its existing Keahole site, HELCO incorporated plans to start work on certain Pre-PSD facilities before receipt of the Prevention of Significant Deterioration ("PSD") air permit, if necessary, in order to shorten the time required to complete the installation of the new generating units after the PSD permit was received. This strategy previously had been followed successfully by HELCO and Maui Electric Company, Limited ("MECO") under similar circumstances, and the pre-PSD work contemplated by HELCO was the same type of pre-PSD work that was performed by HELCO and MECO on earlier generating units under previous DOH and EPA approvals. The "Pre-PSD Projects" included (1) a shop/warehouse building completed in December 1998, (2) upgrades to the fire protection system completed in September 1999, and (3) a water treatment system upgrade for CT-2 completed in December 1999. They were designed to support the needs of HELCO's planned generating

unit additions at Keahole, and the needs of the existing generating station. If the PSD air permit was received on a timely basis, the construction of these facilities was expected to start and finish at the same time as CT-4 and CT-5. However, as HELCO noted in Docket No. 7049 in 1992, and in Docket Nos. 7048 and 7623, HELCO anticipated that work on the Pre-PSD facilities could begin before receipt of the PSD permit if (as actually occurred) the PSD permit was delayed. Expediting the ultimate installation of new generation at Keahole was not the only reason for installing the pre-PSD projects as soon as possible. Completing the pre-PSD work also enabled the pre-PSD facilities to begin serving HELCO's then existing Keahole generating units (CT-2 and six diesel units), and the Keahole generating station. Maintaining reliable service from HELCO's existing generation at Keahole became an all the more important goal given the delays in adding CT-4 and CT-5 at Keahole, and the key role HELCO's Keahole generation plays in maintaining voltage support and frequency control on HELCO's system.

GENERATION SITING IN WEST HAWAII

Q. Where was CT-4 initially intended to be located?

A. The intention was to have CT-4 be the first generating unit at HELCO's proposed new 200 MW West Hawaii generating facility. However, HELCO's efforts to acquire a site at Kawaihae from the Department of Hawaiian Homelands ("DHHL") were unsuccessful.

HELCO then attempted to procure a site at Puuanahulu, owned by the State of Hawaii, but efforts to acquire the site from the State of Hawaii were also unsuccessful.

Q. Why did HELCO decide to return to its existing Keahole facility?

A. In late 1992, with the need date for additional generating capacity approaching, HELCO evaluated its options and determined that installing CT-4 at its existing

Keahole Power Plant and separating the next generation addition from the longer-term efforts to acquire a new West Hawaii site was prudent. Accordingly, in September 1992, HELCO filed an amendment to its PUC application identifying the Keahole site as the location for the CT-4 unit.

KEAHOLE ALTERNATIVES

Q. Did HELCO consider repowering existing generation as an alternative to Keahole?

A. At the time of the decision to go to Keahole, there was no reason to consider Puna or Hill as alternative sites, particularly given the objection of installing new generation on the west side of the Big Island, closer to load growth, and not on the east side, where Puna and Hill are located.

HELCO did attempt to first obtain sites for new generating stations at Kawaihae and Puuanahulu, but was unable to do so (at least in a timely fashion). The need to add new generation was considered to be urgent, and the siting of generation at an existing generation station is generally considered to be quicker than obtaining and permitting a new site, despite opposition to siting more generation at the existing site. This was MECO's experience with respect to both of its Maalaea DTCC units. The Commission considered these factors in Docket No. 7048, and described the siting issue at length in D&O 13050 before concluding that the location of CT-4 at Keahole is reasonable.

A primary objective of HELCO's was to install new generation on the west side of the Big Island, closer to load growth, not on the east side where Puna and Hill are located. It is beneficial to site new generation in West Hawaii because most of HELCO's generation is on the east side of the Big Island, including its base-loaded Hill steam units and PGV's geothermal unit. However, the majority of HELCO's load is on the west side of the island. The installation of generation

at Keahole provides needed generation in West Hawaii for area reliability and voltage support, reduces the need for upgrades to its transmission system, and reduces transmission losses. If HELCO had gone back to Puna, even more generation would have been sited on the east side of the Big Island, which would impact long-term transmission capital costs and transmission losses.

Q. Did HELCO consider repowering of existing generation at its Puna or Hill Power Plants as part of its contingency planning to address delays in adding new generation?

A. Yes. As part of that process, on February 6, 1996, Black & Veatch completed a study to identify the technical feasibility and cost of various repowering options for the Puna Power Plant and Hill Unit 5 ("Puna Repowering Study"). My group analyzed these repowering options in the March 1996 HELCO Contingency Plan Update.

Q. Which repowering option was recommended as a possible contingency option?

A. Of the five options analyzed, option 4 was preferred. It could provide a net increase of approximately 12MW with Phase 1 and 30 MW with Phase 2.

Q. Was it HELCO's intention to proceed with Puna repowering option 4 instead of Keahole CT-4 and CT-5?

A. No. The repowering project was intended to be a contingency option and was not intended to replace the Keahole DTCC project.

Q. What is a contingency option?

A. A contingency option is a firm capacity resource that would take the place of a planned resource, if the planned resource is no longer attainable within a reasonable time period, or to have additional generation available pending installation of the delayed generation. Examples of contingency options examined

by HELCO include the installation of new generating units at another location, and purchasing firm capacity from a NUG.

Q. Please explain why Puna repowering option 4 was not intended to replace the Keahole DTCC project.

A. There are several reasons. First, one of HELCO's strategies has been to maximize its generation options by accelerating new additions. HELCO's contingency plan would have been to proceed in parallel with the Keahole DTCC and the Puna repowering project, if a firm PPA for a large increment of new capacity could not be negotiated. Second, the west side of the Big Island is a better location to site new generation for reasons stated earlier in my testimony. Puna and Hill Power Plants are on the east side. Further, compared to the 56 MW combined cycle Keahole project as it was originally proposed, all of the Hill/Puna repowering options were of lower generating capacity; hence the repowering options were not equivalent in capacity to Keahole CT-4/5. Moreover, repowering options were not without their own shortcomings. For example, given the location of the repowering options on the east side of the Big Island, transmission upgrades and possibly another cross-island line would have had to be built (these were identified in the March 1996 Contingency Plan Update, but the costs were not quantified.) Also, HELCO would be starting the air permit process all over again, from scratch, when it appeared that HELCO had almost completed its air permit process for Keahole. The air permitting process for the repowering project would have involved its own risks. Thus, the repowering options were considered to be <u>contingency</u> options, as discussed in HELCO's Contingency Plan updates.

Q. Why did HELCO stop proceeding with this contingency option?

A. After HELCO obtained its land use authorization, the developer of a proposed IPP project, Enserch Development Corporation ("Enserch") lowered its proposed

prices and was willing to negotiate the remaining terms and conditions leading to a PPA. By June 1997, the terms and conditions of the PPA had been negotiated subject to Commission approval of a settlement agreement between Enserch and HELCO. At that point in time, a PPA between HELCO and Enserch's project entity (Encogen) seemed very likely. HELCO and Encogen signed a PPA on October 22, 1997. On October 28, 1997, also HELCO received its air permit for Keahole, and was awaiting resolution of appeals.

IPP ALTERNATIVES

Q. KDC contends that:

> The threat of competition from Independent Power Producers such as Puna Geothermal Venture and Kawaihae Cogeneration Partners, caused the Company to build the Projects as 'cheaply' and as 'fast' as possible, even if that meant foregoing required mitigation measures and willfully ignoring or avoiding permitting requirements. . . . If the Company was unable or unwilling to build a Company-owned facility in a timely manner and at a competitive cost, then the Company should have negotiated with independent power producers in good faith and should have purchased capacity." (KDC Position Statement, pages 1-2.)

What is HELCO's response?

A. In effect, KDC claims that firm capacity proposals from certain independent power producers ("IPPs") were available to HELCO at the time the Company decided to site new generation at Keahole, and that HELCO deliberately avoided purchasing power from them. The assertions are not supported by any reliable, probative or substantial evidence. Moreover, the assertions are contradicted by the Commission's findings in Docket No. 7048 and the evidence presented in the IPP proceedings. The facts demonstrate that:

(1) The Commission explicitly found in Docket No. 7048 that IPP proposals were not a viable alternative to siting CT-4 at Keahole. (See D&O 13050, pages 8, 14.)

(2) There was no showing in Docket No. 7048 and nothing but speculation has been offered in this docket to show that any IPP was a viable alternative.

(3) HELCO did not rely only on adding its own generation to meet its need for new generation. HELCO continued to negotiate with Enserch and KCP, as well as with other IPPs, and ultimately concluded a PPA with Encogen. Encogen only became a viable option from a price standpoint in 1997 -- after HELCO obtained its Keahole land use permits.

(4) KCP's proposed facility was never a viable, less contentious, source of power for the Big Island. KCP's pricing proposal was always well above HELCO's avoided cost. In addition, Waimana's land lease at Kawaihae was invalidated as a result of the lack of an Environmental Impact Statement ("EIS"), and Diamond Energy (the partner providing the financing for KCP) discontinued its business in the United States.

(5) The Commission has never found that HELCO refused to negotiate in good faith with an IPP, and explicitly rejected KCP's contention to that effect. HELCO was unable to conclude a PPA with KCP primarily because its proposed prices were substantially higher than HELCO's long-term avoided costs. HELCO was ultimately able to reach an agreement with Enserch (Encogen) in June 1997 after Enserch reduced its price to a level at or below long-term avoided costs. Enserch reduced its price only after the Commission provided guidance on the avoided cost calculation, and only after HELCO obtained its land use approvals to use its Keahole site.

(6) HELCO purchases a large percentage of its capacity (HEP, PGV) and energy (HEP, PGV, HRD, Apollo, etc) from IPPs, as addressed in HELCO T-5.

Q. Has the Commission conducted proceedings regarding HELCO's negotiations with the IPPs?

A. Yes. The Commission has never found that HELCO has refused to negotiate in good faith with the IPPs. In the case of KCP, the Commission explicitly rejected KCP's contention that HELCO refused to negotiate in good faith with KCP. The Commission also found "that we are not persuaded that the only obstacle to finalizing a KCP/HELCO contract is HELCO's refusal to sign a PPA." (Order No. 14502 (January 26, 1996), Docket No. 7956, page 4.)

In Order No. 16375 (page 4), issued June 9, 1998, the Commission again rejected KCP's contention that HELCO refused to negotiate in good faith with KCP:

> KCP's motion for sanctions arises from HELCO's alleged failure to negotiate in good faith and in a timely fashion. KCP accuses HELCO of deliberately refusing to complete a PPA with KCP. KCP complains that HELCO, while stalling negotiations with KCP, has finalized a PPA with Enserch Development Corporation (EDC or Encogen) and is pursuing the installation of HELCO's own units at Keahole.
>
> HELCO denies KCP's allegations and asserts that no PPA has been reached with KCP because KCP insists on a contract that calls for capacity and energy payments that are substantially above HELCO's avoided costs. HELCO points to the numerous meetings HELCO has had with KCP and to the sizeable amount of information HELCO provided KCP as indicators of good faith attempts on HELCO's part to consummate an agreement with KCP.
>
> The record in this docket does not sustain KCP's allegations of bad faith on HELCO's part. HELCO appears to have been responsive to KCP's requests for information, although the information supplied may not have been fully satisfactory to

> KCP in all instances. The record further reveals that HELCO expended a considerable amount of time and resources in negotiating with KCP. We, thus, deny KCP's motion for sanctions.

Q. In general, what was the tenor of the negotiations between HELCO and IPPs during the period?

A. Some of the IPP negotiations were more contentious than others. The IPPs generally sought to maximize the payments they would receive, minimize their own obligations, and maximize the financeability of their PPAs on a project-financed basis (thereby minimizing the equity they would have to put into their projects). HELCO recognized that the prices agreed to in any PPA would be in place for the full 30-year term of the PPA, and HELCO vigorously negotiated for the lowest prices consistent with its obligations under PURPA, and the Commission's rules implementing PURPA.

Q. How did HELCO respond to IPP proposals?

A. In each case, HELCO responded to the IPPs' proposals in a timely fashion and negotiated at length. HELCO was unable to accept the IPPs' original power purchase prices and/or terms and conditions because they were above HELCO's avoided costs, and not in the interest of HELCO's ratepayers. As a result of the impasse, these IPPs chose to file petitions for hearings with the Commission. When the Commission established guidelines for the calculation of avoided cost, HELCO accepted the determinations made by the Commission and negotiated prices accordingly.

Q. Please briefly describe the negotiations with KCP and Enserch.

A. On July 31, 1995, the Commission issued Decision and Order No. 14030 ("D&O 14030") in the KCP proceeding, Docket No. 7956, which provided guidance on the calculation of avoided costs and other issues that HELCO and KCP could not

agree on during earlier negotiations. In response, HELCO recalculated avoided costs for both KCP and Enserch, and provided both IPPs with a proposed PPA. After the issuance of Order No. 14502, issued January 26, 1996 in the KCP proceeding providing further guidance, HELCO revised its avoided cost calculation for KCP and Enserch accordingly. KCP wanted HELCO to ignore Enserch, and only negotiate with KCP. HELCO's decision to provide the same kind of information to Enserch absent a decision and order in Docket No. 94-0079 was affirmed in D&O No. 14284 in Docket No. 7623 (regarding commitment of funds for the purchase and installation of CT-5 and ST 7). In order to facilitate the negotiations, Docket No. 94-0079 was also reopened by stipulation at HELCO's suggestion. PPA negotiations occurred between September 1995 and June 1997.

Q. What was the outcome of HELCO's negotiations with Encogen?

A. HELCO's PPA with Encogen was finalized in June 1997, after Encogen reduced its price to a level at or below avoided costs determined in accordance with: (1) the Commission's rules implementing PURPA, (2) the Commission's decisions and orders in various IPP proceedings, and (3) a settlement agreement with respect to the remaining avoided cost issues, which was approved by the Commission in August 1997.

Q. Why was HELCO able to conclude a PPA with Encogen?

A. HELCO entered into a PPA with Encogen (the partnership of Enserch and Jones Capital Corp.), because Encogen reduced its price to a level at or below avoided cost as determined in accordance with the Commission's guidance, and the parties were able to reach agreement on all other terms and conditions. HELCO also agreed with the Commission that HELCO should maximize, rather than minimize, its strategies to meet the need for additional capacity on the Big Island. Thus,

HELCO determined that it should continue with installation of CT-4 and CT-5 as expeditiously as possible, while entering into a PPA with Encogen.

Q. How would you describe the negotiations with KCP, and Waimana Enterprises, Inc. ("Waimana", one of the partners in KCP)?

A. The negotiations and proceedings with KCP were certainly more contentious than the negotiations and proceedings with Enserch. Initially, KCP claimed that HELCO would <u>not</u> enter into a PPA with <u>any</u> QF because of HELCO's own project at Keahole. For example, in its December 12, 1996 "Motion for Approval of Legally Enforceable Obligation", KCP alleged that "HELCO's proposed solution to the Big Island's generation shortfall... concentrates exclusively on favorably resolving the Keahole expansion..." (KCP's Memorandum in Support of Motion, filed December 12, 1996 in HPUC Docket No. 7956, page 23.) However, when it became apparent that HELCO might reach agreement with Encogen, KCP changed its story and alleged that HELCO had "promised the next power plant to EDC" back in 1992. (KCP's Memorandum in Support of Motion for Sanctions, filed May 1, 1997 in HPUC Docket No. 7956, page 5.) KCP even appealed the Commission's ruling that it could not intervene in the Encogen PPA approval proceeding, which appeal was denied by the 1st Circuit Court, and filed a petition with the Federal Energy Regulatory Commission ("FERC") requesting that FERC initiate an enforcement action against the Commission for alleged violations of the Public Utility Regulatory Policies Act of 1978, as amended ("PURPA"). KCP's petition was dismissed by FERC based on HELCO's response.

Q. What role does purchased power currently play in HELCO's resource mix?

A. HELCO relies on purchased power for a substantial portion of its resource mix. As stated in HELCO T-5, in the 2006 test year, HELCO estimated that it would

purchase approximately 710.1 GWh in energy, which represents approximately 57% of the total net energy produced of 1,251.2 GWh required in the test year 2006. (HELCO T-5, page 85.) HELCO purchases power from IPPs under PPAs negotiated with each IPP, and which have been approved by the Commission.

During the period from 1995 to 2000, when I was working with HELCO on its contingency planning, HELCO negotiated six PPAs. They included (1) the Amended and Restated Power Purchase Agreement with HCPC, dated March 24, 1995 and filed March 31, 1995 in Docket No. 95-0075; (2) the Performance Agreement and Fourth Amendment to the Purchase Power Contract Dated March 24, 1986 As Amended with PGV, dated February 12, 1996 and filed February 14, 1996 in Docket No. 96-0042; (3) the Power Purchase Agreement with Encogen Hawaii, L.P. (now known as HEP), dated October 22, 1997 and filed January 16, 1998 in Docket No. 98-0013; (4) a Power Purchase Contract For As-Available Energy with Cyanotech Corporation, dated September 17, 1998 and filed October 23, 1998 in Docket No. 98-0363; (5) the Second Amended and Restated Power Purchase Agreement with HCPC, dated October 4, 1999 and filed October 12, 1999 in Docket No. 99-0346; and (6) a Power Purchase Contract For As-Available Energy with Kahua Power Partners, dated August 17, 1999 and filed June 2, 2000 in Docket No. 00-0177.

Q. Please describe HELCO's experience regarding the ability of its IPPs to deliver power in accordance with the terms of their purchase power agreements.

A. HELCO has had to expend substantial efforts to obtain and maintain power deliveries from independent power producers with firm power purchase agreements ("PPAs"). The Commission was familiar with the delays encountered by PGV in providing firm capacity from Docket Nos. 7048, 7049 and 7623, prior to PGV's commercial in-service date in June 1993. The Commission was familiar

with HELCO's efforts to rearrange HCPC's maintenance schedules to maximize available generation, and to modify PPAs to allow continuation of power deliveries from HCPC and Hamakua during the pendency of bankruptcy proceedings, due to filings made by HELCO in Docket Nos. 7093, 7298, 7314, 94-0271, 95-0008, 95-0075 (HCPC), and Docket Nos. 7662, 7732 (Hamakua). The Commission's decision in Docket No. 7623 specifically noted the problems associated with HELCO's power purchases from non-utility generators, including Hamakua (which went out of business), HCPC and PGV. (See Decision and Order No. 14282 (September 22, 1995), pages 8-9.) From its informal review of HELCO's generation situation in November 2002 and HELCO's annual Adequacy of Supply letters, the Commission also was kept informed of HEP's unit trips and extended outages after its commencement of commercial service at the end of 2000, and PGV's severe, extended deratings due to well problems since 2002. Ms. Lisa Giang provides more detail in HELCO RT-4.

Q. KDC refers to the termination of HCPC's short-term contract as a "transparent attempt to eliminate HCPC as a competing independent power producer." (KDC Position Statement, page 32.) Please provide the background with respect to HELCO's purchase of power from Hilo Coast Power Company and its predecessor, Hilo Coast Processing Company (both of which are referred to as "HCPC").

A. Briefly, the background is as follows:

(1) By letter dated March 25, 1994, pursuant to a requirement in its then-existing PPA to give three years' notice of early termination of the PPA, Hilo Coast Processing Company notified HELCO of its intent to abandon the production of power on March 26, 1997 due to the absence of adequate sugar legislation.

(2) When HCPC's primary sugar milling business could not be sustained even through March 1997, HCPC filed a voluntary petition for bankruptcy and provided HELCO with two weeks' notice in December 1994 of its intent to shut down its power plant. HCPC took this action despite a requirement in its then-existing PPA to give three years' notice of early termination of the PPA. HELCO had to obtain a temporary restraining order ("TRO"), granted by the Bankruptcy Court on December 23, 1994, which required HCPC to continue operating the plant past its unilateral shut down date. The TRO was extended after January 6, 1995, and modified, pursuant to stipulations between HELCO and Hilo Coast Processing Company.

(3) On January 5, 1995, HELCO and HCPC entered into a Letter Agreement setting the terms and conditions of the amended PPA, to be effective through December 31, 1999. The Commission approved the amended power purchase arrangement by Decision and Order No. 13739, issued January 20, 1995 in Docket No. 95-0008. HCPC began supplying an additional 4 MW in May 1995, for a total of 22 MW. (See the Application in Docket No. 96- 0042. To obtain this additional capacity, HELCO agreed to increase payments to HCPC and advanced $2.5 million for capital improvements.

(4) HELCO entered into a PPA replacing the Letter Agreement, which was executed March 24, 1995 and became effective in August 1995 after Bankruptcy Court dismissal of the Bankruptcy proceeding. The Commission approved the new PPA by Decision and Order No. 14207 issued September 6, 1995 in Docket No. 95-0075, after allowing HELCO to continue to include its energy payments to HCPC in HELCO's ECAC pursuant to Interim Decision and Order. No. 13895, issued May 15, 1995 in Docket No. 95-0075.

(5) In July 1997, the rights and obligations under the Existing PPA were assumed by Hilo Coast Power Company ("HCPC") and Hilo Coast Processing Company was dissolved.

Q. What arrangement was negotiated when the HCPC PPA was set to expire at the end of 1999?

A. When this agreement was due to expire at the end of 1999, HELCO and HCPC attempted to negotiate a new long-term agreement, but HCPC determined that the avoided cost determined in a Commission proceeding initiated by HCPC was too low in comparison to the price proposed by it for a long term PPA. The parties instead agreed to a short-term extension of the existing PPA. The 5-year Amended PPA restructured the arrangement between HELCO and HCPC so that HELCO would be purchasing power from HCPC primarily during HELCO's on-peak period. HCPC s commitment was to be available on a regular basis only 5 days per week for a 14-hour period in a 16-hour window (from 6:00 A.M. to 10:00 P.M.). For other periods, HELCO had to use its reasonable best efforts to notify HCPC of the need for emergency energy, and HCPC had to use its reasonable best efforts to provide HELCO with emergency energy at the time it was required. In addition, the Amended PPA provided that if HELCO requested HCPC to provide capacity in addition to the 5 days per week and during off-peak periods, HELCO would pay the incremental labor costs. Further, HELCO had to use its reasonable best efforts, taking into account Good Engineering and Operating Practices to dispatch HCPC's unit at a minimum average load level of 18 MW when the unit was operated, so that HCPC's energy costs would be covered.

Q. What was contemplated by the parties?

A. It was contemplated by the parties that the short-term Amended PPA would remain in place only until sufficient firm capacity was added to HELCO's system, and the Amended PPA contained explicit provisions for the earlier termination of the agreement if circumstances permitted. HELCO provided the requisite notice of termination in May 2004 (ending the arrangement by the end of 2004) only after the additional capacity was in place.

Q. Which witness addresses the reasons for terminating the HCPC short-term Amended PPA at the end of its five-year contract term?

A. That is discussed in the rebuttal testimony of HELCO RT-4, Ms. Lisa Giang.

Q. From a system planning perspective, what are the benefits of having new generation at Keahole rather than purchasing power from HCPC?

A. The benefits of having new, fully dispatchable, generation at Keahole from a generating and grid system reliability standpoint are addressed in the rebuttal testimony of Ms. Lisa Giang in HELCO RT-4. In contrast, HCPC's facility was subject to substantial constraints with respect to its availability and dispatchability, and was located on the grid where it contributed to transmission system concerns rather than helped alleviate them. Moreover, the unit (which was installed in the early 1970s) was becoming more prone to forced outages, given the constant cycling of the unit in recent years, and the lower maintenance expenditures in recent years based on the expectation of a 2004 end-of-service date. Its continued operation under the terms of the short-term agreement after the HRD wind farm was added in 2005 and the Apollo wind farm is repowered in 2007 also would have constrained HELCO's ability to accept as-available renewable energy from these new facilities.

PROCEEDING IN PARALLEL WITH ENCOGEN

Q. KDC asserts that HELCO's efforts to bring CT-4 and CT-5 on line in parallel with other capacity options was motivated by an alleged "threat of competition" that KDC claims "caused the Company to build the Projects as 'cheaply' and as 'fast' as possible . . . ." (KDC SOP, page 1) Is there a factual basis for this contention?

A. No. HELCO, in parallel with its efforts to construct its own generation, continued to negotiate with IPPs, as contemplated by the Commission, which concluded in Docket No. 7623 that:

> "Thus, in this docket, we will continue to leave open the option of HELCO obtaining additional generation through its own facility. We will allow HELCO to continue to pursue construction of its own facility and to commit funds for such purpose, except as reserved in part D below. This authorization is subject to the condition that HELCO, in parallel with its efforts to construct its own facility, negotiate in good faith with Enserch, Waimana/KCP, and any other party that may propose a power purchase contract, to the end that the generating unit that can be most expeditiously put into service at allowable cost, whether constructed by HELCO, Enserch, Waimana/KCP, or any other person, will constitute the next unit to be added to HELCO's system." (D&O 14284, pages 12-13.)

Q. What was the result of the negotiations?

A. As stated earlier, HELCO successfully negotiated a PPA with Encogen, Enserch's project entity, in 1997.

Q. Why did HELCO decide to enter into a PPA with Encogen, while continuing to install generation at Keahole?

A. HELCO determined in early 1997 that it would be prudent to proceed with the installation of generation at Keahole (i.e., to complete the installation of CT-4 and CT-5), while at the same time entering into a PPA with Encogen.

Q. When did the Encogen facility at Hamakua become a viable option?

A. Encogen did not become a viable option from a price standpoint until 1997 -- after HELCO obtained its Keahole land use authorizations. HELCO and Encogen finalized the price, terms and conditions of their PPA in 1997. At that time, there were still three principal factors that could delay Encogen's in-service date -- receipt of its financing commitment, its final air permit, and final, non-appealable PUC approval of the PPA. Encogen waived its financing "out" in January 1999, and its final air permit was received in April 1999. The PPA (as amended to extend the time for approval after the Consumer Advocate initially opposed approval of the PPA) was approved in July 1999, and the PPA became effective after the period for appeal expired as of August 23, 2000.

HELCO further recognized that IPPs using project financing are not as flexible as utilities. Encogen did not offer to install only the first two CTs of its proposed facility and to defer the installation of its steam turbine generator ("STG"). HELCO, however, could defer the installation of its STG, even though it recognized that significantly deferring the installation date could impact its ability to ultimately complete the Keahole DTCC facility. Thus, HELCO deferred the planned installation of ST-7, and planned to put some of its own capacity (at that time, its Puna steam unit) on cold standby reserve status until additional generation was needed.

Q. Which was expected to be installed first?

A. Given the status at the time of the necessary permits and approvals, it appeared that CT-4 and CT-5 could be installed in 1998. However, as HELCO also stated at the time, it was possible that either CT-4/CT-5 would end up being installed first, or that Encogen's Phase 1 and/or Phase 2 would end up being installed first.

Q. Please summarize the reasons for proceeding in parallel with the installations of CT-4, CT-5 and the Encogen (now HEP) facility.

A. The reasons, which were addressed in a number of dockets, were to allow HELCO (1) to increase its opportunity to install generation as soon as possible, (2) to address the possibility that the Encogen facility or HELCO's Keahole additions might be further delayed, (3) to meet the continuing need for generation after the "next" increment of generation is added to HELCO's system, (4) to add generation in West Hawaii (and, ultimately, to complete an efficient DTCC unit at Keahole), and (5) to obtain the benefits from HELCO's planned unit additions at Keahole for which most of the expenditures already had been incurred.

Q. Was HELCO encouraged to maximize its opportunities to install generation as soon as possible?

A. Yes. The Commission has stated on numerous occasions that, under the circumstances, "HELCO must obviously maximize, rather than minimize, its strategies to meet the demand for additional capacity." (D&O 14030, page 25.) In Order No. 14502, issued January 26, 1996 in Docket No. 7956 ("Order 14502") the Commission reiterated that: "HELCO's critical need for additional capacity to meet its load requirements is unquestioned, and clearly, the primary consideration is to have the next generation unit on line as quickly as possible." (Order 14502, page 4.)

In Decision and Order No. 15053, issued October 4, 1996 in Docket No. 94-0079, the Commission stated that:

> "In seeking to fulfill the Big Island's acute generation needs, *we remind HECO that its primary consideration is to have* the next generation unit on line as quickly as possible. To this end, HELCO may decide to pursue its own generation at Keahole; but, at the same time, it must in good faith negotiate with EDC, KCP, and any other independent power producer that proposes to build capacity and provide energy to HELCO. In this respect, we emphasize our full expectation that HELCO, in its dealings with EDC and other QFs

proposing projects, will fulfill its obligations with in the intent and spirit of PURPA." (D&O 15053, page 31.)

Q. Is it appropriate to consider uncertainties with respect to when firm capacity from IPPs can be installed when determining the timing of a utility's own generation additions?

A. Yes, even though such uncertainties are not explicitly considered in the generation planning criteria. The Commission has recognized that the timing of generation additions cannot be determined solely through application of the generation planning criteria, because the criteria do not consider a number of factors. The Commission's decision in Docket No. 7623 recognized the need to consider factors other than those explicitly considered in the generation planning criteria, such as power purchase uncertainties in generation planning, and specifically noted the problems associated with HELCO's power purchases from non-utility generators, including Hamakua Sugar, HCPC, and PGV. (Decision and Order No. 14282 (September 22, 1995), pages 8-9.) The Commission also recognized in Docket No. 6643, in which it approved HELCO's commitment of funds for CT-3, that unit need may be based on uncertainty with respect to the addition of QF capacity (in that case, PGV), as well as application of the generation capacity expansion criteria. (Decision and Order No. 11556 (March 23, 1992), pages 5-6.)

Q. What was the basis for the need to add more capacity that that added by the first DTCC unit?

A. HELCO's generation resource plan since the early 1990's included (1) the phased installation of a DTCC unit at HELCO's existing Keahole power plant, with the first two phases consisting of combustion turbines (CT-4 and CT 5), and the last phase consisting of a steam turbine generator (ST-7) and related facilities, (2) followed by the phased installation of generic DTCC units at a new West

Hawaii site, and (3) the retirements of existing older, smaller units as new generation is installed. (See Docket No. 7048, Decision and Order No. 13050 (January 21, 1992); Docket No. 7623, Decision and Order No. 14284 (September 22, 1995), and Docket No. 7259, Decision and Order No. 14708 (May 29, 1996).)

For example, HELCO's 1993 Integrated Resource Plan approved in Docket No. 7259 (which was developed prior to PPA amendments moving up the termination date for the HCPC power purchase arrangements to December 31, 1999) included the completion of the first DTCC unit in 1997, followed by the phased installation of the next DTCC unit beginning in 2000. The 1996 generation resource plan used in the calculation of avoided costs for the Encogen (now HEP) facility included the phased installation of the second DTCC unit beginning in 1999 (to reflect the change in HCPC's termination date, and the addition of 5 MW from PGV).

THE BENEFITS OF SITING GENERATION AT KEAHOLE

Q. Why is it beneficial to add generation in West Hawaii?

A. Because of economic and system reliability considerations, it is preferable to locate generation facilities as close to the load as possible. While the majority of HELCO's base load generation is currently located on the East side of the island, HELCO's most recent load growth has occurred on the West side of the island, and most of the future load growth is projected to take place there. Locating future power generation on the West side will allow HELCO to postpone construction of additional east-west transmission lines, minimize transmission line losses, and provide greater system stability during power disturbances.

Q. What are the benefits of adding CT-4 and CT-5 at Keahole?

A. The demand for electric power is evenly divided between East and West Hawaii, but approximately three-fourths (3/4's) of the power is produced in East Hawaii. Consequently, a significant portion of the power is transmitted over four major transmission lines from east to west to meet the demand in West Hawaii.

The Keahole Generating Station ("Keahole") has been operating since 1973. At present, with the addition of CT-4 and CT-5 (and the coincidental retirement of D18, D19, and D20), there are three combustion turbines and three diesel engines with a combined generating capacity of approximately 65 MWs. If fully dispatched at the daily system peak, it serves approximately 35% of the island-wide demand and up to 75% of the demand in West Hawaii.

Keahole is located at a critical location in the electric grid in terms of power stability and quality. It provides generation near the demand center in Kailua and thus helps sustain voltages in West Hawaii within acceptable tolerances. Generation at Keahole relieves the necessity to transmit electricity from power plants in East Hawaii, which results in lower transmission losses and lower operating currents on the transmission lines.

The potential benefits of West Hawaii generation (as compared to increasing the imbalance by adding more East Hawaii generation) have been studied on previous occasions as part of HELCO Integrated Resource Planning ("IRP") process. Most recently as part of IRP-2, the transmission planning study concluded that adding new generation to the Keahole Power Plant would provide needed voltage support in West Hawaii, would relieve operating currents on east-to-west transmission lines, would reduce transmission losses between the point of power generation and the customer, and requisite transmission system upgrades to meet transmission system planning criteria would cost substantially less.

Q. Does the type of generation HELCO installed at Keahole benefit the addition of renewable energy on the Big Island?

A. Yes it does. With the type of dispatchable generation HELCO installed, HELCO is better able to accommodate renewable energy from Hawi Renewable Development, a 10MW wind resource located at the north end of the island; and the Apollo wind farm; a 20MW wind resource located at South Point. Ms. Giang addresses this in her rebuttal testimony in HELCO RT-4 under the section titled, "CT-5 Helps to Accommodate Renewable Energy."

STEPS TAKEN TO MAINTAIN
SYSTEM RELIABILITY IN SPITE OF THE DELAYS

Q. What steps did HELCO take to maintain its load service capability while waiting for its permits to be finalized?

A. HELCO had to expend substantial efforts to obtain and maintain power deliveries from independent power producers with firm PPAs. The Commission is familiar with the delays encountered by PGV in providing firm capacity from Docket Nos. 7048, 7049 and 7623, prior to PGV's commercial in service date in June 1993. The Commission is also familiar with HELCO's efforts to rearrange HCPC's maintenance schedules to maximize available generation, and to modify PPAs to allow continuation of power deliveries from HCPC and Hamakua during the pendency of bankruptcy proceedings. (See Docket Nos. 7093, 7298, 7314, 94-0271, 95-0008, 95-0075 (HCPC); Docket Nos. 7662, 7732 (Hamakua).)

Since 1992, HELCO has added to its generation capacity, through the addition of CT-3 and the addition of power from IPPs. HELCO added 20.8 MW with CT-3 in August 1992. HELCO added 25 MW of generation from PGV in June 1993, and HELCO was able to conclude a PPA with PGV for an additional 5 MW on February 12, 1996. (Application for Approval of PGV Performance

Agreement, filed February 14, 1996 in Docket No. 96-0042.) HCPC began supplying an additional 4 MW in May 1995, for a total of 22 MW. To obtain this additional capacity, HELCO agreed to increase payments to HCPC and advanced $2.5 million for capital improvements.

In order to keep the lights on pending the addition of new generation, HELCO planned for and successfully implemented many mitigation measures and contingency options to maintain its load service capability, including:

(1) deferring the retirements of HELCO's older, smaller units, and taking steps to restore the capabilities of existing generation (such as CT-1 and CT-2);

(2) adding 5 MW from PGV through a PPA amendment;

(3) preserving HCPC's 18 MW (and increasing it to 22 MW), first through 1999 despite its exit from the sugar business, and the announced discontinuation of its power supply activities in connection with its bankruptcy filing in December 1994, and now through 2004 if needed for that long;

(4) negotiating numerous load management rate rider agreements, and aggressively implementing demand-side management energy efficiency DSM measures, so as to minimize the peak load to be served by HELCO's system;

(5) adding four small (1 MW) dispersed diesel generators, and

(6) managing the overhauls and outages of its own and purchased power units so as to maximize the availability of its existing generation.

Q. Does this conclude your testimony?

A. Yes, it does.

Hawaii Electric Light Company, Inc.

Jose S. Dizon, P.E.

EDUCATIONAL BACKGROUND AND EXPERIENCE

Business Address:	Hawaii Electric Light Company, Inc. 57 Halekauila Street Hilo, HI 96720
Position:	Manager, Engineering Department
Education:	Bachelor of Science in Electrical Engineering Computer Sciences and Nuclear Engineering University of California, Berkeley, 1982
Other Qualifications:	Registered Professional Engineer Hawaii Electrical Branch - 1992
Experience:	February 2007 to present Manager, Engineering Department Hawaii Electric Light Company, Inc. August 2006 to January 2007 Director, Corporate Communications Hawaiian Electric Company, Inc. July 2003 to August 2006 Senior Communications Consultant Corporate Communications Hawaiian Electric Company, Inc. March 2000 to July 2003 Operating Superintendent Power Supply Operations & Maintenance Department Hawaiian Electric Company, Inc.

January 1995 to March 2000
Director, Generation Planning
Power Supply Planning & Engineering Department
Hawaiian Electric Company, Inc.

1991 - 1994
Electrical Engineer
Generation Planning Department
Hawaiian Electric Company, Inc.

1984 - 1991
Strategic Planner, Assistant Engineering
Department Head, Engineering Division
Officer - Submarine Force
United States Navy

Other Curriculum:

Corporate Training Course
Zenger-Miller Supervision Course
Utility Finance and Accounting

Utility Resource Planning
Electric Power Research Institute and
UC Berkeley

Previous Testimony:

Hawaii Electric Light Company, Inc.
Rate Case
Docket No. 99-0207

Hawaii Electric Light Company, Inc.
HELCO-Encogen PPA
Docket No. 98-0013

Hawaii Electric Light Company, Inc.
Hilo Coast Power Company Complaint
Docket No. 97-0102

Hawaii Electric Light Company, Inc.
Kawaihae Cogeneration Partners Negotiations
Docket No. 7956

Hawaii Electric Light Company, Inc.
Rate Case
Docket No. 97-0420

Hawaii Electric Light Company, Inc.
Rate Case
Docket No. 94-0140

Maui Electric Company, Ltd.
Rate Case
Docket No. 97-0346

Maui Electric Company, Ltd.
Integrated Resource Planning
Docket No. 7258

Arbitration Proceedings
Kalaeloa Partners, Limited Partnership and Hawaiian Electric Company, Inc.

HELCO RT-5
DOCKET NO. 05-0315

REBUTTAL TESTIMONY OF
NORMAN VERBANIC

MANAGER
PRODUCTION DEPARTMENT
HAWAII ELECTRIC LIGHT COMPANY, INC.

Subject: Production Other O&M Expense
Production Materials and Supply Inventory
Purchase Power Expense

INTRODUCTION

Q. Please state your name and position.

A. My name is Norman Verbanic, and I am the Manager of the Production Department for Hawaii Electric Light Company, Inc. ("HELCO" or the "Company").

Q. Have you previously submitted testimony in this proceeding?

A. No. My predecessor, Dan Giovanni, had previously submitted written direct testimony, exhibits, and supporting workpapers as HELCO T-5.

Q. Have you reviewed Mr. Giovanni's written direct testimony, exhibits, and supporting workpapers?

A. Yes, I have.

Q. Are you adopting Mr. Giovanni's written direct testimony, exhibits, and supporting workpapers?

A. Yes, I am.

Q. What is the scope of your rebuttal testimony?

A. My rebuttal testimony will:

1) Present HELCO's rebuttal position with respect to other production operations and maintenance ("O&M") expenses;

2) Present HELCO's rebuttal position with respect to production materials and supplies inventory; and

3) Present HELCO's rebuttal position with respect to purchased power expense.

Q. How is your rebuttal testimony organized?

A. I will:

1) Summarize HELCO's rebuttal position, including the changes made by

HELCO in preparing its rebuttal position, and identify the changes that were accepted by the Consumer Advocate in the testimony of its witnesses;

2) Summarize additional adjustments to which HELCO and the Consumer Advocate agreed during settlement discussions; and

3) List and summarize all of the areas where the Consumer Advocate and HELCO agree.

HELCO'S REBUTTAL POSITION

Q. How did HELCO arrive at its final rebuttal position for other production O&M expense?

A. HELCO started with the position set forth in the direct testimony of HELCO T-5 which is summarized in HELCO-R-501, column (D). The direct testimony 2006 test year estimates were then modified to incorporate adjustments and normalizations set forth in HELCO's response to CA-IR-447. The results are summarized in HELCO-R-501, column (F). HELCO then made further changes to the adjusted O&M expense estimates to take into account additional adjustments to which HELCO and the Consumer Advocate agreed during settlement discussions. HELCO's final 2006 test year settlement rebuttal position for production O&M expense, which incorporates adjustments agreed-upon in settlement, is summarized in HELCO-R-501, column (H).

Q. Why did the Company adjust its direct testimony estimates?

A. Adjustments were made for a variety of reasons, including changes to reflect updated information, to correct forecast errors, and to reduce the number of issues in this case.

Q. What is HELCO's settlement rebuttal position with respect to production O&M expense?

A. HELCO's settlement rebuttal estimate of the total test year 2006 other production O&M expense is $21,041,000 as shown in HELCO-R-501, column (H), line 9.

Production Operations Expense

Q. What revisions to the production operations – labor expense 2006 test year direct testimony estimates were made by HELCO prior to settlement discussions with the Consumer Advocate?

A. Production operations – labor expense was reduced by $89,400 as a result of an adjustment reflected in HELCO's response to CA-IR-447. (See HELCO-R-501, column (E1).) This reduction is the result of the elimination of a Technical Superintendent position as explained in detail in HELCO's response to CA-IR-406.

Q. What revisions to the production operations – non-labor expense were made by HELCO prior to settlement discussions with the Consumer Advocate?

A. Production operations – non-labor expense was increased by $7,000 which is the net result of two adjustments reflected in HELCO's response to CA-IR-447. This adjustment appears on HELCO-R-501, column (E1).

Q. Please explain the two adjustments.

A. As summarized in HELCO's response to CA-IR-447, the two adjustments are as follows:

1) The amount for continuous emissions monitoring services ("CEMS") was increased by $256,300; as explained in more detail in HELCO's responses to CA-IR-447 (T-5), Attachment 1, page 5 and CA-IR-331, the amount budgeted for CEMS was determined to be too low based upon actual monthly billings for January through September 2006 and forecasted billings for the last three months of 2006; and

2) As explained in HELCO's response to CA-IR-447 (T-5), Attachment 1, page 13, the amount for materials was reduced by $249,300 to remove duplication of costs for boiler chemicals, demineralizer chemicals and for lube oil.

Production Maintenance Expense

Q. What revisions to the production maintenance – labor expense 2006 test year direct testimony estimate were made prior to settlement discussions with the Consumer Advocate?

A. Production maintenance – labor expense was reduced by $303,000 as a result of an adjustment reflected in HELCO's response to CA-IR-447. (See HELCO-R-501, column (E1).) As explained in HELCO's response to CA-IR-409, this adjustment was made because some of the forecasted labor hours will be spent on capital projects.

Q. What revisions to the production maintenance – non-labor expense were made prior to settlement discussions with the Consumer Advocate?

A. Production maintenance –non-labor expense was reduced by $917,000 which is the net result of eight adjustments reflected in HELCO's response to CA-IR-447. (See HELCO-R-501, columns (E1) and (E2).)

Q. Please explain the eight adjustments.

A. As summarized in HELCO's response to CA-IR-447, the eight adjustments to production maintenance – non-labor expense are as follows:

1) $83,700 was removed to account for the cancellation of the Hill Boiler Draw Engineering Docs project as explained in HELCO's responses to CA-IR-447 (T-5), Attachment 1, page 4 and CA-IR-340;

2) $75,000 was removed to reflect a change in the cycle for overhauling

dispersed diesel generating units such that one unit is overhauled every two years as explained in more detail in HELCO's responses to CA-IR-447 (T-5), Attachment 1, page 6, CA-IR-255 and CA-IR-256;

3) $80,200 was removed because of an error in budgeting for outside services – general as explained in HELCO's responses to CA-IR-447 (T-5), Attachment 1, page 7 and CA-IR-338, pages 2 and 3;

4) $155,000 was removed to take into account the cost of overhauling a diesel swing engine unit once every other year which is discussed in more detail in HELCO's responses to CA-IR-447 (T-5), Attachment 1, page 8 and CA-IR-255, page 3;

5) $193,200 was removed to reflect a revised estimate of the cost of the Waiau penstock repairs based upon a closer inspection of the situation once right-of-way clearing began as further explained in HELCO's responses to CA-IR-447 (T-5), Attachment 1, page 9 and CA-IR-343;

6) $86,800 was removed to reflect a revised estimate of the cost of the Puueo penstock repairs for the same reason as in the case of the Waiau penstock repairs discussed above and in HELCO's responses to CA-IR-447 (T-5), Attachment 1, page 9 and CA-IR-343;

7) $93,000 was removed to reduce the budgeted amount for outside services – legal to take into account a revised estimate for expenses for legal services incurred in connection with purchase power agreement negotiations through the end of 2006 as discussed in HELCO's responses to CA-IR-447 (T-5), Attachment 1, page 10 and CA-IR-80, pages 4 and 5; and

8) $150,000 was removed because a project to install variable frequency drive upgrades for Hill 6 has been moved from 2006 to 2007 for completion as

noted in HELCO's responses to CA-IR-447 (T-5), Attachment 1, page 12 and CA-IR-342, page 3.

Q. Has the Consumer Advocate taken a position on each of the adjustments you've just described which are summarized in HELCO's response to CA-IR-447 (T-5), Attachment 1, page 2?

A. Yes. In the testimony of Consumer Advocate witness CA-T-1, Michael Brosch, each of HELCO's rebuttal adjustments summarized in HELCO's response to CA-IR-447 (T-5), Attachment 1, page 2 have been accepted. The accepted adjustments are summarized in CA-101, Schedule C-3. The total amount of the adjustments accepted by the Consumer Advocate is $1,303,000. (See HELCO-R-501, columns (E1) and (E2), line 9.)

Production O&M Expense Adjustments Agreed Upon in Settlement

Q. In addition to the rebuttal adjustments you have just described, have HELCO and the Consumer Advocate agreed to other adjustments to production O&M expenses?

A. Yes. HELCO's rebuttal position also includes three adjustments proposed by the Consumer Advocate and accepted by HELCO during settlement discussions:

1) The Consumer Advocate proposed reducing production operations – labor expense by $185,000. This adjustment was accomplished by subtracting the 2006 actual production O&M - labor expense from the direct testimony 2006 test year estimate of production O&M labor expense, which resulted in a reduction of $1,110,000. Mr. Brosch then offset two expense adjustments against the $1,110,000, namely $392,700 in production O&M – labor proposed by HELCO in its response CA-IR-447 (T-5), Attachment 1, pages 3 and 11, and explained in my rebuttal testimony, above, and $532,800 for

amounts spent, but not budgeted, in 2006 for outside services – temporary hire. The net resulting adjustment to production O&M – labor expense is a reduction of $185,000 as set forth in CA-101, Schedule C-4. To minimize the issues in this proceeding, the Company accepted the Consumer Advocate's proposed -$185,000 adjustment. The adjustment is reflected in HELCO-R-501, column (G1).

2) The Consumer Advocate proposed an adjustment to production maintenance – non-labor expenses by removing $130,000 for low pressure turbine ("LPT") replacement projects as set forth in CA-101, Schedule C-6. Mr. Brosch did not accept the normalization adjustment proposed by the Company for future "condition-based" LPT replacement projects for CT-4 and CT-5 that may possibly be required, after runtime hours accumulate on the CT's, up to seven years in the future. Although the Company maintains that such overhauls are necessary, and that its total normalized estimate for overhaul expense (with the net adjustments summarized in the response to CA-IR-447 (T-5), page 2) is not unreasonable, the Company agreed to the Consumer Advocate's proposed adjustment of -$130,000 for the purpose of minimizing the issues in this proceeding. The adjustment is reflected in HELCO-R-501, column (G2).

3) The Consumer Advocate also proposed reducing production O&M – non-labor miscellaneous material expense by $382,000. HELCO's pre-settlement rebuttal testimony 2006 test year estimate for production O&M - non-labor expense was $12,848,000 (HELCO-R-501, column (F)) which included $2,614,000 for miscellaneous materials (i.e., non-project materials). Mr. Brosch calculated the adjustment by (a) taking a three-year

average of historical actual 2004-2006 (corrected) material expense, (b) subtracting HELCO's 2006 test year production O&M non-labor non-project material expense, and subtracting certain reversals of materials cost noted by HELCO (see CA-101, Schedule C-3). The net result is a reduction of $382,000. HELCO initially opposed this adjustment for several reasons. HELCO did not contest the reasonableness of the adjustment when viewed in isolation, but maintained that actual 2006 production O&M non-labor expenses should be considered in total, as the Consumer Advocate did in adjusting production O&M labor expenses. Actual 2006 Production O&M non-labor expenses (after subtracting outside temporary services, which the Consumer Advocate accounted for as labor-like expenses in Schedule C-4), are higher than HELCO's test year estimate. The actual expenses for production O&M - non-labor for 2006 were $13,937,000 (HELCO-R-501, column (I)), including the $532,800 for outside temporary services. HELCO's rebuttal testimony estimate prior to settlement discussions with the Consumer Advocate was $12,848,000, as shown on HELCO-R-501, column (F). In addition, while the Company recognizes that non-labor expenses in prior years were lower, it did not appear that the adjustment took into account recent significant trends and current operations of HELCO's production system, which will necessarily result in higher ongoing production O&M expenses, as discussed in detail in HELCO T-5, pages 16-20, and related information responses.

The Consumer Advocate pointed out, however, that non-labor expenses include overhaul expenses, which the parties agree should be normalized, and that the normalization adjustments for the test year were based on the adjusted budget

estimates for 2006, and not the 2006 actual overhaul expenses. The Consumer Advocate was unwilling to accept actual 2006 non-labor expenses as the basis for the normalized test year estimate without conducting further discovery, which could be extensive, with respect to whether the 2006 actual non-labor expenses were representative of the normal on-going level of expenses. In order to affect the global settlement between the Company and the Consumer Advocate, the Company agreed to accept the Consumer Advocate's proposed adjustment for this expense. The agreed-upon adjustment appears in HELCO-R-501, column (G1).

Q. Please summarize HELCO's settlement 2006 test year position for production O&M expense.

A. HELCO's settlement 2006 test year production O&M expense is $21,041,000, which consists of the following:

- Production Operations – Labor: $5,780,000;
- Production Operations – Non-Labor: $3,540,000;
- <u>Total Production Operations expense: $9,320,000;</u>
- Production Maintenance – Labor: $2,925,000;
- Production Maintenance – Non-Labor: $8,796,000;
- <u>Total Production Maintenance expense: $11,721,000;</u>

<u>Total Production O&M expense: $21,041,000.</u> (See HELCO-R-501, column (H).)

Q. Do you have any further comments regarding actual 2006 expenses?

A. Mr. Brosch suggests in his testimony CA-T-1 on pages 26-27 that HELCO may have "accelerated cost commitments at year end to create favorable comparisons to its rate case forecast." I would like to note that this was not the case. HELCO incurred much of its overhaul expense at the end of the year. Overhauls of HELCO's own units had to move to the latter months in the year, and the 2006

overhaul schedule had to be adjusted, due to Puna Geothermal Venture ("PGV") and Hamakua Energy Partners ("HEP") generation problems, as well as some HELCO issues, throughout the course of the test year. These overhaul schedule adjustments were required for HELCO to maintain sufficient generating margin to cover the loss of largest unit throughout 2006. This pushed work that was to be done earlier in the year to later in the year, resulting in the noted billing activity by outside contractors and vendors. This was discussed in HELCO's response to CA-IR-77(d), "[T]the Company has rescheduled a number of its overhauls for later in the year and thus expects to incur the associated expenses for this work at the end of 2006." In addition, it is not uncommon for HELCO to receive large numbers of invoices at the end of each quarter and year.

Production Materials and Supplies Inventory

Q. What is HELCO's rebuttal position with respect to production materials and supplies inventory?

A. There have been no changes or adjustments to HELCO's 2006 test year estimate for production materials and supplies inventory since the filing of HELCO's direct testimony. HELCO's 2006 test year and 2006 rebuttal year-end inventory value are both $1,061,943 as shown on HELCO-R-502.

Q. What is the Consumer Advocate's position regarding production materials and supplies inventory?

A. The Consumer Advocate's position is set forth in its response to HELCO/CA-IR-111, namely that the Consumer Advocate accepts the production materials and supplies inventory average test year value of $1,035,000 shown in HELCO-1603 rather than the higher figure of $1,062,000 provided in HELCO's response to CA-IR-448, HELCO T-16, page 9.

Purchased Power

Q. What is HELCO's rebuttal position with respect to purchased power expense?

A. HELCO's revised 2006 test year estimate of purchased power expense is $117,210,000. This is a reduction of $108,000 from HELCO's direct testimony 2006 test year estimate of $117,318,000 as shown on HELCO-R-545. The purchased power expense is comprised of purchased energy expense of $99,280,000, and purchased capacity expense of $17,930,000, as shown on HELCO-R-548.

Q. Why has HELCO revised its estimate of purchased energy for the 2006 test year?

A. As discussed by Lisa Giang in HELCO RT-4, HELCO has updated its direct testimony test year production simulation by incorporating entire year 2006 data in the as-available assumptions for Lalamilo Wind Farm, Waiau hydro, Wailuku hydro and Other IPP hydro.

Q. How has HELCO revised its test year estimate for energy purchases?

A. HELCO has slightly decreased its estimate of energy purchased by 810 MWh, from 710.07 GWh to 709.26 GWh. See HELCO-R-546 and HELCO RT-4 at page 2.

Q. Why has the estimate of energy purchased decreased?

A. The estimate of energy purchased was decreased after the production simulation indicated that there would be less energy production from Hamakua Energy Partners ("HEP").

Q. How has HELCO revised its test year estimate of purchased energy expense?

A. The test year purchased energy expense has decreased by $108,000 from $99,388,000 to $99,280,000. See HELCO-R-548.

Q. Why did HELCO revise the test year estimate of purchased energy expense?

A. The primary reasons for the revision are to reflect 1) the slight decrease in the avoided energy rates used to calculate energy cost, 2) the slight decrease in MWh forecast for HEP, and 3) the increase in Hawi Renewable Development ("HRD") payments due to change in on-peak and off-peak allocation from time of day allocation (58% on-peak, 42% off-peak) to 2006 recorded allocation (69% on-peak, 31% off-peak).

Q. What position did the Consumer Advocate take in its testimony regarding the purchased power expense?

A. The Consumer Advocate proposed a purchased power expense of $116,776,000, which is $542,000 lower than HELCO's direct testimony 2006 test year estimate of $117,318,000 and $434,000 lower than HELCO's rebuttal 2006 test year expense of $117,210,000.

Q. Did the Consumer Advocate adjust payments to specific independent power producers?

A. Yes. As shown in CA-211, the Consumer Advocate's proposed expense for energy payments is $98,846,000, consisting of $34,321,000 in payments to PGV and $53,777,000 to HEP, together with estimated energy payments of $10,749,000 to as-available power producers. HELCO's direct testimony 2006 test year estimates are $34,393,000 in energy payments to PGV and $54,246,000 to HEP, together with estimated payments of $10,749,000 to as-available power producers for a total of $99,388,000. See CA-211. HELCO's rebuttal testimony 2006 test year estimate for energy payments to PGV, HEP, and as-available power producers are $34,316,000, $54,121,000, and $10,843,000, respectively. See HELCO-R-545.

Q. Have HELCO and the Consumer Advocate resolved their difference over this issue?

A. Yes. In settlement discussions, the Consumer Advocate agreed to accept HELCO's rebuttal testimony 2006 test year purchased power expense estimate as set forth in HELCO-R-545 for the purpose of limiting the number of disputed issues in this proceeding.

Q. Are there any other purchased power issues in dispute between HELCO and the Consumer Advocate?

A. No.

AREAS OF AGREEMENT

Q. In what areas are the Consumer Advocate and HELCO in agreement?

A. With respect to production O&M expenses, the Consumer Advocate and HELCO agree on the following adjustments:

1) The Consumer Advocate has accepted all of the adjustments shown in HELCO's response to CA-IR-447 totaling approximately $1,303,000. Each of the adjustments was explained briefly earlier in my rebuttal testimony at pages 3 - 6. The Consumer Advocate recognized and accepted all of these adjustments in CA-101, Schedule C-3 and CA-T-1 at 29. These adjustments are reflected on HELCO-R-501, columns (E1) and (E2).

2) HELCO and the Consumer Advocate in settlement discussions have agreed to the Consumer Advocate's proposed reduction of production O&M labor expense in the amount of $185,000 as shown in CA-101, Schedule C-4. This adjustment is reflected on HELCO-R-501, column (G1).

3) HELCO and the Consumer Advocate in settlement discussions also have agreed to the Consumer Advocate's proposed adjustment to production

O&M expense by removing $130,000 for low pressure turbine replacement projects for CT-4 and CT-5 as set forth in CA-101, Schedule C-6. This adjustment is reflected on HELCO-R-501, column (G2).

4) HELCO and the Consumer Advocate have agreed to the $382,000 reduction of the production O&M non-labor materials 2006 test year estimated expense proposed by the Consumer Advocate in CA-101, Schedule C-5. The agreed-upon adjustment appears in HELCO-R-501, column (G1).

Q. Have HELCO and the Consumer Advocate agreed on the amount for production materials and supplies inventory?

A. The Consumer Advocate's position is set forth in its response to HELCO/CA-IR-111, namely that the Consumer Advocate accepts the value of $1,035,000 shown in HELCO-1603 rather than the higher figure of $1,062,000 provided in HELCO's response to CA-IR-448 T-16, page 9. (See, HELCO-R-502.) For the purpose of simplifying issues in this proceeding, HELCO has agreed to accept the Consumer Advocate's figure of $1,035,000 for production materials and supplies inventory.

Q. Have HELCO and the Consumer Advocate agreed on the 2006 test year purchased power expense?

A. Yes. The Consumer Advocate in settlement discussions has agreed to accept HELCO's rebuttal testimony 2006 test year purchased power expense estimate of $117,210,000 as set forth in HELCO-R-545 for the purpose of limiting the number of disputed issues in this proceeding.

Q. Are there any areas of disagreement between HELCO and the Consumer Advocate with respect to production O&M expense, production materials and supplies inventory and purchased power expense?

A. No. HELCO and the Consumer Advocate have reached agreement with respect to production O&M expense, production materials and supplies inventory and purchased power expense.

SUMMARY

Q. Please summarize your rebuttal testimony with respect to the adjustments proposed by the Consumer Advocate.

A. HELCO's rebuttal estimate for production O&M expense for the 2006 test year following settlement discussions with the Consumer Advocate is $21,041,000; $9,320,000 for production operations expense and $11,721,000 for production maintenance expense as shown on HELCO-R-501, column (H). HELCO's rebuttal estimate for production materials and supplies inventory for the 2006 test year following settlement discussions with the Consumer Advocate is $1,035,000. HELCO's rebuttal estimate for purchased power expense for the 2006 test year following settlement discussions with the Consumer Advocate is $117,210,000 as shown in HELCO-R-545.

Q. Does this conclude your testimony?

A. Yes, it does.

Hawaii Electric Light Company, Inc.
2006 TEST YEAR

OTHER PRODUCTION
OPERATIONS & MAINTENANCE EXPENSE
($ Thousands)

	(A)	(B)	(C)	(D)	(E1)	(E2)	(F)	(G1)	(G2)	(H)	(I)
					CA-IR-447			SETTLEMENT			
	2006 OPERATING BUDGET	BUDGET ADJUST	NORMS	DIRECT TESTIMONY 2006 TEST YEAR	BUDGET ADJUST	NORMS	HELCO ADJUSTED 2006 TEST YEAR	BUDGET ADJUST	NORM	HELCO / CONSUMER ADVOCATE SETTLEMENT 2006 TEST YEAR	ACTUAL 2006 TEST YEAR
OTHER PROD OPERATIONS EXPENSE											
1 Labor	$ 6,054	$ -	$ -	$ 6,054	$ (89)	$ -	$ 5,965	$ (185)	$ -	$ 5,780	$ 5,338
2 Non-Labor	$ 3,527	$ 200	$ (194)	$ 3,533	$ 7	$ -	$ 3,540	$ -	$ -	$ 3,540	$ 3,537
3 TOTAL	$ 9,581	$ 200	$ (194)	$ 9,587	$ (82)	$ -	$ 9,505	$ (185)	$ -	$ 9,320	$ 8,875
OTHER PROD MAINTENANCE EXPENSE											
4 Labor	$ 3,228	$ -	$ -	$ 3,228	$ (303)	$ -	$ 2,925	$ -	$ -	$ 2,925	$ 2,834
5 Non-Labor	$ 10,493	$ (557)	$ 289	$ 10,225	$ (407)	$ (510)	$ 9,308	$ (382)	$ (130)	$ 8,796	$ 10,400
6 TOTAL	$ 13,721	$ (557)	$ 289	$ 13,453	$ (710)	$ (510)	$ 12,233	$ (382)	$ (130)	$ 11,721	$ 13,234
7 SUBTOTAL LABOR	$ 9,282	$ -	$ -	$ 9,282	$ (393)	$ -	$ 8,889	$ (185)	$ -	$ 8,705	$ 8,172
8 SUBTOTAL NON-LABOR	$ 14,020	$ (357)	$ 95	$ 13,758	$ (400)	$ (510)	$ 12,848	$ (382)	$ (130)	$ 12,336	$ 13,937
9 PRODUCTION TOTAL	$ 23,302	$ (357)	$ 95	$ 23,040	$ (793)	$ (510)	$ 21,737	$ (567)	$ (130)	$ 21,041	$ 22,109

Note 1: HELCO applied the $382,000 reduction for Non-labor (non-project) expense to Production Maintenance because the majority of the non-labor (non-project) expense was budgeted for production maintenance. The Consumer Advocate did not breakout the adjustment between Production Operations Non-labor expense and Production Maintenance Non-labor expense.

Note: Totals may not add exactly due to rounding.

HAWAII ELECTRIC LIGHT COMPANY, INC.
2006 TEST YEAR
REBUTTAL TESTIMONY

PRODUCTION MATERIAL INVENTORY
13-MONTH AVERAGE
(DECEMBER 1 - DECEMBER 31)

						DIRECT 2006 TEST YEAR	2006 REBUTTAL	2005 vs 2006	
	(A) 2002	(B) 2003	(C) 2004	(D) 2005	(E) 2006	2006	(F=E-D) $	(F/D) %
1 Year-End Value	$ 862,838	$ 879,834	$ 1,004,029	$ 1,006,978	$ 1,061,943	$ 1,061,943	$ 54,965	5.5
2 Difference		$ 16,996	$ 124,195	$ 2,949	$ 57,914			

HELCO-R-503 to HELCO-R-544

NOT USED.

Hawaii Electric Light Company, Inc.

TEST YEAR 2006 PURCHASED POWER EXPENSE TOTAL
REBUTTAL Testimony

Line	Purchased Power ($000)	(A) Direct Testimony ($000)	(B) Rebuttal Testimony ($000)	(C) Net Change ($000)
	Firm Power: (Energy & Capacity)			
1	Puna Geothermal Venture (PGV)			
	- Energy Payments	$ 34,393	$ 34,316	$ (77)
	- Capacity Payments	$ 4,256	$ 4,256	$ (0)
	Total PGV Payments	$ 38,649	$ 38,572	$ (77)
2	Hamakua Energy Partners (HEP)			
	- Energy Payments	$ 54,246	$ 54,121	$ (125)
	- Capacity Payments	$ 13,674	$ 13,674	$ 0
	Total HEP Payments	$ 67,920	$ 67,795	$ (125)
	As Available Power: (Energy)			
3	Wailuku River Hydro (WRH)	$ 4,412	$ 4,404	$ (8)
4	Hawi Renewable Development (HRD)	$ 5,496	$ 5,603	$ 107
5	Apollo Energy Corp (Kamaoa)	$ 677	$ 675	$ (2)
6	Other Small Hydro	$ 164	$ 161	$ (3)
7	Total	$ 117,318	$ 117,210	$ (108)

Reference:
Column A = HELCO-545
Column B = HELCO-RWP-545, pages 1, 2 & 3
Column C = Column B - Column A

Note: Totals may not add exactly due to rounding.

Hawaii Electric Light Company, Inc.

TEST YEAR 2006 NET PURCHASED ENERGY (GWH)
Rebuttal Testimony

Purchased Power	(A) Direct Testimony (GWH)	(B) Rebuttal Testimony (GWH)	(C) Net Change (GWH)
Firm Power:			
1. Puna Geothermal Venture (PGV)	221.94	221.94	(0.00)
2. Hamakua Energy Partners (HEP)	420.56	419.74	(0.82)
Subtotal Firm Power	642.51	641.69	(0.82)
As Available Power:			
3. Wailuku River Hydro	27.48	27.50	0.02
4. Hawi Renewable Development	34.23	34.23	(0.00)
5. Apollo Energy Corp (Kamaoa Wind Farm)	4.84	4.84	-
6. Other Small Hydro	1.02	1.01	(0.01)
Subtotal As-Available Power	67.56	67.57	0.00
Total Purchased Power (GWH)	710.07	709.26	(0.81)

Reference:
Column A = HELCO-546
Column B = HELCO-RWP-545, page 1
Column C = Column B - Column A
Note: Totals may not add exactly due to rounding.

Hawaii Electric Light Company, Inc.

HISTORICAL PURCHASED ENERGY (ANNUAL GWH)
Rebuttal Testimony

Purchased Power (GWH)	FY 2001	FY 2002	FY 2003	FY 2004	FY 2005	Direct TY 2006	**Rebuttal TY 2006**
Firm Power:							
1. Puna Geothermal Venture (PGV)	207	74	176	211	221	222	**222**
2. Hamakua Energy Partners (HEP)	322	421	439	442	431	421	**420**
3. Hilo Coast Power Company (HCPC)	69	89	82	79	-	-	**-**
Subtotal Firm Power	598	584	697	731	652	643	**642**
As Available Power:							
4. Wailuku River Hydro	33	27	24	26	30	27	**27**
5. Hawi Renewable Development	-	-	-	-	-	34	**34**
6. Apollo Energy Corp (Kamaoa Wind Farn	15	10	10	6	5	5	**5**
7. Other Small Wind and Hydro	1	1	1	1	1	1	**1**
Subtotal As-Available Power	49	38	35	33	35	68	**68**
Total HELCO Purchased Power	648	622	732	764	688	710	**709**

Note: Totals may not add exactly due to rounding.

Hawaii Electric Light Company, Inc.

HISTORICAL PURCHASED POWER EXPENSES
Rebuttal Testimony

Purchased Power Expense	2004 Recorded ($000)	2005 Recorded ($000)	Direct TY 2006 Estimate ($000s)	Rebuttal TY 2006 Estimate ($000)
1. Puna Geothermal Venture (PGV)	$ 21,067	$ 30,746	$ 34,393	$ 34,316
2. Hamakua Energy Partners (HEP)	$ 37,489	$ 49,380	$ 54,246	$ 54,121
3. Hilo Coast Power Company (HCPC)	$ 7,040	$ -	$ -	$ -
4. Wailuku River Hydro (WRH)	$ 2,555	$ 4,394	$ 4,412	$ 4,404
5. Hawi Renewable Development (HRD)	$ -	$ -	$ 5,496	$ 5,603
6. Apollo Energy Corporation (AEC)	$ 535	$ 573	$ 677	$ 675
7. Other Small Wind & Hydro	$ 62	$ 129	$ 164	$ 161
Total Energy Payments	$ 68,748	$ 85,222	$ 99,388	$ 99,280
1. Puna Geothermal Venture (PGV)	$ 3,950	$ 4,104	$ 4,256	$ 4,256
2. Hamakua Energy Partners (HEP)	$ 13,500	$ 13,569	$ 13,674	$ 13,674
3. Hilo Coast Power Company (HCPC)	$ 4,930	$ -	$ -	$ -
Total Capacity Payments	$ 22,380	$ 17,672	$ 17,930	$ 17,930
Total HELCO Purchased Power Expense	$ 91,128	$ 102,894	$ 117,318	$ 117,210

Note: Totals may not add exactly due to rounding.

HELCO RT-6
DOCKET NO. 05-0315

REBUTTAL TESTIMONY OF
JAY M. IGNACIO

MANAGER
DISTRIBUTION DEPARTMENT
HAWAII ELECTRIC LIGHT COMPANY, INC.

Subject: Transmission and Distribution ("T&D") System
T&D Operation and Maintenance ("O&M") Expense
T&D Materials Inventory

INTRODUCTION

Q. Please state your name and business address.

A. My name is Jay Ignacio and my business address is 54 Halekauila Street, Hilo Hawaii.

Q. Mr. Ignacio, have you previously submitted testimony in this proceeding?

A. Yes. I submitted written direct testimony, exhibits, and supporting work papers as HELCO T-6.

Q. What is the scope of your rebuttal testimony?

A. My rebuttal testimony will:

1) Present HELCO's rebuttal position with respect to transmission and distribution ("T&D") operations and maintenance ("O&M") expense; and,
2) Present HELCO's rebuttal position with respect to T&D materials inventory.

Q. How is your rebuttal testimony organized?

A. I will:

1) Summarize HELCO's rebuttal position, including the changes made by HELCO in preparing its rebuttal position, and identify the changes that were accepted by the Consumer Advocate in the testimony of its witnesses;
2) Summarize additional adjustments to which HELCO and the Consumer Advocate agreed during settlement discussions; and
3) List and summarize all of the areas where the Consumer Advocate and HELCO agree.

HELCO's REBUTTAL T&D O&M EXPENSE

Q. How did HELCO arrive at its final rebuttal position for T&D O&M expense?

A. HELCO started with the position set forth in my direct testimony in HELCO T-6

which is summarized in HELCO-R-601, column (D). The direct testimony 2006 test year estimates were then modified to incorporate adjustments and normalizations set forth in HELCO's response to CA-IR-447. The results are summarized in HELCO-R-601, column (F). HELCO then made further changes to the adjusted O&M expense estimates to take into account an additional adjustment to which HELCO and the Consumer Advocate agreed during settlement discussions. HELCO's final 2006 test year rebuttal position for T&D O&M expense, which incorporates adjustment agreed-upon in settlement, is summarized in HELCO-R-601, column (H).

Q. What is HELCO's settlement rebuttal position regarding T&D O&M expense for the 2006 test year?

A. HELCO's rebuttal position for the 2006 test year is $8,705,000; $2,341,000 for transmission O&M expense and $6,364,000 for distribution O&M expense, as shown on HELCO-R-601. This is $295,000 lower than our position in direct testimony, as shown on HELCO-R-601.

Q. Please explain the adjustments to HELCO's direct testimony 2006 test year forecast made before settlement discussions.

A. For T&D O&M expense, an adjustment to <u>reduce</u> the direct testimony 2006 test year expense by <u>$131,606</u> was made. This adjustment is the net of:

• increases for transformer mounting plate replacements	$ 62,065
• increase for manhole cover replacements	$ 5,872
• decreases for abandoned capital projects	($ 92,459)
• decreases for not filling 4 trouble inspector positions	<u>($107,084)</u>
Decrease in T&D O&M expense	<u>($131,606)</u>

Q. Please explain these adjustments.

A. A brief explanation of these adjustments is as follows:

1) The $62,065 adjustment for the transformer mounting replacement program is to fund a program to replace transformer mounting plates that are prone to cracking. The program was started in mid-2006 and the $62,065 represents the estimated amount expended in 2006.

2) The $5,872 adjustment for manhole cover replacements is to fund a replacement program for manhole covers that have deteriorated and are causing potential hazards to employees and the public. The $5,872 represents the estimated amount expended on the program in 2006.

3) The adjustment amount of ($92,459) for abandoned capital projects, which consists of an adjustment to correct an over-statement of $86,000 in direct testimony, and a further reduction of $6,459, was made as more accurate information was obtained in 2006 for capital projects that were abandoned.

4) The adjustment of ($107,084) for the trouble inspector positions was made due to not filling four trouble inspector positions that were intended to expand coverage from 2 shifts 7 days per week to 3 shifts 7 days per week in 2006.

Each of these four adjustments is the net result of additional adjustments made in different accounts within Transmission Operations – Labor, Transmission Operations – Non-Labor, Transmission Maintenance – Labor, Transmission Maintenance – Non-Labor, Distribution Operations – Labor, Distribution Operations – Non-Labor, Distribution Maintenance – Labor and Distribution Maintenance – Non-Labor. Each of these adjustments is described in detail in HELCO's response to CA-IR-447 (T-6), pages 7-9, as well as in HELCO-R-602,

and the adjustments are summarized in HELCO-R-601, column (E).

Q. Has the Consumer Advocate taken a position regarding these four adjustments that you summarized above?

A. Yes. In CA-T-3, at page 100, the Consumer Advocate recognized and accepted the four adjustments for the transformer mounting plate replacements, manhole cover replacements, abandoned capital projects and four trouble inspectors. (See CA-101, Schedule C-14.)

T&D O&M Expense Adjustments Agreed Upon in Settlement

Q. In addition to the rebuttal adjustments you have just described, have HELCO and the Consumer Advocate agreed to other T&D adjustments?

A. Yes. In response to CA-IR-447 and as revised in CA-SIR-37, HELCO submitted an adjustment that estimated T&D training expense (which is recorded in Accounts 925.01 and 926.06 and is discussed by Mr. Paul Fujioka in HELCO RT-9) to be $846,300 in the test year. Also provided in the response to CA-IR-447 were the associated improvements to training being made in the department that caused the increase in expense. However, the actual training expense in 2006 was $716,000 and the Consumer Advocate proposed an adjustment in CA-101, Schedule C-15 to set the test year T&D training expense at the amount actually expended in 2006. In the interest of reducing the number of disputed issues in this proceeding, the Company accepted the Consumer Advocate's proposal and the estimate for T&D training expense is revised to $716,000 in the Company's rebuttal testimony. The revised amount is part of Mr. Paul Fujioka's rebuttal testimony, HELCO RT-9.

Q. Were any other adjustments agreed upon as a result of settlement negotiations?

A. Yes. A reduction to the T&D O&M – labor expense estimate in the amount of

1 $163,000 was agreed upon during settlement discussions between HELCO and the
2 Consumer Advocate.
3 Q. What was the Consumer Advocate's rationale for proposing the adjustment upon
4 which the settlement compromise was based?
5 A. Consumer Advocate witness CA-T-3, Steven Carver, proposed an adjustment in
6 CA-101, Schedule C-19 to reduce T&D O&M labor expense by $326,000. This
7 adjustment was the result of Mr. Carver eliminating ten positions (two linemen,
8 one helper and seven senior helpers) from HELCO's T&D O&M 2006 test year
9 labor estimate. Mr. Carver estimated the labor costs attributable to these ten
10 positions and arrived at an adjustment that reduced HELCO's test year estimated
11 labor expense by $326,000. (CA-T-3, page 111, line 18 to page 112, line 8.)
12 Q. What was HELCO's initial position regarding this adjustment?
13 A. HELCO initially disagreed with this adjustment on several grounds. HELCO
14 maintained that the primary focus should be on T&D O&M expenses, not merely
15 the staffing headcount. HELCO's actual 2006 T&D O&M labor expense of
16 $3,652,000 was $280,000 higher than its pre-settlement 2006 T&D O&M labor
17 expense estimate of $3,372,000. The same pattern appears in non-labor expenses.
18 In 2006, actual non-labor expense for T&D O&M related activities was
19 $5,955,000, which is $459,000 higher than the $5,496,000 that is included in the
20 2006 test year rebuttal estimate as presented in HELCO-R-601. Moreover, in
21 HELCO's view, the proposed adjustment did not take into account that (1) the
22 46,578 recorded 2006 overtime hours for labor classes that generally incur
23 overtime (HDC-Techcrew, HDH-crew, HDK-crew and HDW-crew), significantly
24 exceeded the 2006 forecasted 34,856 overtime hours as shown in HELCO-R-603,
25 (2) O&M contractor services (which are used to supplement the HELCO labor

force, and are accounted for as non-labor expenses) were higher than in recent years, as shown in HELCO-R-604, or (3) HELCO is actively recruiting to fill positions in T&D and expects that the staffing count will soon exceed the 109 positions recognized by the Consumer Advocate's adjustment in CA-101, Schedule C-19. In addition, the higher than forecast labor expenses were not due to "extraordinary" earthquake damage repair. The total T&D O&M expense recorded in 2006 for the earthquake was about $195,000, of which $78,000 was labor expense. See HELCO-R-605. However, in the interest of reducing the number of disputed issues in this proceeding, the Company and Consumer Advocate have agreed on an adjustment of $163,000 to reduce the direct testimony estimate for labor expense.

REBUTTAL T&D MATERIALS INVENTORY

Q. What is HELCO's rebuttal position regarding the T&D materials inventory for the 2006 test year?

A. The rebuttal testimony amount for the 13-month average inventory is $2,512,000. This is the same as the amount stated in direct testimony and is shown on HELCO-R-606.

Q. Does the Consumer Advocate recognize HELCO's 13-month average inventory balance of $2,512,000 presented in HELCO RT-6 as a reasonable amount?

A. Yes. As noted in its response to HELCO/CA-IR-111, the Consumer Advocate does not object HELCO's T&D materials inventory balance.

AREAS OF AGREEMENT

Q. Please summarize the areas in which the Consumer Advocate and HELCO are in agreement.

A. HELCO and the Consumer Advocate have agreed upon T&D O&M expenses

discussed above in my rebuttal testimony and summarized in HELCO-R-601, column (H). The Consumer Advocate also has accepted the Company's 13-month average T&D materials inventory balance of $2,512,000 shown in HELCO-R-606.

AREAS OF DISAGREEMENT

Q. What are the areas where the Consumer Advocate and HELCO disagree?

A. There are no areas of disagreement.

SUMMARY

Q. Please summarize your rebuttal testimony.

A. HELCO's rebuttal estimate for the 2006 test year is $8,705,000; $2,341,000 for transmission O&M expense and $6,364,000 for distribution O&M expense, as shown on HELCO-R-601, page 1. HELCO's rebuttal T&D materials inventory is $2,512,000 as shown on HELCO-R-606.

Q. Does this conclude your rebuttal testimony?

A. Yes, it does.

Hawaii Electric Light Company, Inc.
REBUTTAL - 2006 TEST YEAR
TRANSMISSION AND DISTRIBUTION
OPERATIONS & MAINTENANCE EXPENSE
($000s)

	(A) 2006 OPERATING BUDGET	(B) BUDGET ADJUST	(C) NORM	(D) DIRECT TESTIMONY 2006 TEST YEAR	(E) CA-IR-447 BUDGET ADJUST	(F) ADJUSTED 2006 TEST YEAR	(G) SETTLEMENT ADJUST	(H) HELCO / CONSUMER ADVOCATE SETTLEMENT 2006 TEST YEAR	(I) ACTUAL 2006 TEST YEAR
Transmission Operations									
Labor	$ 465.3	$ 2.0	$ -	$ 467.3	$ (2.7)	$ 464.6	$ (18.0)	$ 446.6	$ 404.7
Non-Labor	479.9	11.6	-	491.5	(7.6)	483.9	-	483.9	660.4
SUB-TOTAL	945.2	13.6	-	958.8	(10.3)	948.5	(18.0)	930.5	1,065.1
								-	
Transmission Maintenance								-	
Labor	461.9	0.2	-	462.1	(3.0)	459.1	(26.5)	432.6	464.7
Non-Labor	980.2	0.2		980.4	(2.8)	977.6	-	977.6	870.8
SUB-TOTAL	1,442.1	0.4	-	1,442.5	(5.8)	1,436.7	(26.5)	1,410.2	1,335.5
								-	
TOTAL TRANSMISSION	2,387.3	14.0	-	2,401.3	(16.1)	2,385.2	(44.5)	2,340.7	2,400.6
								-	
Distribution Operations								-	
Labor	1,164.6	(22.1)	-	1,142.5	(17.4)	1,125.1	(42.9)	1,082.2	1,218.9
Non-Labor	1,222.9	121.4	-	1,344.3	(103.6)	1,240.7	-	1,240.7	1,055.2
SUB-TOTAL	2,387.5	99.3	-	2,486.8	(121.0)	2,365.8	(42.9)	2,322.9	2,274.1
								-	
Distribution Maintenance								-	
Labor	1,297.5	26.7	-	1,324.2	(1.1)	1,323.1	(75.6)	1,247.5	1,563.3
Non-Labor	2,762.2	24.8	-	2,787.0	6.6	2,793.6	-	2,793.6	3,368.8
SUB-TOTAL	4,059.7	51.5	-	4,111.2	5.5	4,116.7	(75.6)	4,041.1	4,932.1
						-		-	
TOTAL DISTRIBUTION	6,447.2	150.8	-	6,598.0	(115.5)	6,482.5	(118.5)	6,364.0	7,206.2
						-		-	
TOTAL LABOR	3,389.3	6.8		3,396.1	(24.2)	3,371.9	(163.0)	3,208.9	3,651.6
TOTAL NON-LABOR	5,445.2	158.0		5,603.2	(107.4)	5,495.8	-	5,495.8	5,955.2
						-		-	
GRAND TOTAL	$ 8,834.5	$ 164.8	$ -	$ 8,999.3	$ (131.6)	$ 8,867.7	$ (163.0)	$ 8,704.7	$ 9,606.8

Hawaii Electric Light Company, Inc.

REBUTTAL 2006 TEST YEAR

TRANSMISSION AND DISTRIBUTION
OPERATIONS & MAINTENANCE EXPENSES

Adjustments

1. Increases for Transformer mounting plate replacements	$ 62,065
2. Increase for manhole cover replacements	$ 5,872
3. Decrease for abandoned capital projects	($ 92,459)
4. Decrease for not filling 4 trouble inspector positions	($107,084)
5. Decrease in labor expense as agreed in settlement	($163,000)
TOTAL ADJUSTMENT	($294,606)

Hawaii Electric Light Company, Inc.
REBUTTAL - 2006 TEST YEAR

TRANSMISSION ADJUSTMENTS
OPERATIONS & MAINTENANCE EXPENSE

TRANSMISSION OPERATIONS		
LABOR		
Reduction of four 24 hour troublemen inspectors forecasted to start July 2006, Account 563.	$	(2,739.0)
Reduction in labor expense as agreed in settlement	$	(18,000.0)
SUB-TOTAL	$	(20,739.0)
NON-LABOR		
Reduction of four 24 hour troublemen inspectors forecasted to start July 2006, Account 563.	$	(2,551.0)
Adjustment for abandoned capital project costs written off to O&M expense, account 566. (Note: original increase of $152,000 was overstated by $86,000 as stated on HELCO-602, page 2 of 5.		(97.0)
Adjustment for abandoned capital project costs written off to O&M expense, account 560. (Note: original increase of $152,000 was overstated by $86,000 as stated on HELCO-602, page 2 of 5.		(4,614.0)
Adjustment for abandoned project amount normalized CA-IR-273, page 2 of 3. (Note: Aina Lea Golf Res Comm Project and Prelim Matls China US Center), account 566.		(7.0)
Adjustment for abandoned project amount normalized CA-IR-273, page 2 of 3. (Note: Aina Lea Golf Res Comm Project and Prelim Matls China US Center), account 560.		(347.0)
SUB-TOTAL	$	(7,616.0)
TOTAL TRANSMISSION OPERATIONS	$	(28,355.0)
TRANSMISSION MAINTENANCE		
LABOR		
Reduction of four 24 hour troublemen inspectors forecasted to start July 2006, Account 571.	$	(2,974.0)
Reduction in labor expense as agreed in settlement	$	(26,500.0)
SUB-TOTAL	$	(29,474.0)
NON-LABOR		
Reduction of four 24 hour troublemen inspectors forecasted to start July 2006, Account 571.	$	(2,769.0)
SUB-TOTAL	$	(2,769.0)
TOTAL TRANSMISSION MAINTENANCE	$	(32,243.0)
GRAND TOTAL TRANSMISSION O&M	$	(60,598.0)

Source
CA-IR-447 HELCO (T-6)/Settlement Agreement

Hawaii Electric Light Company, Inc.
REBUTTAL - 2006 TEST YEAR

DISTRIBUTION ADJUSTMENTS
OPERATIONS & MAINTENANCE EXPENSE

DISTRIBUTION OPERATIONS	
LABOR	
Reduction of four 24 hour troublemen inspectors forecasted to start July 2006, Account 583.	$ (9,313.0)
Reduction of four 24 hour troublemen inspectors forecasted to start July 2006, Account 586.	$ (8,100.0)
Reduction in labor expense as agreed in settlement	$ (42,900.0)
SUB-TOTAL	$ (60,313.0)
NON-LABOR	
Reduction of four 24 hour troublemen inspectors forecasted to start July 2006, Account 583.	$ (8,673.0)
Adjustment for abandoned capital project costs written off to O&M expense, account 586. (Note: original increase of $152,000 was overstated by $86,000 as stated on HELCO-602, page 2 of 5.	(848.0)
Adjustment for abandoned project amount normalized CA-IR-273, page 2 of 3. (Note: Aina Lea Golf Res Comm Project and Prelim Matls China US Center), account 586.	(64.0)
Adjustment for abandoned capital project costs written off to O&M expense, account 588. (Note: original increase of $152,000 was overstated by $86,000 as stated on HELCO-602, page 2 of 5.	(9,777.0)
Adjustment for abandoned project amount normalized CA-IR-273, page 2 of 3. (Note: Aina Lea Golf Res Comm Project and Prelim Matls China US Center), account 588.	(734.0)
Adjustment for abandoned capital project costs written off to O&M expense, account 580. (Note: original increase of $152,000 was overstated by $86,000 as stated on HELCO-602, page 2 of 5.	(70,664.0)
Adjustment for abandoned project amount normalized CA-IR-273, page 2 of 3. (Note: Aina Lea Golf Res Comm Project and Prelim Matls China US Center), account 580.	(5,307.0)
Reduction of four 24 hour troublemen inspectors forecasted to start July 2006, Account 586.	(7,543.0)
SUB-TOTAL	$ (103,610.0)
TOTAL DISTRIBUTION OPERATIONS	$ (163,923.0)

Source:
CA-IR-447 HELCO (T-6)/Settlement Agreement

Hawaii Electric Light Company, Inc.

REBUTTAL - 2006 TEST YEAR

DISTRIBUTION ADJUSTMENTS
OPERATIONS & MAINTENANCE EXPENSE

DISTRIBUTION MAINTENANCE

LABOR	
Reduction of four 24 hour troublemen inspectors forecasted to start July 2006, Account 593.	$ (30,209.0)
New Manhole Cover Replacement Project proposed over the next 5 years. 2007-2011 $100K per year, Account 594.	1,174.0
New Transformer Bracket Replacement Project proposed over the next 5 years (2007-2011 $100K), Account 593.	30,052.0
Reduction of four 24 hour troublemen inspectors forecasted to start July 2006, Account 598.	(2,113.0)
Reduction in labor expense as agreed in settlement	(75,600.0)
SUB-TOTAL	$ (76,696.0)
NON-LABOR	
Reduction of four 24 hour troublemen inspectors forecasted to start July 2006, Account 593.	$ (28,132.0)
New Manhole Cover Replacement Project proposed over the next 5 years. 2007-2011 $100K per year, Account 594.	4,698.0
New Transformer Bracket Replacement Project proposed over the next 5 years (2007-2011 $100K), Account 593.	32,013.0
Reduction of four 24 hour troublemen inspectors forecasted to start July 2006, Account 598.	(1,968.0)
SUB-TOTAL	$ 6,611.0
TOTAL DISTRIBUTION MAINTENANCE	$ (70,085.0)
GRAND TOTAL DISTRIBUTION O&M	$ (234,008.0)

Source:
CA-IR-447 HELCO (T-6)/Settlement Agreement

HAWAII ELECTRIC LIGHT COMPANY, INC

HISTORICAL OVERTIME HOURS VS. ST HOURS

LINE	A 2000 Recorded	B 2001 Recorded	C 2002 Recorded	D 2003 Recorded	E 2004 Recorded	F 2005 Recorded	G 2006 Forecast	H 2006 Recorded
OVERTIME HOURS								
1 HDC - TECHCREW	2,823.7	1,813.6	3,355.7	4,078.7	4,261.2	7,375.4	2,796.0	10,049.7
2 HDH - CREW (HiLO)	15,859.3	8,306.0	11,655.9	14,627.1	14,845.6	15,485.0	14,796.0	20,791.3
3 HDK - CREW (Kona)	6,069.8	7,924.6	11,757.8	10,067.1	11,492.3	8,377.2	11,000.0	10,145.9
4 HDW - CREW (Waimea)	7,631.0	5,197.9	6,264.5	6,366.5	6,654.5	4,869.5	6,264.0	5,591.3
TOTALS	32,383.8	23,242.1	33,033.9	35,139.4	37,253.6	36,107.1	34,856.0	46,578.2
ST HOURS								
1 HDC - TECHCREW	31,318.5	31,687.0	26,603.3	28,935.1	25,718.1	26,486.3	37,936.0	35,482.6
2 HDH - CREW (HiLO)	53,211.5	42,272.5	38,208.5	40,289.1	41,439.9	44,667.5	53,188.0	48,238.0
3 HDK - CREW (Kona)	19,835.5	19,684.5	24,381.0	23,779.0	23,610.4	23,933.0	33,732.0	26,755.4
4 HDW - CREW (Waimea)	23,712.8	17,808.0	16,999.0	17,571.2	19,262.5	16,522.1	23,496.0	19,033.8
TOTALS	128,078.3	111,452.0	106,191.8	110,574.4	110,030.9	111,608.9	148,352.0	129,509.8
OVERTIME % OF ST								
1 HDC - TECHCREW	9%	6%	13%	14%	17%	28%	7%	28%
2 HDH - CREW (HiLO)	30%	20%	31%	36%	36%	35%	28%	43%
3 HDK - CREW (Kona)	31%	40%	48%	42%	49%	35%	33%	38%
4 HDW - CREW (Waimea)	32%	29%	37%	36%	35%	29%	27%	29%

NOTE: Revised from CA-IR-86

Hawaii Electric Light Company
TY 2006 Rate Case - Rebuttal (Contractor Costs)

			Years						
		Indicators	2000	2001	2002	2003	2004	2005	2006
	Contractor Costs:								
Substation constructi	ACA Services								
		NI/NR							
		NE							26,030
		TOTAL	-	-	-	-	-	-	26,030
Substation constructi	Electrical Services								
		NI/NR							
		NE							32,340
		TOTAL	-	-	-	-	-	-	32,340
Line Construction	PAR								
		NI/NR						3,470,014	5,015,017
		NE						9,866	415,245
		BT						33,213	93,046
		NS							
									(1)
		TOTAL	-	-	-	-	-	3,513,093	5,523,306
Line Construction	Mauna Kea Electric								
		NI/NR	949,499	387,676	1,541,180	2,718,176	1186476.36	1,048,517	1,131,175
		NE	19,687	7,925	105,326	206,189	53,859.64	45,852	44,263
		BT		32,031	1,629	414		2,963	10,673
		NS							813
		NC						1,880	966
				(1)					(1)
		TOTAL	969,186	427,631	1,648,135	2,924,779	1,240,336	1,099,212	1,187,889
Line Construction	Telecable								
		NI/NR					491,327	1,089,661	893,875
		NE						88,267	272,051
		BT						1,380	-
		NC							8,173
								1	1
		TOTAL	-	-	-	-	491,327	1,179,309	1,174,100
Line Construction	Asplundh								
		NI/NR				173,394	281,808		
		NE							
		BT							
		NS							
		TOTAL	-	-	-	173,394	281,808	-	-
	Total								
		NI/NR	$949,499	$ 387,676	$1,541,180	$2,891,570	$ 1,959,611	$5,608,192	$ 7,040,067
		NE	19,687	7,925	105,326	206,189	53,860	143,985	789,930
		BT	-	32,031	1,629	414	-	37,556	103,718
		NS	-	-				1,880	-
		NC							9,139
				(1)		(2)		2	(1)
		TOTAL	$969,186	$ 427,631	$1,648,135	$3,098,171	$ 2,013,471	$5,791,614	$ 7,942,853

Indicators:
NI-non-billable install (capital)
NR-non-billable removal (capital)
NE-non-billable O&M expense
BT-billable temporary (to customer)
NS-non-billable supervisory
NC-non-billable clearing
Source: CA-IR-97, PART A.

Hawaii Electric Light Company, Inc.
Earthquake O&M Expenses as of 12/31/06
Transmission/Distribution - Project E0013743

Activity	ACCT	Activity Description	Oct	Nov	Dec	2006 Total	Total Labor	Overhead Cost	Contr Serv/Mat Cost
328	563	Trans OH Line Inspection	$ 10,608		$ 10,158	$ 20,766	$ 6,016	$ 4,592	$ 10,158
330	562	Trans Subst Structure Inspect	21,385	542	501	22,428	10,407	12,021	
364	571	Trans OH Line Repair - Storm	16,177	1,088	10,237	27,502	8,479	6,877	12,145
366	570	Trans Subst Equip Repair - Storm	32,410	11,287	5,228	48,925	21,184	22,513	5,228
458	583	Dist OH Line Inspection	6,193	80	278	6,552	3,924	2,628	
507	593	Dist OH Line Repair - Storm	39,371	872	479	40,721	19,352	19,387	1,982
508	594	Dist UG Line Repair - Storm	1,106	0	-	1,106	537	569	
509	592	Dist Subst Equip Repair - Storm	11,403	1,374	3,642	16,419	6,211	6,566	3,642
511	595	Dist OH Line Trans Repair - Storm	805		2,358	3,162	1,762	1,242	159
932	932	Repair Bldgs and Grounds	-	6,939	-	6,939	-	-	6,939
		TOTALS	**$ 139,458**	**$ 22,182**	**$ 32,881**	**$ 194,521**	**$ 77,872**	**$ 76,395**	**$ 40,253**

Hawaii Electric Light Company, Inc.

REBUTTAL - TRANSMISSION & DISTRIBUTION MATERIALS INVENTORY

line		A	B	C	D	E	F	G
		2000 Recorded	2001 Recorded	2002 Recorded	2003 Recorded	2004 Recorded	2005 Recorded	2006 Rebuttal
1	Inventory Level Year-End ($ Thousands)	1,579	1,385	1,636	1,742	1,871	2,501	2,547
2	13-Month Average Inventory Level ($ Thousands)	1,512	1,477	1,523	1,692	1,695	2,055	2,512
3	Total Issues ($ Thousands)	2,505	3,357	2,319	2,809	2,503	3,481	2,772
4	Annual Turnover Ratio	1.68	2.43	1.84	1.72	1.60	1.78	1.18

Source: HELCO-WP-606, pg. 1-9.

REBUTTAL TESTIMONY OF
PAUL N. FUJIOKA

MANAGER
CUSTOMER SERVICE DEPARTMENT
HAWAII ELECTRIC LIGHT COMPANY, INC.

Subject: Customer Accounts Expense
Other Operating Revenues
Customer Deposit
Revenue Collection Lag Days

1 INTRODUCTION

2 Q. Please state your name and business address.

3 A. My name is Paul N. Fujioka and my business address is 1200 Kilauea Avenue,
4 Hilo, Hawaii.

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

6 A. I am the Manager of the Customer Service Department at Hawaii Electric Light
7 Company, Inc. ("HELCO").

8 Q. Have you previously testified in this proceeding?

9 A. Yes, I submitted written direct testimony, exhibits, and supporting workpapers as
10 HELCO T-7, HELCO T-9 and HELCO RT-9.

11 Q. What is the scope of your rebuttal testimony?

12 A. My rebuttal testimony will:

13 1) Present HELCO's rebuttal position with respect to customer accounts
14 expense, other operating revenue, customer deposits, and revenue
15 collection lag days, and

16 2) Address the differences between the Company and the Consumer
17 Advocate with respect to the customer accounts expense accounts, other
18 operating revenue, customer deposits, and revenue collection lag days.

19 Q. How is your rebuttal testimony organized?

20 A. I will:

21 1) Summarize HELCO's rebuttal position, including the changes made by
22 HELCO in preparing its rebuttal position;

23 2) List and summarize the areas where the Consumer Advocate and HELCO
24 agree;

25 3) List the areas where the Consumer Advocate and HELCO disagree; and

4) Discuss each area of disagreement.

HELCO'S REBUTTAL POSITION

Customer Accounts Expense

Q. What is HELCO's rebuttal position with respect to the various subject areas you address in this docket?

A. HELCO's test year estimate of customer accounts expense is $3,574,000, as shown in HELCO-R-702. This includes $388,000 in uncollectibles, which is the same amount from HELCO's direct position. (See HELCO-R-702.) The revised customer accounts expense estimate reflects the following:

1) a decrease of $7,000 in account 904 - uncollectible accounts expense (at proposed rates).

Q. What is HELCO's revised uncollectible accounts expense estimate?

A. HELCO's revised uncollectible accounts expense estimate at proposed rates is $417,000, which is $7,000 less than the $424,000 presented in direct testimony. (See HELCO-R-704.) There is no change to HELCO's uncollectible accounts expense estimate at present rates. (See HELCO-R-702.)

Q. Why is the uncollectible accounts expense estimate at proposed rates being revised?

A. HELCO is making this revision because the electric sales revenues were revised from $323,184,200 to $323,147,700 at present rates, and from $353,064,500 to $347,541,600 at proposed rates, as discussed in HELCO RT-3. These revisions result in no change in uncollectible accounts expense at present rates and a decrease of $7,000 at proposed rates. (See HELCO-R-704.) The Consumer Advocate has agreed with the percentage HELCO used to calculate uncollectible

accounts expense, which was 0.12%. (See CA-T-1, page 50 and CA-101, Schedule A-1, Column C, Line 7.)

Customer Deposits and Interest on Customer Deposits

Q. What is HELCO's Test Year estimate for customer deposits, and interest on customer deposits?

A. HELCO's rebuttal estimate of average customer deposits is $930,500 and interest on customer deposits is $56,000. These amounts have not changed from what was presented in direct testimony. (See HELCO-706.)

Revenue Lag Days

Q. What is HELCO's rebuttal position regarding revenue lag days?

A. HELCO position is that revenue lag days is 38 days, as it was in direct testimony. (See HELCO-708.) HELCO is not updating this number because year-end 2006 actuals show this estimate to be reasonable. The year-end 2006 revenue lag days was 38.7 days, as shown in HELCO-R-705.

Other Operating Revenues

Q. What is the 2006 test year rebuttal estimate of other operating revenues?

A. Other operating revenues for the 2006 test year is $1,055,100 at present rates and $1,096,500 at proposed rates. A summary of the revised other operating revenues is shown in HELCO-R-706, page 1.

Q. Why did the company revise its 2006 test year other operating revenues estimate?

A. The company revised its 2006 test year other operating revenues estimate due to a revision in its 2006 test year revenue from electric sales estimate from $323,184,200 to $323,147,700. Second, HELCO is using the Consumer Advocate's estimate for service establishment charge revenues, which resulted in an increase in other operating revenues by $21,000 from $904,400 used by

HELCO in its direct testimony to $925,400 (prior to adjusting other operating revenues for the Rule No. 8 charges proposed by the Consumer Advocate as discussed below) used in HELCO's rebuttal testimony. Third, HELCO is accepting the Consumer Advocate's proposal to increase service charges for the service establishment, service reconnection, returned payment and field collection as discussed in CA-T-5, page 74. By accepting the Consumer Advocate's proposal, the Company's other operating revenues has increased by $129,700 to $1,055,100 at present rates. (See HELCO-R-706, page 1.)

AREAS OF AGREEMENT

Customer Accounts Expense

Q. What are the areas of agreement?

The Consumer Advocate has accepted HELCO's estimates for account 901 – supervision, account 902 – meter reading, and account 903 – records and collection. (See CA-T-1, page 49.) HELCO and the Consumer Advocate are also in agreement with respect to the uncollectible accounts expense factor and the method used to calculate bad debt expense. HELCO and the Consumer Advocate are in agreement on uncollectible accounts expense of $388,000 at present rates (See HELCO-R-702, Line 5, Column H and CA-101, Schedule C, Line 10, Column D.) Since the Consumer Advocate is in agreement with the uncollectible accounts expense factor of 0.12% and also the method used to calculate bad debt expense, there should be no issues with respect to uncollectible accounts expense at proposed rates between the Consumer Advocate and the Company.

Customer Deposits

Q. What are the areas of agreement?

A. HELCO and the Consumer Advocate are in agreement on the average customer deposits and interest on customer deposits of $930,500 and $56,000, respectively. (See CA-T-1, CA-101, Schedule B, Page 1 for customer deposits and CA-T-1, CA-101, Schedule C, Page 1 for interest on customer deposits.)

Q. Are there areas of disagreement between HELCO and the Consumer Advocate with respect to customer deposits and interest on customer deposits?

A. No.

Revenue Lag Days

Q. What are the areas of agreement?

A. The Consumer Advocate accepted HELCO's test year estimate for revenue lag days. (See CA-T-1, CA-101, Schedule B, page 1, footnote b.). Since the Consumer Advocate's methodology in adjusting the working cash amount is to use a ratio of the Consumer Advocate's proposed rate increase to the Company's proposed rate increase, indirectly, the Consumer Advocate's revenue lag days used is the same as that used by HELCO in its filing.

Q. With respect to revenue lag days, are there any areas of disagreement?

A. No.

Other Operating Revenues

Q. What is HELCO's 2006 test year rebuttal estimate of other operating revenues?

A. HELCO's 2006 test year rebuttal estimate for other operating revenues is $925,400 at present rates (prior to adjusting other operating revenues for the Rule No. 8 charges proposed by the Consumer Advocate as discussed previously and again below), $1,055,100 at present rates (after adjusting other operating revenues for the Rule No. 8 charges proposed by the Consumer Advocate), and $1,096,500 at proposed rates. (See HELCO-R-706.)

Q. What is the Consumer Advocate's 2006 test year estimate for other operating revenues?

A. The Consumer Advocate's 2006 test year estimate is $925,400 at present rates (prior to adjusting other operating revenues for the Rule No. 8 charges proposed by the Consumer Advocate; see CA-T-1, CA-101, Schedule C, Page 1, Column D, Line 2), $1,055,100 at present rates (after adjusting other operating revenues for the Rule No. 8 charges proposed by the Consumer Advocate - $925,400 at present rates plus $129,700 per cell DA368 of the Excel file titled "05-0315 CA-101-CA_HELCO Rev Requirement" provided by Consumer Advocate with CA-T-1 direct testimony that supports its revenue requirement).

Q. What are the areas of agreement with respect to other operating revenues?

A. HELCO and the Consumer Advocate agreed with the following test year estimates for other operating revenues:

1) field collection charge revenues,
2) returned payment charge revenues,
3) The 0.17% factor used to determine late payment charges for electric sales,
4) reconnection fee charge revenues,
5) service establishment charge revenues,
6) rent revenue,
7) metering and other revenues, and
8) late payment charge on OCARS.

(See HELCO-R-706)

In addition, the Company is accepting the Consumer Advocate's proposal to increase service charges for the service establishment, service reconnection,

returned payment and field collection charges as discussed in CA-T-5, page 74. Although HELCO has not conducted any cost studies, HELCO acknowledges that the costs to provide such services have likely increased since its last rate case proceeding in Docket No. 99-0207. By accepting the Consumer Advocate's proposal, the Company's other operating revenues has increased by $129,700. (See HELCO-R-706, page 1.)

Q. Is there a disagreement between the Company and the Consumer Advocate with the estimate for late payment charges?

A. No. Since the Consumer Advocate is in agreement with the 0.17% factor used to determine late payment charges, there should be no issues with respect to late payment charges at proposed rates between the Consumer Advocate and the Company.

AREAS OF DISAGREEMENT

Q. What are the areas where the Consumer Advocate disagrees with HELCO's test year 2006 estimates?

A. The Consumer Advocate and HELCO have no areas of disagreement with respect to customer accounts expense, other operating revenues, customer deposits and interest on customer deposits, and revenue lag days.

SUMMARY

Q. Please summarize your rebuttal testimony.

A. HELCO and the Consumer Advocate are in agreement with HELCO's estimates for account 901 – supervision, account 902 – meter reading, account 903 – customer records & collection, account 904 – uncollectible accounts, the net write-off factor of 0.12%, customer deposits and interest on customer deposits, revenue lag days, and other operating revenues.

1 Q. Does this conclude your testimony?

2 A. Yes, it does.

HAWAII ELECTRIC LIGHT COMPANY, INC.
2006 TEST YEAR
CUSTOMER ACCOUNTS EXPENSE
($ THOUSANDS)

Line	Block Of Accounts	(A) HELCO Adjusted TY 2006	(B) Consumer Advocate Direct TY 2006	(C) HELCO / Consumer Advocate Settlement TY 2006
1	Customer Accounts*	3,574	3,574	3,574

Source
Column A: HELCO-R-702, column H
Column B: CA-101, Schedule C, Column D, Line 9 + Line 10
Column C: No change in Consumer Advocate's position from its direct position

* Includes account 904 - uncollectibles at present rates

HAWAII ELECTRIC LIGHT COMPANY, INC.
2006 TEST YEAR
CUSTOMER ACCOUNTS EXPENSE
($ THOUSANDS)

Line		(A) Operating Budget	(B) Budget Adjts	(C) Rate Case Adjts Normali-zations	(D) Direct Testimony	(E) CA-IR-447 Adjts	(F) HELCO Adjusted TY 2006	(G) Settlement	(H) HELCO / Consumer Advocate Settlement TY 2006	(I) 2006 Recorded
1	901 Supervision	128	0	0	128	0	128	0	128	107
2	902 Meter Reading	695	47	0	742	0	742	0	742	710
3	903 Customer Records & Collection	2,163	153	0	2,316	0	2,316	0	2,316	2,199
4	Subtotal	2,986	200	0	3,186	0	3,186	0	3,186	3,016
5	904 Uncollectibles*	450	(62)	0	388	0	388	0	388	489
6	TOTAL	3,436	138	0	3,574	0	3,574	0	3,574	3,504

Source

Column A - D: HELCO-701, page 2

Column E: No Adjustments

Column F: Column D + Column E

Column G: No Adjustments

Column H: Column F + Column G

Column I: HELCO 12/31/06 Trial Balance Report #SUB960A

* Account 904 - uncollectibles at present rates

HAWAII ELECTRIC LIGHT COMPANY, INC.
2006 TEST YEAR
CUSTOMER ACCOUNTS EXPENSE
BY LABOR & NON-LABOR EXPENSES
($ THOUSANDS)

		(A)	(B)	(C)	(D)	(E)
		2006				
Line		Direct Testimony	Rebuttal Adjustments	HELCO Adjusted TY 2006	CA Testimony	HELCO Adjusted TY 2006 - CA Difference
	Labor					
1	901 Supervision	100		100	100	0
2	902 Meter Reading	585		585	585	0
3	903 Customer Records & Collection	1,281		1,281	1,281	0
4	Total Labor	1,966	0	1,966	1,966	0
	Non-Labor					
5	901 Supervision	28		28	28	0
6	902 Meter Reading	157		157	157	0
7	903 Customer Records & Collection	1,036		1,036	1,036	0
8	904 Uncollectibles	388 *		388	388	0
9	Total Non-Labor	1,608	0	1,608	1,608	0
10	TOTAL	3,574	0	3,574	3,574	0

Source
Column A: HELCO-701, page 3, column D
Column B: No Adjustments
Column C: Column A + Column B
Column D, Line 10: CA-101, Schedule C, Column D, Line 9 + Line 10
Column E : Column C - Column D

* Account 904 - uncollectibles at present rates

HAWAII ELECTRIC LIGHT COMPANY, INC.

2006 TEST YEAR
UNCOLLECTIBLE ACCOUNTS EXPENSE
($ THOUSANDS)

Line	(A) Description	(B) 2006 Direct Test Year Revenue	(C) 2006 Rebuttal Test Year Revenue	(D) Difference
1	Electric Sales Revenue (Present Rates)	$323,184	$323,148	($36)
2	Uncollectible Factor	x 0.12%	x 0.12%	x 0.12%
3	Uncollectible Accounts Expense (Present Rates)	$388	$388	$0
4	Electric Sales Revenue (Proposed Rates)	$353,065	$347,541	($5,524)
5	Uncollectible Factor	x 0.12%	x 0.12%	x 0.12%
6	Uncollectible Accounts Expense (Proposed Rates)	$424	$417	($7)

Source

Line 1: HELCO-301 and HELCO-R-304
Line 2 & 5: HELCO-WP-705, Column C, Line 14
Line 4: HELCO-301 and HELCO-R-304

Column B: HELCO-705, page 7

HAWAII ELECTRIC LIGHT COMPANY, INC.
CALCULATION OF REVENUE COLLECTION LAG

	AMOUNT (2006)	LAG DAYS	DOLLAR DAYS
SALES REVENUE (Less Unclaimed Refunds)	$337,979,405	38.68	13073043385
Add: UNCLAIMED REFUNDS	$21	547.5	11497.5
Total Sales Revenue	$337,979,426		13073054883
Revenue Collection Lag Days, Including Unclaimed Refunds			38.7

Sources and References

1. 2005 Amounts - HELCO Accounting Department

2. LAGS

Sales Revenue	HELCO KWH Sales and Revenue - Billed Revenue	
Unclaimed Refunds	Service Period 01/01/06 through 12/31/06	
	Midpoint Days	182.5
	Payment Date - One year later	365
	Lag Days	547.5
Lag Days	HELCO-R-705, page 2	

HAWAII ELECTRIC LIGHT COMPANY, INC.
CALCULATION OF REVENUE COLLECTION LAG

SUMMARY - REVENUE COLLECTION LAG

Variable Collection Lag

Average Daily Receivables Balance	20,976	Calculated per ACCESS Rpt CSH217-01 ACCESS Cycle Control
Divided By		
Average Revenue Per Day	926	Calculated per HELCO KWH Sales & Revenue - Billed Revenue
Variable Collection Lag	22.7	Days

Total Revenue Collection Lag

Fixed Collection Lag		
Service Period Lag	15.0	Days
Billing Lag	1.0	Days
Fixed Collection Lag, Total	16.0	Days
Variable Collection Lag	22.7	Days
Total Revenue Collection Lag	38.7	Days

HAWAII ELECTRIC LIGHT COMPANY, INC.

2006 TEST YEAR
Summary of Test Year Other Operating Revenues
Present and Proposed Rates

Line	Account No.	Description	A Present Rates (Before Rate Adjt)** $1,000	B Present Rates (After Rate Adjt)** $1,000	C Change Due To Rate Adjustment	D Proposed Rates (After Rate Adjt)** $1,000
	450	Other Revenues				
1		Field Collection Charge	12.0	16.0	4.0	16.0
2		Returned Payment Charge	33.0	35.2	2.2	35.2
3		Late Payment Charge	549.4	549.4	0.0	590.8
4		Subtotal Other Revenues	594.4	600.6	6.2	642.0
	451	Misc. Service Revenues				
5		Svc. Establishment Charge	249.0	332.0	83.0	332.0
6		Reconnection Fee	27.0	67.5	40.5	67.5
7		Subtotal Misc. Svc. Rev.	276.0	399.5	123.5	399.5
8	454	Rent from Electric Property	30.0	30.0	0.0	30.0
	456	Other Electric Revenues				
9		Metering	2.0	2.0	0.0	2.0
10		Miscellaneous	5.0	5.0	0.0	5.0
11		Subtotal Other Elec. Rev.	7.0	7.0	0.0	7.0
12	414	Sale of Mililani	0.0	0.0	0.0	0.0
13	419	OCARS Late Payment Charge	18.0	18.0	0.0	18.0
14		Total Other Operating Rev	925.4	1,055.1	129.7	1,096.5

Source:
HELCO-RWP-703, pages 1-6

** The Consumer Advocate has proposed (per CA-T-5, Page 74), and the Company has agreed to, adjusting the Rule No. 8 Charges as follows:

	Current	Proposed
Sevice Establishment Charge	$15	$20
Reconnection Charge	$10	$25
Returned Payment Charge	$15	$16
Field Collection Charge	$15	$20

HAWAII ELECTRIC LIGHT COMPANY, INC.

2006 TEST YEAR
Summary of Test Year Other Operating Revenues
Present Rates
(Direct and Rebuttal Estimates)

line	Description	A HELCO Direct Estimate $1,000	B HELCO Rebuttal Estimate $1,000	C HELCO Difference $1,000	D CA $1,000	E HELCO-CA Difference $1,000
	450 - Other Revenues					
1	Field Collection Charge	12.0	12.0	0.0	12.0	0.0
2	Returned Payment Charge	33.0	33.0	0.0	33.0	0.0
3	Late Payment Charge	549.4	549.4	0.0	549.4	0.0
4	Subtotal Other Revenues	594.4	594.4	0.0	594.4	0.0
	451 - Misc. Service Revenues					
5	Svc. Establishment Charge	228.0	249.0	21.0	249.0	0.0
6	Reconnection fee	27.0	27.0	0.0	27.0	0.0
7	Temporary Facilities	0.0	0.0	0.0	0.0	0.0
8	Subtotal Misc. Svc. Rev.	255.0	276.0	21.0	276.0	0.0
9	454 - Rent from Electric Property	30.0	30.0	0.0	30.0	0.0
	456 - Other Electric Revenues					
10	Metering	2.0	2.0	0.0	2.0	0.0
11	Miscellaneous	5.0	5.0	0.0	5.0	0.0
12	Subtotal Other Elec. Rev.	7.0	7.0	0.0	7.0	0.0
13	414 -Sale of Mililani	0.0	0.0	0.0	0.0	0.0
14	419- OCARS Late Payment Charge	18.0	18.0	0.0	18.0	0.0
15	Total Other Operating Revenues	904.4	925.4	21.0	925.4	0.0

Source:
Column A: HELCO-710, column A
Column B: HELCO-RWP-703, page 1, column H
Column C: Column B - Column A
Column D, Line 15: CA-101, Schedule C, Page 1. column D, Line 2
(Note that the CA's direct testimony and exhibits does not show a breakdown of the $925.4 between the various miscllaneous revenue types. However, the CA's proposed test year estimate in CA-101, Schedule C, Page 1, Line 2 shows that it has accepted HELCO's Other Operating Revenues of $904.4 plus a $21.0 upward adjustment ot Service Establishment Charge Revenues for a total test year estimate of $925.4.)
Column E: Column B - Column D

HELCO RT-8
DOCKET NO. 05-0315

REBUTTAL TESTIMONY OF
CURTIS A. BECK

MANAGER
ENERGY SERVICES DEPARTMENT
HAWAII ELECTRIC LIGHT COMPANY, INC.

Subject: Customer Service Expense

INTRODUCTION

Q. Please state your name and business address.

A. My name is Curtis A. Beck and my business address is 1200 Kilauea Avenue, Hilo, Hawaii. I am the Manager of the Energy Services Department of the Hawaii Electric Light Company, Inc. ("HELCO").

Q. Have you provided other testimony in this docket?

A. Yes, I submitted direct testimony in HELCO T-2 on Electricity Sales and Customers and HELCO T-8 on Customer Services Expenses, and also rebuttal testimony in HELCO RT-2 on Electricity Sales and Customers.

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

A. My rebuttal testimony in HELCO RT-8 will:

1) present the Company's rebuttal test year 2006 estimates for customer service expense, and

2) present the Company's response to the three issues raised by the Consumer Advocate relating to:

   a. Demand-side management base labor costs;

   b. Customer service projects; and

   c. Renewable Energy and Energy Efficiency Program for Affordable Housing ("REEEPAH").

CUSTOMER SERVICE EXPENSE

Q. What is HELCO's rebuttal test year 2006 estimate of customer service expense?

A. Based on the results of settlement negotiations, HELCO's rebuttal test year 2006 estimate of customer service expense is $1,508,800, as shown in HELCO-R-801. As discussed further below in this testimony, HELCO and the Consumer Advocate are now in agreement on the test year 2006 estimate of customer service expense.

Q. What adjustments to the test year 2006 estimate of customer service expense are proposed by the Consumer Advocate?

A. The following three adjustments are proposed in direct testimony by the Consumer Advocate in CA-T-1:

1. a "reclassification" of indirect labor costs to administer DSM programs of $168,000 from base rate recovery to IRP clause recovery, as shown in Exhibit CA-101, Schedule C-9;
2. a reduction of $96,000 for several outside service expense items related to HELCO's Combined Heat and Power ("CHP") project development efforts and customer service project costs, as shown in Exhibit CA-101, Schedule C-11; and
3. a reduction of $500,000 to eliminate HELCO's proposed funding for REEEPAH, as shown in Exhibit CA-101, Schedule C-10.

Q. Does HELCO agree with the adjustments to its test year estimate of customer service expenses proposed by the Consumer Advocate?

A. Based on the results of settlement negotiations, the three issues have been resolved as follows:

1. indirect labor costs to administer DSM programs of $168,000 will be reclassified from base rate recovery to IRP clause recovery, as proposed by the Consumer Advocate;
2. outside service expense items related to CHP project development efforts and customer service project costs will be reduced by $75,200, to reflect recorded 2006 expenses for Customer Service Projects; and
3. the REEEPAH proposal, including the $500,000 per year proposed funding, will be excluded from test year expenses, as proposed by the Consumer Advocate.

INDIRECT LABOR COSTS TO ADMINISTER
DSM PROGRAMS CURRENTLY RECOVERED IN BASE RATES

Q. How does HELCO currently treat indirect labor costs to administer DSM programs?

A. Indirect labor costs to administer DSM programs are currently recovered in base rates.

Q. What is the Consumer Advocate proposing with respect to indirect labor costs to administer DSM programs?

A. The Consumer Advocate is recommending that, prospectively, all DSM activities and expenses, including incremental program expenditures as well as indirect labor costs to administer DSM programs, be fully recovered through the existing IRP Cost Recovery Provision, as described in CA-T-1, page 54, lines 4-7.

Q. Why is the Consumer Advocate proposing this change?

A. The Consumer Advocate is proposing this change to facilitate the discontinuation of ratepayer funding of utility labor costs to administer DSM programs when the transition of such programs to a non-utility market structure, as provided for in the Commission's D&O No. 23258, issued in Docket 05-0069, is completed.

Q. Is the Consumer Advocate proposing any disallowance of HELCO's labor costs to administer DSM programs?

A. No. The Consumer Advocate is proposing a "re-classification" of DSM labor expense for IRP clause recovery commencing with the effective date of new base rates in this rate case. Effective with the implementation of new base rates in this Docket, HELCO would commence adding $168,000 annually to its IRP Cost Recovery Provision, and this amount would continue to be added until transition to the non-utility market structure is completed.

Q. What is HELCO's position with respect to the Consumer Advocate's proposal for

base labor costs for DSM programs?

A. HELCO agrees with the Consumer Advocate's proposal, and, accordingly, HELCO reduced its rebuttal test year 2006 customer service expense estimate by $168,000 as proposed by the Consumer Advocate, as shown in HELCO-R-802.

CHP PROJECT DEVELOPMENT AND CUSTOMER SERVICE PROJECTS

Q. What was HELCO's estimate for CHP project development prior to settlement negotiations?

A. HELCO's estimate for CHP project development prior to settlement negotiations was $45,979.

Q. What does the Consumer Advocate propose in the area of CHP project development?

A. The Consumer Advocate accepts HELCO's reduction of $29,192 for CHP project development support, included in responses to CA-IR-354, -447, and -460, as shown in CA-T-1, Schedule C-11.

Q. What adjustment did the Consumer Advocate propose in the area of outside services for customer service projects?

A. The Consumer Advocate proposes to reduce HELCO's estimate of expenses for customer service projects by $67,000, as shown in CA-T-1, Schedule C-11.

Q. How did the Consumer Advocate determine its proposed adjustment?

A. The Consumer Advocate arrived at its proposed adjustment by annualizing the year-to-date ("YTD") October, 2006 recorded expenses for this category using an extrapolation of YTD costs applied to the final two months of 2006. Specifically, the Consumer Advocate multiplied the YTD October, 2006 recorded expenses by a factor of 1.2 to derive estimated annualized expenses of $26,000, as shown in CA-T-1, Schedule C-11.

Q. What was HELCO's recorded 2006 test year expense for customer service

projects?

A. HELCO's recorded expense for customer service projects for test year 2006 was $47,200, as shown in HELCO-R-803, page 2.

Q. What is HELCO's rebuttal position on the test year 2006 estimate of expenses for customer service projects?

A. Based on the results of settlement negotiations, HELCO and the Consumer Advocate agree that the 2006 actual expenses for customer service projects shall be used for the test year estimate. This results in reducing the test year 2006 estimate of expenses for CHP project development and customer service projects presented in HELCO's direct testimony by $75,200, based on the recorded expenses in 2006, as shown in HELCO-R-803, page 3.

RENEWABLE ENERGY AND ENERGY EFFICIENCY PROGRAM FOR AFFORDABLE HOUSING

Q. What is HELCO's REEEPAH proposal?

A. In general, HELCO's REEEPAH proposal provides $500,000 per year for energy efficiency and renewable energy for affordable housing. The proposal was discussed in direct testimonies (HELCO T-1, T-8, and T-20), and also in responses to the Consumer Advocate's information requests (CA-IR-14, -106, -239, -240, -241, -242, -267, -351, -352, -353, and -422).

Q. What is the Consumer Advocate's position on HELCO's proposed REEEPAH funding?

A. The Consumer Advocate's recommendation is to eliminate the $500,000 of funding for REEEPAH which HELCO proposes to include in test year 2006 customer service expenses, as described in CA-T-1, page 61, lines 19 and 20.

Q. What is HELCO's rebuttal position with respect to the Consumer Advocate's recommendation to eliminate HELCO's REEEPAH proposal?

A. Based on the results of settlement negotiations, HELCO's rebuttal excludes the $500,000 for REEEPAH in its test year 2006 estimate of customer service expenses. HELCO and the Consumer Advocate have agreed that REEEPAH should go through the IRP process, with cost recovery of program costs through a new renewable energy cost recovery provision that is similar to the DSM cost recovery provision in the IRP Cost Recovery Provision. Mr. Young, in HELCO RT-20, provides testimony regarding this renewable energy cost recovery provision.

SUMMARY

Q. Please summarize your testimony.

A. Based on the results of settlement negotiations, the three issues raised by the Consumer Advocate in its written testimony have been resolved, as discussed in greater detail in my testimony above. Accordingly, HELCO's test year 2006 estimate for customer service expense is $1,508,800.

Q. Does this conclude your testimony?

A. Yes, it does.

Hawaii Electric Light Company, Inc.
2006 TEST YEAR

CUSTOMER SERVICE EXPENSE
($ Thousands)

Line	Account	(A) 2006 OPERATING BUDGET	(B) BUDGET ADJUSTMENTS	(C) NORMALIZATION	(D) DIRECT TESTIMONY 2006 TEST YEAR	(E1) DR-447 REVISIONS ADJUSTMENTS	(E2) DR-447 REVISIONS NORMALIZATION	(F) HELCO ADJUSTED TEST YEAR 2006	(G) SETTLEMENT ADJUSTMENTS TEST YEAR 2006	(H) SETTLEMENT TEST YEAR 2006	(I) HELCO RECORDED 2006
1	909 - SUPERVISION	401.8	-70.8	500.0	831.0	0.0	0.0	831.0	-500.0	331.0	213.0
2	910 - CUSTOMER ASSISTANCE	2,477.3	385.8	-1,527.2	1,335.9	-29.2	0.0	1,306.7	-213.8	1,092.9	2,054.0
3	911 - INFORMATIONAL ADVERTISING	84.7	0.0	0.0	84.7	0.0	0.0	84.7	0.0	84.7	78.0
4	912 - MISCELLANEOUS	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	12.0
5	CUSTOMER SERVICE - TOTAL	2,963.8	315.0	-1,027.2	2,251.6	-29.2	0.0	2,222.4	-713.8	1,508.6	2,357.0

NOTES:
1. In Column (H), Line 5, total amount ($1,508.6) not equal to settlement amount ($1,508.8) due to rounding.

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Hawaii Electric Light Company, Inc.
2006 TEST YEAR

RE-CLASSIFICATION OF INDIRECT DSM LABOR EXPENSES
CURRENTLY RECOVERED IN BASES RATES
(ACTIVITY 713)

	(A)		(B)	(C)
Line	Description	Account No.	Test Year Estimate ($ Thousands)	Reference
1	Test Year Proposed DSM Administration Costs - Base Rates			
2	Energy Services Department - Direct Labor	910	102.5	1
3	Customer Services Department - Direct Labor	910	41.4	2
4	Energy Services Department - Labor Overhead	910	18.8	3
5	Customer Services Department - Labor Overhead	910	5.8	4
6	Total Base Rate Indirect Labor Expense for DSM Program Administration		168.5	5

References:
1 HELCO-WP-101(F), page 658
2 HELCO-WP-101(F), page 659
3 HELCO-WP-101(H), page 863
4 HELCO-WP-101(H), page 864
5 Differs from Consumer Advocate's number (CA-101, Schedule C-9) of $168,000 due to rounding.

HAWAII ELECTRIC LIGHT COMPANY, INC.
Account 909 - Supervision
Activity 210 - Plan and Approve Projects*
Test Year 2006 Estimate - Updated

HECO Services Per Direct Testimony, CA-IR-2, HELCO T-8, Attachment B, Page 8	75,171
Updated Estimate -	
YTD October 31, 2006 Costs	20,179
Actual Through December 31, 2006	25,800
Updated Total 2006 Expenses for Activity 210	45,979
Decrease From Direct Testimony	29,192

* Combined Heat and Power (CHP) - Project Development

Reference: Response to CA-IR-447, page 2.

Hawaii Electric Light Company, Inc.
2006 TEST YEAR

CUSTOMER SERVICE PROJECT EXPENSE

	(A)	(B)	(C)
Line	Description	Test Year Estimate	Year Ending December 31, 2006 Recorded Expenses
1	HES 102 HEL NE NHEZZZZZ 501 Electro Technologies, Acct 910	15,000	13,000
2	HES 110 HEL NE NHEZZZZZ 501 Technical Support, Acct 910	24,000	15,000
3	HEA 110 HEL NS H0000528 501 Customer Assistance, Acct 910	54,177	19,204
4	Totals (Line 1 + Line 2 + Line 3)	93,177	47,204

Reference: Response to CA-IR-357, page 5, with recorded expenses updated to YTD December 31, 2006.

Hawaii Electric Light Company, Inc.
2006 TEST YEAR

CUSTOMER SERVICE PROJECT ADJUSTMENTS

	(A)	(B)	(C)
Line	Description	Test Year Estimate	Reference
1	CHP Project Support from HECO - Revised Cost Estimate	46.0	1
2	Less: Test Year Estimate	75.2	2
3	Adjustment for CHP Project Support	-29.2	3
4	Customer Service Projects - Recorded Expenses	47.2	4
5	Less: Test Year Estimate	93.2	5
6	Adjustment for Customer Service Project Support	-46.0	
7	Total Adjustment (Line 3 + Line 6)	-75.2	

References:
1 See HELCO-R-803, page 1
2 See HELCO-R-803, page 1
3 See HELCO-R-803, page 1
4 See HELCO-R-803, page 2
5 HELCO-WP-101(H), page 864

REBUTTAL TESTIMONY OF
PAUL N. FUJIOKA

MANAGER
CUSTOMER SERVICES DEPARTMENT
HAWAII ELECTRIC LIGHT COMPANY, INC.

Subject: A&G Operations and Maintenance Expenses
Pension Asset and OPEB Amount
Ratebase Treatment of CIAC and Customer Advances
Keahole AFUDC

INTRODUCTION

Q. Please state your name and business address.

A. My name is Paul N. Fujioka, and my business address is 1200 Kilauea Avenue, Hilo, Hawaii.

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

A. I am the Manager of Customer Services for Hawaii Electric Light Company, Inc. ("HELCO" or the "Company").

Q. Have you previously submitted testimony in this proceeding?

A. Yes, I submitted written direct testimony, rebuttal testimony, exhibits, and supporting workpapers as HELCO T-7, HELCO RT-7 and HELCO T-9.

Q. What is the scope of your rebuttal testimony herein?

A. My rebuttal testimony will:

1) Present HELCO's rebuttal position with respect to Administrative and General ("A&G") Expenses, except Accounts 926000 - 926010 (employee benefits series of accounts) which are discussed by Ms. Julie Price (HELCO RT-10);

2) Explain changes in the accounting for pension and other postretirement benefits other than pensions ("OPEB") since direct testimony;

3) Address the differences that existed between the Company and the Consumer Advocate with respect to Pension Asset and rate base treatment of Contributions in Aid of Construction and Customer Advances and the subsequent resolution of these items due to settlement negotiations; and

4) Comment on (a) the Consumer Advocate's calculation of its proposed Allowance For Funds Used During Construction ("AFUDC") amount for CT-4 and CT-5, (b) the Company's AFUDC recorded for CT-4 and CT-5,

and (3) the Company's calculation of AFUDC foregone due to the suspension of AFUDC in December 1998.

Q. How is your rebuttal testimony organized?

A. I will:

1) Summarize HELCO's rebuttal position, including the changes made by HELCO in preparing its rebuttal position;

2) List and summarize the areas where the Consumer Advocate and HELCO agree;

3) List the areas where the Consumer Advocate and HELCO disagree; and

4) Discuss each area of disagreement.

HELCO'S REBUTTAL POSITION

Q. What is HELCO's rebuttal position with respect to the various subject areas you address in this docket?

A. HELCO's normalized estimate of the total test year 2006 A&G Expenses is $15,214,000.

Q. Does the rebuttal estimate for test year 2006 A&G Expenses reflect adjustments to the Company's direct testimony estimate?

A. Yes, the Company's direct testimony estimates were adjusted as discussed below, and as shown on HELCO-R-901 and HELCO-R-902.

AREAS OF AGREEMENT

Q. Where are the Consumer Advocate and HELCO in agreement?

A. The Consumer Advocate and HELCO agree with all test year 2006 estimates for A&G Expenses that I am responsible for (Account Nos. 926000 – 926010 are addressed by Ms. Julie Price in HELCO RT-10) after the adjustments described below, including test year 2006 estimates for the following accounts:

1 Administrative Accounts -
2 920.00 – Administrative & General Salaries
3 921.00 – Office Supplies and Expenses
4 922.01 - Administrative Expenses Transferred - Credit
5 Outside Services Accounts -
6 923.01 – Outside Legal Services
7 923.02 - Other Outside Services
8 923.03 – Services From Associated Companies
9 Insurance Accounts -
10 924.00 – Property Insurance
11 925.01 – Injuries & Damages - Employees
12 925.02 - Injuries & Damages – Public
13 Employee Benefits Accounts -
14 926.90 – Employee Benefits Transferred
15 Miscellaneous Accounts -
16 928.00 – Regulatory Commission Expense
17 930.21 – Community Service Activities
18 930.22 - Company Membership Expenses
19 930.24 - Research & Development Expenses
20 930.25 - Preferred Stock & Long-term Debt Expenses
21 930.28 - Directors Fees & Expenses
22 932.00 – Maintenance of General Plant
23 Q. What adjustments did the Company make to its direct testimony estimates?
24 A. Adjustments were made for a variety of reasons, including changes to reflect
25 updated information, to correct forecast errors, and to reduce the number of issues

in this case. As discussed below, these amounts were previously provided in this Docket (e.g., in responses to Consumer Advocate Information Requests, etc.). The revisions to the estimates provided in direct testimony are as follows:

1) The Company increased Account No. 921.00 – Administrative and General Expense – Non-Labor by $89,000 to reflect (a) the corrected and updated estimate of HELCO's share of the HECO Data Center costs ($159,000) based on recorded YTD October 31, 2006 information (Refer to HELCO's response to CA-IR-448, T-9, page 2 and 3), (b) the corrected estimate of copy machine costs (-$30,000) for a forecast error included in the test year estimate (Refer to HELCO's response to CA-IR-448, T-9, page 4), and (c) the updated Engineering Department microfilming costs (-$40,000) (Refer to HELCO's response to CA-IR-447, T-9, page 8).

2) The Company decreased Account No. 923.02 – Other Outside Services by $17,000 to reflect updated estimates of the KPMG Sarbanes-Oxley Section 404 and Financial Audit fees. (Refer to HELCO's response to CA-IR-447, T-9, page 9).

3) The Company decreased Account No. 923.03 – Other Services – Associated Companies by $127,800 to reflect (a) the deferral of the HR Suites project to 2007 (-$127,000) (Refer to HELCO's response to CA-IR-447, T-9, page 11) and (b) the correct Company Line of Credit fees (-$800) (Refer to HELCO's response to CA-IR-447, T-9, pages 12 and 13).

4) The Company decreased Account No. 925.01 – Injuries and Damage - Employees by $20,600 to reflect (a) lower Production safety training costs (-$73,000) (Refer to HELCO's response to CA-IR-447, T-5, Attachment 1, page 14) and (b) higher Distribution safety training costs ($52,400) as

follows:

$ 166,100	Refer to HELCO's response to CA-IR-447, T-6, page 4
$(5,700)	Refer to HELCO-WP-601, page 3
$(108,000)	Refer to CA-T-1, CA-101, Schedule C-15
$ 52,400	

5) The Company increased Account No. 926.03 – Employee Pension - Funded by $2,612,300 to reflect updated estimates for pension costs ($58,300) and the amortization of the pension asset ($2,554,000). The $58,300 adjustment is discussed by Ms. Julie Price in HELCO RT-10 and the $2,554,000 adjustment is discussed by Ms. Tayne Sekimura in HELCO RT-18.

6) The Company increased Account No. 926.06 – Other Employee Benefits by $198,100 primarily to reflect higher non-safety training costs in the Distribution Department as follows:

$ 238,700	Refer to HELCO's response to CA-IR-447, T-6, page 4
$(2,800)	Refer to HELCO-WP-601, page 3
$(24,000)	Refer to CA-T-1, CA-101, Schedule C-15
$ 211,900	Subtotal non-safety training adjustment
$(13,800)	Refer to HELCO's response to CA-IR-447, T-10, page 2
$ 198,100	Total Account 926.06 adjustment

This adjustment is discussed by Ms. Julie Price in HELCO RT-10.

7) The Company decreased Account No. 926.09 – Post-Retirement Benefits by $48,500 to reflect updated estimates. This adjustment is discussed by Ms. Julie Price in HELCO RT-10

8) The Company increased Account No. 928.00 – Regulatory Commission Expenses by $41,000 to reflect (a) updated estimate for the A&G Consultant

($10,000) and (b) additional costs for the Act 162 Consultant ($31,000) (Refer to HELCO's response to CA-IR-447, T-9, page 14). While the Company will be incurring costs for a Land Use Consultant, Air Permit Consultant and Accounting Policy Consultant as part of its case concerning CT-4 and CT-5, its rebuttal test year estimate will not be adjusted further.

9) The Company increased Account No. 932.00 – A&G Maintenance Expense by $16,300 to reflect the corrected estimate based on historical costs. (Refer to HELCO-917).

AREAS OF DISAGREEMENT

Q. What are the areas where the Consumer Advocate disagrees with HELCO's test year 2006 estimates?

A. The Consumer Advocate and HELCO have no areas of disagreement with respect to A&G expenses that I am responsible for (Account Nos. 926000 – 926010 are addressed by Ms. Julie Price in HELCO RT-10), as shown in HELCO-R-901. HELCO-R-901 shows HELCO's direct testimony estimates for A&G expenses, revisions to HELCO's direct testimony estimates, and the settlement amount for A&G expense.

Q. What is the issue with respect to the Pension Asset and the OPEB amount?

A. Based on the results of settlement discussions, there is no issue with respect to the Pension Asset and the OPEB amount to include in rate base for ratemaking purposes. However, the Consumer Advocate and HELCO are not in agreement on the rationale of why the pension asset is includable in rate base. As discussed in the rebuttal testimony of Ms. Tayne Sekimura (HELCO RT-18), the Company and the Consumer Advocate have negotiated a settlement on the Consumer Advocate's proposal to implement a pension tracking mechanism.

Q. What is the issue with respect to Contributions in Aid of Construction ("CIAC") and Customer Advances?

A. Based on the results of settlement discussions, there is no issue with respect to CIAC and Customer Advances, as discussed in greater detail below.

Q. What is the issue with respect to the calculation of CT-4 and CT-5 AFUDC?

A. Based on the results of settlement discussions, there is no issue with respect to the amount of AFUDC for CT-4 and CT-5. The Company will be commenting on the Consumer Advocate's calculation of its proposed allowable AFUDC amount for CT-4 and CT-5 as well as the Company's AFUDC recorded for CT-4 and CT-5 and the calculation of AFUDC foregone due to the suspension of AFUDC in December 1998.

PENSION ASSET AND OPEB AMOUNT

Q. What are HELCO's test year 2006 estimates for the Pension Asset and the OPEB amount?

A. HELCO's test year 2006 estimates are $14,143,000 for the Pension Asset and zero for the OPEB amount. As previously discussed, based on the results of settlement negotiations discussions, there is no issue with respect to the Pension Asset and the OPEB amount to include in rate base for ratemaking purposes.

Q. What is the pension asset?

A. The pension asset is an investment that results from the impact of the cumulative pension contributions made to the pension fund in excess of the cumulative pension costs recognized.

Q. What is the OPEB amount?

A. The OPEB amount is an investment that results from the impact of the cumulative OPEB contributions made net of the cumulative OPEB costs recognized.

Q. Does the pension asset represent the same investment as the prepaid pension asset that was presented in direct testimony?

A. Yes, the prepaid pension asset presented in direct testimony represents the same investment as the pension asset presented here.

Q. Does the OPEB amount represent the same investment as the unamortized OPEB regulatory asset net with the OPEB liability that was presented in direct testimony?

A. Yes, the investment represented by the OPEB regulatory asset net with the OPEB liability in direct testimony represents the same investment as the OPEB amount presented here.

Q. Why did the presentations of pension asset and OPEB amount change?

A. The change in presentation of the prepaid pension asset to a pension asset and change in presentation of the OPEB regulatory asset and OPEB liability to OPEB amount is to reflect the adoption of Statement of Financial Accounting Standards ("SFAS"), No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106 and 132 (R)", which for HELCO, became effective on December 31, 2006. The result of adopting SFAS No. 158 was discussed in response to CA-IR-468.

Q. Please describe how the adoption of SFAS No. 158 impacted the pension asset and OPEB amount.

A. SFAS No. 158 requires balance sheet recognition of the funded status of defined benefit pension plans measured as the difference between the fair value of the pension plan assets and the projected benefit obligation ("PBO"). The PBO is an estimate of the pension obligation as of a specified date, and is measured using an assumption as to future compensation levels. SFAS No. 158 also requires balance

1 sheet recognition of the funded status of the OPEB plan measured as the
2 difference between the fair value of the OPEB plan's assets and the accumulated
3 postretirement benefit obligation ("APBO") for the OPEB plan.
4 More specifically, under SFAS No. 158, HELCO was required to:
5 (1) recognize the overfunded or underfunded status of its benefit plan (based on
6 the difference between the fair value of the plan assets and the PBO for pensions
7 and the difference between the fair value of the plans assets and the APBO for
8 OPEB) on its balance sheet, (2) recognize as a component of Accumulated Other
9 Comprehensive Income ("AOCI"), net of tax, the actuarial gains and losses, the
10 prior service costs and credits that arise during the period but are not recognized
11 as components of net periodic pension costs, and any remaining transition
12 obligation from the initial application of SFAS No. 87 or SFAS No. 106, and
13 (3) disclose additional information in the notes to financial statements about
14 certain effects on net periodic pension and other postretirement benefit costs.
15 SFAS No. 158 also required the reversal of any recorded prepaid pension asset in
16 the event the PBO exceeds the fair value of the pension plan assets.
17 HELCO's pension plan was underfunded by $12,015,000 at December 31,
18 2006. SFAS No. 158 required the reversal of the prepaid pension asset of
19 $12,770,626, recording a charge to AOCI of $24,785,000 (the sum of the prepaid
20 pension asset and underfunding) and recording a liability of $12,015,000 (the
21 amount of the underfunding). The impact of these entries is $12,771,000 which is
22 equal to the prepaid pension asset previously recorded and reversed under SFAS
23 No. 158. This reconciliation is shown on HELCO-R-903.
24 HELCO's OPEB plan was underfunded by $7,044,000 at December 31,
25 2006. SFAS No. 158 required recording a charge to AOCI of $7,044,000 and

recording a liability of $7,044,000 (the underfunding). HELCO also records an unamortized OPEB regulatory asset of $1,583,000 and OPEB liability of $1,583,000 at December 31, 2006 that arose from the adoption of SFAS No. 106. The impact of these OPEB components is zero, which is equal to the unamortized OPEB regulatory asset and OPEB liability presented in direct testimony. To capture the impact of all OPEB components recorded as required under SFAS No. 158 and SFAS No. 106, HELCO includes an OPEB amount in rate base. This reconciliation is shown on HELCO-R-904.

Q. Why did the estimate of the average pension asset change?

A. The decrease in the average pension asset resulted from reflecting the actual 2006 net periodic pension cost of $2,744,000 (compared to the $2,686,000 forecast used in direct testimony). The change in NPPC reduced the ending pension asset by $58,000 (from $12,829,000 presented in direct to the $12,771,000 presented in this testimony). As a result, the test year average pension asset decreased by $29,000 ($58,000/2). The adjusted pension asset was presented in response to CA-IR-464.

Q. Why is the pension asset included in rate base?

A. The pension asset is included in rate base for the same reasons the prepaid pension asset was included in rate base. These reasons were discussed in my direct testimony.

Q. What is the Consumer Advocate's position with respect to including the pension asset in rate base?

A. The Consumer Advocate is not proposing any adjustment to HELCO's inclusion of the pension asset in determining rate base, as discussed by Mr. Carver in CA-T-3, beginning at page 13.

Q. Does the Company agree with Mr. Carver's pension asset analysis to determine whether the pension asset should be included in rate base?

A. No. Mr. Carver prepares a historical analysis to assess whether ratepayers, through utility rates, have or have not "participated" in the reduced pension costs that gave rise to the recording of the prepaid pension asset. Mr. Carver presented a similar analysis in HECO's 2005 test year rate case (Docket No. 04-0133), in which he reached a different conclusion. Like the Consumer Advocate's analysis in HECO's 2005 test year rate case, the analysis in this proceeding is also erroneous. HECO's explanation of why the Consumer Advocate's analysis is flawed and resulted in an erroneous conclusion in the HECO rate case, and the evidence and authorities in that case supporting HECO's positions are summarized in HECO's Opening Brief filed December 5, 2005 (pages 102 to 111) and HECO's Reply Brief filed December 19, 2005 (pages 3 to 10) in Docket No. 04-0113.

Q. What alternative pension ratemaking treatment is included in the Company's rebuttal revenue requirements?

A. The Consumer Advocate proposed to implement a pension tracking mechanism, which in part, would impact the pension cost included in test year revenue requirements. Ms. Sekimura describes the pension tracking mechanism which has been agreed to by the Company and the Consumer Advocate in HELCO RT-18. The rebuttal revenue requirements include $2,554,000, which is the amortization of the ending pension asset balance (ending pension asset of $12,771,000 divided by 5), in addition to the test year NPPC of $2,744,000.

Q. Has an OPEB tracking mechanism also been agreed to by the parties?

A. Yes. HELCO proposed, and the Consumer Advocate accepted, a tracking mechanism for OPEB, which mirrors the pension tracking mechanism referred to above. Ms. Tayne Sekimura describes the proposed OPEB tracking mechanism in HELCO RT-18. The adoption of the OPEB tracking mechanism does not impact revenue requirements in this docket. However, the OPEB tracking mechanism specifies ratemaking treatment which allows financial statement treatment of benefit costs to be smoothed based on the amount of net periodic benefit costs ("NPBC") established in this rate case and addresses potential situations in the future where contributions to OPEB trusts are not equal to the NPBC recognized.

CONTRIBUTIONS IN AID OF CONSTRUCTION

Q. What is HELCO's test year 2006 estimate for CIAC?

A. Based on the results of settlement negotiations, HELCO's test year 2006 average balance for unamortized CIAC included in the calculation of rate base is $58,431,000 (calculated using recorded year-end CIAC balance of $59,936,000), which is shown in HELCO-R-1603.

Q. What was the Consumer Advocate's test year 2006 estimate for CIAC?

A. In its filed testimony, the Consumer Advocate estimated the average unamortized CIAC balance (before its proposed "Adjustments for Post-TY Collections for 2006 Plant Additions", which will be discussed later) at $58,159,000, as shown in CA-101, Schedule B-2.

Q. What were the reasons for the difference in estimates?

A. The Consumer Advocate's 2006 year end balance for unamortized CIAC of $59,393,000 reflected actual (preliminary) amounts for contributions received by HELCO during 2006, and estimated amounts for transfers from Customer Advances and CIAC amortizations during the year. The Company's 2006 year

end balance for unamortized CIAC of $59,936,000 reflects later information, i.e., actual amounts for all of the factors affecting the unamortized CIAC balance.

Q. Has the difference in estimates between HELCO and the Consumer Advocate been resolved?

A. Yes. In settlement discussions between HELCO and the Consumer Advocate, the Consumer Advocate has accepted HELCO's later estimate of $58,431,000 for the average unamortized CIAC balance included in the calculation of rate base. The settlement discussion concerning CIAC is also discussed by Mr. Jose Dizon in HELCO RT-14.

Q. What was the Consumer Advocate's proposed "Adjustments for Post-TY Collections for 2006 Plant Additions"?

A. In its filed testimony, the Consumer Advocate proposed to include additional CIAC that might be collected subsequent to 2006 for certain projects included in test year rate base in the calculation of its test year 2006 rate base (once the amounts become available). (See CA-T-3, page 10, line 11 through page 12 line 22 and CA-101, Schedule B-2).

Q. What was HELCO's response to the Consumer Advocate's proposal?

A. HELCO disagreed with the Consumer Advocate's proposal. The proposed adjustment would not be appropriate for ratemaking purposes because it would represent activity outside of (beyond) the test year, it was inconsistently applied, and HELCO's test year estimate represents normal operating conditions.

Q. Has this issue between HELCO and the Consumer Advocate been settled?

A. Yes. As a result of settlement discussions between HELCO and the Consumer Advocate, the Consumer Advocate agreed to withdraw its proposed "Adjustments for Post-TY Collections for 2006 Plant Additions".

1 CUSTOMER ADVANCES FOR CONSTRUCTION

2 Q. What is HELCO's test year 2006 estimate for Customer Advances for
3 Construction ("Customer Advances")?

4 A. Based on the results of settlement discussions, HELCO's test year 2006 average
5 balance for Customer Advances is $30,189,000 (calculated using recorded year-
6 end Customer Advances of $31,780,000, which is shown in HELCO-R-1604).

7 Q. What was the Consumer Advocate's test year 2006 estimate for Customer
8 Advances for Construction?

9 A. In its filed testimony, the Consumer Advocate estimated the average 2006
10 Customer Advances balance (before its proposed "Adjustments for Post-TY
11 Collections for 2006 Plant Additions") at $30,517,000, as shown in CA-101,
12 Schedule B-2.

13 Q. What were the reasons for the difference in estimates?

14 A. The Consumer Advocate's 2006 year end balance for Customer Advances of
15 $32,436,000 reflected actual (preliminary) amounts for advances received by
16 HELCO during 2006, and estimated amounts for refunds of advances to customers
17 and transfers from Customer Advances to CIAC during the year. The Company's
18 2006 year end balance for Customer Advances of $31,780,000 reflects later
19 information, i.e., actual amounts for all of the factors affecting the Customer
20 Advances balance.

21 Q. Has the difference in estimates between HELCO and the Consumer Advocate
22 been resolved?

23 A. Yes. In settlement discussions between HELCO and the Consumer Advocate, the
24 Consumer Advocate has accepted HELCO's later estimate of $30,189,000 for the
25 average 2006 Customer Advances balance included in the calculation of rate base.

Q. What was the Consumer Advocate's proposed "Adjustments for Post-TY Collections for 2006 Plant Additions"?

A. As is the case with respect to CIAC discussed earlier, the Consumer Advocate proposed, in its filed testimony, to include in the calculation of test year 2006 rate base (once the amounts become available), additional Customer Advances that might be collected subsequent to 2006 for certain projects included in the test year rate base.

Q. What was HELCO's response to the Consumer Advocate's proposal?

A. The Company disagreed with the Consumer Advocate's proposal for the same reasons discussed earlier with respect to CIAC.

Q. Has this issue between HELCO and the Consumer Advocate been settled?

A. Yes. As a result of settlement discussions between HELCO and the Consumer Advocate, the Consumer Advocate agreed to withdraw its proposed "Adjustments for Post-TY Collections for 2006 Plant Additions".

KEAHOLE AFUDC

Consumer Advocate's Calculation Of Its Proposed Allowable AFUDC

Q. As previously discussed, based on the results of settlement negotiations, AFUDC for CT-4 and CT-5 has been resolved, subject to Commission approval. Prior to reaching settlement, was there an issue with the Consumer Advocate concerning the amount of AFUDC for CT-4 and CT-5?

A. Yes, as adjusted to reflect the Keahole adjustment discussed by Mr. Warren Lee in HELCO RT-1.

Q. Please describe HELCO's proposal to include the installed cost of CT-4 and CT-5 in rate base.

A. As discussed in HELCO T-15, CT-4 became commercially operational in May 2004, followed by CT-5 on June 30, 2004. The total costs incurred for CT-4 and CT-5 as of December 31, 2006 were $117,609,535 (including the costs for the three Pre-PSD facilities placed in service prior to 2000), which includes $21,661,087 of AFUDC. (See HELCO-R-1503).

Q. Do the total costs incurred as of December 31, 2006 of $117,609,535 include costs previously approved by the Commission to be included in rate base?

A. Yes. In Decision and Order No. 18365 ("D&O 18365") issued February 8, 2001, in Docket No. 99-0207 (pages 34–35), the Commission allowed the Company to include a total of $7,570,152 in rate base for Pre-PSD facilities as follows:

Shop/Warehouse	$ 972,599
Fire Protection System	$ 745,548
Water Treatment System	$5,852,005
Total	$7,570,152

Q. Does the amount already approved by the Commission to be included in rate base of $7,570,152 include any AFUDC?

A. Yes. In D&O 18365 (page 34), the Commission used the cost estimates presented in the Encogen avoided cost estimates to calculate the proportionate amount of costs that HELCO was entitled to include in rate base at that time for the above Pre-PSD facilities. The Commission determined that these amounts represent the respective portions of the three projects found by the Commission to be used or useful to support the existing generating units at Keahole. (See D&O 18365, page 23.) As shown in HELCO-R-905, of the total Encogen avoided cost estimate of $18,569,165, AFUDC represented 19.79% ($3,674,336 divided by $18,569,165) of the total avoided cost estimate. Therefore, it is reasonable to

1 conclude that 19.79% of the $7,570,152 previously approved by the Commission
2 to be included in rate base, or $1,497,928 ($7,570,152 x 19.79%), is the amount of
3 AFUDC already included in rate base. (See HELCO-R-905).
4 Q. What was the Consumer Advocate's position with respect to the amount of
5 AFUDC allowable for CT-4 and CT-5?
6 A. In its written testimony, the Consumer Advocate proposed to allow $7,253,860 (of
7 a total of $21,661,087) of AFUDC for CT-4 and CT-5. (See CA-T-3, page 53, as
8 revised by HELCO/CA-IR-304). As noted above, of the $21,661,087 of total
9 AFUDC for CT-4 and CT-5, the Commission previously approved $1,497,928
10 of AFUDC to be included in rate base. Based on the results of settlement
11 negotiations, the costs for CT-4 and CT-5 to be included in rate base have been
12 resolved, subject to Commission approval.
13 Q. The Consumer Advocate referred to a "Pre-CIP" AFUDC adjustment of
14 $1,201,837 (CA-101, Schedule B and its response to HELCO/CA-IR-304). What
15 did that amount represent?
16 A. Based on my review of the Consumer Advocate's calculation, the amount
17 represented AFUDC for the period from June 1991 (when HELCO began
18 incurring costs for CT-4) to January 1994 (when the Commission approved the
19 commitment of funds for CT-4), based on the Consumer Advocate's calculation of
20 AFUDC, which included stopping AFUDC during the period from October 1994
21 through July 1997. The AFUDC amount for the period prior to January 1994 was
22 approximately $1 million, and amounted to the Consumer Advocate's $1.2 million
23 over the period the Consumer Advocate proposed to calculate AFUDC.
24 Q. Would the amount of AFUDC related to the period prior to January 1994 be the
25 same based on HELCO's calculation?

A. No, HELCO's amount of AFUDC related to the period prior to January 1994 is greater, since HELCO's position is that the application of AFUDC should have continued during the period that the Consumer Advocate proposed to stop accruing AFUDC. HELCO calculates the amount of "Pre-CIP AFUDC to be $1,557,760. (See HELCO-R-906, pages 1-3).

HELCO's Keahole AFUDC Recorded As of December 31, 2006

Q. What is the total amount of AFUDC recorded for CT-4 and CT-5?

A. As of December 31, 2006, the total amount of AFUDC recorded for CT-4 and CT-5 was $21,661,087. This is also shown in HELCO's response to CA-IR-190, pages 6 and 7 ($14,099,896 for CT-4 + $7,561,191 for CT-5).

Q. What was the total amount of AFUDC that the Consumer Advocate used as a starting point in calculating its proposed disallowance for AFUDC relating to CT-4 and CT-5?

A. In CA-T-3, page 53 and CA-101, Schedule B-7, the Consumer Advocate used $21,661,087 for AFUDC relating to CT-4 and CT-5.

Q. In HELCO's response to CA-IR-447 (T-15), which is a revision to HELCO-1503, the amount of AFUDC shown there is $21,283,972. What is the reason for the difference of $377,115 from the $21,661,087 referred to above?

A. The difference of $377,115 of AFUDC between that which was used in HELCO's response to CA-IR-190 of $21,661,087 and that which was used in HELCO's response to CA-IR-447 (T-15) is due to HELCO including the AFUDC related to the Well Development and Supply Well Pump costs with the non-AFUDC costs of those two cost items, as opposed to including the AFUDC portion relating to those two items with the total AFUDC amount:

	Well Develpt	Supply Well Pump	AFUDC
Balance As Reported			
Per CA-IR-447 (T-15)	$1,145,511	$ 266,785	$21,283,972
Correct Classification	$(349,046)	$(28,069)	$ 377,115
Corrected Balance Per HELCO-R-1503 (Exh. III)	$ 796,465	$ 238,716	$21,661,087

Q. Why were the AFUDC amounts related to the Well Development and Supply Well Pump classified as part of those two items' non-AFUDC costs as opposed to classified as AFUDC costs in CA-IR-447 (T-15)?

A. The Well Development (subproject # L3191161) and Supply Well Pump (subproject # L3191127) costs were originally two of several subprojects accounted for under the Water Treatment System component H3191000. When it became apparent that these two subprojects would not be completed at the time the Water Treatment System was going to be completed, HELCO opened up two new subproject #s (G0005653 for the Well Development and G0005651 for the Supply Well Pump) and transferred the costs (including related AFUDC) from L3191161 to G0005653 (for the Well Development) and from L3191127 to G0005651 (for the Supply Well Pump). This was done so that the costs for component #H3191000, with the exception of the Well Development and Supply Well costs, could be closed to plant when completed. The costs for the Well Development and Supply Well Pump would then be closed to plant when subsequently completed. At the time HELCO's response to CA-IR-447, T-15 was submitted, HELCO inadvertently did not pick up the $377,115 of AFUDC costs related to the Well Development and Supply Well Pump when arriving at the total

AFUDC amount of $21,283,972. Instead, such AFUDC costs were still reflected in the non-AFUDC costs for the Well Development and Supply Well Pump.

Q. Is the $21,661,087 the correct total AFUDC costs for CT-4 and CT-5 (including the AFUDC costs for the three Pre-PSD facilities placed into service prior to 2000)?

A. Yes it is.

Q. Has this amount been corrected elsewhere in the Company's rebuttal filing?

A. Yes. In HELCO-R-1503 (Exhibit III), Mr. Ken Fong has submitted a revised breakdown of the costs of the project to reflect the correct AFUDC costs of $21,661,087.

Q. Does the above correction change the total costs for CT-4 and CT-5 as of December 31, 2006 of $117,609,535?

A. No. As discussed above, the above correction simply reclassifies $377,115 of costs from non-AFUDC costs to AFUDC costs.

<u>HELCO's AFUDC Foregone Calculation</u>

Q. At CA-T-3, page 80, Mr. Carver comments on the amount of additional AFUDC the Company would have charged to the Keahole project absent the suspension of AFUDC in December 1998. The amount of AFUDC forgone and costs borne by the shareholders was calculated to be $39.7 million (reference HELCO-1501, pages 97 - 98). Continuing on, Mr. Carver determined that the Company's calculation of the $39.7 million of AFUDC foregone was in error, and indicated that the correct amount should be $52.6 million. Please comment on this.

A. Mr. Carver is correct. HELCO's calculation of the amount of AFUDC foregone as submitted in HELCO-1501, pages 97–98, was in error. The correct amount should be $52.6 million, as shown in HELCO-R-907.

SUMMARY

Q. Please summarize your rebuttal testimony with respect to A&G O&M expenses.

A. HELCO and the Consumer Advocate do not have any issues with test year 2006 A&G expenses (other than accounts 926000 – 926010, which are addressed by Ms. Price in HELCO RT-10).

Q. Please summarize your rebuttal testimony with respect to Pension Asset.

A. HELCO and the Consumer Advocate agree with inclusion of the pension asset in rate base. HELCO and the Consumer Advocate also agree on the Consumer Advocate's proposal to implement a pension tracking mechanism and this is addressed by Ms. Sekimura in HELCO RT-18.

Q. Please summarize your rebuttal testimony with respect to Contributions in Aid of Construction and Customer Advances.

A. HELCO and the Consumer Advocate agree with the test year 2006 average balance of $58,431,000 for CIAC and $30,189,000 for Customer Advances to be included in rate base.

Q. Does this conclude your testimony?

A. Yes, it does.

Hawaii Electric Light Co., Inc.
Administrative and General Expenses
($ in Thousands)

Account #	Account Description	(A) Operating Budget	(B) Budget Adjustments	(C) Rate Case Adjts/ Normali-zations	(D) Direct Testimony	(E) CA-IR-447, CA-IR-448 & CA-SIR-35 Adjustments	(F) HELCO Pre-Settlement	(G) Settlement Adjustment	(H) Settlement Test Year 2006	(I) 2006 Recorded
ADMINISTRATIVE										
92000	A&G Salaries	2,706	(47)	(360)	2,300	0	2,300		2,300	2,260
92100	Office Supplies & Expenses	1,613	(973)	27	667	89	756		756	826
92201	A&G Trsfd to Construction	(1,031)	117	0	(915)	0	(915)		(915)	(906)
	Total Administrative	3,288	(903)	(332)	2,052	89	2,141	0	2,141	2,180
OUTSIDE SERVICES										
92301	Outside Legal Services	50	16	0	66	0	66		66	153
92302	Other Outside Services	92	175	(45)	221	(17)	204		204	111
92303	Services From Assoc. Co.	2,178	(340)	0	1,838	(128)	1,710		1,710	1,786
	Total Outside Services	2,319	(149)	(45)	2,125	(145)	1,981	0	1,981	2,051
INSURANCE										
92400	Property Insurance	591	(55)	0	536	0	536		536	565
92501/2	Injs & Damages-Empl/Public	2,311	(378)	0	1,933	87	2,021	(108)	1,913	1,380
	Total Insurance	2,902	(433)	0	2,469	87	2,557	(108)	2,449	1,945
EMPLOYEE BENEFITS										
926000 - 926020	Employee Benefits**	5,094	(29)	(156)	4,909	232	5,141	2,530	7,671	5,019
	Total Employee Benefits	5,094	(29)	(156)	4,909	231.9	5,141	2,530	7,671	5,019
MISCELLANEOUS										
92800 - 93200	Miscellaneous	745	191	(21)	915	57	973	0	973	493
	Total Miscellaneous	745	191	(21)	915	57	973	0	973	493
TOTAL ADMIN & GENERAL EXPENSES		14,348	(1,322)	(555)	12,471	321	12,792	2,422	15,214	11,687

Column	
A - D	HELCO-902
E & G	HELCO-R-902
F	Column D + Column E
H	Column F + Column G
I	HELCO 12/31/06 Trial Balance Report #SUB960A
**	Refer to HELCO RT-10 for details on employee benefit series of accounts

HAWAII ELECTRIC LIGHT CO., INC.
ADMIN & GENL O&M EXPENSE
TEST YEAR 2006 ($1000's)

	TEST YEAR 2006			
	Direct Testimony	CA-IR-447, CA-IR-448 & CA-SIR-35 Adjustments	Settlement	HELCO Rebuttal
ADMINISTRATIVE				
92000 ADMIN & GENL EXP-LABR				
LABOR	2,299.6	0.0	0.0	2,299.6
NON-LABOR	0.0	0.0	0.0	0.0
TOTAL 92000	2,299.6	0.0	0.0	2,299.6
92100 ADMIN & GENL EXP-NLABR				
NON-LABOR	667.3 (A)	89.0	0.0	756.3
TOTAL 92100	667.3	89.0	0.0	756.3
92201 ADMIN EXP TRFD TO CONSTR				
NON-LABOR	(914.9)	0.0	0.0	(914.9)
TOTAL 92201	(914.9)	0.0	0.0	(914.9)
TOTAL ADMIN	2,052.0	89.0	0.0	2,141.0

HAWAII ELECTRIC LIGHT CO., INC.
ADMIN & GENL O&M EXPENSE
TEST YEAR 2006 ($1000's)

	TEST YEAR 2006				
	Direct Testimony		CA-IR-447, CA-IR-448 & CA-SIR-35 Adjustments	Settlement	HELCO Rebuttal
OUTSIDE SERVICES					
92301 LEGAL SERVICES					
NON-LABOR	66.0		0.0	0.0	66.0
TOTAL 92301	66.0		0.0	0.0	66.0
92302 OTHER OUTSIDE SERVICES					
NON-LABOR	221.4	(A)	(17.0)	0.0	204.4
TOTAL 92302	221.4		(17.0)	0.0	204.4
92303 OTHER SERVICES - ASSOC CO					
NON-LABOR	1,837.9	(A)	(127.8)	0.0	1,710.1
TOTAL 92303	1,837.9		(127.8)	0.0	1,710.1
TOTAL OS SVCS	2,125.3		(144.8)	0.0	1,980.5

HAWAII ELECTRIC LIGHT CO., INC.
ADMIN & GENL O&M EXPENSE
TEST YEAR 2006 ($1000's)

	TEST YEAR 2006			
	Direct Testimony	CA-IR-447, CA-IR-448 & CA-SIR-35 Adjustments	Settlement	HELCO Rebuttal
INSURANCE				
92400 PROPERTY INSURANCE				
NON-LABOR	536.0	0.0	0.0	536.0
TOTAL 92400	536.0	0.0	0.0	536.0
92501 INJURIES & DAMAGES - EMPLOYEE				
LABOR	551.2 (A)	4.7 (B)	(108.0)	447.9
NON-LABOR	632.0 (A)	82.7	0.0	714.7
TOTAL 92501	1,183.2	87.4	(108.0)	1,162.6
92502 INJURIES & DAMAGES - PUBLIC				
LABOR	38.5	0.0	0.0	38.5
NON-LABOR	711.5	0.0	0.0	711.5
TOTAL 92502	750.0	0.0	0.0	750.0
TOTAL INSURANCE	2,469.2	87.4	(108.0)	2,448.6

HAWAII ELECTRIC LIGHT CO., INC.
ADMIN & GENL O&M EXPENSE
TEST YEAR 2006 ($1000's)

	TEST YEAR 2006			
	Direct Testimony	CA-IR-447, CA-IR-448 & CA-SIR-35 Adjustments	Settlement	HELCO Rebuttal
EMPLOYEE BENEFITS				
92600 EMPL BENEFITS - FLEX CREDITS				
NON-LABOR	(368.2)	0.0	0.0	(368.2)
TOTAL 92600	(368.2)	0.0	0.0	(368.2)
92601 EMPL PENSIONS - NONFUNDED				
NON-LABOR	0.0	0.0	0.0	0.0
TOTAL 92601	0.0	0.0	0.0	0.0
92602 EMPL BENEFITS - DENTAL PLAN				
NON-LABOR	315.4	0.0	0.0	315.4
TOTAL 92602	315.4	0.0	0.0	315.4
92603 EMPL PENSION - FUNDED				
NON-LABOR	2,686.0 (A)	58.3 (C)	2,554.0	5,298.3
TOTAL 92603	2,686.0	58.3	2,554.0	5,298.3
92604 EMPL GROUP LIFE INSURANCE				
NON-LABOR	300.2	0.0	0.0	300.2
TOTAL 92604	300.2	0.0	0.0	300.2
92605 EMPL GROUP MED & HOSPITAL INS				
NON-LABOR	1,973.2	0.0	0.0	1,973.2
TOTAL 92605	1,973.2	0.0	0.0	1,973.2

HAWAII ELECTRIC LIGHT CO., INC.
ADMIN & GENL O&M EXPENSE
TEST YEAR 2006 ($1000's)

	TEST YEAR 2006			
	Direct Testimony	CA-IR-447, CA-IR-448 & CA-SIR-35 Adjustments	Settlement	HELCO Rebuttal
92606 OTHER EMPL BENEFITS				
LABOR	106.0 (A)	107.0 (B)	(24.0)	189.0
NON-LABOR	329.9 (A)	115.1	0.0	445.0
TOTAL 92606	435.9	222.1	(24.0)	634.0
92607 EMPLOYEE VISION				
NON-LABOR	49.5	0.0	0.0	49.5
TOTAL 92607	49.5	0.0	0.0	49.5
92608 LONG-TERM DISABILITY PLAN				
NON-LABOR	183.3	0.0	0.0	183.3
TOTAL 92608	183.3	0.0	0.0	183.3
92609 POST-RETIREMENT BENEFITS				
NON-LABOR	1,458.9 (A)	(48.5)	0.0	1,410.4
TOTAL 92609	1,458.9	(48.5)	0.0	1,410.4
92690 EMPL BEN TFRD TO CONSTR				
NON-LABOR	(2,125.1)	0.0	0.0	(2,125.1)
TOTAL 92690	(2,125.1)	0.0	0.0	(2,125.1)
TOTAL EMP BEN	4,909.1	231.9	2,530.0	7,671.0

HAWAII ELECTRIC LIGHT CO., INC.
ADMIN & GENL O&M EXPENSE
TEST YEAR 2006 ($1000's)

	TEST YEAR 2006			
	Direct Testimony	CA-IR-447, CA-IR-448 & CA-SIR-35 Adjustments	Settlement	HELCO Rebuttal
OTHER ADMIN & GENL				
92800 REGULATORY COMMISSION EXPENSES				
NON-LABOR	275.0 (A)	41.0	0.0	316.0
TOTAL 92800	275.0	41.0	0.0	316.0
93010 INSTITUTN/GOODWILL ADVERT EXPENSES				
LABOR	0.0	0.0	0.0	0.0
NON-LABOR	0.0	0.0	0.0	0.0
TOTAL 93010	0.0	0.0	0.0	0.0
93021COMMUNITY SERVICE ACTIVITIES				
NON-LABOR	56.5	0.0	0.0	56.5
TOTAL 93021	56.5	0.0	0.0	56.5
93022 COMPANY MEMBERSHIP EXPENSES				
NON-LABOR	59.5	0.0	0.0	59.5
TOTAL 93022	59.5	0.0	0.0	59.5
93024 RESEARCH & DEVELOPMENT EXPENSES				
NON-LABOR	323.5	0.0	0.0	323.5
TOTAL 93024	323.5	0.0	0.0	323.5
93025 PREF STK & L-T DEBT EXPENSES				
NON-LABOR	46.1	0.0	0.0	46.1
TOTAL 93025	46.1	0.0	0.0	46.1

HAWAII ELECTRIC LIGHT CO., INC.
ADMIN & GENL O&M EXPENSE
TEST YEAR 2006 ($1000's)

	TEST YEAR 2006			
	Direct Testimony	CA-IR-447, CA-IR-448 & CA-SIR-35 Adjustments	Settlement	HELCO Rebuttal
93028 DIRECTORS FEES & EXPENSES				
NON-LABOR	14.5	0.0	0.0	14.5
TOTAL 93028	14.5	0.0	0.0	14.5
93200 ADMIN AND GENL MAINTENANCE				
LABOR	12.1	0.0	0.0	12.1
NON-LABOR	128.0 (A)	16.3	0.0	144.3
TOTAL 93200	140.1	16.3	0.0	156.4
TOTAL OTHER A&G	915.2	57.3	0.0	972.5
TOTAL	12,470.8	320.8	2,422.0	15,213.6

HAWAII ELECTRIC LIGHT CO., INC.
ADMIN & GENL O&M EXPENSE
TEST YEAR 2006 ($1000's)

	TEST YEAR 2006			
	Direct Testimony	CA-IR-447, CA-IR-448 & CA-SIR-35 Adjustments	Settlement	HELCO Rebuttal
LABOR	3,007.4	111.7	(132.0)	2,987.1
NON-LABOR	9,463.4	209.1	2,554.0	12,226.5
TOTAL	12,470.8	320.8	2,422.0	15,213.6

Notes	Account	Description	Amount
(A)	Various	Refer to HELCO's response to CA-IR-448, pages 2 - 7.	320.5
(B)	92501 & 92606	Refer to CA-T-1, CA-101, Schedule C-15.	(132.0)
(C)	92603	Refer to HELCO/Consumer Advocate Settlement Agreement	2,554.0
			2,742.5

Hawaii Electric Light Company, Inc.
Pension Balances
($ thousands)

	12/31/2006	
Projected Benefit Obligation	$ 125,458	[A]
Fair Value of Plan Assets	113,443	[B]
Overfunded (Underfunded)	(12,015)	[C] = [B] - [A]
Less: Pension Balance	12,771	[D]
AOCI Charge (Pre-Tax)	(24,785)	[E] = [C] - [D]
AOCI Tax Effect	9,644	[F] = - [E] * tax rate
AOCI Charge	$ (15,141)	[G] = [E] + [F]
Reconciliation to Rate Base:		
Pension AOCI Charge (Pre-Tax)	$ 24,785	[E]
Pension Liability	(12,015)	[C]
Rate Base (excluding Deferred Tax impact)	12,771	[H] = [D] = [E] + [C]
Deferred Tax	(4,969)	[I] = - [H] * tax rate
Net Rate Base (including Deferred Tax impact)	7,802	[J] = [H] + [I]

Composite Effective Income Tax Rate 38.91%

Note: Totals may not add due to rounding.

Sources:
[A] & [B] Estimates per Watson Wyatt
[D] See MECO-928 p. 1 of 2 in Docket No. 2006-0387

Hawaii Electric Light Company, Inc.
OPEB Balances
$ thousands

	12/31/2006	
Accumulated Postretirement Benefit Obligation	$ 29,060	[A]
Fair Value of Plan Assets	$ 22,016	[B]
Overfunded (Underfunded)	$ (7,044)	[C] = [B] - [A]
Less: OPEB Liability (SFAS 106)	$ (1,583)	[D]
AOCI Charge (Pre-Tax)	$ (5,461)	[E] = [C] - [D]
AOCI Tax Effect	$ 2,125	[F] = - [E] * tax rate
AOCI Charge	$ (3,336)	[G] = [E] + [F]
SFAS 106 OPEB Regulatory Asset	$ 1,583	[H]
SFAS 158 OPEB AOCI Charge	5,461	[I]
OPEB Liability	(7,044)	[C]
Rate Base (excluding Deferred Tax impact)	-	[J] = [F] + [E] + [C]

Composite Effective Income Tax Rate 38.91%

Note: Exec Life eliminated from all amounts.

Sources:
[A] & [B] Estimates per Watson Wyatt
[D] See MECO-929 pages 1 of 4 and 3 of 4 in Docket No. 2006-0387
[F] See MECO-929 p. 3 of 4 in Docket No. 2006-0387

Excerpt From CA-SIR-1432 in Docket No. 99-0207
Pre-PSD Estimates included in Encogen AC Estimate

		Percentage AFUDC	Pre-PSD Costs Allowed In 2000 TY	Allocated AFUDC
Warehouse				
	Encogen AC 1996			
Materials	$148,900			
Engineering	$291,801			
Construction	$2,075,905			
Labor	$0			
AFUDC	$620,810	19.79%	$972,599	$192,451
	==========			
Total	$3,137,416			
Fire Protection				
	Encogen AC 1996			
Materials	$246,300			
Engineering	$346,705			
Construction	$2,397,115			
Labor	$0			
AFUDC	$737,619	19.79%	$745,548	$147,524
	==========			
Total	$3,727,739			
Water Treatment				
	Encogen AC 1996			
Materials	$3,352,600			
Engineering	$1,088,553			
Construction	$4,873,700			
Labor	$73,250			
AFUDC	$2,315,907	19.79%	$5,852,005	$1,157,954
	==========			
Total	$11,704,010			
Total Pre-PSD				
Warehouse	$3,137,416			
Fire Protection	$3,727,739			
Water Treatment	$11,704,010			
	==========			
Total	$18,569,165		$7,570,152	$1,497,928

Keahole CT-4 & CT-5

Month	Cap Ex Excl. AFUDC	AFUDC	Total Incl. AFUDC	Closed To Plant	Cummulative Balance	AFUDC Rate
Jun-91	$0	$0	$0		$0	0.006584
Jul-91	$0	$2,773	$2,773		$2,773	0.006584
Aug-91	$0	$2,905	$2,905		$5,678	0.006584
Sep-91	$0	$3,228	$3,228		$8,906	0.006584
Oct-91	$0	$3,390	$3,390		$12,296	0.006584
Nov-91	$0	$3,745	$3,745		$16,041	0.006584
Dec-91	$0	$3,969	$3,969		$20,010	0.006584
Jan-92	$0	$4,152	$4,152		$24,162	0.006444
Feb-92	$0	$4,656	$4,656		$28,818	0.006444
Mar-92	$0	$4,942	$4,942		$33,760	0.006444
Apr-92	$0	$5,110	$5,110		$38,870	0.006444
May-92	$0	$5,254	$5,254		$44,124	0.006444
Jun-92	$0	$5,437	$5,437		$49,562	0.006444
Jul-92	$0	$5,767	$5,767		$55,329	0.006444
Aug-92	$0	$6,186	$6,186		$61,515	0.006444
Sep-92	$0	$6,426	$6,426		$67,941	0.006444
Oct-92	$0	$7,296	$7,296		$75,237	0.006444
Nov-92	$0	$10,673	$10,673		$85,910	0.006444
Dec-92	$0	$12,819	$12,819		$98,729	0.006444
Jan-93	$0	$31,803	$31,803		$130,532	0.008233
Feb-93	$0	$21,674	$21,674		$152,205	0.008233
Mar-93	$0	$25,817	$25,817		$178,023	0.008233
Apr-93	$0	$26,409	$26,409		$204,432	0.008233
May-93	$0	$29,928	$29,928		$234,360	0.008233
Jun-93	$0	$62,175	$62,175		$296,536	0.008233
Jul-93	$0	$64,273	$64,273		$360,808	0.008233
Aug-93	$0	$103,898	$103,898		$464,706	0.008233
Sep-93	$0	$111,586	$111,586		$576,293	0.008233
Oct-93	$0	$130,203	$130,203		$706,496	0.008233
Nov-93	$0	$133,033	$133,033		$839,529	0.008233
Dec-93	$0	$137,170	$137,170		$976,698	0.008233
Jan-94	$0	$8,187	$8,187		$984,885	0.008382
Feb-94	$0	$8,255	$8,255		$993,140	0.008382
Mar-94	$0	$8,325	$8,325		$1,001,465	0.008382
Apr-94	$0	$8,394	$8,394		$1,009,859	0.008382
May-94	$0	$8,465	$8,465		$1,018,324	0.008382
Jun-94	$0	$8,536	$8,536		$1,026,859	0.008382
Jul-94	$0	$8,265	$8,265		$1,035,125	0.008049
Aug-94	$0	$8,332	$8,332		$1,043,456	0.008049
Sep-94	$0	$8,399	$8,399		$1,051,855	0.008049
Oct-94	$0	$7,897	$7,897		$1,059,753	0.007508
Nov-94	$0	$7,957	$7,957		$1,067,709	0.007508
Dec-94	$0	$8,016	$8,016		$1,075,725	0.007508
Jan-95	$0	$8,581	$8,581		$1,084,307	0.007977
Feb-95	$0	$8,470	$8,470		$1,092,776	0.007811
Mar-95	$0	$8,536	$8,536		$1,101,312	0.007811
Apr-95	$0	$8,602	$8,602		$1,109,914	0.007811
May-95	$0	$8,670	$8,670		$1,118,584	0.007811
Jun-95	$0	$9,280	$9,280		$1,127,863	0.008296
Jul-95	$0	$9,357	$9,357		$1,137,220	0.008296
Aug-95	$0	$9,384	$9,384		$1,146,604	0.008252
Sep-95	$0	$9,462	$9,462		$1,156,066	0.008252
Oct-95	$0	$9,540	$9,540		$1,165,606	0.008252
Nov-95	$0	$9,619	$9,619		$1,175,225	0.008252
Dec-95	$0	$9,698	$9,698		$1,184,923	0.008252
Jan-96	$0	$9,545	$9,545		$1,194,467	0.008055

Keahole CT-4 & CT-5

Month	Cap Ex Excl. AFUDC	AFUDC	Total Incl. AFUDC	Closed To Plant	Cummulative Balance	AFUDC Rate
Feb-96	$0	$9,621	$9,621		$1,204,089	0.008055
Mar-96	$0	$9,699	$9,699		$1,213,788	0.008055
Apr-96	$0	$9,777	$9,777		$1,223,565	0.008055
May-96	$0	$9,856	$9,856		$1,233,420	0.008055
Jun-96	$0	$9,935	$9,935		$1,243,356	0.008055
Jul-96	$0	$10,015	$10,015		$1,253,371	0.008055
Aug-96	$0	$10,096	$10,096		$1,263,467	0.008055
Sep-96	$0	$10,177	$10,177		$1,273,644	0.008055
Oct-96	$0	$10,259	$10,259		$1,283,903	0.008055
Nov-96	$0	$10,342	$10,342		$1,294,245	0.008055
Dec-96	$0	$10,425	$10,425		$1,304,670	0.008055
Jan-97	$0	$10,607	$10,607		$1,315,277	0.008130
Feb-97	$0	$10,693	$10,693		$1,325,970	0.008130
Mar-97	$0	$10,780	$10,780		$1,336,751	0.008130
Apr-97	$0	$10,314	$10,314		$1,347,065	0.007716
May-97	$0	$10,394	$10,394		$1,357,459	0.007716
Jun-97	$0	$10,474	$10,474		$1,367,933	0.007716
Jul-97	$0	$10,555	$10,555		$1,378,488	0.007716
Aug-97	$0	$10,636	$10,636		$1,389,124	0.007716
Sep-97	$0	$10,718	$10,718		$1,399,843	0.007716
Oct-97	$0	$10,801	$10,801		$1,410,644	0.007716
Nov-97	$0	$10,885	$10,885		$1,421,529	0.007716
Dec-97	$0	$10,969	$10,969		$1,432,497	0.007716
Jan-98	$0	$10,959	$10,959		$1,443,456	0.007650
Feb-98	$0	$11,042	$11,042		$1,454,498	0.007650
Mar-98	$0	$11,127	$11,127		$1,465,625	0.007650
Apr-98	$0	$11,212	$11,212		$1,476,837	0.007650
May-98	$0	$11,298	$11,298		$1,488,135	0.007650
Jun-98	$0	$11,384	$11,384		$1,499,519	0.007650
Jul-98	$0	$11,471	$11,471		$1,510,990	0.007650
Aug-98	$0	$11,559	$11,559		$1,522,549	0.007650
Sep-98	$0	$11,648	$11,648		$1,534,197	0.007650
Oct-98	$0	$11,737	$11,737		$1,545,934	0.007650
Nov-98	$0	$11,826	$11,826		$1,557,760	0.007650
Dec-98	$0	$0	$0		$1,557,760	0.007650
Jan-99	$0	$0	$0		$1,557,760	0.007700
Feb-99	$0	$0	$0		$1,557,760	0.007700
Mar-99	$0	$0	$0		$1,557,760	0.007700
Apr-99	$0	$0	$0		$1,557,760	0.007700
May-99	$0	$0	$0		$1,557,760	0.007700
Jun-99	$0	$0	$0		$1,557,760	0.007700
Jul-99	$0	$0	$0		$1,557,760	0.007700
Aug-99	$0	$0	$0		$1,557,760	0.007700
Sep-99	$0	$0	$0		$1,557,760	0.007700
Oct-99	$0	$0	$0		$1,557,760	0.007700
Nov-99	$0	$0	$0		$1,557,760	0.007700
Dec-99	$0	$0	$0		$1,557,760	0.007700
Jan-00	$0	$0	$0		$1,557,760	0.007639
Feb-00	$0	$0	$0		$1,557,760	0.007639
Mar-00	$0	$0	$0		$1,557,760	0.007639
Apr-00	$0	$0	$0		$1,557,760	0.007639
May-00	$0	$0	$0		$1,557,760	0.007639
Jun-00	$0	$0	$0		$1,557,760	0.007639
Jul-00	$0	$0	$0		$1,557,760	0.007639
Aug-00	$0	$0	$0		$1,557,760	0.007639
Sep-00	$0	$0	$0		$1,557,760	0.007639

Keahole CT-4 & CT-5

Month	Cap Ex Excl. AFUDC	AFUDC	Total Incl. AFUDC	Closed To Plant	Cummulative Balance	AFUDC Rate
Oct-00	$0	$0	$0		$1,557,760	0.007639
Nov-00	$0	$0	$0		$1,557,760	0.007639
Dec-00	$0	$0	$0		$1,557,760	0.007639
Jan-01	$0	$0	$0		$1,557,760	0.007676
Feb-01	$0	$0	$0		$1,557,760	0.007676
Mar-01	$0	$0	$0		$1,557,760	0.007676
Apr-01	$0	$0	$0		$1,557,760	0.007676
May-01	$0	$0	$0		$1,557,760	0.007676
Jun-01	$0	$0	$0		$1,557,760	0.007676
Jul-01	$0	$0	$0		$1,557,760	0.007676
Aug-01	$0	$0	$0		$1,557,760	0.007676
Sep-01	$0	$0	$0		$1,557,760	0.007676
Oct-01	$0	$0	$0		$1,557,760	0.007676
Nov-01	$0	$0	$0		$1,557,760	0.007676
Dec-01	$0	$0	$0		$1,557,760	0.007676
Jan-02	$0	$0	$0		$1,557,760	0.007583
Feb-02	$0	$0	$0		$1,557,760	0.007583
Mar-02	$0	$0	$0		$1,557,760	0.007583
Apr-02	$0	$0	$0		$1,557,760	0.007583
May-02	$0	$0	$0		$1,557,760	0.007583
Jun-02	$0	$0	$0		$1,557,760	0.007583
Jul-02	$0	$0	$0		$1,557,760	0.007583
Aug-02	$0	$0	$0		$1,557,760	0.007583
Sep-02	$0	$0	$0		$1,557,760	0.007583
Oct-02	$0	$0	$0		$1,557,760	0.007583
Nov-02	$0	$0	$0		$1,557,760	0.007583
Dec-02	$0	$0	$0		$1,557,760	0.007583
Jan-03	$0	$0	$0		$1,557,760	0.007619
Feb-03	$0	$0	$0		$1,557,760	0.007619
Mar-03	$0	$0	$0		$1,557,760	0.007619
Apr-03	$0	$0	$0		$1,557,760	0.007619
May-03	$0	$0	$0		$1,557,760	0.007619
Jun-03	$0	$0	$0		$1,557,760	0.007619
Jul-03	$0	$0	$0		$1,557,760	0.007619
Aug-03	$0	$0	$0		$1,557,760	0.007619
Sep-03	$0	$0	$0		$1,557,760	0.007619
Oct-03	$0	$0	$0		$1,557,760	0.007619
Nov-03	$0	$0	$0		$1,557,760	0.007619
Dec-03	$0	$0	$0		$1,557,760	0.007619
Jan-04	$0	$0	$0		$1,557,760	0.007337
Feb-04	$0	$0	$0		$1,557,760	0.007337
Mar-04	$0	$0	$0		$1,557,760	0.007337
Apr-04	$0	$0	$0		$1,557,760	0.007337
May-04	$0	$0	$0		$1,557,760	0.007337
Jun-04	$0	$0	$0		$1,557,760	0.007337
Jul-04	$0	$0	$0		$1,557,760	0.007337
Aug-04	$0	$0	$0		$1,557,760	0.007337
Sep-04	$0	$0	$0		$1,557,760	0.007337
Oct-04	$0	$0	$0		$1,557,760	0.007337
Nov-04	$0	$0	$0		$1,557,760	0.007337
Dec-04	$0	$0	$0	(1,557,760)	$0	0.007337
Total	**$0**	**$1,557,760**	**$1,557,760**	**($1,557,760)**	**$0**	

Hawaii Electric Light Company, Inc.
Keahole CT-4 & 5 - Analysis of AFUDC
December 1998 - December 2004

Month	CWIP Balance	Closed To Plant	Adjusted CWIP Balance	AFUDC Base	Monthly AFUDC Rate	AFUDC
Nov-98	74,042,854		74,042,854	74,042,854	0.7650%	
Dec-98	74,601,954	(972,599)	73,629,355	73,629,355	0.7650%	566,428
Jan-99	74,962,744	(972,599)	73,990,145	74,556,573	0.7700%	566,946
Feb-99	75,323,534	(972,599)	74,350,935	75,484,309	0.7700%	574,086
Mar-99	75,684,324	(972,599)	74,711,725	76,419,184	0.7700%	581,229
Apr-99	76,045,114	(972,599)	75,072,515	77,361,204	0.7700%	588,428
May-99	76,405,904	(972,599)	75,433,305	78,310,421	0.7700%	595,681
Jun-99	76,766,694	(972,599)	75,794,095	79,266,893	0.7700%	602,990
Jul-99	77,127,484	(972,599)	76,154,885	80,230,673	0.7700%	610,355
Aug-99	77,488,274	(972,599)	76,515,675	81,201,818	0.7700%	617,776
Sep-99	77,849,060	(1,718,147)	76,130,913	80,853,603	0.7700%	625,254
Oct-99	78,118,981	(1,718,147)	76,400,834	81,755,922	0.7700%	622,573
Nov-99	78,388,901	(1,718,147)	76,670,754	83,222,500	0.7700%	629,521
Dec-99	79,790,841	(7,570,152)	72,220,689	79,401,955	0.7700%	640,813
Jan-00	79,939,492	(7,570,152)	72,369,340	80,191,420	0.7639%	606,552
Feb-00	80,088,143	(7,570,152)	72,517,991	80,946,622	0.7639%	612,582
Mar-00	80,236,794	(7,570,152)	72,666,642	81,707,856	0.7639%	618,351
Apr-00	80,385,445	(7,570,152)	72,815,293	82,474,858	0.7639%	624,166
May-00	80,508,693	(7,570,152)	72,938,541	83,222,272	0.7639%	630,025
Jun-00	80,631,941	(7,570,152)	73,061,789	83,975,546	0.7639%	635,735
Jul-00	80,755,189	(7,570,152)	73,185,037	84,734,528	0.7639%	641,489
Aug-00	80,878,437	(7,570,152)	73,308,285	85,499,266	0.7639%	647,287
Sep-00	81,001,685	(7,570,152)	73,431,533	86,269,801	0.7639%	653,129
Oct-00	81,124,935	(7,570,152)	73,554,783	87,046,180	0.7639%	659,015
Nov-00	81,142,578	(7,570,152)	73,572,426	87,722,838	0.7639%	664,946
Dec-00	81,145,065	(7,570,152)	73,574,913	88,390,270	0.7639%	670,115
Jan-01	81,197,297	(7,570,152)	73,627,145	89,112,617	0.7676%	678,484
Feb-01	81,249,529	(7,570,152)	73,679,377	89,843,333	0.7676%	684,028
Mar-01	81,252,322	(7,570,152)	73,682,170	90,530,154	0.7676%	689,637
Apr-01	81,516,100	(7,570,152)	73,945,948	91,483,570	0.7676%	694,909
May-01	81,539,315	(7,570,152)	73,969,163	92,201,694	0.7676%	702,228
Jun-01	81,562,530	(7,570,152)	73,992,378	92,927,137	0.7676%	707,740
Jul-01	81,585,745	(7,570,152)	74,015,593	93,658,092	0.7676%	713,309
Aug-01	81,608,960	(7,570,152)	74,038,808	94,394,616	0.7676%	718,920
Sep-01	81,632,176	(7,570,152)	74,062,024	95,136,751	0.7676%	724,573
Oct-01	81,851,602	(7,570,152)	74,281,450	96,080,751	0.7676%	730,270
Nov-01	82,071,027	(7,570,152)	74,500,875	97,030,445	0.7676%	737,516
Dec-01	82,281,951	(7,570,152)	74,711,799	97,978,885	0.7676%	744,806

Hawaii Electric Light Company, Inc.
Keahole CT-4 & 5 - Analysis of AFUDC
December 1998 - December 2004

Month	CWIP Balance	Closed To Plant	Adjusted CWIP Balance	AFUDC Base	Monthly AFUDC Rate	AFUDC
Jan-02	82,912,809	(7,570,152)	75,342,657	99,354,549	0.7583%	742,974
Feb-02	83,543,667	(7,570,152)	75,973,515	100,728,381	0.7583%	753,406
Mar-02	84,174,525	(7,570,152)	76,604,373	102,112,644	0.7583%	763,823
Apr-02	84,805,383	(7,570,152)	77,235,231	103,507,326	0.7583%	774,320
May-02	85,436,241	(7,570,152)	77,866,089	104,912,504	0.7583%	784,896
Jun-02	86,067,099	(7,570,152)	78,496,947	106,328,258	0.7583%	795,552
Jul-02	86,697,957	(7,570,152)	79,127,805	107,754,667	0.7583%	806,287
Aug-02	87,328,815	(7,570,152)	79,758,663	109,191,812	0.7583%	817,104
Sep-02	87,959,673	(7,570,152)	80,389,521	110,639,774	0.7583%	828,002
Oct-02	88,590,531	(7,570,152)	81,020,379	112,098,634	0.7583%	838,981
Nov-02	89,221,389	(7,570,152)	81,651,237	113,568,473	0.7583%	850,044
Dec-02	89,852,244	(7,570,152)	82,282,092	115,049,372	0.7583%	861,190
Jan-03	90,423,367	(7,570,152)	82,853,215	116,481,685	0.7619%	876,561
Feb-03	90,486,170	(7,570,152)	82,916,018	117,421,049	0.7619%	887,474
Mar-03	90,606,254	(7,570,152)	83,036,102	118,428,607	0.7619%	894,631
Apr-03	90,854,281	(7,570,152)	83,284,129	119,571,265	0.7619%	902,308
May-03	90,929,374	(7,570,152)	83,359,222	120,548,665	0.7619%	911,013
Jun-03	91,036,970	(7,570,152)	83,466,818	121,567,275	0.7619%	918,460
Jul-03	91,139,634	(7,570,152)	83,569,482	122,588,399	0.7619%	926,221
Aug-03	91,180,030	(7,570,152)	83,609,878	123,555,016	0.7619%	934,001
Sep-03	91,270,844	(7,570,152)	83,700,692	124,579,831	0.7619%	941,366
Oct-03	91,385,093	(7,570,152)	83,814,941	125,635,446	0.7619%	949,174
Nov-03	91,576,085	(7,570,152)	84,005,933	126,775,612	0.7619%	957,216
Dec-03	91,543,643	(7,570,152)	83,973,491	127,700,386	0.7619%	965,903
Jan-04	92,025,515	(7,570,152)	84,455,363	129,148,161	0.7337%	936,938
Feb-04	92,947,600	(7,570,152)	85,377,448	131,007,184	0.7337%	947,560
Mar-04	95,466,115	(7,570,152)	87,895,963	134,473,259	0.7337%	961,200
Apr-04	96,586,415	(7,570,152)	89,016,263	136,554,759	0.7337%	986,630
May-04	99,944,854	(57,524,318)	42,420,536	90,945,662	0.7337%	1,001,902
Jun-04	100,702,810	(97,965,752)	2,737,058	52,264,086	0.7337%	667,268
Jul-04	102,790,850	(99,470,258)	3,320,592	53,514,889	0.7337%	383,462
Aug-04	104,228,823	(100,611,533)	3,617,290	54,195,048	0.7337%	392,639
Sep-04	105,988,259	(101,906,900)	4,081,359	55,051,756	0.7337%	397,629
Oct-04	106,262,307	(102,162,154)	4,100,153	55,468,179	0.7337%	403,915
Nov-04	106,667,172	(102,348,876)	4,318,296	56,090,237	0.7337%	406,970
Dec-04	110,801,039	(110,801,039)	0	52,178,911	0.7337%	411,534
						52,590,445

Hawaii Electric Light Co., Inc.
Administrative and General Expenses
($ in Thousands)

Block Of Accounts	(A) HELCO Rebuttal Test Year	(B) Consumer Advocate Direct Test Year	(C) Consumer Advocate Settlement Position	(D) Difference HELCO Rebuttal vs. Consumer Advocate Settlement Position
ADMINISTRATIVE & GENERAL EXPENSES	15,214	12,660	15,214	0

Column
(A) HELCO-R-902
(B) CA-101, Schedule C, Page 1, Column D, Line 12
(C) HELCO/Consumer Advocate Settlement Agreement, Subject To Commission Approval
(D) Column (A) - Column (C)

Hawaii Electric Light Co., Inc.
Administrative and General Expenses
($ in Thousands)

Account #	Account Description	(A) Operating Budget	(B) Budget Adjustments	(C) Rate Case Adjts/ Normali-zations	(D) Direct Testimony	(E) CA-IR-447, CA-IR-448 & CA-SIR-35 Adjustments	(F) HELCO Pre-Settlement	(G) Settlement	(H) HELCO Rebuttal	(I) 2006 Recorded
ADMINISTRATIVE										
92000	A&G Salaries	2,706	(47)	(360)	2,300	0	2,300		2,300	2,260
92100	Office Supplies & Expenses	1,613	(973)	27	667	89	756		756	826
92201	A&G Trsfd to Construction	(1,031)	117	0	(915)	0	(915)		(915)	(906)
	Total Administrative	3,288	(903)	(332)	2,052	89	2,141	0	2,141	2,180
OUTSIDE SERVICES										
92301	Outside Legal Services	50	16	0	66	0	66		66	153
92302	Other Outside Services	92	175	(45)	221	(17)	204		204	111
92303	Services From Assoc. Co.	2,178	(340)	0	1,838	(128)	1,710		1,710	1,786
	Total Outside Services	2,319	(149)	(45)	2,125	(145)	1,981	0	1,981	2,051
INSURANCE										
92400	Property Insurance	591	(55)	0	536	0	536		536	565
92501/2	Injs & Damages-Empl/Public	2,311	(378)	0	1,933	87	2,021	(108)	1,913	1,380
	Total Insurance	2,902	(433)	0	2,469	87	2,557	(108)	2,449	1,945
EMPLOYEE BENEFITS										
926000 - 926020	Employee Benefits**	5,094	(29)	(156)	4,909	232	5,141	2,530	7,671	5,019
	Total Employee Benefits	5,094	(29)	(156)	4,909	231.9	5,141	2,530	7,671	5,019
MISCELLANEOUS										
92800 - 93200	Miscellaneous	745	191	(21)	915	57	973	0	973	493
	Total Miscellaneous	745	191	(21)	915	57	973	0	973	493
TOTAL ADMIN & GENERAL EXPENSES		14,348	(1,322)	(555)	12,471	321	12,792	2,422	15,214	11,687

Column	
A - D	HELCO-902
E & G	HELCO-R-903
F	Column D + Column E
H	Column F + Column G
I	HELCO 12/31/06 Trial Balance Report #SUB960A
**	Refer to HELCO RT-10 for details on employee benefit series of accounts

HAWAII ELECTRIC LIGHT CO., INC.
ADMIN & GENL O&M EXPENSE
TEST YEAR 2006 ($1000's)

	TEST YEAR 2006			
	Direct Testimony	CA-IR-447, CA-IR-448 & CA-SIR-35 Adjustments	Settlement	HELCO Rebuttal
ADMINISTRATIVE				
92000 ADMIN & GENL EXP-LABR				
LABOR	2,299.6	0.0	0.0	2,299.6
NON-LABOR	0.0	0.0	0.0	0.0
TOTAL 92000	2,299.6	0.0	0.0	2,299.6
92100 ADMIN & GENL EXP-NLABR				
NON-LABOR	667.3 (A)	89.0	0.0	756.3
TOTAL 92100	667.3	89.0	0.0	756.3
92201 ADMIN EXP TRFD TO CONSTR				
NON-LABOR	(914.9)	0.0	0.0	(914.9)
TOTAL 92201	(914.9)	0.0	0.0	(914.9)
TOTAL ADMIN	2,052.0	89.0	0.0	2,141.0

HAWAII ELECTRIC LIGHT CO., INC.
ADMIN & GENL O&M EXPENSE
TEST YEAR 2006 ($1000's)

	TEST YEAR 2006				
	Direct Testimony		CA-IR-447, CA-IR-448 & CA-SIR-35 Adjustments	Settlement	HELCO Rebuttal
OUTSIDE SERVICES					
92301 LEGAL SERVICES					
NON-LABOR	66.0		0.0	0.0	66.0
TOTAL 92301	66.0		0.0	0.0	66.0
92302 OTHER OUTSIDE SERVICES					
NON-LABOR	221.4	(A)	(17.0)	0.0	204.4
TOTAL 92302	221.4		(17.0)	0.0	204.4
92303 OTHER SERVICES - ASSOC CO					
NON-LABOR	1,837.9	(A)	(127.8)	0.0	1,710.1
TOTAL 92303	1,837.9		(127.8)	0.0	1,710.1
TOTAL OS SVCS	2,125.3		(144.8)	0.0	1,980.5

HAWAII ELECTRIC LIGHT CO., INC.
ADMIN & GENL O&M EXPENSE
TEST YEAR 2006 ($1000's)

	TEST YEAR 2006			
	Direct Testimony	CA-IR-447, CA-IR-448 & CA-SIR-35 Adjustments	Settlement	HELCO Rebuttal
INSURANCE				
92400 PROPERTY INSURANCE				
NON-LABOR	536.0	0.0	0.0	536.0
TOTAL 92400	536.0	0.0	0.0	536.0
92501 INJURIES & DAMAGES - EMPLOYEE				
LABOR	551.2 (A)	4.7 (B)	(108.0)	447.9
NON-LABOR	632.0 (A)	82.7	0.0	714.7
TOTAL 92501	1,183.2	87.4	(108.0)	1,162.6
92502 INJURIES & DAMAGES - PUBLIC				
LABOR	38.5	0.0	0.0	38.5
NON-LABOR	711.5	0.0	0.0	711.5
TOTAL 92502	750.0	0.0	0.0	750.0
TOTAL INSURANCE	2,469.2	87.4	(108.0)	2,448.6

HAWAII ELECTRIC LIGHT CO., INC.
ADMIN & GENL O&M EXPENSE
TEST YEAR 2006 ($1000's)

	TEST YEAR 2006 Direct Testimony	CA-IR-447, CA-IR-448 & CA-SIR-35 Adjustments	Settlement	HELCO Rebuttal
EMPLOYEE BENEFITS				
92600 EMPL BENEFITS - FLEX CREDITS				
NON-LABOR	(368.2)	0.0	0.0	(368.2)
TOTAL 92600	(368.2)	0.0	0.0	(368.2)
92601 EMPL PENSIONS - NONFUNDED				
NON-LABOR	0.0	0.0	0.0	0.0
TOTAL 92601	0.0	0.0	0.0	0.0
92602 EMPL BENEFITS - DENTAL PLAN				
NON-LABOR	315.4	0.0	0.0	315.4
TOTAL 92602	315.4	0.0	0.0	315.4
92603 EMPL PENSION - FUNDED				
NON-LABOR	2,686.0 (A)	58.3 (C)	2,554.0	5,298.3
TOTAL 92603	2,686.0	58.3	2,554.0	5,298.3
92604 EMPL GROUP LIFE INSURANCE				
NON-LABOR	300.2	0.0	0.0	300.2
TOTAL 92604	300.2	0.0	0.0	300.2
92605 EMPL GROUP MED & HOSPITAL INS				
NON-LABOR	1,973.2	0.0	0.0	1,973.2
TOTAL 92605	1,973.2	0.0	0.0	1,973.2

HAWAII ELECTRIC LIGHT CO., INC.
ADMIN & GENL O&M EXPENSE
TEST YEAR 2006 ($1000's)

	TEST YEAR 2006					
	Direct Testimony		CA-IR-447, CA-IR-448 & CA-SIR-35 Adjustments		Settlement	HELCO Rebuttal
92606 OTHER EMPL BENEFITS						
LABOR	106.0	(A)	107.0	(B)	(24.0)	189.0
NON-LABOR	329.9	(A)	115.1		0.0	445.0
TOTAL 92606	435.9		222.1		(24.0)	634.0
92607 EMPLOYEE VISION						
NON-LABOR	49.5		0.0		0.0	49.5
TOTAL 92607	49.5		0.0		0.0	49.5
92608 LONG-TERM DISABILITY PLAN						
NON-LABOR	183.3		0.0		0.0	183.3
TOTAL 92608	183.3		0.0		0.0	183.3
92609 POST-RETIREMENT BENEFITS						
NON-LABOR	1,458.9	(A)	(48.5)		0.0	1,410.4
TOTAL 92609	1,458.9		(48.5)		0.0	1,410.4
92690 EMPL BEN TFRD TO CONSTR						
NON-LABOR	(2,125.1)		0.0		0.0	(2,125.1)
TOTAL 92690	(2,125.1)		0.0		0.0	(2,125.1)
TOTAL EMP BEN	4,909.1		231.9		2,530.0	7,671.0

HAWAII ELECTRIC LIGHT CO., INC.
ADMIN & GENL O&M EXPENSE
TEST YEAR 2006 ($1000's)

	TEST YEAR 2006			
	Direct Testimony	CA-IR-447, CA-IR-448 & CA-SIR-35 Adjustments	Settlement	HELCO Rebuttal
OTHER ADMIN & GENL				
92800 REGULATORY COMMISSION EXPENSES				
NON-LABOR	275.0 (A)	41.0	0.0	316.0
TOTAL 92800	275.0	41.0	0.0	316.0
93010 INSTITUTN/GOODWILL ADVERT EXPENSES				
LABOR	0.0	0.0	0.0	0.0
NON-LABOR	0.0	0.0	0.0	0.0
TOTAL 93010	0.0	0.0	0.0	0.0
93021COMMUNITY SERVICE ACTIVITIES				
NON-LABOR	56.5	0.0	0.0	56.5
TOTAL 93021	56.5	0.0	0.0	56.5
93022 COMPANY MEMBERSHIP EXPENSES				
NON-LABOR	59.5	0.0	0.0	59.5
TOTAL 93022	59.5	0.0	0.0	59.5
93024 RESEARCH & DEVELOPMENT EXPENSES				
NON-LABOR	323.5	0.0	0.0	323.5
TOTAL 93024	323.5	0.0	0.0	323.5
93025 PREF STK & L-T DEBT EXPENSES				
NON-LABOR	46.1	0.0	0.0	46.1
TOTAL 93025	46.1	0.0	0.0	46.1

HAWAII ELECTRIC LIGHT CO., INC.
ADMIN & GENL O&M EXPENSE
TEST YEAR 2006 ($1000's)

	TEST YEAR 2006				
	Direct Testimony		CA-IR-447, CA-IR-448 & CA-SIR-35 Adjustments	Settlement	HELCO Rebuttal
93028 DIRECTORS FEES & EXPENSES					
NON-LABOR	14.5		0.0	0.0	14.5
TOTAL 93028	14.5		0.0	0.0	14.5
93200 ADMIN AND GENL MAINTENANCE					
LABOR	12.1		0.0	0.0	12.1
NON-LABOR	128.0	(A)	16.3	0.0	144.3
TOTAL 93200	140.1		16.3	0.0	156.4
TOTAL OTHER A&G	915.2		57.3	0.0	972.5
TOTAL	12,470.8		320.8	2,422.0	15,213.6

HAWAII ELECTRIC LIGHT CO., INC.
ADMIN & GENL O&M EXPENSE
TEST YEAR 2006 ($1000's)

	TEST YEAR 2006			
	Direct Testimony	CA-IR-447, CA-IR-448 & CA-SIR-35 Adjustments	Settlement	HELCO Rebuttal
LABOR	3,007.4	111.7	(132.0)	2,987.1
NON-LABOR	9,463.4	209.1	2,554.0	12,226.5
TOTAL	12,470.8	320.8	2,422.0	15,213.6

Notes	Account	Description	Amount
(A)	Various	Refer to HELCO's response to CA-IR-448, pages 2 - 7.	320.5
(B)	92501 & 92606	Refer to CA-T-1, CA-101, Schedule C-15.	(132.0)
(C)	92603	Refer to HELCO/Consumer Advocate Settlement Agreement	2,554.0
			2,742.5

Hawaii Electric Light Company, Inc.
Pension Balances
($ thousands)

	12/31/2006	
Projected Benefit Obligation	$ 125,458	[A]
Fair Value of Plan Assets	113,443	[B]
Overfunded (Underfunded)	(12,015)	[C] = [B] - [A]
Less: Pension Balance	12,771	[D]
AOCI Charge (Pre-Tax)	(24,785)	[E] = [C] - [D]
AOCI Tax Effect	9,644	[F] = - [E] * tax rate
AOCI Charge	$ (15,141)	[G] = [E] + [F]
Reconciliation to Rate Base:		
Pension AOCI Charge (Pre-Tax)	$ 24,785	[E]
Pension Liability	(12,015)	[C]
Rate Base (excluding Deferred Tax impact)	12,771	[H] = [D] = [E] + [C]
Deferred Tax	(4,969)	[I] = - [H] * tax rate
Net Rate Base (including Deferred Tax impact)	7,802	[J] = [H] + [I]

Composite Effective Income Tax Rate 38.91%

Note: Totals may not add due to rounding.

Sources:
[A] & [B] Estimates per Watson Wyatt
[D] See MECO-928 p. 1 of 2 in Docket No. 2006-0387

Hawaii Electric Light Company, Inc.
OPEB Balances
$ thousands

	12/31/2006	
Accumulated Postretirement Benefit Obligation	$ 29,060	[A]
Fair Value of Plan Assets	$ 22,016	[B]
Overfunded (Underfunded)	$ (7,044)	[C] = [B] - [A]
Less: OPEB Liability (SFAS 106)	$ (1,583)	[D]
AOCI Charge (Pre-Tax)	$ (5,461)	[E] = [C] - [D]
AOCI Tax Effect	$ 2,125	[F] = - [E] * tax rate
AOCI Charge	$ (3,336)	[G] = [E] + [F]
SFAS 106 OPEB Regulatory Asset	$ 1,583	[H]
SFAS 158 OPEB AOCI Charge	5,461	[I]
OPEB Liability	(7,044)	[C]
Rate Base (excluding Deferred Tax impact)	-	[J] = [F] + [E] + [C]

Composite Effective Income Tax Rate	38.91%

Note: Exec Life eliminated from all amounts.

Sources:
[A] & [B] Estimates per Watson Wyatt
[D] See MECO-929 pages 1 of 4 and 3 of 4 in Docket No. 2006-0387
[F] See MECO-929 p. 3 of 4 in Docket No. 2006-0387

Excerpt From CA-SIR-1432 in Docket No. 99-0207
Pre-PSD Estimates included in Encogen AC Estimate

		Percentage AFUDC	Pre-PSD Costs Allowed In 2000 TY	Allocated AFUDC
Warehouse				
	Encogen AC 1996			
Materials	$148,900			
Engineering	$291,801			
Construction	$2,075,905			
Labor	$0			
AFUDC	$620,810	19.79%	$972,599	$192,451
	==========			
Total	$3,137,416			
Fire Protection				
	Encogen AC 1996			
Materials	$246,300			
Engineering	$346,705			
Construction	$2,397,115			
Labor	$0			
AFUDC	$737,619	19.79%	$745,548	$147,524
	==========			
Total	$3,727,739			
Water Treatment				
	Encogen AC 1996			
Materials	$3,352,600			
Engineering	$1,088,553			
Construction	$4,873,700			
Labor	$73,250			
AFUDC	$2,315,907	19.79%	$5,852,005	$1,157,954
	==========			
Total	$11,704,010			
Total Pre-PSD				
Warehouse	$3,137,416			
Fire Protection	$3,727,739			
Water Treatment	$11,704,010			
	==========			
Total	$18,569,165		$7,570,152	$1,497,928

Keahole CT-4 & CT-5

Month	Cap Ex Excl. AFUDC	AFUDC	Total Incl. AFUDC	Closed To Plant	Cummulative Balance	AFUDC Rate
Jun-91	$0	$0	$0		$0	0.006584
Jul-91	$0	$2,773	$2,773		$2,773	0.006584
Aug-91	$0	$2,905	$2,905		$5,678	0.006584
Sep-91	$0	$3,228	$3,228		$8,906	0.006584
Oct-91	$0	$3,390	$3,390		$12,296	0.006584
Nov-91	$0	$3,745	$3,745		$16,041	0.006584
Dec-91	$0	$3,969	$3,969		$20,010	0.006584
Jan-92	$0	$4,152	$4,152		$24,162	0.006444
Feb-92	$0	$4,656	$4,656		$28,818	0.006444
Mar-92	$0	$4,942	$4,942		$33,760	0.006444
Apr-92	$0	$5,110	$5,110		$38,870	0.006444
May-92	$0	$5,254	$5,254		$44,124	0.006444
Jun-92	$0	$5,437	$5,437		$49,562	0.006444
Jul-92	$0	$5,767	$5,767		$55,329	0.006444
Aug-92	$0	$6,186	$6,186		$61,515	0.006444
Sep-92	$0	$6,426	$6,426		$67,941	0.006444
Oct-92	$0	$7,296	$7,296		$75,237	0.006444
Nov-92	$0	$10,673	$10,673		$85,910	0.006444
Dec-92	$0	$12,819	$12,819		$98,729	0.006444
Jan-93	$0	$31,803	$31,803		$130,532	0.008233
Feb-93	$0	$21,674	$21,674		$152,205	0.008233
Mar-93	$0	$25,817	$25,817		$178,023	0.008233
Apr-93	$0	$26,409	$26,409		$204,432	0.008233
May-93	$0	$29,928	$29,928		$234,360	0.008233
Jun-93	$0	$62,175	$62,175		$296,536	0.008233
Jul-93	$0	$64,273	$64,273		$360,808	0.008233
Aug-93	$0	$103,898	$103,898		$464,706	0.008233
Sep-93	$0	$111,586	$111,586		$576,293	0.008233
Oct-93	$0	$130,203	$130,203		$706,496	0.008233
Nov-93	$0	$133,033	$133,033		$839,529	0.008233
Dec-93	$0	$137,170	$137,170		$976,698	0.008233
Jan-94	$0	$8,187	$8,187		$984,885	0.008382
Feb-94	$0	$8,255	$8,255		$993,140	0.008382
Mar-94	$0	$8,325	$8,325		$1,001,465	0.008382
Apr-94	$0	$8,394	$8,394		$1,009,859	0.008382
May-94	$0	$8,465	$8,465		$1,018,324	0.008382
Jun-94	$0	$8,536	$8,536		$1,026,859	0.008382
Jul-94	$0	$8,265	$8,265		$1,035,125	0.008049
Aug-94	$0	$8,332	$8,332		$1,043,456	0.008049
Sep-94	$0	$8,399	$8,399		$1,051,855	0.008049
Oct-94	$0	$7,897	$7,897		$1,059,753	0.007508
Nov-94	$0	$7,957	$7,957		$1,067,709	0.007508
Dec-94	$0	$8,016	$8,016		$1,075,725	0.007508
Jan-95	$0	$8,581	$8,581		$1,084,307	0.007977
Feb-95	$0	$8,470	$8,470		$1,092,776	0.007811
Mar-95	$0	$8,536	$8,536		$1,101,312	0.007811
Apr-95	$0	$8,602	$8,602		$1,109,914	0.007811
May-95	$0	$8,670	$8,670		$1,118,584	0.007811
Jun-95	$0	$9,280	$9,280		$1,127,863	0.008296
Jul-95	$0	$9,357	$9,357		$1,137,220	0.008296
Aug-95	$0	$9,384	$9,384		$1,146,604	0.008252
Sep-95	$0	$9,462	$9,462		$1,156,066	0.008252
Oct-95	$0	$9,540	$9,540		$1,165,606	0.008252
Nov-95	$0	$9,619	$9,619		$1,175,225	0.008252
Dec-95	$0	$9,698	$9,698		$1,184,923	0.008252
Jan-96	$0	$9,545	$9,545		$1,194,467	0.008055

Keahole CT-4 & CT-5

Month	Cap Ex Excl. AFUDC	AFUDC	Total Incl. AFUDC	Closed To Plant	Cummulative Balance	AFUDC Rate
Feb-96	$0	$9,621	$9,621		$1,204,089	0.008055
Mar-96	$0	$9,699	$9,699		$1,213,788	0.008055
Apr-96	$0	$9,777	$9,777		$1,223,565	0.008055
May-96	$0	$9,856	$9,856		$1,233,420	0.008055
Jun-96	$0	$9,935	$9,935		$1,243,356	0.008055
Jul-96	$0	$10,015	$10,015		$1,253,371	0.008055
Aug-96	$0	$10,096	$10,096		$1,263,467	0.008055
Sep-96	$0	$10,177	$10,177		$1,273,644	0.008055
Oct-96	$0	$10,259	$10,259		$1,283,903	0.008055
Nov-96	$0	$10,342	$10,342		$1,294,245	0.008055
Dec-96	$0	$10,425	$10,425		$1,304,670	0.008055
Jan-97	$0	$10,607	$10,607		$1,315,277	0.008130
Feb-97	$0	$10,693	$10,693		$1,325,970	0.008130
Mar-97	$0	$10,780	$10,780		$1,336,751	0.008130
Apr-97	$0	$10,314	$10,314		$1,347,065	0.007716
May-97	$0	$10,394	$10,394		$1,357,459	0.007716
Jun-97	$0	$10,474	$10,474		$1,367,933	0.007716
Jul-97	$0	$10,555	$10,555		$1,378,488	0.007716
Aug-97	$0	$10,636	$10,636		$1,389,124	0.007716
Sep-97	$0	$10,718	$10,718		$1,399,843	0.007716
Oct-97	$0	$10,801	$10,801		$1,410,644	0.007716
Nov-97	$0	$10,885	$10,885		$1,421,529	0.007716
Dec-97	$0	$10,969	$10,969		$1,432,497	0.007716
Jan-98	$0	$10,959	$10,959		$1,443,456	0.007650
Feb-98	$0	$11,042	$11,042		$1,454,498	0.007650
Mar-98	$0	$11,127	$11,127		$1,465,625	0.007650
Apr-98	$0	$11,212	$11,212		$1,476,837	0.007650
May-98	$0	$11,298	$11,298		$1,488,135	0.007650
Jun-98	$0	$11,384	$11,384		$1,499,519	0.007650
Jul-98	$0	$11,471	$11,471		$1,510,990	0.007650
Aug-98	$0	$11,559	$11,559		$1,522,549	0.007650
Sep-98	$0	$11,648	$11,648		$1,534,197	0.007650
Oct-98	$0	$11,737	$11,737		$1,545,934	0.007650
Nov-98	$0	$11,826	$11,826		$1,557,760	0.007650
Dec-98	$0	$0	$0		$1,557,760	0.007650
Jan-99	$0	$0	$0		$1,557,760	0.007700
Feb-99	$0	$0	$0		$1,557,760	0.007700
Mar-99	$0	$0	$0		$1,557,760	0.007700
Apr-99	$0	$0	$0		$1,557,760	0.007700
May-99	$0	$0	$0		$1,557,760	0.007700
Jun-99	$0	$0	$0		$1,557,760	0.007700
Jul-99	$0	$0	$0		$1,557,760	0.007700
Aug-99	$0	$0	$0		$1,557,760	0.007700
Sep-99	$0	$0	$0		$1,557,760	0.007700
Oct-99	$0	$0	$0		$1,557,760	0.007700
Nov-99	$0	$0	$0		$1,557,760	0.007700
Dec-99	$0	$0	$0		$1,557,760	0.007700
Jan-00	$0	$0	$0		$1,557,760	0.007639
Feb-00	$0	$0	$0		$1,557,760	0.007639
Mar-00	$0	$0	$0		$1,557,760	0.007639
Apr-00	$0	$0	$0		$1,557,760	0.007639
May-00	$0	$0	$0		$1,557,760	0.007639
Jun-00	$0	$0	$0		$1,557,760	0.007639
Jul-00	$0	$0	$0		$1,557,760	0.007639
Aug-00	$0	$0	$0		$1,557,760	0.007639
Sep-00	$0	$0	$0		$1,557,760	0.007639

Keahole CT-4 & CT-5

Month	Cap Ex Excl. AFUDC	AFUDC	Total Incl. AFUDC	Closed To Plant	Cummulative Balance	AFUDC Rate
Oct-00	$0	$0	$0		$1,557,760	0.007639
Nov-00	$0	$0	$0		$1,557,760	0.007639
Dec-00	$0	$0	$0		$1,557,760	0.007639
Jan-01	$0	$0	$0		$1,557,760	0.007676
Feb-01	$0	$0	$0		$1,557,760	0.007676
Mar-01	$0	$0	$0		$1,557,760	0.007676
Apr-01	$0	$0	$0		$1,557,760	0.007676
May-01	$0	$0	$0		$1,557,760	0.007676
Jun-01	$0	$0	$0		$1,557,760	0.007676
Jul-01	$0	$0	$0		$1,557,760	0.007676
Aug-01	$0	$0	$0		$1,557,760	0.007676
Sep-01	$0	$0	$0		$1,557,760	0.007676
Oct-01	$0	$0	$0		$1,557,760	0.007676
Nov-01	$0	$0	$0		$1,557,760	0.007676
Dec-01	$0	$0	$0		$1,557,760	0.007676
Jan-02	$0	$0	$0		$1,557,760	0.007583
Feb-02	$0	$0	$0		$1,557,760	0.007583
Mar-02	$0	$0	$0		$1,557,760	0.007583
Apr-02	$0	$0	$0		$1,557,760	0.007583
May-02	$0	$0	$0		$1,557,760	0.007583
Jun-02	$0	$0	$0		$1,557,760	0.007583
Jul-02	$0	$0	$0		$1,557,760	0.007583
Aug-02	$0	$0	$0		$1,557,760	0.007583
Sep-02	$0	$0	$0		$1,557,760	0.007583
Oct-02	$0	$0	$0		$1,557,760	0.007583
Nov-02	$0	$0	$0		$1,557,760	0.007583
Dec-02	$0	$0	$0		$1,557,760	0.007583
Jan-03	$0	$0	$0		$1,557,760	0.007619
Feb-03	$0	$0	$0		$1,557,760	0.007619
Mar-03	$0	$0	$0		$1,557,760	0.007619
Apr-03	$0	$0	$0		$1,557,760	0.007619
May-03	$0	$0	$0		$1,557,760	0.007619
Jun-03	$0	$0	$0		$1,557,760	0.007619
Jul-03	$0	$0	$0		$1,557,760	0.007619
Aug-03	$0	$0	$0		$1,557,760	0.007619
Sep-03	$0	$0	$0		$1,557,760	0.007619
Oct-03	$0	$0	$0		$1,557,760	0.007619
Nov-03	$0	$0	$0		$1,557,760	0.007619
Dec-03	$0	$0	$0		$1,557,760	0.007619
Jan-04	$0	$0	$0		$1,557,760	0.007337
Feb-04	$0	$0	$0		$1,557,760	0.007337
Mar-04	$0	$0	$0		$1,557,760	0.007337
Apr-04	$0	$0	$0		$1,557,760	0.007337
May-04	$0	$0	$0		$1,557,760	0.007337
Jun-04	$0	$0	$0		$1,557,760	0.007337
Jul-04	$0	$0	$0		$1,557,760	0.007337
Aug-04	$0	$0	$0		$1,557,760	0.007337
Sep-04	$0	$0	$0		$1,557,760	0.007337
Oct-04	$0	$0	$0		$1,557,760	0.007337
Nov-04	$0	$0	$0		$1,557,760	0.007337
Dec-04	$0	$0	$0	(1,557,760)	$0	0.007337
Total	**$0**	**$1,557,760**	**$1,557,760**	**($1,557,760)**	**$0**	

Hawaii Electric Light Company, Inc.
Keahole CT-4 & 5 - Analysis of AFUDC
December 1998 - December 2004

Month	CWIP Balance	Closed To Plant	Adjusted CWIP Balance	AFUDC Base	Monthly AFUDC Rate	AFUDC
Nov-98	74,042,854		74,042,854	74,042,854	0.7650%	
Dec-98	74,601,954	(972,599)	73,629,355	73,629,355	0.7650%	566,428
Jan-99	74,962,744	(972,599)	73,990,145	74,556,573	0.7700%	566,946
Feb-99	75,323,534	(972,599)	74,350,935	75,484,309	0.7700%	574,086
Mar-99	75,684,324	(972,599)	74,711,725	76,419,184	0.7700%	581,229
Apr-99	76,045,114	(972,599)	75,072,515	77,361,204	0.7700%	588,428
May-99	76,405,904	(972,599)	75,433,305	78,310,421	0.7700%	595,681
Jun-99	76,766,694	(972,599)	75,794,095	79,266,893	0.7700%	602,990
Jul-99	77,127,484	(972,599)	76,154,885	80,230,673	0.7700%	610,355
Aug-99	77,488,274	(972,599)	76,515,675	81,201,818	0.7700%	617,776
Sep-99	77,849,060	(1,718,147)	76,130,913	80,853,603	0.7700%	625,254
Oct-99	78,118,981	(1,718,147)	76,400,834	81,755,922	0.7700%	622,573
Nov-99	78,388,901	(1,718,147)	76,670,754	83,222,500	0.7700%	629,521
Dec-99	79,790,841	(7,570,152)	72,220,689	79,401,955	0.7700%	640,813
Jan-00	79,939,492	(7,570,152)	72,369,340	80,191,420	0.7639%	606,552
Feb-00	80,088,143	(7,570,152)	72,517,991	80,946,622	0.7639%	612,582
Mar-00	80,236,794	(7,570,152)	72,666,642	81,707,856	0.7639%	618,351
Apr-00	80,385,445	(7,570,152)	72,815,293	82,474,858	0.7639%	624,166
May-00	80,508,693	(7,570,152)	72,938,541	83,222,272	0.7639%	630,025
Jun-00	80,631,941	(7,570,152)	73,061,789	83,975,546	0.7639%	635,735
Jul-00	80,755,189	(7,570,152)	73,185,037	84,734,528	0.7639%	641,489
Aug-00	80,878,437	(7,570,152)	73,308,285	85,499,266	0.7639%	647,287
Sep-00	81,001,685	(7,570,152)	73,431,533	86,269,801	0.7639%	653,129
Oct-00	81,124,935	(7,570,152)	73,554,783	87,046,180	0.7639%	659,015
Nov-00	81,142,578	(7,570,152)	73,572,426	87,722,838	0.7639%	664,946
Dec-00	81,145,065	(7,570,152)	73,574,913	88,390,270	0.7639%	670,115
Jan-01	81,197,297	(7,570,152)	73,627,145	89,112,617	0.7676%	678,484
Feb-01	81,249,529	(7,570,152)	73,679,377	89,843,333	0.7676%	684,028
Mar-01	81,252,322	(7,570,152)	73,682,170	90,530,154	0.7676%	689,637
Apr-01	81,516,100	(7,570,152)	73,945,948	91,483,570	0.7676%	694,909
May-01	81,539,315	(7,570,152)	73,969,163	92,201,694	0.7676%	702,228
Jun-01	81,562,530	(7,570,152)	73,992,378	92,927,137	0.7676%	707,740
Jul-01	81,585,745	(7,570,152)	74,015,593	93,658,092	0.7676%	713,309
Aug-01	81,608,960	(7,570,152)	74,038,808	94,394,616	0.7676%	718,920
Sep-01	81,632,176	(7,570,152)	74,062,024	95,136,751	0.7676%	724,573
Oct-01	81,851,602	(7,570,152)	74,281,450	96,080,751	0.7676%	730,270
Nov-01	82,071,027	(7,570,152)	74,500,875	97,030,445	0.7676%	737,516
Dec-01	82,281,951	(7,570,152)	74,711,799	97,978,885	0.7676%	744,806

Hawaii Electric Light Company, Inc.
Keahole CT-4 & 5 - Analysis of AFUDC
December 1998 - December 2004

Month	CWIP Balance	Closed To Plant	Adjusted CWIP Balance	AFUDC Base	Monthly AFUDC Rate	AFUDC
Jan-02	82,912,809	(7,570,152)	75,342,657	99,354,549	0.7583%	742,974
Feb-02	83,543,667	(7,570,152)	75,973,515	100,728,381	0.7583%	753,406
Mar-02	84,174,525	(7,570,152)	76,604,373	102,112,644	0.7583%	763,823
Apr-02	84,805,383	(7,570,152)	77,235,231	103,507,326	0.7583%	774,320
May-02	85,436,241	(7,570,152)	77,866,089	104,912,504	0.7583%	784,896
Jun-02	86,067,099	(7,570,152)	78,496,947	106,328,258	0.7583%	795,552
Jul-02	86,697,957	(7,570,152)	79,127,805	107,754,667	0.7583%	806,287
Aug-02	87,328,815	(7,570,152)	79,758,663	109,191,812	0.7583%	817,104
Sep-02	87,959,673	(7,570,152)	80,389,521	110,639,774	0.7583%	828,002
Oct-02	88,590,531	(7,570,152)	81,020,379	112,098,634	0.7583%	838,981
Nov-02	89,221,389	(7,570,152)	81,651,237	113,568,473	0.7583%	850,044
Dec-02	89,852,244	(7,570,152)	82,282,092	115,049,372	0.7583%	861,190
Jan-03	90,423,367	(7,570,152)	82,853,215	116,481,685	0.7619%	876,561
Feb-03	90,486,170	(7,570,152)	82,916,018	117,421,049	0.7619%	887,474
Mar-03	90,606,254	(7,570,152)	83,036,102	118,428,607	0.7619%	894,631
Apr-03	90,854,281	(7,570,152)	83,284,129	119,571,265	0.7619%	902,308
May-03	90,929,374	(7,570,152)	83,359,222	120,548,665	0.7619%	911,013
Jun-03	91,036,970	(7,570,152)	83,466,818	121,567,275	0.7619%	918,460
Jul-03	91,139,634	(7,570,152)	83,569,482	122,588,399	0.7619%	926,221
Aug-03	91,180,030	(7,570,152)	83,609,878	123,555,016	0.7619%	934,001
Sep-03	91,270,844	(7,570,152)	83,700,692	124,579,831	0.7619%	941,366
Oct-03	91,385,093	(7,570,152)	83,814,941	125,635,446	0.7619%	949,174
Nov-03	91,576,085	(7,570,152)	84,005,933	126,775,612	0.7619%	957,216
Dec-03	91,543,643	(7,570,152)	83,973,491	127,700,386	0.7619%	965,903
Jan-04	92,025,515	(7,570,152)	84,455,363	129,148,161	0.7337%	936,938
Feb-04	92,947,600	(7,570,152)	85,377,448	131,007,184	0.7337%	947,560
Mar-04	95,466,115	(7,570,152)	87,895,963	134,473,259	0.7337%	961,200
Apr-04	96,586,415	(7,570,152)	89,016,263	136,554,759	0.7337%	986,630
May-04	99,944,854	(57,524,318)	42,420,536	90,945,662	0.7337%	1,001,902
Jun-04	100,702,810	(97,965,752)	2,737,058	52,264,086	0.7337%	667,268
Jul-04	102,790,850	(99,470,258)	3,320,592	53,514,889	0.7337%	383,462
Aug-04	104,228,823	(100,611,533)	3,617,290	54,195,048	0.7337%	392,639
Sep-04	105,988,259	(101,906,900)	4,081,359	55,051,756	0.7337%	397,629
Oct-04	106,262,307	(102,162,154)	4,100,153	55,468,179	0.7337%	403,915
Nov-04	106,667,172	(102,348,876)	4,318,296	56,090,237	0.7337%	406,970
Dec-04	110,801,039	(110,801,039)	0	52,178,911	0.7337%	411,534
						52,590,445

REBUTTAL TESTIMONY OF
PATSY H. NANBU

CONTROLLER
HAWAIIAN ELECTRIC COMPANY, INC.

ASSISTANT TREASURER
HAWAII ELECTRIC LIGHT COMPANY, INC.

Subject: Accounting Policy - Allowance for Funds Used During Construction

INTRODUCTION

Q. Please state your name and business address.

A. My name is Patsy H. Nanbu and my business address is 900 Richards Street, Honolulu, Hawaii, 96813.

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

A. I am employed by the Hawaiian Electric Company, Inc. ("HECO") as its Controller. I also serve as one of the Assistant Treasurers for Hawaii Electric Light Company, Inc. ("HELCO"). My educational background and experience are shown in HELCO-R-9A00.

Q. Have you previously submitted testimony in this proceeding?

A. No, I have not.

Q. What is the scope of your rebuttal testimony?

A. In my testimony, I (1) describe HELCO's accounting policy and practices regarding the application of Allowance for Funds Used During Construction ("AFUDC") and (2) address the application of HELCO's AFUDC policy for CT-4 and CT-5 (which is sometimes referred to as the Keahole project, and includes the AFUDC for pre-PSD facilities already included in rate base as a result of Decision and Order No. 18365 issued February 8, 2001 in Docket No. 99-0207, HELCO's 2000 test year rate case). Mr. Michael Adams, Managing Director in the Energy Practice of Navigant Consulting, Inc., will discuss the reasonableness of the Company's policies and procedures with respect to accruing AFUDC on CT-4 and CT-5, discuss the Consumer Advocate's proposed AFUDC disallowance for CT-4 and CT-5, and provide possible alternatives to the AFUDC amounts for CT-4 and CT-5.

HELCO AFUDC POLICY

Q. What is AFUDC?

A. In simple terms, AFUDC represents the cost of investor supplied funds used by a utility to pay for capital project costs during the period the capital project costs are incurred. A more rigorous definition is as follows:

> An amount recorded by a company to represent the cost of those funds used to finance Construction Work in Progress (CWIP – defined herein).
>
> These amounts:
>
> (1) are credited on the income statement during the construction period most commonly as an allowance for borrowed funds used during construction, which reduces the net interest charges, and as an allowance for (i.e., equity) funds used during construction, which adds to other income, and
>
> (2) are capitalized during the construction period along with other construction costs, to be recovered over the life of the plant through depreciation, so that the company is made whole ....

See 1991 Glossary of Electric Utility Terms, Edison Electric Institute, page 2.

Q. When does HELCO start AFUDC?

A. The application of AFUDC is started when expenditures for a project begin on a "planned progressive basis", (i.e. without delay, except for the delays that are inherent in the asset acquisition process such as the ordering, purchasing and delivering of long lead time material, and delays due to permitting and external approval processes). The application of AFUDC generally begins after a project is formally approved by HELCO's management, and engineering charges recorded against the project are classified as construction work in progress ("CWIP").

Q. How is AFUDC applied?

A. AFUDC is added to the cost of a project each month in an amount equal to the AFUDC rate (percentage) times the total project cost amount included in CWIP.

Q. When does HELCO stop applying AFUDC to a capital project?

A. After the initial application, AFUDC is applied every month until the project is completed (i.e., the facility is used or useful), or until the project is delayed at management's discretion, or is abandoned.[1] When a project is completed, its costs are transferred from CWIP to one or more appropriate utility plant accounts. If a project is abandoned, the application of AFUDC is stopped at the point where the determination is made to abandon the project, if the application had not been previously stopped. In the case of a project delayed at management's discretion, AFUDC is stopped at the point of delay, and is resumed when the project is re-activated. The application of AFUDC is continued if a project delay is caused by external factors. If the project delay is caused by external factors and events beyond management's control, continuing to calculate and capitalize AFUDC is appropriate. In this situation, the Company is actively pursuing construction of the project, and is doing its best to proceed with, and complete, the project on a planned progressive basis. As such, the related financing costs should be treated as asset acquisition costs.

Q. Why is it appropriate to continue applying AFUDC during periods of delay caused by external factors?

A. Investors expect a reasonable rate of return on their funds used for HELCO's capital construction program. The return is provided through the rate of return on rate base for completed projects, and through the addition of AFUDC to the cost

[1] A long standing distinction between the accounting treatment of projects "canceled" before the commencement of construction and projects abandoned after the commencement of construction was eliminated pursuant to a Stipulation in HELCO's 2000 test year rate case.

of projects currently being constructed. If the Company is not allowed to apply AFUDC during periods of project delays caused by external factors, and the investment is not allowed in the rate base as CWIP, then there is no way, currently, for investors to earn a return on their investment. This would not be fair to investors in the case where the project delays are caused by external factors which are beyond the Company's control.

Q. Are there any projects that do not accumulate AFUDC?

A. Yes. AFUDC is not applied to (1) projects established to purchase land or land rights, and (2) projects established for "turn-key" purchases such as transformers, automobiles, furniture, equipment, and other items that do not require construction before being placed into service (i.e., the items become used or useful immediately or almost immediately). In addition, HELCO does not accrue AFUDC on projects that are funded by customer contributions.

Q. What types of costs qualify for the application of AFUDC?

A. The National Association of Regulatory Utility Commissioners ("NARUC") Uniform System of Accounts ("USOA") for Electric and Gas Utilities describes AFUDC as the net cost for the period of funds used for construction purposes. NARUC Uniform System of Accounts Utility Plant Instruction No. 3, Components of Construction Cost lists the types of costs includable in the cost of capital projects (see HELCO-9A01 for a copy of Utility Plant Instruction No. 3). As shown under Components of Construction Cost, the costs of construction includes contract work, labor, materials and supplies, transportation, special machine service, shop service, cost of protecting the utility's property in connection with construction work, expenditures and damages in connection with construction work, permits and rights in connection with construction work, rents,

engineering and supervision, general and administrative work, engineering services, insurance, legal expenses, taxes and AFUDC. The components of construction costs clearly indicate that the costs are not simply costs during installation of a capital project, but include costs for planning, designing and permitting the construction work. Specifically, NARUC describes the item "engineering and supervision" as including "the portion of the pay and expenses of engineers, surveyors, draftsmen, inspectors, superintendents and their assistants applicable to construction work". As noted, "Engineering Services" include the amounts paid to other companies, firms or individuals engaged by the utility to plan, design, prepare estimates, supervise, inspect, or give general advice and assistance in connection with construction work. Further, "Privileges and permits" include expenses incurred in securing temporary privileges, permits or rights in connections with construction work, such as for the use of private or public property.

Q. Are there any other standards that may provide guidance for the costs that qualify for AFUDC?

A. Yes. Statement of Financial Accounting Standards ("SFAS") No. 34, Capitalization of Interest Cost, provides some guidance, as the capitalization of interest costs incurred for the acquisition of an asset is very similar to the capitalization of AFUDC (interest costs are paid to a third party for borrowed funds directly related to a project, while AFUDC also recognizes the use of investor equity funds used during construction). SFAS No. 34 indicates that the cost of activities qualifying for interest capitalization should be construed broadly. "It encompasses more than physical construction, it includes all the steps required to prepare the asset for its intended use. For example, it includes administrative

and technical activities during the pre-construction stage, such as development of plans or the process of obtaining permits from governmental authorities; it includes activities undertaken after construction has begun in order to overcome unforeseen obstacles, such as technical problems, labor disputes, or litigation." (Paragraph 17 of SFAS No. 34.)

Q. How does HELCO calculate its AFUDC rate?

A. The AFUDC rate is calculated in a manner that is generally consistent with the way the Company's cost of capital is calculated in rate decisions. A more detailed discussion with respect to HELCO's AFUDC rate is provided in HELCO-R-9A02.

Q. Did the Consumer Advocate take issue with HELCO's conceptual framework surrounding the application of AFUDC?

A. The Consumer Advocate, in its proposed calculation of AFUDC for the project, utilized HELCO's AFUDC rates and, thus, did not appear to have an issue with the determination of the AFUDC rate or how AFUDC is calculated. On page 32 of CA-T-3, Mr. Carver states, "I do not take issue with the conceptual framework as to when the capitalization of AFUDC should commence, be suspended or terminated, but rather with how that framework was applied to these specific projects." However, despite this statement, Mr. Carver did take issue with when the capitalization of AFUDC should commence, as I discuss later in my testimony.

Q. What was the Consumer Advocate's proposal regarding AFUDC for CT-4 and CT-5?

A. Prior to the settlement with HELCO with respect to the Keahole adjustment (or writedown) discussed by Mr. Warren Lee in HELCO RT-1, the Consumer

Advocate proposed to exclude $14,407,227 of the $21,661,087 total AFUDC HELCO has accrued for the entire Keahole project, including AFUDC for pre-PSD facilities, which is already included in rate base. (The amount of AFUDC that had been allocated to the pre-PSD facilities amounts to $1,497,928 as discussed by Mr. Fujioka, in HELCO RT-9.) Thus, the Consumer Advocate proposes to include only $7,253,860, or about one-third, of the amount of AFUDC HELCO accrued for the project.

Q. What was the Consumer Advocate's issue with respect to the amount of AFUDC recorded for CT-4 and CT-5?

A. Based on the Consumer Advocate's proposed AFUDC adjustment to HELCO's cost for CT-4 and CT-5 (the project) [2], it appears that the Consumer Advocate proposed to reduce AFUDC for the project by (1) delaying the start of AFUDC accrual until January 1, 1994, when the Commission issued its decision and order approving the commitment of funds for CT-4, instead of starting AFUDC when capital expenditures actually commenced for CT-4 in June 1991 and in July 1993 for CT-5, and (2) stopping the accrual during periods of significant project delays, which the Consumer Advocate identifies as between October 1994 through July 1997. With respect to the "periods of significant delays," Mr. Carver maintained HELCO knew or should have known of alleged significant challenges relating to siting new generation at Keahole. Based on this claim, Mr. Carver concluded that HELCO materially contributed to events leading to the protracted construction schedule, and under NARUC Interpretation No. 83, AFUDC should not be

[2] The Consumer Advocate's proposed AFUDC adjustment relates to AFUDC for the Keahole project (CT-4, CT-5 and the pre-PSD facilities already included in rate base pursuant to Decision and Order No. 18365 issued February 8, 2001 in Docket No. 99-0207, HELCO's 2000 test year rate case.) Reference to the project refers to the Keahole project.

accrued during periods of interrupted construction. Further, the proposed AFUDC adjustment did not consider AFUDC that would have been accrued during later periods of construction under the "start/stop" methodology presented by Mr. Carver.

Q. How is the Consumer Advocate's proposed AFUDC adjustment addressed in rebuttal testimony?

A. I address HELCO's application of its accounting policies and procedures for AFUDC, including HELCO's application in relation to NARUC Interpretation No. 83. Other HELCO witnesses address the challenges faced by HELCO when it made the decision to locate the new generation at Keahole (and the Commission found such decision to be reasonable) and whether or not HELCO materially contributed to events leading to the protracted construction schedule. Mr. Paul Fujioka, in HELCO RT-9, comments on the Consumer Advocate's calculation of its proposed allowable AFUDC, the Company's recorded AFUDC as of December 31, 2006, and the Company's calculation of AFUDC foregone as a result of suspending AFUDC in December 1998. Mr. Michael Adams, in HELCO-RT9B, provides an external perspective on the reasonableness of the Company's application of its policies and procedures for accruing AFUDC on CT-4 and CT-5, and addresses the Consumer Advocate's proposed AFUDC disallowance for CT-4 and CT-5.

APPLICATION OF AFUDC POLICY FOR CT-4 AND CT-5

Q. Mr. Carver cites Interpretation No. 83 of the NARUC USOA for Electric and Gas Utilities for the Consumer Advocate's proposal that HELCO should have started

AFUDC for CT-4 and CT-5 only after the Commission approved the commitment of funds for CT-4. What does Interpretation No. 83 state?

A. Interpretation No. 83 states in part as follows:

> Question:
> What is the proper period for capitalization of allowance for funds used during construction?
>
> Answer:
> Allowance for funds used during construction (AFUDC) may be capitalized starting from the date that construction costs are continuously incurred on a planned progressive basis. Interest should not be accrued for the period prior to (1) the date of issuance of the preliminary permit by the Commission of a licensed hydroelectric project; and (2) the date of the application to the Commission for a certificate to construct facilities by a natural gas company. AFUDC may be allowed by the Commission for the period prior to the above dates if so justified by the company. No AFUDC interest should be accrued during period of interrupted construction unless the company can justify the interruption as being reasonable under the circumstances...

The Federal Energy Regulatory Commission's ("FERC") Accounting Release AR-5 (Revised) effective January 1, 1968, is very similar to Interpretation No. 83 provided by NARUC.

Q. What is HELCO's response to Mr. Carver's proposal to begin AFUDC only after the Commission approved the commitment of funds for the project?

A. AFUDC should begin when expenditures commence on a project, in accordance with the long-standing practice in Hawaii. Interpretation No. 83 does not require that the application of AFUDC on CT-4 and CT-5 start only after receiving a Commission decision and order approving the project. Indeed, the interpretation states that AFUDC "may be capitalized starting from the date that construction costs are continuously incurred on a planned progressive basis".

Mr. Carver's basis for starting AFUDC when the Commission approved the

commitment of funds for the project seems to rely on the portion of the interpretation that is specifically addressing a hydroelectric plant (the date of issuance of the preliminary permit by the Commission of a licensed hydroelectric plant) or natural gas company (the date of the application to the Commission for a certificate to construct facilities by a natural gas company). The Keahole project is not a licensed hydroelectric plant nor is HELCO a natural gas company. Thus, those specific items should not apply, and the application of AFUDC should start when construction costs are continuously incurred on a planned progressive basis.

Q. In its proposed AFUDC adjustment, when did the Consumer Advocate propose that AFUDC commence?

A. The Consumer Advocate's AFUDC adjustment calculation reflected commencing AFUDC in January 1994. HELCO, however, began incurring project costs for CT-4 in June 1991 and in July 1993 for CT-5.

Q. What is the impact of the proposal to accrue AFUDC only from January 1994?

A. The effect of starting AFUDC in January 1994 instead of June 1991 for CT-4 and July 1993 for CT-5 when costs were initially incurred for the project amounts to approximately $1 million, and because such AFUDC would accrue AFUDC over time, it represents $1.2 million of the Consumer Advocate's proposed disallowance under its proposed calculation. Note that the amount of AFUDC related to the period from June 1991 through January 1994 is even greater based on HELCO's calculation of AFUDC for the project, since the Consumer Advocate's proposed calculation also stopped accruing AFUDC between October 1994 and July 1997.

Q. How have project costs incurred prior to Commission approval for the commitment of funds been treated for other projects?

A. Project costs (including AFUDC) incurred prior to Commission approval for the commitment of funds have been included as part of a project's costs for other projects. For example, HELCO accrued AFUDC beginning when costs were incurred on a planned progressive basis for HELCO's Puna CT-3 combustion turbine, prior to the approval by the Commission to commit funds for the project. (See Docket No. 6643.) Mr. Warren Lee in HELCO RT-1 discusses the benefits of proceeding with HELCO's CT-3 project before obtaining Commission approval for the commitment of funds for the project.

Q. Do you have any further comments regarding the Commission's process for the approval to commit funds?

A. Yes. HELCO sought approval for the commitment of funds for the CT-4 and CT-5 (and ST-7) projects pursuant to General Order No. 7. In relevant part, paragraph 2.3.g.2 of General Order No. 7 ("G.O.7") ("Rule 2.3.g.2.") provides that:

> Proposed capital expenditures for any single project related to plant replacement, expansion or modernization, in excess of $500,000 . . . shall be submitted to the Commission for review at least 60 days prior to the commencement of construction or commitment for expenditure, whichever is earlier. If the Commission determines, after hearing on the matter, that any *portion of the proposed project provides facilities which are* unnecessary or are unreasonably in excess of probable future requirements for utility purposes, then the utility shall not include such portion of the project in its rate base. If the utility subsequently convinces the Commission that the property in question has become necessary or useful for public utility purposes, it may then be included in the rate base. Failure of the Commission to act upon the matter and render a decision and order within 90 days of filing by the utility shall allow the utility to include the project in its rate base without the determination by the Commission required by this rule.

Note that Rule 2.3.g.2 was modified to increase the threshold for capital expenditures to those in excess of $2,500,000, excluding customer contributions, in Decision and Order No. 21002 filed May 27, 2004, in Docket No. 03-0257.

Q. What is the purpose of Rule 2.3.g.2.?

A. The intent of Rule 2.3.g.2. is to allow for up front regulatory review of the need for major capital expenditures, and to avoid the need for extensive regulatory review of capital additions in rate cases.[3] In general, the intent is not to unduly restrict the timing of expenditures on capital projects, or even determine whether the utility may proceed with a project.

Q. What is the effect of a negative determination within the 90-day period?

A. A negative determination within the 90-day period provided by Rule 2.3.g.2 for Commission review of capital expenditure projects (which the Commission sometimes suspends to allow more time to review projects) does not prohibit the utility from proceeding, although it would do so at its own risk. As the Commission stated in D&O 11005, "a negative determination may later be reversed upon a showing by the utility that the property has become necessary or useful for public utility purposes." (D&O 11005, page 8 and footnote 1.)

HELCO understands that Commission approval of a project does not guarantee inclusion of all project costs in its rate base in determining rates in its next ratemaking proceeding. Capital expenditures that are shown by reliable, probative and substantial evidence to have been imprudently incurred may be disallowed in a subsequent rate case.

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[3] The Commission has stated that "the basic purpose of rule 2.3(g)(2) is to determine, in other than a rate case proceeding, whether the cost of a proposed project may be included in a utility's rate base." [See Docket No. 6571 (regarding MECO's Waikapu Relocation Project); Decision and Order No. 11005 (March 14, 1991) ("D&O 11005"), page 7.]

Q. What impact does the Rule 2.3.g.2 have on a project's cost?

A. Rule 2.3.g.2 requires that proposed capital expenditures projects be submitted to the Commission for review at least 60 days prior to a "commitment for expenditure". At the same time, the Commission has recognized that some amounts will be expended for preliminary assessment, preliminary design and preparation of the Commission application (i.e., for "preliminary engineering") before an application for a capital expenditures project is filed. The amount of design and engineering work done for a project during the preliminary engineering phase of a project will vary widely from project to project based on considerations such as the permitting requirements[4] and the amount of detail required for the PUC Application.[5]

Q. Are such costs necessary for the construction of a project?

A. Yes. Utilities need to plan and incur costs for potential projects, particularly major generation and transmission projects, many years before the need dates for the projects (which dates may change during the course of the projects). This is necessitated by the long lead times required for such things as land use approvals,

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[4] As has been detailed in the Competitive Bidding docket, Docket No. 03-0372, the time required to obtain project permits and/or land use approvals in Hawaii is extensive, and these permits and approvals are often the "critical path" items for major projects. Work on these "preliminary" activities must be commenced many years in advance of a project's need date, and may be done in parallel with or in advance of the PUC application under G.O. 7. These activities can involve the expenditures of considerable amounts of dollars, particularly if challenges are mounted to the permit or land use approvals.

[5] The more work that is put into preliminary engineering and design work, the more informative and "accurate" the utility's application can be. Transmission and pipeline projects may be impacted by the need for routing studies; which are often done in conjunction with environmental impact statements, and/or statutorily required analyses, such as those required under Act 95 (1997). In order to do these studies and/or analyses, the preliminary design and engineering work for these types of projects may be extensive, and may be done at a more detailed level than for some other capital projects.

siting, routing and environmental studies (which may involve time-consuming public input processes), the acquisition of land and land rights, regulatory approvals, the ordering of long lead time materials (which have to be manufactured and shipped to be available when construction starts), and the construction of the projects. Thus, substantial costs may be incurred by necessity a number of years before the need or completion dates for the projects (which may themselves change). These costs are necessary for a project to proceed on a planned progressive basis.

A fundamental regulatory principle is that prudently incurred costs in the provision of electric service should be recoverable from ratepayers. In the case of capital projects, the incurred costs generally include (1) the costs of planning, designing and permitting the project, (2) the costs of material and equipment incorporated in the project, (3) the costs of constructing and testing the project, and (4) AFUDC.

Q. Are you aware of other support regarding the appropriateness of project costs incurred prior to the approval by the Commission for the commitment of funds?

A. According to USOA Utility Plant Instruction No. 3 Components of Construction Cost (provided in HELCO-R-9A01), "construction costs" include engineering and supervision costs as well as costs related to engineering services paid to others to "plan, design, prepare estimates, supervise, inspect, or give general advice and assistance in connection with construction work." HELCO follows this instruction, as the application of AFUDC does not start until expenditures for a project begin on a "planned progressive basis" – from the point where expenditures (including planning and permitting costs) related to a project begin and are expected to continue without delay, except for the delays that are inherent

in the asset acquisition process such as the ordering, purchasing and delivering of long lead time material, and delays due to permitting and external approval processes.

Q. Getting back to Interpretation No. 83, with respect to periods of interrupted construction, please comment on HELCO's application of the interpretation.

A. HELCO is also in line with Interpretation No. 83 with respect to delays in construction. Interpretation No. 83 allows AFUDC to continue to accrue during periods of interrupted construction provided that the interruption is reasonable under the circumstances. A general guideline in this area has been to consider delays which are beyond the control of management to be reasonable.

Q. Do you have any support for the general guideline?

A. Yes. HELCO has relied on a document titled "Federal Power Commission Staff Audit Guidelines for Determining Accounting for Allowance for Funds Used During Construction", which is provided in HELCO-R-9A03. In the document, it indicates that delays beyond the control of management are considered to be reasonable.

Q. Are there any other standards that may provide guidance to the application of AFUDC?

A. Yes. SFAS No. 34 states that "...interest is not to be capitalized during periods when the enterprise intentionally defers or suspends activities related to the asset. Interest cost incurred during such periods is a holding cost, not an acquisition cost. However, delays that are inherent in the asset acquisition process and interruptions in activities that are imposed by external forces are unavoidable in acquiring the asset and as such do not call for a cessation of interest capitalization." (SFAS No. 34, paragraph 58.)

Q. Did the delays encountered with respect to CT-4 and CT-5 warrant the cessation of AFUDC?

A. No. The CT-4 and CT-5 projects were subject to delays caused by external factors, which were beyond the control of HELCO, including the process of obtaining permits from governmental authorities, and stoppage due to litigation. Under HELCO's policy, which is consistent with NARUC Interpretation No. 83, the Federal Power Commission[6] Staff Audit Guidelines, and related information in SFAS No. 34, AFUDC was applied to the project, and continued to be applied during the project delays caused by external factors. Under HELCO's policy, under unusual circumstances, if a project is suspended for more than two years, the Accounting Manager and HECO's Controller would be advised. For the Keahole project, as a result of the Environmental Appeals Board ("EAB") decision (see discussion of the EAB decision by Mr. Scott Seu, in HELCO RT-15A) on November 25, 1998, HELCO realized there would be further, substantial delays in HELCO's construction of CT-4 and CT-5. At that point, while HELCO management had acted prudently with respect to the Keahole project, a decision was made to stop the accrual of AFUDC effective December 1, 1998. The length of delays to date at that time and uncertainty over potential future delays to meet EAB's remand requirements, including another round of public comments, were factors considered in the decision to stop the AFUDC accrual. Note that when the air permit was received, HELCO did not re-activate AFUDC on the project.

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[6] The former Federal Power Commission is now the Federal Energy Regulatory Commission.

Q. The Consumer Advocate stated that it "...disagree(s) with HELCO's implication that construction on Keahole CT-4 and CT-5 'continued without significant interruption'." (See CA-T-3, page 81, lines 16 and 18.) Does HELCO contend that there were no significant interruptions?

A. No. HELCO acknowledges that there have been significant interruptions in the construction schedule for CT-4 and CT-5. Nevertheless, continuing to apply AFUDC during those periods of significant interruptions is reasonable for three reasons:

1) Because the project delays were caused by external factors, the status of the construction effort is within the meaning of "planned progressive basis".

2) Continuing to accrue AFUDC during periods of project delays due to external factors is in line with NARUC Interpretation No. 83, Federal Power Commission guidelines with respect to the application of AFUDC and SFAS No. 34.

3) AFUDC needs to be accrued in order to accurately reflect the cost of investor supplied funds used in the project.

Q. Why was the "planned progressive basis" status maintained for the construction of CT-4 and CT-5 even during periods of significant project delays?

A. The Company's definition of "planned progressive basis" includes periods of project delays caused by external factors. As previously defined, "planned progressive basis" means proceeding without delay, except for the delays that are inherent in the asset acquisition process such as the ordering, purchasing and delivering of long lead time material, and delays due to permitting and external approval processes.

Q. Why did the Consumer Advocate take the position that accrual of AFUDC should have been suspended in September 1994?

A. Mr. Carver maintained that: "[S]ignificant facts were known in the September 1994 time frame that consistently signaled further delays in the permitting and construction schedule. At that time, HELCO knew or should have known that limited physical construction would be allowed for a potentially protracted period, which should have reasonably resulted in a decision to suspend AFUDC capitalization until the necessary permits were received allowing construction activities to proceed on a reasonably planned and progressive schedule of activities." (CA-T-3, pages 73-74.)

Q. Should HELCO have suspended the accrual of AFUDC in September 1994?

A. No. First, under HELCO's policy regarding AFUDC, if a project delay is caused by external factors and events beyond management's control, continuing to calculate AFUDC is appropriate. Under HELCO's policy if a project is suspended for more than two years, the Controller should be advised and a decision on whether or not stop the application of AFUDC would be made on a case by case basis. Second, given this policy, the facts and circumstances did not warrant suspending the accrual of AFUDC.

Q. What factual circumstances are cited by Mr. Carver?

A. The facts at the time that Mr. Carver cites are: (1) DOH's conclusion that a second public hearing was required on HELCO's air permit, because "HELCO submitted a request to modify the air permit for the Keahole CT-2 unit, using more current meteorological data than was presented in the application for the planned generation additions;" and (2) project opponents were challenging HELCO's "'default entitlement,' with the Third Circuit Court granting a stay on

HELCO's ability to proceed with construction." Mr. Carver then notes that the Circuit Court remanded HELCO's CDUA application back to DLNR for a contested case hearing in November 1994.

Q. Which witnesses address HELCO's expectations with respect to completing the air permitting and CDUA processes in this time frame?

A. Mr. Scott Seu, in HELCO RT-15A, and Mr. James Clary in HELCO RT-15B, address the air permitting process. Mr. Barry Nakamoto, in HELCO RT-15C, addresses HELCO's plans to install certain "Pre-PSD" facilities at Keahole if the CDUA process was completed before the Prevention of Significant Deterioration ("PSD") air permit was obtained. Mr. Warren Lee, in HELCO RT-1, and Mr. Ben Tsukazaki, in HELCO RT-15F, address the CDUA process.

In summary, HELCO reasonably expected to complete the CDUA process within a year, given that the Final EIS had already been accepted, and there was a limited time frame within which the Board of Land and Natural Resources was required to act on the application. Even though the process took longer than expected due to circumstances beyond HELCO's reasonable control, the Third Circuit Court ultimately ruled that HELCO had validly obtained a default entitlement as of April 1996 (although the court's amended ruling confirming that default entitlement was not issued until July 1997).

The further delays encountered in obtaining the final air permit needed to install CT-4 and CT-5 at Keahole were extraordinary, and again were beyond HELCO's reasonable control. HELCO took prudent and diligent actions to obtain the final PSD air permit, and HELCO could not have reasonably anticipated the substantial delays in the PSD air permit process.

Q. Does the Consumer Advocate acknowledge that the delays in the CT-4 and CT-5 construction schedule, at least in part, were due to external factors?

A. Mr. Carver states that "...I do not disagree that external forces contributed to project delays, ..." (see CA-T-3, page 87, lines 14-15).

Q. Besides the fact that the project delays were caused by external factors, why should AFUDC be applied during periods of project delays which are outside of management's control?

A. AFUDC is a cost actually incurred in the construction of plant facilities. Investor supplied funds have been used and invested in the Keahole project, and the investors expect and deserve a return on the funds prudently applied by HELCO. AFUDC is just as much a cost of construction as are labor and material costs. In fact, the NARUC USOA includes AFUDC in its listing of Components of Construction Costs (see NARUC USOA Utility Plant Instruction No. 3).

Q. How do you respond to the Consumer Advocate's comment that such discussion only addresses what is considered fair and reasonable from the perspective of HELCO's investors, and that there is no discussion of reasonableness or fairness from the perspective of the Company's ratepayers?

A. Mr. Jose Dizon in HELCO RT-4A discusses the need, urgency for additional generation on the Big Island, and reasons for pursing the project for the benefit of the ratepayers. In addition, the Consumer Advocate's position did not adequately consider the amount of AFUDC foregone when AFUDC was discontinued in December 1998, and the fact that AFUDC was not re-activated during later periods of actual construction.

Q. How do you respond to the claims that the amount of AFUDC recorded against CT-4 and CT-5 is excessive?

A. Although the total amount of AFUDC applied to CT-4 and CT-5 is higher than what one would expect for such a project under a normal construction schedule, the recorded AFUDC was nevertheless actually incurred, and the amount of AFUDC is reasonable given the length of project delays which were externally imposed and were beyond the control of HELCO's management. HELCO needed to proceed with the project and tried its best to obtain the necessary permits to construct the units on a timely basis. The higher than expected amount of AFUDC recorded for the project resulted from project delays as a result of external factors beyond management's control. Other witnesses address what the Company had known at the time the project was proceeding. The higher than expected amount of AFUDC did not result from a misapplication of HELCO's accounting policies and procedures with respect to AFUDC.

Q. Have there been other projects that encountered delays due to permitting?

A. Yes, there have been other projects where there were delays due to permitting, and AFUDC was accrued during the delay period.

SUMMARY

Q. Please summarize your testimony.

A. HELCO's policy of accruing AFUDC on project costs is consistent with NARUC, SFAS No. 34 and Federal Power Commission guidelines. The Consumer Advocate does not appear to have an issue with HELCO's conceptual framework surrounding the application of AFUDC. HELCO's application of AFUDC for the Keahole project is consistent with HELCO's policy.

Q. Does this conclude your testimony?

A. Yes, it does.

HAWAIIAN ELECTRIC COMPANY, INC.

PATSY H. NANBU

EDUCATIONAL BACKGROUND AND EXPERIENCE

Business Address:	Hawaiian Electric Company, Inc. 900 Richards Street Honolulu, HI 96813
Position:	Controller May 2005 to Present
Previous Positions:	Director, Regulatory Affairs Director, Internal Audit Senior Regulatory Analyst Budget Administrator Budget Analyst
Years of Service:	20 years
Education:	Bachelor of Business Administration in Accounting with Distinction, University of Hawaii, 1981 Master of Accountancy, University of Hawaii, 1983
Professional Registration:	Certified Public Accountant (not in public practice) State of Hawaii, 1984
Other Experience:	Senior Auditor, Arthur Young & Company
Previous Testimony:	Docket No. 2006-0386 – HECO 2007 Test Year Rate Case Administrative & General Expense; Accounting for Computer Software Development Costs; Abandoned Capital Project Costs; Unamortized Gain on Sale of Land; Iolani Court Plaza Lease Premium; Accounting for Pensions and Postretirement Benefits Other than Pensions; General Accounting Department Staffing Docket No. 05-0146 – Community Benefits Package Accounting and Ratemaking Treatment for Reverse Osmosis Water Pipeline Project and Environmental Monitoring Programs

UTILITY PLANT INSTRUCTIONS

B. When the consideration given for property is other than cash, the value of such consideration shall be determined on a cash basis. In the entry recording such transaction, the actual consideration shall be described with sufficient particularity to identify it. The utility shall be prepared to furnish the Commission the particulars of its determination of the cash value of the consideration if other than cash.

C. When property is purchased under a plan involving deferred payments, no charge shall be made to the utility plant accounts for interest, insurance, or other expenditures occasioned solely by such form of payment.

D. Utility plant contributed to the utility or constructed by it from contributions to it of cash or its equivalent shall be charged to the utility plant accounts at cost of construction, estimated if not known. There shall be credited to the accounts for accumulated depreciation and amortization the estimated amount of depreciation and amortization applicable to the property at the time of its contribution to the utility. The difference between the amounts included in the utility plant accounts and the accumulated depreciation and amortization shall be credited to account 271, Contributions in Aid of Construction.

3. Components of Construction Cost.

The cost of construction properly includible in the utility plant accounts shall include, where applicable, the direct and overhead costs as listed and defined hereunder.

(1) "Contract work" includes amounts paid for work performed under contract by other companies, firms, or individuals, costs incident to the award of such contracts, and the inspection of such work.

(2) "Labor" includes the pay and expenses of employees of the utility engaged on construction work, and related workmen's compensation insurance, payroll taxes and similar items of expense. It does not include the pay and expenses of employees which are distributed to construction through clearing accounts nor the pay and expenses included in other items hereunder.

(3) "Materials and supplies" includes the purchase price at the point of free delivery plus customs duties, excise taxes, the cost of inspection, loading and transportation, the related stores expenses, and the cost of fabricated materials from the utility's shop. In determining the cost of materials and supplies used for construction, proper allowance shall be made for unused materials and supplies, for materials recovered from temporary structures used in performing the work involved, and for discounts allowed and realized in the purchase of materials and supplies.

Note.--The cost of individual items of equipment of small value (for example, $50 or less) or of short life, including small portable tools and implements, shall not be charged to utility plant accounts unless the correctness of the accounting therefor is verified by current inventories. The cost shall be charged to the appropriate operating expense or clearing accounts, according to the use of such items, or, if such items are consumed directly in construction work, the cost shall be included as part of the cost of the construction.

UTILITY PLANT INSTRUCTIONS

(4) "Transportation" includes the cost of transporting employees, materials and supplies, tools, purchased equipment, and other work equipment (when not under own power) to and from points of construction. It includes amounts paid to others as well as the cost of operating the utility's own transportation equipment. (See item 5 following.)

(5) "Special machine service" includes the cost of labor (optional), materials and supplies, depreciation, and other expenses incurred in the maintenance, operation and use of special machines, such as steam shovels, pile drivers, derricks, ditchers, scrapers, material unloaders, and other labor saving machines; also expenditures for rental, maintenance and operation of machines of others. It does not include the cost of small tools and other individual items of small value or short life which are included in the cost of materials and supplies. (See item 3, above.) When a particular construction job requires the use for an extended period of time of special machines, transportation or other equipment, the net book cost thereof, less the appraised or salvage value at time of release from the job, shall be included in the cost of construction.

(6) "Shop service" includes the proportion of the expense of the utility's shop department assignable to construction work except that the cost of fabricated materials from the utility's shop shall be included in "materials and supplies."

(7) "Protection" includes the cost of protecting the utility's property from fire or other casualties and the cost of preventing damages to others, or to the property of others, including payments for discovery or extinguishment of fires, cost of apprehending and prosecuting incendiaries, witness fees in relation thereto, amounts paid to municipalities and others for fire protection, and other analogous items of expenditures in connection with construction work.

(8) "Injuries and damages" includes expenditures and losses in connection with construction work on account of injuries to persons and damages to the property of others; also the cost of investigation of and defense against actions for such injuries and damages. Insurance recovered or recoverable on account of compensation paid for injuries to persons incident to construction shall be credited to the account or accounts to which such compensation is charged. Insurance recovered or recoverable on account of property damages incident to construction shall be credited to the account or accounts charged with the cost of the damages.

(9) "Privileges and permits" includes payments for an expenses incurred in securing temporary privileges, permits or rights in connection with construction work, such as for the use of private or public property, streets, or highways, but it does not include rents, or amounts chargeable as franchises and consents for which see account 302, Franchises and Consents.

(10) "Rents" includes amounts paid for the use of construction quarters and office space occupied by construction forces and amounts properly includible in construction costs for such facilities jointly used.

(11) "Engineering and supervision" includes the portion of the pay and expenses of engineers, surveyors, draftsmen, inspectors, superintendents and their assistants applicable to construction work.

UTILITY PLANT INSTRUCTIONS

(12) "General administration capitalized" includes the portion of the pay and expenses of the general officers and administrative and general expenses applicable to construction work.

(13) "Engineering services" includes amounts paid to other companies, firms or individuals engaged by the utility to plan, design, prepare estimates, supervise, inspect, or give general advice and assistance in connection with construction work.

(14) "Insurance" includes premiums paid or amounts provided or reserved as self-insurance for the protection against loss and damages in connection with construction, by fire or other casualty, injuries to or death of persons other than employees, damages to property of others, defalcation of employees and agents, and the nonperformance of contractual obligations of others. It does not include workmen's compensation or similar insurance on employees included as "labor" in item 2, above.

(15) "Law expenditures" includes the general law expenditures incurred in connection with construction and the court and legal costs directly related thereto, other than law expenses included in protection, item 7, and in injuries and damages, item 8.

(16) "Taxes" includes taxes on physical property (including land) during the period of construction and other taxes properly includible in construction costs before the facilities become available for service.

(17) "Allowance for funds used during construction" includes the net cost for the period of construction of borrowed funds used for construction purposes and a reasonable rate on other funds when so used. No allowance for funds used during construction shall be included in these accounts upon expenditures for construction projects which have been abandoned. (See note.)

Note.--When a part only of a plant or project is placed in operation or is completed and ready for service but the construction work as a whole is incomplete, that part of the cost of the property placed in operation, or ready for service, shall be treated as "Utility Plant Service" and allowance for funds used during construction thereon as a charge to construction shall cease. Allowance for funds used during construction on that part of the cost of the plant which is incomplete may be continued as a charge to construction until such time as it is placed in operation or is ready for service, except as limited in item 17, above.

(18) "Earnings and expenses during construction." The earnings and expenses during construction shall constitute a component of construction costs.

(a) The earnings shall include revenues received or earned for power produced by generating plants during the construction period and sold or used by the utility. Where such power is sold to an independent purchaser before intermingling with power generated by other plants, the credit shall consist of the selling price of the energy. Where the power generated by a plant under construction is delivered to the utility's electric system for distribution and sale, or is delivered to an associated company, or is delivered to and used by the utility for purposes other than distribution and sale (for manufacturing or industrial use, for example), the credit shall be the

fair value of energy so delivered. The revenues shall also include rentals for lands, buildings, etc., and miscellaneous receipts not properly includible in other accounts.

(b) The expenses shall consist of the cost of operating the power plant, and other costs incident to the production and delivery of the power for which construction is credited under paragraph (a), above, including the cost of repairs and other expenses of operating and maintaining lands, buildings, and other property, and other miscellaneous and like expenses not properly includible in other accounts.

4. Overhead Construction Costs.

A. All overhead construction costs, such as engineering, supervision, general office salaries and expenses, construction engineering and supervision by others than the accounting utility, law expenses, insurance, injuries and damages, relief and pensions, taxes and interest, shall be charged to particular jobs or units on the basis of the amounts of such overheads reasonably applicable thereto, to the end that each job or unit shall bear its equitable proportion of such costs and that the entire cost of the unit, both direct and overhead, shall be deducted from the plant accounts at the time the property is retired.

B. As far as practicable, the determination of payroll charges includible in construction overheads shall be based on time card distributions thereof. Where this procedure is impractical, special studies shall be made periodically of the time of supervisory employees devoted to construction activities to the end that only such overhead costs as have a definite relation to construction shall be capitalized. The addition to direct construction costs of arbitrary percentages or amounts to cover assumed overhead costs is not permitted.

C. The records supporting the entries for overhead construction costs shall be so kept as to show the total amount of each overhead for each year, the nature and amount of each overhead expenditure charged to each construction work order and to each utility plant account, and the basis of distribution of such costs.

5. Utility Plant Purchased or Sold.

A. When utility plant constituting an operating unit or system is acquired by purchase, merger, consolidation, liquidation, or otherwise, after the effective date of this system of accounts, the cost of acquisition, including expenses incidental thereto properly includible in utility plant, shall be charged to account 102, Utility Plant Purchased or Sold.

B. The accounting for the acquisition, shall then be completed as follows:

(1) The original cost of plant, estimated if not known, shall be credited to account 102, Utility Plant Purchased or Sold, and concurrently charged to the appropriate utility plant in service accounts and to account 104, Utility Plant Leased to Others, account 105, Property Held For Future Use, and account 107, Construction Work in Progress, as appropriate.

(2) The requirements for accumulated provision for depreciation and amortization applicable to the original cost of the properties purchased, if required by the Commission to be recorded by the accounting utility, determined with due regard to operating practices of the purchaser and his plans regarding such property,

GENERAL DISCUSSION OF HELCO'S AFUDC RATE

HELCO's AFUDC rate is based on a weighted average cost of capital formula. The computation of the AFUDC rate uses an average of 13 months of estimated capitalization balances and annual simple average rates for short-term debt (STD), long-term debt (LTD), preferred stock (PFD), hybrid securities (QUIDs), and common equity (CE). Each capital component of the AFUDC rate computed is weighted according to its percentage of total capitalization. (i.e., the AFUDC rate is the sum of the simple average annual cost of short-term debt multiplied by the percentage of short-term debt to HELCO's total capitalization, plus the simple average cost of long term debt multiplied by the percentage of long-term debt to HELCO's total capitalization, plus the average cost of preferred stock multiplied by the percentage of preferred stock to HELCO's total capitalization, plus the simple average cost of hybrid securities multiplied by the percentage of hybrid securities to HELCO's total capitalization and the cost of common equity multiplied by the percentage of common equity to HELCO's total capitalization.)

HELCO's capitalization is based on a projected capital structure for the given year. The cost of debt, preferred stock and hybrid securities uses the embedded costs and any anticipated issuance of new securities and retirement of existing securities for the year. The calculation also utilizes the cost of common equity found to be fair and reasonable in the most recent rate decision. The annual rate is converted to a monthly rate, which is then adjusted downward to produce a result as if the compounding is

done quarterly. This adjusted monthly rate is applied to expenditures of qualifying projects when construction has begun on a "planned progressive basis."

The estimated AFUDC rate is reviewed quarterly during the year and adjusted if the rate using actual monthly balances differs from the estimated rate by more than 0.15%.

By letter dated February 10, 1984, HECO, HELCO and MECO informed the Commission that the Companies would calculate AFUDC following a method prescribed by FERC, modified slightly to conform to regulatory practices in Hawaii.

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Federal Power Commission Staff Audit Guidelines for Determining Accounting For Allowance For Funds Used During Construction

Audit guidelines utilized by the Division of Audits for determining the propriety of the accounting for allowance for funds used during construction can be divided into three categories:

1. The Investment Base
2. The Method of Computation
3. The Capitalization Period

1. THE INVESTMENT BASE

The investment base for calculating the allowance should be limited to amounts properly includible in Account 107, Construction work in progress, but excluding the following elements:

A. Projects which require little or no construction time, i.e., meters, transformers, transportation equipment, etc.,

B. Land and land rights acquired over an unreasonably long period prior to active construction (the reasonableness for each item to be determined on an ad hoc basis),

C. Suspended payments or contract retentions,

D. Projects which have been suspended by management for higher priority jobs,

E. Materials and supplies prior to their use in active construction projects.

Staff has taken exception to inclusion of blanket work orders in the allowance base if reasonable procedures have not been instituted to determine the construction period of these projects.

Staff has also encouraged placing dollar limitations and minimum construction periods on projects subject to the allowance for certain companies that compute the allowance manually because of the work involved in such a process.

2. METHOD OF COMPUTATION

In computing the monthly accrual for the allowance for funds used during construction the method used should give recognition to the timing of construction expenditures. This can be accomplished through the following method:

$$\left(PMB + \frac{CME}{2}\right) \times \frac{AR}{12} = AC$$

where PMB is actual prior month balance
CME is actual current month expenditures
AR is the allowance rate for the year
AC is the allowance capitalized

Procedural exceptions are not to be taken by the staff to other methods of calculating the allowance as long as these other methods produced the same amount of allowance capitalization. In all other cases, compliance exceptions should be taken so as to obtain conformity in the future with established staff methods. The question of whether adjustments should be proposed is a matter to be determined on an individual case basis, taking into account all facts and circumstances, upon consultation with the Washington office.

3. COMPUTATION PERIOD

In reviewing the computation period for the allowance, staff has used Accounting Release Number AR-5 (Revised) as its guide. As such, the staff position as to computation period has been as follows:

A. The starting date for allowance capitalization has been interpreted to mean:

1. for licensed hydroelectric projects, the date of issuance of the preliminary permit,

2. for natural gas pipeline companies, the date of certificate application to the Commission, and

3. for both public utilities and natural gas pipelines, generally the date that construction expenditures are incurred on a planned progressive basis.

In starting the allowance period, the main problem area recently noted pertained to land and land rights. Staff's present position on this matter is that an allowance cannot properly be computed on land and land rights held for a considerable period of time prior to active construction. The propriety of capitalizing an allowance on land included in Accounts 105, 107 and 121 will be the subject of a future staff position paper.

B. The allowance should not be accrued during periods of interrupted construction unless the interruption is justifiable under the circumstances. A general guideline in this area has been to consider delays which were beyond the control of management to be reasonable.

C. In computing the allowance in the final month of construction, accrual of the allowance shall cease the date facilities are tested and are ready for service. For the majority of projects normally under construction where the use of an average in-service date would not distort results of

operations for the year, an average of 15-day in-service dates can be assumed. In the case of unusually large projects, i.e., generating stations, transmission lines, etc., the exact number of days of construction should be used.

In the case of multi-unit generating plants, allowance should cease on all common plant facilities when the first unit went into operation. Allowance can be computed on remaining units until appropriate in-service dates of such units. Staff has also permitted the use of an average in-service date (also called the offset method) in arriving at the allowance cut off date of the complete project. Under this approach, the days of nonproduction attributable to construction are offset against the days of production in the period to arrive at an average in-service date. The use of this method eliminates the requirement of crediting construction with the value of power produced during this period. The average in-service date method was accepted by the Commission in early licensed project accounting actions and its use has been accepted by the staff primarily with respect to the cost of hydroelectric projects.

As a result of circumstances surrounding the construction and commercial operations of nuclear plants, staff is in the process of developing criteria to determine the proper cut off period for the allowance computation on these plants.

In the area of gas storage plant, staff has taken the position that the facilities are available for service, and hence allowance computation ceases, when top storage gas is first injected into the facility.

REBUTTAL TESTIMONY OF

MICHAEL J. ADAMS

NAVIGANT CONSULTING, INC.

SPONSORED ON BEHALF OF
HAWAII ELECTRIC LIGHT COMPANY, INC.

Subject: Allowance for Funds Used During Construction

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Michael Adams. My business address is 77 South Bedford Street, Suite 400, Burlington, MA. 01803.

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

A. I am a Managing Director in the Energy Practice of Navigant Consulting, Inc.

Q. Please describe Navigant Consulting, Inc.

A. Navigant Consulting, Inc. ("NCI") is a specialized independent consulting firm providing professional services to assist clients in identifying practical solutions to the challenges of uncertainty, risk and distress. We focus on large industry segments that are typically highly regulated and are undergoing significant change.

NCI has served the electric and natural gas industries since 1983. We offer a wide range of consulting services related to business strategy and planning, operations advisory management, financial and transaction advisory activities, and technology and innovation management designed to assist our clients in a business environment of changing regulation, increased competition and evolving technology.

Q. What are your responsibilities in your current position?

A. As a consultant, my responsibilities include assisting clients in identifying and addressing business issues. My primary areas of focus have been regulatory-, financial- and accounting-related issues.

Q. Please describe your qualifications.

A. I have over twenty-five years of direct experience in the public utility industry. I have worked for an investor-owned utility, a regulatory agency, and most recently

as a consultant to the energy industry. I have managed and/or participated in a wide variety of consulting engagements and have testified in other regulatory proceedings. I have provided expert testimony or reports regarding financial, operational or regulatory matters before the Arkansas Public Service Commission, the Illinois Commerce Commission, the Massachusetts Department of Telecommunications and Energy, the Missouri Public Service Commission, the Oklahoma Public Service Commission, the Ontario Energy Board, and the Pennsylvania Public Utility Commission. I am a member of the American Institute of Certified Public Accountants and the Illinois Society of Certified Public Accountants.

Q. Please describe your education.

A. I have an MBA in Finance from the University of Illinois at Springfield and a BS in Accounting from Illinois College.

Q. On whose behalf are you sponsoring this testimony?

A. I am sponsoring this testimony on behalf of Hawaii Electric Light Company, Inc. ("HELCO" or the "Company").

Q. Have you previously sponsored testimony in this proceeding?

A. No, I have not.

II. PURPOSE AND SCOPE

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to respond to the discussion and alternate calculation of the level of Allowance for Funds Used During Construction ("AFUDC") presented by the Consumer Advocate witness Steven Carver

associated with the permitting and installation of combustion turbines referred to as "CT-4" and "CT-5" at the Keahole site.

Q. Are you sponsoring any schedules?

A. Yes. In addition to my prepared testimony, I am sponsoring HELCO-R-9B01 through HELCO-R-9B04. I will discuss the nature of the exhibits later in my testimony.

III. BACKGROUND INFORMATION ON CT-4 AND CT-5

Q. Please describe the combustion turbines that HELCO has constructed at the Keahole site?

A. HELCO has installed two 20 megawatt ("MW") simple-cycle combustion turbines, referred to as CT-4 and CT-5, at the Keahole generating station site.

Q. Did the Hawaii Public Utilities Commission (the "Commission") approve the commitment of funds associated with installation of the two units?

A. Yes. The Commission approved the commitment of funds for CT-4 and CT-5 in Decision and Order ("D&O") No. 13050 issued January 21, 1994 in Docket No. 7048 and in Decision and Order No. 14284 (D&O 14284) issued September 22, 1995, which includes certain conditions.

Q. When was the need for additional capacity identified?

A. Based on its capacity planning criteria, the Company initially determined the need for additional increments of capacity in 1994-1995 (20 MW), 1996 (20 MW) and 1997 (18 MW) due to forecast load growth and planned retirements of older generating units.[1] HELCO explored a number of possible alternatives for the first 20 MW increment of capacity, but HELCO determined, and the Commission

[1] HELCO-1501 (Appendix C, page 2 of 22).

agreed, that CT-4 was the only alternative with the possibility of fruition in the 1994-1995 timeframe.[2] The Commission stated: "All parties agree that HELCO requires additional capacity to meet its future load requirements. The Consumer Advocate agrees with HELCO that there is an immediate need for additional generation in West Hawaii."[3] The Commission ultimately found that "HELCO's proposed project is reasonable and in the public interest."[4]

Q. When did the Company file its application with the Commission for CT-4?

A. The application was filed with the Commission in July 1991 and was amended in September 1992 to reflect a change in siting to the Keahole site.[5] Given the urgency of the need, HELCO acted expeditiously to obtain the needed permits and equipment for CT-4.

Q. Did the filing of other required permit approvals follow shortly thereafter?

A. Yes. The application for an amendment to the Company's Keahole Conservation District Use Permit ("CDUP") was filed with the Department of Land and Natural Resources in August 1992. The application for the air permit was filed with the Department of Health ("DOH") in January 1993. In addition, a letter of intent for the purchase of the combustion turbine was sent on October 31, 1991 (subject to cancellation without penalty before June 1, 1992).[6]

Q. Did the Company initiate work on the project prior to receiving a Prevention of Significant Deterioration ("PSD") permit?

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[2] D&O 13050, page 8.
[3] Id., p. 3.
[4] Id., p. 14.
[5] HECO-1501 (Appendix C, page 3 of 22).
[6] Id., p. 3 of 22.

A. Yes. HELCO commenced pre-PSD work before receipt of the PSD permit in order to shorten the time to install CT-4 and CT-5 once the PSD permit was received.

Q. Was it reasonable for the Company to proceed with Pre-PSD work?

A. Yes. HELCO requested permission to perform activities involving certain pre-PSD work in 1994. The DOH and the U.S. Environmental Protection Agency ("EPA") approved in writing HELCO's proposed pre-PSD permitting and installation activities. The pre-PSD work contemplated by HELCO was the same type of pre-PSD work that was performed by HELCO and Maui Electric Company, Limited on earlier generating units under previous DOH and EPA approvals.[7]

Q. What were the original cost estimates for CT-4 and CT-5?

A. The cost estimate for CT-4 included in the D&O approving the commitment of expenditures was $35,798,200, which included $2,710,000 of AFUDC. The cost estimate for CT-5 included in the D&O approving the commitment of expenditures was $24,073,400, which included $2,602,900 of AFUDC. The total estimate for CT-4 and CT-5 was $59,871,600.[8]

CT-4 costs were presented in HELCO-R-405, Docket No. 7048, which was filed on February 12, 1993, and revised by letter dated February 22, 1993. The cost estimate was included in D&O No. 13050, dated January 21, 1994.

CT-5 costs were presented in HELCO-R-402, Docket No. 7623, which was filed on July 1, 1994. The cost estimate was included in D&O No. 14284, dated September 22, 1995.

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[7] Id., p. 6 of 22.
[8] Id., Exhibit I, page 2.

Q. What were the actual costs incurred by the Company associated with the permitting and installation of CT-4 and CT-5?

A. The actual cost of constructing both CT-4 and CT-5 was $117,609,535 which included $21,661,087 of AFUDC.[9] (The $117,609,535 includes $7,570,152 already included in rate base for pre-PSD facilities that went into service prior to 2000.[10])

Q. You previously mentioned that the cost estimates and the final cost included AFUDC. What is AFUDC?

A. AFUDC is an accounting procedure for capitalizing the cost of funds used to finance construction projects during the construction period. As Company witness Nanbu states in her rebuttal testimony "AFUDC represents the cost of investor supplied funds used by a utility to pay for capital projects during the period the capital project costs are incurred."[11]

Q. The final cost represents a four-fold increase in the level of AFUDC charged to the projects over the estimated levels. To what do you attribute the increase?

A. The increased level of AFUDC is directly attributable to the duration of the projects and unforeseen delays experienced associated with the completion of the project.

Q. Does the Company have written policies or procedures regarding the capitalization of AFUDC?

A. Yes. The Company's AFUDC policy is discussed in detail in the rebuttal testimony of Company witness Patsy H. Nanbu (HELCO RT-9A).

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[9] See HELCO-R-1503.
[10] See Rebuttal Testimony of Paul Fujioka, HELCO RT-9.
[11] Rebuttal Testimony of Patsy Nanbu, HELCO RT-9A.

1 Q. Did the Company adhere to these policies or procedures with regards to the
2 capitalization of AFUDC for CT-4 and CT-5?
3 A. Yes. Based upon my review of documentation related to the permitting and
4 installation of CT-4 and CT-5, the Company did adhere to its AFUDC policies.
5 Q. When did HELCO begin accruing AFUDC on the projects?
6 A. The Company began capitalizing AFUDC for the Projects in June 1991 for CT-4
7 and July 1993 for CT-5.[12]
8 Q. Why did the Company begin accruing AFUDC associated with CT-4 in June
9 1991?
10 A. The Company began accruing AFUDC associated with the installation of CT-4 in
11 June 1991 because that is the point in time at which work commenced on the
12 planning for the project. As is discussed in detail by Company witness Patsy
13 Nanbu, in HELCO RT-9A, the Company's AFUDC policy requires the accrual of
14 AFUDC once work has commenced on a project in a planned progressive manner.
15 Q. Was it appropriate for the Company to commence work on the CT-4 and CT-5
16 projects and the capitalization of AFUDC charges prior to receiving the
17 Commission's Orders approving the commitment of expenditures?
18 A. Yes. Based upon my discussions with Company representatives, HELCO had a
19 reasonable expectation, based upon past experiences, that the necessary approvals
20 would be received in a timely manner. Given the expedited schedule and the
21 agreed-upon need for the capacity, the Company was justified and acted prudently
22 in proceeding with the work on the projects prior to receipt of Commission
23 approvals. The Company had operated in a similar manner on other construction
24 projects.

[12] HELCO Response to CA-IR-190.

1 Q. Did HELCO continue to accrue AFUDC until completion of the projects?
2 A. No, it did not.
3 Q. When did HELCO cease the capitalization of AFUDC?
4 A. The Company voluntarily ceased capitalizing AFUDC on the Projects on
5 December 1, 1998.
6 Q. Why did HELCO cease the capitalization of AFUDC for CT-4 and CT-5?
7 A. Management of the Company decided to stop the accrual of AFUDC due to
8 prolonged project delays caused by external factors. In late November 1998, the
9 EPA Environmental Appeals Board ("EAB") remanded the Keahole expansion
10 PSD permit proceedings to the DOH. The remand meant further extended delays
11 in the project schedule. Although management had acted prudently with respect
12 to the Keahole project, it decided to stop the accrual of AFUDC effective
13 December 1, 1998. The length of delays to date and uncertainty over potential
14 further delays to meet the EAB's remand requirements, including another round of
15 public comments, were factors considered in the decision.[13]
16 Q. Was the cessation of the capitalization of AFUDC consistent with the Company's
17 policies?
18 A. Yes, it was. HELCO's general policy is that if project delays are the result of
19 external factors, continuing to accrue AFUDC is appropriate. Under unusual
20 circumstances, Company policy is for management to make AFUDC start and
21 stop decisions based on the facts and circumstances surrounding the project. In
22 the case of CT-4 and CT-5, where lengthy delays had already been experienced,
23 and further, substantial delays were expected, once management of the Company
24 determined that there was uncertainty over the length of potential future delays to

[13] Company response to CA-SIR-1428, Docket No. 99-0207, page 1.

meet the additional air permitting requirements, management made a decision to stop the accrual of AFUDC on the project.

Q. *Does the NARUC or the FERC offer any guidance regarding when to start or stop the capitalization of AFUDC?*

A. As will be discussed by Company witness Nanbu, the National Association of Regulatory Utility Commissioners ("NARUC") Uniform System of Accounts ("USOA") Interpretation No. 83 addresses the issue of AFUDC accruals. The Federal Energy Regulatory Commission's ("FERC") Accounting Release Number AR-5 (Revised), effective January 1, 1968 also addresses when AFUDC should be accrued.

According to NARUC's USOA Interpretation No. 83, "No AFUDC interest should be accrued during period of interrupted construction unless the company can justify the interruption as being reasonable under the circumstances."[14] FERC's guidance, which dates back to 1968 and is provided in Release AR-5, is very similar in nature to that provided by the NARUC.[15]

Q. Are there other accounting guidelines or proclamations pertaining to the topic of AFUDC?

A. Yes. In October 1979, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 34, entitled Capitalization of Interest Cost ("SFAS No. 34").[16] SFAS No. 34 basically requires that interest cost be capitalized as an integral part of the cost of an asset in certain situations contingent on the nature of the asset being acquired and the

[14] CA-SIR-1422 (e), p. 7, Docket No. 99-0207.
[15] CA-SIR-1422 (e), p. 8, Docket No. 99-0207.
[16] Statement of Financial Accounting Standards No. 34, Capitalization of Interest Cost (Stamford: FASB, 1979).

nature of the acquiring company's capital structure.[17] SFAS No. 34 indicates that interest should be capitalized only for those assets that require a period of time to prepare them for their intended use. Interest is capitalized over the term when the following three conditions are being met:

1) Interest is being incurred,
2) Activities are being undertaken to get an "asset" ready for its intended use, and
3) Expenditures have been made on the asset.

SFAS No. 34 states that after the asset is ready for its intended use, the capitalization period ends.[18]

From a regulatory perspective, SFAS No. 34 contains some guidance with regard to what investors expect as a reasonable rate of return on their funds used for HELCO's capital construction expenditures.

> Some assets are ready for their intended use when purchased. Others are constructed or otherwise developed for a particular use by a series of activities whereby diverse resources are combined to form a new asset or a less valuable resource is transformed into a more valuable resource. Activities take time for their accomplishment. During the period of time required, the expenditures for the materials, labor, and other resources used in creating the asset must be financed. Financing has a cost. The cost may take the form of explicit interest on borrowed funds, or it may take the form of a return foregone on an alternative use of funds, but regardless of the form it takes, a financing cost is necessarily incurred. On the premise that the historical cost of acquiring an asset should include all costs necessarily incurred to bring it to the condition and location necessary for its intended use, the Board concluded that, in principle, the cost incurred in financing expenditures for an asset during a required construction or development period is itself a part of the asset's historical acquisition cost.[19]

[17] Ibid., para. 8.
[18] Ibid., para. 17.
[19] Ibid., para. 40.

SFAS No. 34 also provides the following guidance at paragraph 58:

> ...interest is not to be capitalized during periods when the enterprise intentionally defers or suspends activities related to the asset. Interest cost incurred during such periods is a holding cost, not an acquisition cost. However, delays that are inherent in the asset acquisition process and interruptions in activities that are imposed by external forces are unavoidable in acquiring the asset and as such do not call for cessation of interest capitalization.[20]

Q. Are the Company's internal policies and procedures consistent with those of the NARUC and the FERC with regards to the capitalization of AFUDC?

A. Yes. The Company's internal policies and procedures associated with the accrual of AFUDC are consistent with those of the NARUC and the FERC, as well as with SFAS No. 34.

IV. SUMMARY OF CONSUMER ADVOCATE WITNESS CARVER'S PROPOSED ADJUSTMENT

Q. Have you reviewed the direct testimony of Consumer Advocate witness Carver?

A. Yes, I have.

Q. Please summarize Mr. Carver's proposed adjustment regarding AFUDC.

A. The Consumer Advocate recommended that the Commission disallow AFUDC in the approximate amounts of $9.1 million for CT-4 and $5.3 million for CT-5. The proposed disallowance represented two-thirds of the Company's recorded level of AFUDC, as provided in the Consumer Advocate's electronic file, Keahole AFUDC-suspended.xls provided in response to HELCO/CA-IR-301.

[20] CA-SIR-1422, page 11, Docket No. 99-0207.

1 According to Mr. Carver, HELCO attempted to install CT-4 and CT-5 on
2 an accelerated construction schedule at the Keahole site where it "'knew or should
3 have known' that achieving an accelerated schedule would be unlikely."[21]
4 Q. Do you concur with the Consumer Advocate's proposed adjustment to the accrued
5 levels of AFUDC?
6 A. No, I do not. Based upon the information that I have reviewed, the Company has
7 been, in fact, conservative with regards to the accrual of AFUDC related to CT-4
8 and CT-5.
9 Q. Do you consider the actual AFUDC charges, which are four times the originally
10 budgeted levels, to be conservative?
11 A. While I acknowledge that the actual levels of AFUDC charges are significantly
12 greater than originally estimated, the Company effectively limited the accrued
13 level of AFUDC. Thus, HELCO is seeking recovery of AFUDC costs from its
14 customers that are significantly below the level of AFUDC to which the Company
15 should be entitled. I will discuss my position in greater detail later in my
16 testimony.
17 Q. Will you address issues related to project schedule in your testimony?
18 A. No. Other HELCO witnesses will respond to the positions taken by Mr. Carver
19 (and the Keahole Defense Coalition, or "KDC") with regards to what was known
20 or should have been known by the Company during the permitting and installation
21 of the units.
22 Q. What factors impact the level of AFUDC associated with the permitting and
23 installation of CT-4 and CT-5?

[21] Direct Testimony and Exhibits of Steven C. Carver on behalf of the Division of Consumer Advocacy, CA-T-3, p. 52.

1 A. The level of AFUDC is a result of the AFUDC rate, capital expenditures
2 associated with the project and the duration of the project.
3 Q. Did Mr. Carver take exception to the AFUDC rates used by the Company?
4 A. No. Mr. Carver employed HELCO's monthly AFUDC rates in the development
5 of his models.
6 Q. Was Mr. Carver's proposed adjustment pertaining to the AFUDC capitalization
7 based on the project schedule?
8 A. Yes.
9 Q. Did Mr. Carver's calculation of AFUDC reflect the same start date of AFUDC
10 accrual as the Company utilizes for the accrual of AFUDC?
11 A. No. Mr. Carver's proposed calculation of AFUDC commenced when the
12 Commission approved HELCO's application to commit funds for CT-4 (i.e.,
13 January 1994). The Company began accruing AFUDC in June 1991.
14 Q. Why is the start date for accruing AFUDC an issue?
15 A. Mr. Carver maintained that AFUDC should not have been accrued until the
16 Company received authorization from the Commission to expend funds associated
17 with the capital project. Consistent with past practice and the Company's
18 AFUDC procedure, HELCO began accruing AFUDC when the decision was
19 made to proceed with the project and continued progress was being made on the
20 effort.
21 Q. Was it reasonable for HELCO to begin accruing AFUDC in June 1991?
22 A. Yes, it was. HELCO began accruing AFUDC when it had made a decision to
23 proceed with the project on a progressive basis.
24 Q. Did Mr. Carver's calculation of the AFUDC capitalization utilize a "Start/Stop"
25 approach?

1 A. Yes.

2 Q. What is a "Start/Stop" approach?

3 A. Under a "Start/Stop" methodology the accrual of AFUDC could be stopped if the
4 projects were expected to experience a prolonged delay until such time as work
5 recommences on the project.

6 Q. When did Mr. Carver first propose to stop the capitalization of AFUDC?

7 A. Mr. Carver proposed to cease the accrual of AFUDC for CT-4 and CT-5 in
8 October 1994. He proposed to restart the accrual of AFUDC in August 1997 and
9 continue the accrual until December 1, 1998 when the Company elected to cease
10 the accrual.[22]

11 Q. Why did Mr. Carver propose to stop the capitalization of AFUDC at that time?

12 A. Mr. Carver took the position that, "limited, if any, progressive construction
13 activity was authorized on the projects."[23]

14 Q. Please elaborate on the period of time for which AFUDC would have been
15 accrued under Mr. Carver's proposal.

16 A. Mr. Carver proposed that the Company be allowed AFUDC from January 1994
17 through September 1994, and again from August 1997 until December 1, 1998.

18 Q. Do you concur with the proposed stoppage of the AFUDC capitalization at that
19 time?

20 A. No, I do not. Based upon the rebuttal testimony of other Company witnesses and
21 the documents which I reviewed related to the permitting and installation of CT-4
22 and CT-5, the Company was correct in continuing to accrue AFUDC until
23 December 1, 1998. Further, the Company could have commenced accruing

[22] Response to HELCO/CA-IR-302.
[23] CA-T-3, p. 68, line 14.

AFUDC on the projects again in November 2003, but it unilaterally elected not to accrue additional AFUDC once progressive work on the project was re-initiated out of concern for the overall cost of the project.

Q. When did Mr. Carver propose to begin again the capitalization of AFUDC?

A. Mr. Carver's "suspended analysis" next shows the accrual of AFUDC starting in August 1997 and continuing thru December 1, 1998. Mr. Carver's position was that August 1997 is when "HELCO was first authorized to commence pre-PSD construction...all pre-PSD construction was later halted in September 1998 and not restarted until January 1999."[24]

Q. Based upon his approach, what amount of AFUDC did Mr. Carver propose to disallow?

A. Mr. Carver proposed to disallow $9.1 million of AFUDC associated with CT-4 and $5.3 million of AFUDC attributable to CT-5, for a total proposed disallowance of $14.4 million.[25]

Q. Did Mr. Carver's modeling of AFUDC reflect the accrual of AFUDC once progress was made on the permitting and installation of the units?

A. No. Mr. Carver did not propose to reflect any AFUDC associated with the permitting and installation of the units once work had restarted.

V. RESPONSE TO CONSUMER ADVOCATE WITNESS CARVER

Q. Do you have any comments regarding the Consumer Advocate's proposed disallowance of AFUDC?

[24] CA-T-3, p. 68, lines 18-21.
[25] CA-T-3. pg. 53.

A. Yes. I find the proposed adjustment to be both unreasonable and reflective of an after-the-fact view. Based upon my review of the historical trail of documents associated with CT-4 and CT-5 it is apparent that all parties agreed with the need for the additional generation capacity. In fact, the Commission even encouraged the Company to fast track the projects. To subsequently recommend the disallowance of costs, with the benefit of 20/20 perfect hindsight is, in my opinion, unjustified. The Company has documented its actions and made a good faith effort to bring the needed capacity online when needed. Because of events which were outside of HELCO's control, the project schedule was expanded.

In addition, the Company accrued AFUDC on the projects in accordance with existing policies. The Company's policies were consistent with standards espoused by the NARUC, the FERC, and FASB standards.

Q. Do you agree with the Consumer Advocate's proposed date on which to commence the accrual of AFUDC?

A. No. The Company was correct and justified when it commenced the accrual of AFUDC associated with CT-4 in June 1991 when work started on project planning. The accrual of AFUDC prior to receipt of the order approving the commitment of expenditures by the Commission associated with capital expenditures for the project is consistent with past practices which the Company has been allowed to follow. There has been no reason presented by Mr. Carver why the Commission should deviate from those past practices.

As will be addressed by other HELCO witnesses, the delaying of the AFUDC accrual from June 1991 until January 1994 represents approximately $1 million. As Company witness Fujioka explains in HELCO RT-9, that amount increases to $1.2 million over the period during which AFUDC is accrued by the

Consumer Advocate and represents $1.2 million of the disallowance that was proposed.

Q. Do you agree with Mr. Carver's proposed start/stop methodology to calculate AFUDC?

A. While I agree with the methodology in theory, I do not agree with his application of the methodology.

Q. Please explain.

A. As explained by Company witness Nanbu in HELCO RT-9A, the Company's AFUDC policy provides general guidelines regarding when to stop and start the application of AFUDC in the event of project delays and resumptions, respectively. Under normal circumstances, if the project delays are caused by external factors, AFUDC is continued. Under unusual circumstances, however, as with respect to the CT-4 and CT-5 project, HELCO's AFUDC policy allowed for the stopping and starting of AFUDC as deemed appropriate by management under the circumstances.

Unfortunately, the Consumer Advocate (and KDC) have relied upon hindsight to make judgment calls as to what management did or should have known during the permitting and installation process. The proposed disallowance reflects that hindsight.

VI. ALTERNATIVE AFUDC CALCULATIONS

Q. What amount of AFUDC has HELCO included in the costs of CT-4 and CT-5?

A. According to HELCO's response to CA-IR-190, the amount of AFUDC for the Keahole CT-4 and CT-5 projects is $21,661,087 through December 1, 1998.

1 Q. Were these amounts of AFUDC accrued during the time period from June 1991
2 until December 1, 1998?
3 A. Yes. HELCO's AFUDC accruals for CT-4 were from June 1991 thru December
4 1, 1998 and for CT-5 were from July 1993 thru December 1, 1998.
5 Q. Is the amount of AFUDC which the Company seeks to include in rate base
6 associated with CT-4 and CT-5 reasonable?
7 A. Yes.
8 Q. To what amount of AFUDC do you believe that the Company should be entitled?
9 A. The Company should be allowed to include the requested amount of $21.7 million
10 in rate base. The Company could have been entitled to an additional $52.6 million
11 of AFUDC if the accrual had continued through December 2004. Mr. Carver
12 acknowledges in his testimony that the Company's shareholders have already
13 foregone the incremental AFUDC of approximately $52.6 million as a result of
14 HELCO ceasing the accrual of AFUDC on December 1, 1998.[26]
15 Q. Have you determined the amount of AFUDC to which the Company would be
16 allowed under various scenarios?
17 A. Yes, I have. The Company is seeking the recovery of $21.7 million of AFUDC
18 for the two units. Under the actual scenario, AFUDC was accrued from June 1991
19 through December 1, 1998.
20 Employing the start/stop methodology recommended by Mr. Carver, I
21 have calculated the appropriate level of AFUDC under four different scenarios:
22 1) AFUDC from June 1, 1991 through December 1998 and from May 2002
23 through December 2004;

[26] See HELCO RT-9 discussing foregone AFUDC.

2) AFUDC from June 1, 1991 through December 1998 and from May 2002 through September 2002 and from December 2003 through December 2004;
3) AFUDC from June 1, 1991 through September 1994 and from August 1997 through December 1998 and from May 2002 through September 2002 and from December 2003 through December 2004; and finally
4) AFUDC from January 1994 through September 1994 and from August 1997 through December 1998 and from May 2002 through September 2002 and from December 2003 through December 2004.

Q. Why did you select the first scenario?

A. The first scenario reflects the actual accrual period plus the additional period during which permitting and installation moved at a progressive pace.

Q. Please summarize your findings from the first alternative.

A. As shown on HELCO-R-9B01, under the first scenario the Company would have accrued AFUDC in the amount of $40.3 million. This compares to the amount actually accrued of $21.7 million. Based on the start/stop methodology proposed by Mr. Carver, it appears that HELCO would have been entitled to the incremental amount of AFUDC reflecting the period during which work on the projects was continually progressing.

Q. Why did you choose to analyze the second scenario?

A. The second scenario is largely a further breakdown of the first scenario in that it reflects an additional stoppage of work on the projects from October 2002 through November 2003, due to additional legal challenges to the project.

Q. Please summarize your findings from the second alternative.

1 A. As shown on HELCO-R-9B02, under the second scenario, the Company would
2 have accrued AFUDC in the amount of $29.8 million as opposed to the $21.7
3 million that was actually accrued.
4 Q. What was the basis for choosing the third scenario?
5 A. The third scenario reflects the start/stop dates proposed by Mr. Carver, with the
6 exception that AFUDC accrual commenced in June 1991 and AFUDC continued
7 to accrue once work progressed on the units in May 2002 through September
8 2002, and again from December 2003 through December 2004.
9 Q. Please summarize your findings from the third alternative.
10 A. As shown on HELCO-R-9B03, under Scenario 3, the Company would have
11 accrued AFUDC in the amount of $16.6 million as compared to the $21.7 million
12 that was actually booked.
13 Q. Please describe your final scenario.
14 A. The fourth scenario reflects the start/stop dates proposed by Mr. Carver and
15 accrues AFUDC from May 2002 through September 2002 and again from
16 December 2003 through December 2004.
17 Q. Please summarize your findings from the final alternative.
18 A. As shown on HELCO-R-9B04, under the final alternative, the Company would
19 have accrued AFUDC in the amount of $15.4 million, as opposed to the $21.7
20 million which was actually booked.
21 Q. What conclusions can you draw from your alternative scenarios?
22 A. The results from the various scenarios demonstrate that the amount of AFUDC
23 that the Company accrued was reasonable. Under the first two scenarios, which I
24 believe to be the most reasonable, the Company would have actually accrued
25 more AFUDC than was actually booked.

Even under the most conservative start/stop scenario (i.e., scenario 4), the amount of AFUDC which would have been accrued is more than double the amount recommended by Mr. Carver. Simply put, the AFUDC disallowance proposed by the Consumer Advocate was unreasonable and unwarranted.

VII. CONCLUSION AND RECOMMENDATIONS

Q. Does the mere fact that actual AFUDC charges were greater than original estimated levels mean that the AFUDC was imprudently accrued?

A. No.

Q. What is your recommendation regarding the appropriate level of AFUDC to include in HELCO's rate base associated with CT-4 and CT-5?

A. The Company should be allowed to include in rate base the requested amount of AFUDC, in the amount of $21,661,087.[27]

Q. Please summarize the rationale for your position.

A. My opinion regarding the appropriate level of AFUDC to include in rate base is premised upon my understanding of the facts surrounding the planning and installation of CT-4 and CT-5, as derived from my review of documentation pertaining to the project. Based upon my review of the information provided to me by the Company pertaining to the delays experienced during the permitting and installation of the units, the Company was prudent in continuing to accrue AFUDC until it conservatively stopped the accrual as of December 1, 1998. This practice was in accordance with HELCO's AFUDC policy. Company witness Nanbu discusses HELCO's AFUDC policy. Testimonies of other Company witnesses provide responses to the positions of the Consumer Advocate (and

[27] See HELCO-R-1503.

KDC) regarding what was known or should have been known during the permitting and installation of the units. The evidence provided by other Company witnesses is consistent with the information which I have reviewed and justifies the Company's actions with regards to the accrual of AFUDC up until December 1, 1998.

My position is also premised upon the significant amount of CT-4 and CT-5 related AFUDC which the Company has already foregone by virtue of its decision to forego the accrual of AFUDC once activity on the permitting and installation of the units began again in 2003. The amount of foregone AFUDC ranges from $8.1 million to over $52 million.

Q. Does that conclude your testimony?

A. Yes, it does.

Hawaii Electric Light Company, Inc.
Calculation of AFUDC Under Scenario 1

Line No.	Month	Cap Ex Excl. AFUDC	AFUDC	Total Incl. AFUDC
	(A)	(B)	(C)	(D)
1	Jun-91	$421,134	$0	$421,134
2	Jul-91	17,332	2,773	20,105
3	Aug-91	46,157	2,905	49,062
4	Sep-91	21,280	3,228	24,508
5	Oct-91	50,557	3,390	53,947
6	Nov-91	30,383	3,745	34,128
7	Dec-91	37,448	3,969	41,417
8	Jan-92	74,103	4,152	78,255
9	Feb-92	39,718	4,656	44,374
10	Mar-92	21,182	4,942	26,124
11	Apr-92	19,377	5,110	24,487
12	May-92	23,161	5,268	28,429
13	Jun-92	45,759	5,451	51,210
14	Jul-92	59,128	5,781	64,909
15	Aug-92	31,045	6,200	37,245
16	Sep-92	128,640	6,440	135,080
17	Oct-92	516,729	7,310	524,039
18	Nov-92	322,329	10,687	333,016
19	Dec-92	493,710	12,833	506,543
20	Jan-93	104,888	31,821	136,709
21	Feb-93	481,670	21,692	503,362
22	Mar-93	46,119	25,836	71,955
23	Apr-93	423,055	26,428	449,483
24	May-93	3,889,015	30,129	3,919,144
25	Jun-93	204,118	62,395	266,513
26	Jul-93	255,511	64,589	320,100
27	Aug-93	5,328,320	104,226	5,432,546
28	Sep-93	2,160,121	111,951	2,272,072
29	Oct-93	219,478	130,657	350,135
30	Nov-93	400,155	133,539	533,694
31	Dec-93	3,601,106	137,933	3,739,039
32	Jan-94	513,565	171,771	685,336
33	Feb-94	4,473,820	108,720	4,582,540
34	Mar-94	761,328	286,214	1,047,542
35	Apr-94	335,081	139,075	474,156
36	May-94	453,849	408,580	862,429
37	Jun-94	360,942	235,910	596,852
38	Jul-94	333,055	231,341	564,396
39	Aug-94	917,063	235,884	1,152,947
40	Sep-94	1,254,404	245,164	1,499,568
41	Oct-94	859,787	239,944	1,099,731
42	Nov-94	562,265	248,202	810,467
43	Dec-94	1,071,635	254,286	1,325,921
44	Jan-95	502,742	280,748	783,490
45	Feb-95	100,931	281,025	381,956
46	Mar-95	428,596	284,009	712,605
47	Apr-95	79,513	289,575	369,088
48	May-95	694,622	292,458	987,080

Hawaii Electric Light Company, Inc.
Calculation of AFUDC Under Scenario 1

Line No.	Month	Cap Ex Excl. AFUDC	AFUDC	Total Incl. AFUDC
	(A)	(B)	(C)	(D)
49	Jun-95	278,334	318,806	597,140
50	Jul-95	194,181	323,760	517,941
51	Aug-95	58,058	328,056	386,114
52	Sep-95	199,835	329,502	529,337
53	Oct-95	166,702	333,871	500,573
54	Nov-95	197,735	338,002	535,737
55	Dec-95	359,756	342,422	702,178
56	Jan-96	69,696	339,904	409,600
57	Feb-96	81,301	343,203	424,504
58	Mar-96	592,762	346,623	939,385
59	Apr-96	81,430	354,190	435,620
60	May-96	321,151	357,698	678,849
61	Jun-96	73,092	363,167	436,259
62	Jul-96	115,848	366,681	482,529
63	Aug-96	90,976	370,567	461,543
64	Sep-96	113,500	374,285	487,785
65	Oct-96	126,706	378,215	504,921
66	Nov-96	91,024	382,281	473,305
67	Dec-96	96,729	386,094	482,823
68	Jan-97	22,952	393,614	416,566
69	Feb-97	48,637	397,000	445,637
70	Mar-97	92,670	400,623	493,293
71	Apr-97	128,568	384,029	512,597
72	May-97	30,769	387,984	418,753
73	Jun-97	88,352	391,216	479,568
74	Jul-97	55,862	394,916	450,778
75	Aug-97	(257,887)	280,524	22,637
76	Sep-97	110,285	398,569	508,854
77	Oct-97	60,849	402,495	463,344
78	Nov-97	421,618	406,071	827,689
79	Dec-97	451,213	412,457	863,670
80	Jan-98	375,793	415,535	791,328
81	Feb-98	311,767	421,589	733,356
82	Mar-98	618,664	427,199	1,045,863
83	Apr-98	197,521	435,200	632,721
84	May-98	585,367	440,040	1,025,407
85	Jun-98	1,365,078	447,885	1,812,963
86	Jul-98	2,801,598	461,754	3,263,352
87	Aug-98	2,005,381	486,719	2,492,100
88	Sep-98	1,994,148	505,783	2,499,931
89	Oct-98	3,370,181	524,907	3,895,088
90	Nov-98	977,642	554,706	1,532,348
91	Dec-98	559,100		559,100
92	Jan-99	613,403		613,403
93	Feb-99	15,629		15,629
94	Mar-99	253,016		253,016
95	Apr-99	199,402		199,402
96	May-99	27,944		27,944

Hawaii Electric Light Company, Inc.
Calculation of AFUDC Under Scenario 1

Line No.	Month	Cap Ex Excl. AFUDC	AFUDC	Total Incl. AFUDC
	(A)	(B)	(C)	(D)
97	Jun-99	791,862		791,862
98	Jul-99	516,354		516,354
99	Aug-99	248,868		248,868
100	Sep-99	35,242		35,242
101	Oct-99	169,654		169,654
102	Nov-99	676,988		676,988
103	Dec-99	1,640,524		1,640,524
104	Jan-00	250,752		250,752
105	Feb-00	75,765		75,765
106	Mar-00	221,211		221,211
107	Apr-00	20,450		20,450
108	May-00	(294,804)		(294,804)
109	Jun-00	540,057		540,057
110	Jul-00	54,398		54,398
111	Aug-00	232,583		232,583
112	Sep-00	27,245		27,245
113	Oct-00	124,640		124,640
114	Nov-00	101,926		101,926
115	Dec-00	-		-
116	Jan-01	-		-
117	Feb-01	100,194		100,194
118	Mar-01	50,930		50,930
119	Apr-01	2,531		2,531
120	May-01	-		-
121	Jun-01	-		-
122	Jul-01	260,900		260,900
123	Aug-01	-		-
124	Sep-01	115,962		115,962
125	Oct-01	-		-
126	Nov-01	379,341		379,341
127	Dec-01	227,028		227,028
128	Jan-02	27,656		27,656
129	Feb-02	52,753		52,753
130	Mar-02	92,800		92,800
131	Apr-02	68,199		68,199
132	May-02	36,801	568,370	605,171
133	Jun-02	73,563	572,959	646,522
134	Jul-02	297,479	577,862	875,341
135	Aug-02	239,519	584,499	824,018
136	Sep-02	1,978,436	590,748	2,569,184
137	Oct-02	1,599,619	610,230	2,209,849
138	Nov-02	844,911	626,987	1,471,899
139	Dec-02	2,258,557	638,149	2,896,706
140	Jan-03	571,123	663,248	1,234,371
141	Feb-03	62,803	672,653	735,456
142	Mar-03	120,083	678,257	798,340
143	Apr-03	248,027	684,339	932,366
144	May-03	75,093	691,443	766,536

Hawaii Electric Light Company, Inc.
Calculation of AFUDC Under Scenario 1

Line No.	Month	Cap Ex Excl. AFUDC	AFUDC	Total Incl. AFUDC
	(A)	(B)	(C)	(D)
145	Jun-03	110,596	697,283	807,879
146	Jul-03	102,631	703,438	806,069
147	Aug-03	40,396	709,580	749,976
148	Sep-03	90,814	715,294	806,108
149	Oct-03	114,249	721,435	835,684
150	Nov-03	190,992	727,803	918,795
151	Dec-03	(32,442)	734,803	702,361
152	Jan-04	481,839	712,759	1,194,598
153	Feb-04	922,085	721,524	1,643,609
154	Mar-04	2,518,515	733,583	3,252,098
155	Apr-04	1,120,301	757,444	1,877,744
156	May-04	3,358,439	771,221	4,129,660
157	Jun-04	757,957	510,936	1,268,892
158	Jul-04	583,534	198,561	782,095
159	Aug-04	296,698	204,299	500,997
160	Sep-04	464,070	207,975	672,045
161	Oct-04	18,793	212,906	231,699
162	Nov-04	218,144	214,606	432,750
163	Dec-04	2,714,312	217,781	2,932,093
164	Total	$83,340,210	$40,294,057	$123,634,268

Hawaii Electric Light Company, Inc.
Calcuation of AFUDC Under Scenario 2

Line No.	Month	Cap Ex Excl. AFUDC	AFUDC	Total Incl. AFUDC
	(A)	(B)	(C)	(D)
1	Jun-91	$421,134	$0	$421,134
2	Jul-91	17,332	2,773	20,105
3	Aug-91	46,157	2,905	49,062
4	Sep-91	21,280	3,228	24,508
5	Oct-91	50,557	3,390	53,947
6	Nov-91	30,383	3,745	34,128
7	Dec-91	37,448	3,969	41,417
8	Jan-92	74,103	4,152	78,255
9	Feb-92	39,718	4,656	44,374
10	Mar-92	21,182	4,942	26,124
11	Apr-92	19,377	5,110	24,487
12	May-92	23,161	5,268	28,429
13	Jun-92	45,759	5,451	51,210
14	Jul-92	59,128	5,781	64,909
15	Aug-92	31,045	6,200	37,245
16	Sep-92	128,640	6,440	135,080
17	Oct-92	516,729	7,310	524,039
18	Nov-92	322,329	10,687	333,016
19	Dec-92	493,710	12,833	506,543
20	Jan-93	104,888	31,821	136,709
21	Feb-93	481,670	21,692	503,362
22	Mar-93	46,119	25,836	71,955
23	Apr-93	423,055	26,428	449,483
24	May-93	3,889,015	30,129	3,919,144
25	Jun-93	204,118	62,395	266,513
26	Jul-93	255,511	64,589	320,100
27	Aug-93	5,328,320	104,226	5,432,546
28	Sep-93	2,160,121	111,951	2,272,072
29	Oct-93	219,478	130,657	350,135
30	Nov-93	400,155	133,539	533,694
31	Dec-93	3,601,106	137,933	3,739,039
32	Jan-94	513,565	171,771	685,336
33	Feb-94	4,473,820	108,720	4,582,540
34	Mar-94	761,328	286,214	1,047,542
35	Apr-94	335,081	139,075	474,156
36	May-94	453,849	408,580	862,429
37	Jun-94	360,942	235,910	596,852
38	Jul-94	333,055	231,341	564,396
39	Aug-94	917,063	235,884	1,152,947
40	Sep-94	1,254,404	245,164	1,499,568
41	Oct-94	859,787	239,944	1,099,731
42	Nov-94	562,265	248,202	810,467
43	Dec-94	1,071,635	254,286	1,325,921
44	Jan-95	502,742	280,748	783,490
45	Feb-95	100,931	281,025	381,956
46	Mar-95	428,596	284,009	712,605
47	Apr-95	79,513	289,575	369,088
48	May-95	694,622	292,458	987,080

Hawaii Electric Light Company, Inc.
Calcuation of AFUDC Under Scenario 2

Line No.	Month	Cap Ex Excl. AFUDC	AFUDC	Total Incl. AFUDC
	(A)	(B)	(C)	(D)
49	Jun-95	278,334	318,806	597,140
50	Jul-95	194,181	323,760	517,941
51	Aug-95	58,058	328,056	386,114
52	Sep-95	199,835	329,502	529,337
53	Oct-95	166,702	333,871	500,573
54	Nov-95	197,735	338,002	535,737
55	Dec-95	359,756	342,422	702,178
56	Jan-96	69,696	339,904	409,600
57	Feb-96	81,301	343,203	424,504
58	Mar-96	592,762	346,623	939,385
59	Apr-96	81,430	354,190	435,620
60	May-96	321,151	357,698	678,849
61	Jun-96	73,092	363,167	436,259
62	Jul-96	115,848	366,681	482,529
63	Aug-96	90,976	370,567	461,543
64	Sep-96	113,500	374,285	487,785
65	Oct-96	126,706	378,215	504,921
66	Nov-96	91,024	382,281	473,305
67	Dec-96	96,729	386,094	482,823
68	Jan-97	22,952	393,614	416,566
69	Feb-97	48,637	397,000	445,637
70	Mar-97	92,670	400,623	493,293
71	Apr-97	128,568	384,029	512,597
72	May-97	30,769	387,984	418,753
73	Jun-97	88,352	391,216	479,568
74	Jul-97	55,862	394,916	450,778
75	Aug-97	(257,887)	280,524	22,637
76	Sep-97	110,285	398,569	508,854
77	Oct-97	60,849	402,495	463,344
78	Nov-97	421,618	406,071	827,689
79	Dec-97	451,213	412,457	863,670
80	Jan-98	375,793	415,535	791,328
81	Feb-98	311,767	421,589	733,356
82	Mar-98	618,664	427,199	1,045,863
83	Apr-98	197,521	435,200	632,721
84	May-98	585,367	440,040	1,025,407
85	Jun-98	1,365,078	447,885	1,812,963
86	Jul-98	2,801,598	461,754	3,263,352
87	Aug-98	2,005,381	486,719	2,492,100
88	Sep-98	1,994,148	505,783	2,499,931
89	Oct-98	3,370,181	524,907	3,895,088
90	Nov-98	977,642	554,706	1,532,348
91	Dec-98	559,100		559,100
92	Jan-99	613,403		613,403
93	Feb-99	15,629		15,629
94	Mar-99	253,016		253,016
95	Apr-99	199,402		199,402
96	May-99	27,944		27,944

Hawaii Electric Light Company, Inc.
Calcuation of AFUDC Under Scenario 2

Line No.	Month	Cap Ex Excl. AFUDC	AFUDC	Total Incl. AFUDC
	(A)	(B)	(C)	(D)
97	Jun-99	791,862		791,862
98	Jul-99	516,354		516,354
99	Aug-99	248,868		248,868
100	Sep-99	35,242		35,242
101	Oct-99	169,654		169,654
102	Nov-99	676,988		676,988
103	Dec-99	1,640,524		1,640,524
104	Jan-00	250,752		250,752
105	Feb-00	75,765		75,765
106	Mar-00	221,211		221,211
107	Apr-00	20,450		20,450
108	May-00	(294,804)		(294,804)
109	Jun-00	540,057		540,057
110	Jul-00	54,398		54,398
111	Aug-00	232,583		232,583
112	Sep-00	27,245		27,245
113	Oct-00	124,640		124,640
114	Nov-00	101,926		101,926
115	Dec-00	-		-
116	Jan-01	-		-
117	Feb-01	100,194		100,194
118	Mar-01	50,930		50,930
119	Apr-01	2,531		2,531
120	May-01	-		-
121	Jun-01	-		-
122	Jul-01	260,900		260,900
123	Aug-01	-		-
124	Sep-01	115,962		115,962
125	Oct-01	-		-
126	Nov-01	379,341		379,341
127	Dec-01	227,028		227,028
128	Jan-02	27,656		27,656
129	Feb-02	52,753		52,753
130	Mar-02	92,800		92,800
131	Apr-02	68,199		68,199
132	May-02	36,801	568,370	605,171
133	Jun-02	73,563	572,959	646,522
134	Jul-02	297,479	577,862	875,341
135	Aug-02	239,519	584,499	824,018
136	Sep-02	1,978,436	590,748	2,569,184
137	Oct-02	1,599,619		1,599,619
138	Nov-02	844,911		844,911
139	Dec-02	2,258,557		2,258,557
140	Jan-03	571,123		571,123
141	Feb-03	62,803		62,803
142	Mar-03	120,083		120,083
143	Apr-03	248,027		248,027
144	May-03	75,093		75,093

Hawaii Electric Light Company, Inc.
Calcuation of AFUDC Under Scenario 2

Line No.	Month	Cap Ex Excl. AFUDC	AFUDC	Total Incl. AFUDC
	(A)	(B)	(C)	(D)
145	Jun-03	110,596		110,596
146	Jul-03	102,631		102,631
147	Aug-03	40,396		40,396
148	Sep-03	90,814		90,814
149	Oct-03	114,249		114,249
150	Nov-03	190,992		190,992
151	Dec-03	(32,442)	662,117	629,675
152	Jan-04	481,839	642,230	1,124,069
153	Feb-04	922,085	650,477	1,572,562
154	Mar-04	2,518,515	662,015	3,180,530
155	Apr-04	1,120,301	685,350	1,805,651
156	May-04	3,358,439	698,598	4,057,037
157	Jun-04	757,957	437,781	1,195,737
158	Jul-04	583,534	124,869	708,403
159	Aug-04	296,698	130,067	426,765
160	Sep-04	464,070	133,198	597,268
161	Oct-04	18,793	137,580	156,373
162	Nov-04	218,144	138,727	356,871
163	Dec-04	2,714,312	141,346	2,855,658
164	Total	$83,340,210	$29,799,878	$113,140,087

Hawaii Electric Light Company, Inc.
Calculation of AFUDC Under Scenario 3

Line No.	Month	Cap Ex Excl. AFUDC	AFUDC	Total Incl. AFUDC
	(A)	(B)	(C)	(D)
1	Jun-91	$421,134	$0	$421,134
2	Jul-91	17,332	2,773	20,105
3	Aug-91	46,157	2,905	49,062
4	Sep-91	21,280	3,228	24,508
5	Oct-91	50,557	3,390	53,947
6	Nov-91	30,383	3,745	34,128
7	Dec-91	37,448	3,969	41,417
8	Jan-92	74,103	4,152	78,255
9	Feb-92	39,718	4,656	44,374
10	Mar-92	21,182	4,942	26,124
11	Apr-92	19,377	5,110	24,487
12	May-92	23,161	5,268	28,429
13	Jun-92	45,759	5,451	51,210
14	Jul-92	59,128	5,781	64,909
15	Aug-92	31,045	6,200	37,245
16	Sep-92	128,640	6,440	135,080
17	Oct-92	516,729	7,310	524,039
18	Nov-92	322,329	10,687	333,016
19	Dec-92	493,710	12,833	506,543
20	Jan-93	104,888	31,821	136,709
21	Feb-93	481,670	21,692	503,362
22	Mar-93	46,119	25,836	71,955
23	Apr-93	423,055	26,428	449,483
24	May-93	3,889,015	30,129	3,919,144
25	Jun-93	204,118	62,395	266,513
26	Jul-93	255,511	64,589	320,100
27	Aug-93	5,328,320	104,226	5,432,546
28	Sep-93	2,160,121	111,951	2,272,072
29	Oct-93	219,478	130,657	350,135
30	Nov-93	400,155	133,539	533,694
31	Dec-93	3,601,106	137,933	3,739,039
32	Jan-94	513,565	171,771	685,336
33	Feb-94	4,473,820	108,720	4,582,540
34	Mar-94	761,328	286,214	1,047,542
35	Apr-94	335,081	139,075	474,156
36	May-94	453,849	408,580	862,429
37	Jun-94	360,942	235,910	596,852
38	Jul-94	333,055	231,341	564,396
39	Aug-94	917,063	235,884	1,152,947
40	Sep-94	1,254,404	245,164	1,499,568
41	Oct-94	859,787		859,787
42	Nov-94	562,265		562,265
43	Dec-94	1,071,635		1,071,635
44	Jan-95	502,742		502,742
45	Feb-95	100,931		100,931
46	Mar-95	428,596		428,596
47	Apr-95	79,513		79,513
48	May-95	694,622		694,622

Hawaii Electric Light Company, Inc.
Calculation of AFUDC Under Scenario 3

Line No.	Month	Cap Ex Excl. AFUDC	AFUDC	Total Incl. AFUDC
	(A)	(B)	(C)	(D)
49	Jun-95	278,334		278,334
50	Jul-95	194,181		194,181
51	Aug-95	58,058		58,058
52	Sep-95	199,835		199,835
53	Oct-95	166,702		166,702
54	Nov-95	197,735		197,735
55	Dec-95	359,756		359,756
56	Jan-96	69,696		69,696
57	Feb-96	81,301		81,301
58	Mar-96	592,762		592,762
59	Apr-96	81,430		81,430
60	May-96	321,151		321,151
61	Jun-96	73,092		73,092
62	Jul-96	115,848		115,848
63	Aug-96	90,976		90,976
64	Sep-96	113,500		113,500
65	Oct-96	126,706		126,706
66	Nov-96	91,024		91,024
67	Dec-96	96,729		96,729
68	Jan-97	22,952		22,952
69	Feb-97	48,637		48,637
70	Mar-97	92,670		92,670
71	Apr-97	128,568		128,568
72	May-97	30,769		30,769
73	Jun-97	88,352		88,352
74	Jul-97	55,862		55,862
75	Aug-97	(257,887)	280,524	22,637
76	Sep-97	110,285	398,569	508,854
77	Oct-97	60,849	402,495	463,344
78	Nov-97	421,618	406,071	827,689
79	Dec-97	451,213	412,457	863,670
80	Jan-98	375,793	415,535	791,328
81	Feb-98	311,767	421,589	733,356
82	Mar-98	618,664	427,199	1,045,863
83	Apr-98	197,521	435,200	632,721
84	May-98	585,367	440,040	1,025,407
85	Jun-98	1,365,078	447,885	1,812,963
86	Jul-98	2,801,598	461,754	3,263,352
87	Aug-98	2,005,381	486,719	2,492,100
88	Sep-98	1,994,148	505,783	2,499,931
89	Oct-98	3,370,181	524,907	3,895,088
90	Nov-98	977,642	554,706	1,532,348
91	Dec-98	559,100		559,100
92	Jan-99	613,403		613,403
93	Feb-99	15,629		15,629
94	Mar-99	253,016		253,016
95	Apr-99	199,402		199,402
96	May-99	27,944		27,944

Hawaii Electric Light Company, Inc.
Calculation of AFUDC Under Scenario 3

Line No.	Month	Cap Ex Excl. AFUDC	AFUDC	Total Incl. AFUDC
	(A)	(B)	(C)	(D)
97	Jun-99	791,862		791,862
98	Jul-99	516,354		516,354
99	Aug-99	248,868		248,868
100	Sep-99	35,242		35,242
101	Oct-99	169,654		169,654
102	Nov-99	676,988		676,988
103	Dec-99	1,640,524		1,640,524
104	Jan-00	250,752		250,752
105	Feb-00	75,765		75,765
106	Mar-00	221,211		221,211
107	Apr-00	20,450		20,450
108	May-00	(294,804)		(294,804)
109	Jun-00	540,057		540,057
110	Jul-00	54,398		54,398
111	Aug-00	232,583		232,583
112	Sep-00	27,245		27,245
113	Oct-00	124,640		124,640
114	Nov-00	101,926		101,926
115	Dec-00	-		-
116	Jan-01	-		-
117	Feb-01	100,194		100,194
118	Mar-01	50,930		50,930
119	Apr-01	2,531		2,531
120	May-01	-		-
121	Jun-01	-		-
122	Jul-01	260,900		260,900
123	Aug-01	-		-
124	Sep-01	115,962		115,962
125	Oct-01	-		-
126	Nov-01	379,341		379,341
127	Dec-01	227,028		227,028
128	Jan-02	27,656		27,656
129	Feb-02	52,753		52,753
130	Mar-02	92,800		92,800
131	Apr-02	68,199		68,199
132	May-02	36,801	480,430	517,232
133	Jun-02	73,563	484,353	557,915
134	Jul-02	297,479	488,583	786,062
135	Aug-02	239,519	494,544	734,063
136	Sep-02	1,978,436	500,110	2,478,546
137	Oct-02	1,599,619		1,599,619
138	Nov-02	844,911		844,911
139	Dec-02	2,258,557		2,258,557
140	Jan-03	571,123		571,123
141	Feb-03	62,803		62,803
142	Mar-03	120,083		120,083
143	Apr-03	248,027		248,027
144	May-03	75,093		75,093

Hawaii Electric Light Company, Inc.
Calculation of AFUDC Under Scenario 3

Line No.	Month	Cap Ex Excl. AFUDC	AFUDC	Total Incl. AFUDC
	(A)	(B)	(C)	(D)
145	Jun-03	110,596		110,596
146	Jul-03	102,631		102,631
147	Aug-03	40,396		40,396
148	Sep-03	90,814		90,814
149	Oct-03	114,249		114,249
150	Nov-03	190,992		190,992
151	Dec-03	(32,442)	570,358	537,916
152	Jan-04	481,839	553,194	1,035,033
153	Feb-04	922,085	560,788	1,482,873
154	Mar-04	2,518,515	571,668	3,090,183
155	Apr-04	1,120,301	594,341	1,714,641
156	May-04	3,358,439	606,921	3,965,360
157	Jun-04	757,957	345,431	1,103,387
158	Jul-04	583,534	31,842	615,376
159	Aug-04	296,698	36,357	333,055
160	Sep-04	464,070	38,800	502,870
161	Oct-04	18,793	42,490	61,283
162	Nov-04	218,144	42,939	261,083
163	Dec-04	2,714,312	44,855	2,759,167
164	**Total**	**$83,340,210**	**$16,552,133**	**$99,892,343**

Hawaii Electric Light Company, Inc.
Calculation of AFUDC Under Scenario 4

Line No.	Month	Cap Ex Excl. AFUDC	AFUDC	Total Incl. AFUDC
	(A)	(B)	(C)	(D)
1	Jun-91	$421,134		$421,134
2	Jul-91	17,332		17,332
3	Aug-91	46,157		46,157
4	Sep-91	21,280		21,280
5	Oct-91	50,557		50,557
6	Nov-91	30,383		30,383
7	Dec-91	37,448		37,448
8	Jan-92	74,103		74,103
9	Feb-92	39,718		39,718
10	Mar-92	21,182		21,182
11	Apr-92	19,377		19,377
12	May-92	23,161		23,161
13	Jun-92	45,759		45,759
14	Jul-92	59,128		59,128
15	Aug-92	31,045		31,045
16	Sep-92	128,640		128,640
17	Oct-92	516,729		516,729
18	Nov-92	322,329		322,329
19	Dec-92	493,710		493,710
20	Jan-93	104,888		104,888
21	Feb-93	481,670		481,670
22	Mar-93	46,119		46,119
23	Apr-93	423,055		423,055
24	May-93	3,889,015		3,889,015
25	Jun-93	204,118		204,118
26	Jul-93	255,511		255,511
27	Aug-93	5,328,320		5,328,320
28	Sep-93	2,160,121		2,160,121
29	Oct-93	219,478		219,478
30	Nov-93	400,155		400,155
31	Dec-93	3,601,106		3,601,106
32	Jan-94	513,565	171,771	685,336
33	Feb-94	4,473,820	108,720	4,582,540
34	Mar-94	761,328	286,214	1,047,542
35	Apr-94	335,081	139,075	474,156
36	May-94	453,849	408,580	862,429
37	Jun-94	360,942	235,910	596,852
38	Jul-94	333,055	231,341	564,396
39	Aug-94	917,063	235,884	1,152,947
40	Sep-94	1,254,404	245,164	1,499,568
41	Oct-94	859,787		859,787
42	Nov-94	562,265		562,265
43	Dec-94	1,071,635		1,071,635
44	Jan-95	502,742		502,742
45	Feb-95	100,931		100,931
46	Mar-95	428,596		428,596
47	Apr-95	79,513		79,513
48	May-95	694,622		694,622

Hawaii Electric Light Company, Inc.
Calculation of AFUDC Under Scenario 4

Line No.	Month	Cap Ex Excl. AFUDC	AFUDC	Total Incl. AFUDC
	(A)	(B)	(C)	(D)
49	Jun-95	278,334		278,334
50	Jul-95	194,181		194,181
51	Aug-95	58,058		58,058
52	Sep-95	199,835		199,835
53	Oct-95	166,702		166,702
54	Nov-95	197,735		197,735
55	Dec-95	359,756		359,756
56	Jan-96	69,696		69,696
57	Feb-96	81,301		81,301
58	Mar-96	592,762		592,762
59	Apr-96	81,430		81,430
60	May-96	321,151		321,151
61	Jun-96	73,092		73,092
62	Jul-96	115,848		115,848
63	Aug-96	90,976		90,976
64	Sep-96	113,500		113,500
65	Oct-96	126,706		126,706
66	Nov-96	91,024		91,024
67	Dec-96	96,729		96,729
68	Jan-97	22,952		22,952
69	Feb-97	48,637		48,637
70	Mar-97	92,670		92,670
71	Apr-97	128,568		128,568
72	May-97	30,769		30,769
73	Jun-97	88,352		88,352
74	Jul-97	55,862		55,862
75	Aug-97	(257,887)	280,524	22,637
76	Sep-97	110,285	398,569	508,854
77	Oct-97	60,849	402,495	463,344
78	Nov-97	421,618	406,071	827,689
79	Dec-97	451,213	412,457	863,670
80	Jan-98	375,793	415,535	791,328
81	Feb-98	311,767	421,589	733,356
82	Mar-98	618,664	427,199	1,045,863
83	Apr-98	197,521	435,200	632,721
84	May-98	585,367	440,040	1,025,407
85	Jun-98	1,365,078	447,885	1,812,963
86	Jul-98	2,801,598	461,754	3,263,352
87	Aug-98	2,005,381	486,719	2,492,100
88	Sep-98	1,994,148	505,783	2,499,931
89	Oct-98	3,370,181	524,907	3,895,088
90	Nov-98	977,642	554,706	1,532,348
91	Dec-98	559,100		559,100
92	Jan-99	613,403		613,403
93	Feb-99	15,629		15,629
94	Mar-99	253,016		253,016
95	Apr-99	199,402		199,402
96	May-99	27,944		27,944

Hawaii Electric Light Company, Inc.
Calculation of AFUDC Under Scenario 4

Line No.	Month	Cap Ex Excl. AFUDC	AFUDC	Total Incl. AFUDC
	(A)	(B)	(C)	(D)
97	Jun-99	791,862		791,862
98	Jul-99	516,354		516,354
99	Aug-99	248,868		248,868
100	Sep-99	35,242		35,242
101	Oct-99	169,654		169,654
102	Nov-99	676,988		676,988
103	Dec-99	1,640,524		1,640,524
104	Jan-00	250,752		250,752
105	Feb-00	75,765		75,765
106	Mar-00	221,211		221,211
107	Apr-00	20,450		20,450
108	May-00	(294,804)		(294,804)
109	Jun-00	540,057		540,057
110	Jul-00	54,398		54,398
111	Aug-00	232,583		232,583
112	Sep-00	27,245		27,245
113	Oct-00	124,640		124,640
114	Nov-00	101,926		101,926
115	Dec-00	-		-
116	Jan-01	-		-
117	Feb-01	100,194		100,194
118	Mar-01	50,930		50,930
119	Apr-01	2,531		2,531
120	May-01	-		-
121	Jun-01	-		-
122	Jul-01	260,900		260,900
123	Aug-01	-		-
124	Sep-01	115,962		115,962
125	Oct-01	-		-
126	Nov-01	379,341		379,341
127	Dec-01	227,028		227,028
128	Jan-02	27,656		27,656
129	Feb-02	52,753		52,753
130	Mar-02	92,800		92,800
131	Apr-02	68,199		68,199
132	May-02	36,801	472,999	509,800
133	Jun-02	73,563	476,865	550,427
134	Jul-02	297,479	481,039	778,518
135	Aug-02	239,519	486,942	726,461
136	Sep-02	1,978,436	492,451	2,470,886
137	Oct-02	1,599,619		1,599,619
138	Nov-02	844,911		844,911
139	Dec-02	2,258,557		2,258,557
140	Jan-03	571,123		571,123
141	Feb-03	62,803		62,803
142	Mar-03	120,083		120,083
143	Apr-03	248,027		248,027
144	May-03	75,093		75,093

Hawaii Electric Light Company, Inc.
Calculation of AFUDC Under Scenario 4

Line No.	Month	Cap Ex Excl. AFUDC	AFUDC	Total Incl. AFUDC
	(A)	(B)	(C)	(D)
145	Jun-03	110,596		110,596
146	Jul-03	102,631		102,631
147	Aug-03	40,396		40,396
148	Sep-03	90,814		90,814
149	Oct-03	114,249		114,249
150	Nov-03	190,992		190,992
151	Dec-03	(32,442)	562,604	530,162
152	Jan-04	481,839	545,670	1,027,509
153	Feb-04	922,085	553,209	1,475,294
154	Mar-04	2,518,515	564,033	3,082,548
155	Apr-04	1,120,301	586,650	1,706,950
156	May-04	3,358,439	599,174	3,957,613
157	Jun-04	757,957	337,626	1,095,583
158	Jul-04	583,534	23,980	607,514
159	Aug-04	296,698	28,437	325,135
160	Sep-04	464,070	30,823	494,893
161	Oct-04	18,793	34,454	53,247
162	Nov-04	218,144	34,845	252,989
163	Dec-04	2,714,312	36,701	2,751,013
164	Total	$83,340,210	$15,432,592	$98,772,802

HELCO RT-10
DOCKET NO. 05-0315

REBUTTAL TESTIMONY OF
JULIE K. PRICE

MANAGER
COMPENSATION AND BENEFITS
HAWAIIAN ELECTRIC COMPANY, INC.

Subject: A&G Expenses
Employee Benefits

INTRODUCTION

Q. Please state your name and business address.

A. My name is Julie K. Price, 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., and my title is Manager of Compensation and Benefits.

Q. Have you previously submitted testimony in this proceeding?

A. Yes. My written direct testimony, exhibits and supporting workpapers were provided in HELCO T-10.

Q. What will your rebuttal testimony cover?

A. My rebuttal testimony will (1) present Hawaii Electric Light Company, Inc.'s ("HELCO") rebuttal 2006 test year estimate for employee benefit expenses in account numbers 926000 (employee pensions and benefits) and 926010 (employee benefits-flex credits), and (2) summarize areas of agreement and disagreement with the Consumer Advocate in the area of employee benefits.

REVISED TEST YEAR EXPENSES

Q. What is HELCO's rebuttal test year estimate of employee benefits expenses charged to operations and maintenance ("O&M")?

A. HELCO's rebuttal test year estimate of employee benefits expenses charged to O&M, which takes into account settlement discussions with the Consumer Advocate is $7,671,200 as shown in HELCO-R-1002, column H.

The employee benefits expenses charged to O&M is the net amount resulting from

1) the total cost of employee benefits in account nos. 926000 and 926010, less

2) the amounts transferred to construction and other (account no. 926020). Mr. Paul Fujioka presents HELCO's rebuttal position for the amounts transferred to construction and other (account no. 926020) in HELCO RT-9.

Q. How has HELCO revised employee benefit expenses for the test year from the direct testimony?

A. Following submission of the direct testimony, HELCO submitted revisions to certain employee benefit expenses. Adjustments to HELCO's direct testimony estimates were made for a variety of reasons, including changes to reflect updated information and to reflect settlement discussions between HELCO and the Consumer Advocate.

<u>Account No. 926000 – Employee Pensions and Benefits</u>

Q. What is HELCO's rebuttal position with respect to the qualified pension plan expenses in account no. 926000?

A. HELCO's revised 2006 test year estimate of the qualified pension plan expense is $5,298,300. This is an increase of $2,612,300 from HELCO's direct testimony of $2,686,000 as shown in HELCO-R-1002.

Q. What revisions to the qualified pension plan expense have been made since the filing of HELCO's direct testimony?

A. The qualified pension plan expense was adjusted as follows:

1) An increase of $58,300 to reflect the actual net periodic pension cost ("NPPC") of $2,744,300 for 2006 as determined by Watson Wyatt Worldwide and included in the response to CA-IR-140. The NPPC is the amount that HELCO is required to recognize on its financial statements for the pension plan under the provisions of the Statement of Financial Accounting Standards ("SFAS") No. 87.

2) An increase of $2,554,200 to reflect an alternative pension ratemaking treatment as proposed by the Consumer Advocate.

Q. What is the Consumer Advocate's proposed alternative pension ratemaking treatment?

A. The Consumer Advocate proposed to implement a pension tracking mechanism, which in part, impacts the pension cost included in test year revenue requirements. Ms. Sekimura describes the pension tracking mechanism which has been agreed to by the Company and the Consumer Advocate in HELCO RT-18. The rebuttal revenue requirements include $2,554,200, which is the amortization of the ending pension asset balance (ending pension asset of $12,771,000 divided by 5), in addition to the test year NPPC of $2,744,300.

Q. What is HELCO's rebuttal position with respect to the other postretirement benefit expenses in account no. 926000?

A. HELCO's revised 2006 test year estimate of the other postretirement benefits expense is $1,410,400. This is a decrease of $48,500 from HELCO's direct testimony of $1,458,900 as shown in HELCO-R-1002.

Q. What revisions to the other postretirement benefit expense have been made since the filing of HELCO's direct testimony ?

A. The $48,500 reduction of other postretirement benefit expense is the net result of two adjustments as explained below:

1) $53,700 reduction to reflect actual net periodic postretirement benefit cost ("NPBC") ($1,423,500 estimated NPBC minus $1,369,800 actual) as determined by Watson Wyatt Worldwide. The actual amounts from Watson Wyatt Worldwide were included in HELCO's response to CA-IR-143; and

2) $5,200 increase to reflect actual cost component for executive life

(-$108,500 estimate minus -$103,300 actual). The actual amounts from Watson Wyatt Worldwide were included in HELCO's response to CA-IR-143.

Q. What is HELCO's rebuttal position with respect to the other benefits/administration expense in account no. 926000?

A. HELCO's revised 2006 test year estimate of the other benefits/administration expense is $419,600. This is an increase of $104,800 from HELCO's direct testimony of $314,800 as shown in HELCO-R-1002.

Q. What revisions to the other benefits/administration expense have been made since the filing of HELCO's direct testimony?

A. The $104,800 increase of other benefits/administration expense is the net result of the following adjustments:

1) $130,200 increase for additional T&D safety training included in HELCO's T-6 response to CA-IR-447, page 11;
2) $1,400 reduction for four 24-hour troublemen inspectors in T&D included in HELCO's T-6 response to CA-IR-447, page 10; and
3) $24,000 reduction in T&D training costs to the actual amount incurred in 2006 as proposed by the Consumer Advocate in CA-101, Schedule 15, and referred to later in this testimony.

Q. What other revisions have been made in account no. 926000 since the filing of HELCO's direct testimony?

A. A net increase in labor expense of $107,100 was made which consists of the following adjustments:

1) $108,500 increase in labor expenses for the additional T&D safety training included in HELCO's T-6 response to CA-IR-447, page 11; and

2) $1,400 reduction in labor expenses for the four 24-hour troublemen inspectors in T&D included in HELCO's T-6 response to CA-IR-447, page 10.

Account No. 926010 – Employee Benefits – Flex Credits

Q. What revisions have been made in account no. 926010 since the filing of HELCO's direct testimony?

A. A reduction of $13,700 was made to the other/administration category of account no. 926010 to delete benefit costs related to the four 24-hour troublemen positions in T&D. See HELCO-R-1002, column E.

AREAS OF AGREEMENT

Q. What are the areas in which HELCO and the Consumer Advocate are in agreement?

A. With respect to employee benefit expenses charged to account no. 926000-employee pensions and benefits and account no. 926010-employee benefits-flex credits, the Consumer Advocate and HELCO agree on the following adjustments:

1) The Consumer Advocate has recognized and accepted all of HELCO's adjustments proposed prior to settlement discussions with the Consumer Advocate (see HELCO-R-1002), except for the forecast of T&D training costs. The Consumer Advocate proposed to limit T&D training costs at 2006 actual levels as shown in CA-101, Schedule C-15. To minimize the issues in this proceeding, HELCO in settlement discussions has agreed to accept the Consumer Advocate's proposed adjustment to reduce T&D training costs in account no. 926000 by $24,000. (See HELCO-R-1002, column G).

2) The Consumer Advocate in settlement discussions has agreed to accept

HELCO's proposed adjustment of $2,554,200 to reflect an alternative pension ratemaking treatment as proposed by the Consumer Advocate. (See HELCO-R-1002, column G).

HELCO and the Consumer Advocate are in agreement with HELCO's revised test year expenses for employee benefits charged to O&M (account nos. 926000, 926010 and 926020) as shown in HELCO-R-1001.

AREAS OF DISAGREEMENT

Q. Are there any areas where HELCO and the Consumer Advocate are in disagreement?

A. No. There are no areas of disagreement between HELCO and the Consumer Advocate for account 926000 – employee pensions and benefits and account 926010 – employee benefits-flex-credits.

Q. What other issues were discussed by the Consumer Advocate?

A. While no other issues requiring adjustment to HELCO's test year employee benefit expenses were proposed by the Consumer Advocate, an extensive discussion was included in CA-T-3 by Mr. Carver relative to the inclusion of the prepaid pension asset in rate base and a proposed pension tracking mechanism (see CA-T-3, pages 13-49). HELCO's responses to these issues are covered by Mr. Paul Fujioka in HELCO RT-9 and Ms. Tayne Sekimura in HELCO RT-18.

Q. How does HELCO treat the NPPC in this case?

A. The NPPC is included in O&M expenses in account 926 which includes the capitalized amount and the amount charged to expense. This is consistent with prior cases since the adoption of SFAS 87 as cited in HELCO T-10, page 6.

Q. Did the Consumer Advocate raise any other issues regarding HELCO's employee benefit expenses in account 926?

A. No other issues were raised by the Consumer Advocate.

Q. Does this conclude your rebuttal testimony?

A. Yes it does.

Hawaii Electric Light Co., Inc.
Administrative and General Expenses
Employee Benefits
($ in Thousands)

Description	(A) HELCO Adjusted Test Year 2006	(B) Consumer Advocate Direct Test Year	(C) Settlement Agreed Upon Amount	(D) Difference HELCO vs. Consumer Advocate
Total Employee Benefits Charged to O&M *(account nos. 926000 + 926010 + 926020)*	7,671.2	5,117.0	7,671.2	0.0

Source:
Column A - HELCO-R-1002, column H
Column B - HELCO-R-901 Included in total A&G expenses of 12,660.0
Column C - HELCO/Consumer Advocate Settlement Agreement, Subject to Commission Approval
Column D - Column A - Column C

Hawaii Electric Light Co., Inc.

Administrative and General Expenses
Employee Benefits
($ in Thousands)

Line	Account / Description	(A) Operating Budget	(B) Budget Adjustments	(C) Rate Case Adjts/ Normalizations	(D) Direct Testimony	(E) CA-IR-141 / CA-IR-447 Adjustments	(F) HELCO Pre-Settlement	(G) Settlement	(H) HELCO Adjusted Test Year 2006	(I) 2006 Recorded
	926000 Employee Pensions and Benefits									
1	Qualified Pension Plan	2,686.0			2,686.0	58.3	2,744.3	2,554.2 [1]	5,298.5	
2	Non-Qualified Pension Plans	-6.5		6.5	0.0		0.0		0.0	
3	Other Postretirement Benefits	1,687.4	-120.0	-108.5	1,458.9	-48.5	1,410.4		1,410.4 [3]	
4	Other Benefits/Administration	240.4	93.8	-19.4	314.8	128.8	443.6	-24.0 [2]	419.6	
5	Subtotals: Non-Labor	4,607.3	-26.2	-121.4	4,459.7	138.6	4,598.3	2,530.2	7,128.5	
6	Labor	106.0			106.0	107.1	213.1		213.1	
7	Total 926000	4,713.3	-26.2	-121.4	4,565.7	245.7	4,811.4	2,530.2	7,341.6	4,745.4
	926010 Employee Benefits-Flex Credits									
8	Flex Credits Less Prices	-367.4	-0.8		-368.2		-368.2		-368.2	
9	Group Medical Plan	2,012.3	-39.1		1,973.2		1,973.2		1,973.2	
10	Group Dental Plan	321.3	-5.9		315.4		315.4		315.4	
11	Group Vision Plan	50.5	-1.0		49.5		49.5		49.5	
12	Group Life Insurance Plan	315.2	-15.0		300.2		300.2		300.2	
13	Group Long-Term Disability	185.8	-2.5		183.3		183.3		183.3	
14	Other/Administration	15.1			15.1	-13.7	1.4		1.4	
15	Subtotals: Non-Labor	2,532.8	-64.3	0.0	2,468.5	-13.7	2,454.8		2,454.8	
16	Labor	0.0	0.0		0.0		0.0			
17	Total 926010	2,532.8	-64.3	0.0	2,468.5	-13.7	2,454.8		2,454.8	2,208.9
18	926020 Employee Benefits Transfer	-2,152.0	7.8	19.0	-2,125.2		-2125.2		-2125.2	-1,935.5
19	Grand Total Charged to O&M	5,094.1	-82.7	-102.4	4,909.0	232.0	5,141.0	2,530.2	7,671.2	5,018.8

Source:
Column A-D: HELCO-1002
Column E: Responses to CA-IR-141 and CA-IR-447, T-10, pg. 3
Column F: Column D+E
Column G: [1] Discussed in RT-18
[2] CA-101, Schedule C-15
Column H: Column F+G
[3] (1,369.8 NPBC + 263.9 amortization of regulatory asset -103.3 executive life portion -120.0 electric discount)
Column I: HELCO-902

REBUTTAL TESTIMONY OF
RHEA R. L. NAKAYA

MANAGER
ADMINISTRATION
HAWAII ELECTRIC LIGHT COMPANY, INC.

Subject: Employee Count
Safety and
Security Program
Expense

INTRODUCTION

Q. Please state your name and business address.

A. My name is Rhea R. L. Nakaya and I am the Administration Manager at Hawaii Electric Light Company, Inc. ("HELCO" or "Company"). My business address is 54 Halekauila Street, Hilo, Hawaii, 96720.

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

A. I am HELCO's Manager of Administration and one of its Assistant Secretaries.

Q. Have you previously submitted testimony in this docket?

A. Yes. I submitted written direct testimony, exhibits, and supporting workpapers as HELCO T-11, addressing the Company's total number of employees, Administration Department's employee count and Safety and Security Program expenses.

Q. What will you present in this testimony?

A. In this testimony, I will present:

1) The Company's rebuttal position with respect to employee count.
2) The Company's rebuttal position with respect to the Safety and Security Program expenses for the Test Year.

HELCO'S REBUTTAL POSITION

Q. What is the Company's rebuttal position with respect to employee count?

A. I submitted direct testimony and exhibits on employee count to support the Company's proposed labor expenses for the 2006 test year. Recently, HELCO and the Consumer Advocate settled all issues of contention regarding test year revenue requirements, including those involving test year operations and maintenance labor expenses. Since the expense levels have been set, the issue of

employee count is moot and there is no need to go through the exercise of adjusting the test year employee count.

Q. What is the Company's rebuttal position with regard to the Safety and Security Program expenses?

A. As discussed further below, HELCO and the Consumer Advocate are in agreement with respect to the Safety and Security Program expenses. In CA-T-3, page 102, the Consumer Advocate proposes to revise the Test Year estimate for T&D training costs to the actual level incurred during 2006, as shown in Exhibit CA-101, Schedule C-15. These program expenses are included in Account 925.01 and 926.00. The Consumer Advocate recommends an adjustment to reduce T&D training expenses by $108,000 in Account 925.01 and by $24,000 in Account 926000. In settlement discussions, the Company and the Consumer Advocate agreed to this adjustment. Please refer to the Rebuttal Testimony of Paul Fujioka, HELCO RT-9 with respect to safety training in Account 925.01, and to Julie Price, HELCO RT-10 with respect to other employee training in Account 926000 for further discussion and supporting information.

AREAS OF HELCO – CONSUMER ADVOCATE AGREEMENT AND DISAGREEMENT

Q. What are the areas of agreement?

A. HELCO and the Consumer Advocate are in agreement on Safety and Security Program expenses. As previously discussed, HELCO's rebuttal test year estimates for these expenses are included in the rebuttal testimonies of Paul Fujioka, HELCO RT-9, and Julie Price, HELCO RT-10. As explained above, the issue of employee count is moot.

Q. What are the areas of disagreement?

A. There are no areas of disagreement on Safety and Security Program expenses.

SUMMARY

Q. Please summarize HELCO's rebuttal position in this case with respect to the subject areas for which you are responsible.

A. HELCO and the Consumer Advocate agree on the test year Safety and Security Program expenses. Agreement between HELCO and the Consumer Advocate on test year labor expense levels has rendered the issue of employee count moot.

Q. Does this conclude your testimony?

A. Yes, it does.

Witness HELCO RT-11

has no rebuttal exhibits.

REBUTTAL TESTIMONY OF
DEORNA L. IKEDA

TAX AND PLANT ACCOUNTING ADMINISTRATOR
ACCOUNTING DEPARTMENT
HAWAII ELECTRIC LIGHT COMPANY, INC.

Subject: Depreciation Expense
Accumulated Depreciation

INTRODUCTION

Q. Please state your name and business address.

A. My name is Deorna L. Ikeda and my business address is 1200 Kilauea Avenue, Hilo, Hawaii.

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

A. I am the Tax and Plant Accounting Administrator for Hawaii Electric Light Company, Inc. ("HELCO" or "Company").

Q. Have you previously submitted testimony in this proceeding?

A. Yes, I submitted written direct testimony, exhibits and supporting workpapers as HELCO T-12, covering depreciation expense and accumulated depreciation.

Q. What is the scope of your rebuttal testimony?

A. My rebuttal testimony will present the Company's rebuttal position with respect to depreciation expense and accumulated depreciation.

Q. How is your rebuttal testimony organized?

A. I will:

1) Summarize the Company's rebuttal position, including the changes made by the Company in preparing its rebuttal position; and

2) Summarize the areas where the Company and the Consumer Advocate agree.

HELCO'S REBUTTAL POSITION

Q. What type of revisions did the Company make to its 2006 test year depreciation expense and accumulated depreciation?

A. The 2006 test year depreciation expense and accumulated depreciation were revised to reflect a) actual 2006 amounts and b) amounts to which the Company and the Consumer Advocate agreed during settlement discussions.

1 Depreciation Expense

2 Q. What is the Company's rebuttal position with respect to depreciation expense for
3 the 2006 test year?

4 A. The Company's rebuttal test year depreciation expense, which takes into account
5 settlement discussions with the Consumer Advocate, is $28,772,000 as shown in
6 HELCO-R-1201, column E.

7 Q. Why did the Company revise its 2006 test year depreciation expense?

8 A. The 2006 test year depreciation expense was revised to reflect actual 2006
9 amounts, which included a revision to the amortization of the net SFAS 109
10 regulatory asset.

11 Accumulated Depreciation

12 Q. What is the Company's rebuttal position with respect to the average amount of
13 accumulated depreciation to be deducted in the calculation of rate base for the
14 2006 test year?

15 A. The Company's rebuttal average test year amount of accumulated depreciation to
16 be deducted in the calculation of rate base, which incorporates adjustments
17 resulting from settlement discussions with the Consumer Advocate, is
18 $329,553,000 as shown in HELCO-R-1202, column E.

19 Q. Why did the Company revise its 2006 test year average amount of accumulated
20 depreciation?

21 A. The 2006 test year average amount of accumulated depreciation was revised to
22 reflect actual 2006 amounts for certain elements of accumulated depreciation (the
23 depreciation transfer, salvage, retirements and cost of removal).

AREAS OF AGREEMENT

Depreciation Expense

Q. In what areas of your direct testimony regarding the 2006 test year depreciation expense did the Consumer Advocate agree with the Company?

A. As shown on HELCO-R-1201 (compare columns A and D), the Consumer Advocate calculated its 2006 test year depreciation expense by incorporating the Company's direct testimony test year estimates for depreciation on vehicles, normalized amortization of contributions in aid of construction, amortization of federal ITC and amortization of net SFAS 109 regulatory asset. The Consumer Advocate also agrees with the methodology and rates used to calculate the depreciation expense.

Q. In what areas of your direct testimony regarding the 2006 test year depreciation expense did the Consumer Advocate differ from the Company?

A. The Consumer Advocate calculated the 2006 test year depreciation expense based upon a 2006 test year plant in service balance that the Consumer Advocate adjusted a) to "limit" the AFUDC related to Keahole CT-4 and CT-5 and b) to remove certain legal, landscaping and rezoning costs related to Keahole CT-4 and CT-5. However, subsequent to the filing of the Consumer Advocate's direct testimony, HELCO and the Consumer Advocate settled on a Keahole adjustment, thereby necessitating a recalculation of the test year depreciation expense.

Q. What revisions did the Company make from its direct testimony regarding the 2006 test year depreciation expense?

A. First, the Company reduced by $4,000 its test year estimate of the amortization of net SFAS 109 regulatory assets to reflect the 2006 actual amount of $357,000 (HELCO-R-1201, column C). Second, it revised its depreciation expense

1 according to the settlement between HELCO and the Consumer Advocate on a
2 Keahole adjustment.
3 Q. Did the Consumer Advocate concur with the revised test year amortization of net
4 SFAS 109 regulatory assets?
5 A. Yes. In settlement discussions, the Consumer Advocate agreed with reducing the
6 test year amortization of net SFAS 109 regulatory assets by $4,000.
7 Q. Please describe the settlement on the Keahole adjustment.
8 A. The Company and the Consumer Advocate agreed in settlement discussions to
9 adjust the 2006 test year depreciation expense as presented in the Company's
10 direct testimony by negative $598,000, the calculation of which is shown on
11 HELCO-RWP-1205, page 2. This reduction of the 2006 test year depreciation
12 expense is due to the agreed upon negative $12,898,000 adjustment to the gross
13 plant in service investment related to Keahole CT-4 and CT-5 as shown on
14 HELCO-RWP-1205, page 1. Mr. Warren Lee explains this settlement in HELCO
15 RT-1.
16 Q. What is the resulting 2006 test year estimate for depreciation expense?
17 A. Based on the two adjustments described above, the agreed upon 2006 test year
18 depreciation expense is $28,772,000 as shown on HELCO-R-1201, column E.
19 <u>Accumulated Depreciation</u>
20 Q. In what areas of your direct testimony regarding the 2006 average test year
21 accumulated depreciation did the Consumer Advocate agree with the Company?
22 A. As shown on HELCO-R-1202 (comparing columns A and D), the Consumer
23 Advocate calculated its 2006 average test year accumulated depreciation by
24 incorporating the Company's direct testimony test year estimates for salvage,

retirements and cost of removal. The Consumer Advocate also agrees with the methodology used to calculate the average accumulated depreciation amount.

Q. In what areas of your direct testimony regarding accumulated depreciation did the Consumer Advocate differ from the Company?

A. In its direct testimony, the Consumer Advocate calculated the 2006 average test year accumulated depreciation based on beginning and ending 2006 test year plant balances that incorporated its proposed adjustments to the Keahole CT-4 and CT-5 plant in service amounts. As explained above, HELCO and the Consumer Advocate settled on this issue, thereby necessitating a recalculation of the test year accumulated depreciation.

Q. What revisions did the Company make from its direct testimony regarding the 2006 average test year accumulated depreciation?

A. First, the Company incorporated the actual balances at December 31, 2006 for certain elements of accumulated depreciation (i.e., the depreciation transfer, salvage, retirements and cost of removal). Second, it incorporated the impact of the Keahole adjustment that resulted from settlement discussions.

Q. How does this compare to the Consumer Advocate's estimate for the 2006 average test year accumulated depreciation amount?

A. In its direct testimony, the Consumer Advocate did not object or take issue with the estimates for salvage, retirements and cost of removal presented in the direct testimony as shown on HELCO-R-1202 (compare columns A and D). Further, in settlement discussions, the Consumer Advocate agreed for settlement purposes with the Company's proposal to update the various components of net cost of plant in service (which includes depreciation transfer, salvage, retirements and cost of removal) to 2006 recorded amounts.

Q. Did the Company provide the Consumer Advocate with any updates to the average accumulated depreciation amount?

A. Yes. The Company provided preliminary year end amounts for the 2006 test year related to accumulated depreciation on page 5 of the response to CA-SIR-47. The actual year end amounts for the 2006 test year did not change from these preliminary year end amounts.

Q. Have the Company and the Consumer Advocate reached an agreement regarding the 2006 test year average amount of accumulated depreciation?

A. Yes. The Company and the Consumer Advocate have agreed in settlement discussions to adjust the average amount of accumulated depreciation as presented in the Company's direct testimony by negative $898,000 for the average amount of accumulated depreciation related to the Keahole CT-4 and CT-5 plant additions, the calculation of which is shown on HELCO-RWP-1205, page 2. This reduction of the average amount of accumulated depreciation is due to the agreed upon negative $12,898,000 adjustment to the gross plant in service investment related to Keahole CT-4 and CT-5 as shown on HELCO-RWP-1205, page 1. The Company and Consumer Advocate also agreed upon inclusion of the Company's actual balances at December 31, 2006 for certain elements of accumulated depreciation (the depreciation transfer, salvage, retirements and cost of removal). The agreed upon 2006 test year average amount of accumulated depreciation is $329,553,000 as shown on HELCO-R-1202, column E.

SUMMARY

Q. Please summarize your rebuttal testimony.

A. The Company has revised its estimates of the 2006 test year depreciation expense and average amount of accumulated depreciation to reflect the amounts to which

the Company and the Consumer Advocate agreed during settlement discussions. The agreed upon amounts for depreciation expense and average amount of accumulated depreciation for the 2006 test year are $28,772,000 and $329,553,000, respectively.

Q. Does this conclude your testimony?

A. Yes, it does.

Hawaii Electric Light Company, Inc.
2006 Test Year
Depreciation Expense
($ Thousands)

Line	Description	A HELCO Direct Testimony Test Year Estimate	B HELCO CA-IR-447 Adjustments	C HELCO Adjusted Test Year 2006 (Actuals)	D Consumer Advocate Direct Testimony Test Year	E Settlement Agreed Upon Amounts
1	Depreciation	32,856	0	32,856	31,767	32,258
	Less:					
2	Depreciation on Vehicles	(608)	0	(608)	(608)	(608)
3	Amortization of Contributions in Aid of Construction (CIAC)	(2,677)	0	(2,677)	(2,677)	(2,677)
4	Normalization Adjustment	(370)	0	(370)	(370)	(370)
5	Normalized Amortization of CIAC	(3,047)	0	(3,047)	(3,047)	(3,047)
6	Amortization of Federal ITC	(188)	0	(188)	(188)	(188)
7	Amortization of Net SFAS 109 Regulatory Assets	361	0	357	361	357
8	Depreciation and Amortization Expense	29,374	0	29,370	28,285	28,772

Sources	Column A	Column B	Column C	Column D	Column E
Line 1	HELCO-1201		HELCO-RWP-1202	Note 1	settlement
Line 2	HELCO-1201		HELCO-RWP-1202	Note 2	
Line 3	HELCO-1201		HELCO-RWP-1201, page 3	Note 2	
Line 4	HELCO-1201		HELCO-RWP-1201, page 3	Note 2	
Line 5	HELCO-1201		HELCO-RWP-1201, page 3	Note 2	
Line 6	HELCO-1201		HELCO-1201	Note 2	
Line 7	HELCO-1201		HELCO-RWP-1305	Note 2	settlement
Line 8	HELCO-1201		calculated	Exhibit CA-101, Schedule C, page 1	calculated

Note 1: $32,856 (from HELCO-1201) less $668.5 (from Exhibit CA-101, Schedule C-17) less $420.4 (from Exhibit CA-101, Schedule C-18) = $31,767
2: Consumer Advocate did not take issue with the amount presented in HELCO's direct testimony

Hawaii Electric Light Company, Inc.
2006 Test Year
Accumulated Depreciation
($ Thousands)

Line	Description	A HELCO Direct Testimony Test Year Estimate	B HELCO Preliminary Actuals	C HELCO Adjusted Test Year 2006 (Actuals)	D Consumer Advocate Direct Testimony Test Year	E Settlement Agreed Upon Amounts
1	Accum Depn Beg Bal @ 1/1/06	317,408	317,408	317,408 d	316,319 a	316,810
	Plus:					
2	Depreciation Accrual	32,856	32,856	32,856 e	31,767 b	32,258
2a	Depreciation Transfer		216	216 f		(216)
3	Salvage	(43)	(19)	(19) f	(43) c	(19)
	Less:					
4	Retirements	(3,804)	(4,654)	(4,654) f	(3,804) c	(4,654)
5	Cost of Removal	(1,578)	(1,883)	(1,883) f	(1,578) c	(1,883)
6	Accum Depn End Bal @ 12/31/06	344,839	343,924	343,924	342,661	342,296
7	Average Balance for the Year	331,124	330,666	330,666	329,490	329,553

Sources	Column A	Column B	Column C	Column D	Column E
Line 1	HELCO-1202	Note 1	HELCO-RWP-1202	Note 2	settlement
Line 2	HELCO-1202	Note 1	HELCO-RWP-1202	Note 3	settlement
Line 2a		Note 1	HELCO-RWP-1202		settlement
Line 3	HELCO-1202	Note 1	HELCO-RWP-1202	Note 4	settlement
Line 4	HELCO-1202	Note 1	HELCO-RWP-1202	Note 4	settlement
Line 5	HELCO-1202	Note 1	HELCO-RWP-1202	Note 4	settlement
Line 6	HELCO-1202	Note 1	HELCO-RWP-1202	calculated	calculated
Line 7	HELCO-1202	Note 1	calculated	calculated	calculated

Note 1: Preliminary Actuals as reflected in CA-IR-448, HELCO T-16, page 7 and CA-SIR-47, page 5
2: $317,408 (from HELCO-1202) less $668.5 (from Exhibit CA-101, Schedule C-17) less $420.4 (from Exhibit CA-101, Schedule C-18) = $316,319
3: $32,856 (from HELCO-1202) less $668.5 (from Exhibit CA-101, Schedule C-17) less $420.4 (from Exhibit CA-101, Schedule C-18) = $31,767
4: Consumer Advocate did not take issue with the amount presented in HELCO's direct testimony
5: Analysis of variance between Consumer Advocate's direct testimony and HELCO's adjusted test year 2006 (actuals):

		column F Consumer Advocate	column G HELCO	column H (F-G) acc depn effect	column I (column H / 2 for 2006 amts) 2006 average effect on acc depn
Variance due to Keahole basis adj (effect on beg accum depn)	a	316,319 d	317,408	(1,089)	(1,089)
Variance due to Keahole basis adj (effect on 2006 depn accrual)	b	31,767 e	32,856	(1,089)	(545)
		348,086	350,264	(2,178)	(1,634)
Variance due to use by Consumer Advocate of HELCO's 2006 estimates from direct testimony vs. actuals used by HELCO	c	(5,425) f	(6,340)	915	458
		342,661	343,924	(1,263)	(1,176)

REBUTTAL TESTIMONY OF
LORIE S. K. ISHII

DIRECTOR
CORPORATE TAXES
HAWAIIAN ELECTRIC INDUSTRIES, INC.

Subject: Taxes Other Than Income Taxes
Income Tax Expense
Unamortized Net SFAS 109 Regulatory Asset
Unamortized Investment Tax Credits
Accumulated Deferred Income Taxes
Update on Simplified Service Cost Method Change

INTRODUCTION

Q. Please state your name and business address.

A. My name is Lorie S. K. Ishii and my business address is 900 Richards Street, Honolulu, Hawaii.

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

A. I am the Director of Corporate Taxes for Hawaiian Electric Industries, Inc. ("HEI").

Q. Have you previously testified in these proceedings?

A. Yes, I submitted written direct testimony, exhibits and supporting workpapers as HELCO T-13.

Q. What is the scope of your rebuttal testimony?

A. My rebuttal testimony will cover revisions to my original 2006 test year estimates for Hawaii Electric Light Company, Inc. ("HELCO" or "Company"). It will also cover the Company's rebuttal to the Consumer Advocate's testimony CA-T-1 in the areas of taxes other than income taxes, income tax expense, unamortized net SFAS 109 regulatory asset, unamortized investment tax credits and accumulated deferred income taxes. I will also provide an update on the status of the Company's simplified service cost method change request described in my previously filed testimony (HELCO T-13, pps. 21-22).

HELCO REBUTTAL POSITION

Q. What revisions have you made to the 2006 test year estimates presented in your direct testimony?

A. My rebuttal testimony presents revised estimates in the following areas:

1) Taxes Other Than Income Taxes—The Company's estimate of taxes other than income taxes was revised due to: (a) the reduction in test year end labor

costs, (b) the reduction in the PSC tax and PUC fee resulting from the reduction of gross revenues by the bad debt deduction, and (c) the update of revenue taxes for test year revision of revenues at present and proposed rates.

2) Income Taxes—The Company's estimate of income taxes was updated for: (a) revisions in the test year estimates of revenues and expenses at present and proposed rates, (b) revisions to the interest expense adjustment and the allowance for funds used during construction ("AFUDC") adjustment, and (c) the stand-alone calculation and application of the domestic production activities income deduction ("DPAD"). For purposes of this rate case only, the Company is agreeing, to accept the Consumer Advocate's proposed change in the tax effect of the DPAD (CA-T-1, Exhibit CA-101, Schedule C-20) in order to limit the issues in this proceeding.

3) Unamortized Net SFAS 109 Regulatory Assets and Liabilities—The Company revised its estimate of the net SFAS 109 Regulatory Asset balance to reflect recorded balances as of December 31, 2006.

4) Unamortized Investment Tax Credits—The Company revised its estimate of the Hawaii Capital Goods Excise Tax Credit to: (a) reflect recorded 2006 test year plant additions, and (b) reflect the effect of the $12,898,000 Keahole generating station ("Keahole") cost writedown as settled. Please refer to the discussion of this issue by Mr. Warren Lee at HELCO RT-1.

5) Accumulated Deferred Income Taxes—The Company's estimate of accumulated deferred taxes was revised to: (a) reflect recorded 2006 test year deferred income tax amounts, (b) exclude certain deferred income tax amounts that were agreed to pursuant to the inquiry and response process as summarized in CA-IR-447 (T-13), (c) exclude certain additional Consumer

1 Advocate ADIT adjustments as listed in CA-T-1, Exhibit CA-101, Schedule
2 B-3, and (d) include the effect of the deferred income tax amounts associated
3 with the Keahole cost writedown of $12,898,000.

4 AREAS OF AGREEMENT

5 Q. In what areas of your direct testimony is the Consumer Advocate in agreement
6 with the Company?
7 A. The Consumer Advocate and the Company agree on the following items or issues:
8 1) the methodology, base and rates used in calculating payroll taxes, 2) the
9 methodology, base and rates used in calculating the PSC tax, franchise royalty tax
10 and PUC fee, 3) the methodology and rates used in calculating income taxes,
11 including the computation of the interest expense adjustment, 4) the methodology,
12 base and rates used in calculating the tax credit estimates, and 5) the methodology
13 and rates used in calculating the SFAS 109 net regulatory asset and deferred
14 income taxes related to SFAS 109.
15 Q. Have the Company and Consumer Advocate reached an agreement on the
16 Keahole cost writedown?
17 A. Yes. The Company and Consumer Advocate have reached an agreement on
18 Keahole. Please refer to the discussion by Mr. Warren Lee at HELCO RT-1. The
19 adjustments to the ADIT, unamortized state ITC and amortization of the state ITC,
20 related to the Keahole cost disallowance, are discussed below.
21 Q. Are there any outstanding issues related to the areas of taxes other than income
22 taxes, income tax expense, unamortized net SFAS 109 regulatory asset,
23 unamortized investment tax credits and accumulated deferred income taxes in
24 dispute between the Company and the Consumer Advocate?
25 A. No.

1 Taxes Other Than Income Taxes

2 Q. What is the Company's revised 2006 test year estimate of taxes other than income
3 taxes?

4 A. Under present rates, the revised 2006 test year estimate of taxes other than income
5 taxes is $30,178,000. Under proposed rates, the revised 2006 test year estimate of
6 taxes other than income taxes is $32,354,000. See HELCO-R-1301.

7 Q. Why has the Company revised its estimate of 2006 test year taxes other than
8 income taxes?

9 A. The Company revised its 2006 test year taxes other than income taxes due to
10 changes in both its payroll and revenue taxes.

11 Q. What is the revised payroll tax estimate for the 2006 test year at present and
12 proposed rates?

13 A. The revised 2006 test year estimate for payroll taxes at present and proposed rates
14 is $1,442,000, which represents an $88,000 decrease from direct testimony. The
15 decrease in payroll taxes resulted from a decrease in FICA taxes due to a
16 reduction in estimated 2006 test year labor costs. This reduction in labor costs is
17 comprised of: 1) a decrease in production O&M labor costs, 2) a decrease in
18 transmission and distribution O&M labor, and 3) a reclassification of DSM labor.
19 Refer to HELCO-RWP-1301, Page 1.

20 Q. Prior to settlement discussions, why did the Company's revised payroll tax
21 expense at present and proposed rates differ from the Consumer Advocate's
22 estimate?

23 A. Although the Company applied the Consumer Advocate's methodology to
24 recalculate payroll tax expense in its rebuttal for expediency, HELCO's payroll
25 tax expense was $12,000 greater than the Consumer Advocate's estimate, due to

1 the Consumer Advocate's proposed additional reduction of transmission and
2 distribution O&M labor costs.
3 Q. Have the Company and Consumer Advocate reached an agreement on the
4 reduction of transmission and distribution O&M labor costs?
5 A. Yes. The Company and Consumer Advocate have agreed to an additional
6 reduction of $163,000 in transmission and distribution O&M labor costs. Please
7 refer to Mr. Jay Ignacio's discussion at HELCO RT-6. The Company has
8 presented the payroll tax effect of this agreement in its revised 2006 test year
9 estimate of payroll expense. Refer to HELCO-RWP-1301, Page 1 for the payroll
10 tax calculation.
11 Q. Are there any remaining issues related to payroll tax expense in dispute between
12 the Company and the Consumer Advocate?
13 A. No.
14 Q. Have the Company and the Consumer Advocate reached an agreement on the
15 resulting 2006 test year settlement amount for payroll taxes at present rates?
16 A. Yes. The Company and the Consumer Advocate agree on the resulting 2006 test
17 year settlement amount of $1,442,000 for payroll taxes at present rates, as shown
18 on HELCO-R-1301.
19 Q. What is the Company's revised 2006 test year estimate of revenue taxes under
20 present and proposed rates?
21 A. Under present rates, the revised 2006 test year estimate of revenue taxes is
22 $28,736,000, which represents a $27,000 decrease from direct testimony. Under
23 proposed rates, the revised 2006 test year estimate of revenue taxes is
24 $30,912,000, which represents a $508,000 decrease from direct testimony. Refer
25 to HELCO-R-1301.

1 Q. Why did the estimated 2006 test year revenue tax amount change?

2 A. The decrease resulted from: 1) the application of the bad debt deduction to gross
3 revenues for the PSC tax and PUC fee calculation, and 2) changes to 2006 test
4 year revenues.

5 Q. Why did the estimated 2006 test year revenues change?

6 A. Changes to test year revenues are discussed by Ms. Colleen Miller in HELCO
7 RT-3 and Mr. Paul Fujioka in HELCO RT-7.

8 Q. Prior to settlement discussions, what was the difference between HELCO's
9 revised 2006 test year estimate of revenue taxes and the Consumer Advocate's
10 estimate?

11 A. The Company's revised estimate of $28,736,000 at present rates was greater than
12 the Consumer Advocate's estimate by $387,000. The Company's revised estimate
13 of $30,912,000 at proposed rates was greater than the Consumer Advocate's
14 estimate by $1,087,000.

15 Q. Why was there a difference between the Company's estimate of the 2006 test year
16 revenue taxes and the Consumer Advocate's estimate?

17 A. The difference between the Company's estimate of revenue taxes and the
18 Consumer Advocate's estimate is primarily attributable to differences in the
19 estimated gross revenue base and related bad debt deduction used to calculate
20 revenue taxes.

21 Q. Are there any remaining issues related to revenue taxes in dispute between the
22 Company and the Consumer Advocate?

23 A. No.

24 Q. Have the Company and the Consumer Advocate reached an agreement on the
25 resulting 2006 test year settlement amount for revenue taxes at present rates?

A. Yes. The Company and the Consumer Advocate agree with the resulting 2006 test year settlement amount of $28,736,000 for revenue taxes at present rates.

Q. Have the Company and the Consumer Advocate reached an agreement on the resulting 2006 test year settlement amount for taxes other than income taxes at present rates?

A. Yes. The Company and the Consumer Advocate agree with the resulting 2006 test year settlement amount of $30,178,000 for taxes other than income taxes at present rates, as shown on HELCO-R-1301.

Income Taxes

Q. What is the Company's revised 2006 test year estimates of income tax expense at present and proposed rates?

A. Under present rates, the revised 2006 test year estimate of income tax expense is $3,624,000. Under proposed rates, the revised 2006 test year estimate of income tax expense is $12,324,000. See HELCO-R-1302.

Q. Why did the Company revise its estimate of income tax expense for the 2006 test year?

A. The Company revised its estimate of 2006 test year income tax expense to reflect the: 1) changes in estimated revenues and expenses used to determine operating income before taxes as discussed by the various witnesses, 2) revision of the Company's estimate of interest expense, which is used in the calculation of income tax expense, 3) update of the meals and entertainment disallowance based on the 2006 recorded amount, and 4) application of the stand-alone DPAD federal income tax benefit at present and proposed rates.

Q. Why did the Company revise its estimate of interest expense?

1 A. The Company revised its estimate of interest expense to reflect changes in the
2 estimated cost of debt securities as discussed by Ms. Tayne Sekimura in HELCO
3 RT-18. The interest expense was also adjusted, as a result of updating AFUDC
4 debt to the 12/31/06 recorded amount. Refer to HELCO-RWP-1302, page 1.
5 Q. What is the Consumer Advocate's position on the interest expense adjustment in
6 the income tax calculation?
7 A. The Consumer Advocate has not proposed an adjustment.
8 Q. Why did the Company revise its estimate of the meals and entertainment
9 disallowance in the income tax calculation?
10 A. The Company revised its estimate of the meals and entertainment disallowance to
11 reflect updated 12/31/06 recorded amounts. Refer to HELCO-RWP-1302, page 2.
12 Q. What is the Consumer Advocate's position on the meals and entertainment
13 disallowance in the income tax calculation?
14 A. The Consumer Advocate has not proposed an adjustment.
15 Q. Why did the Company reduce its 2006 test year income tax expense at proposed
16 rates for the federal income tax effect of DPAD?
17 A. The Company appeared to qualify for DPAD on a stand-alone basis, using the
18 2006 test year estimates of generation activity income at proposed rates. The
19 Company calculated its estimate of generation activity income based on its
20 allocated 2006 test year direct production cost of service percentages and applied
21 the 2006 test year deduction rate of 3%.
22 Q. Will the federal consolidated group qualify for DPAD in 2006?
23 A. The 2006 year end estimates of production activity income indicate that the
24 federal consolidated group will not qualify for DPAD in 2006. The HELCO
25 DPAD is a ratemaking adjustment only and represents an actual revenue

1 deficiency to the Company since the benefit is not expected to be realized in the
2 federal consolidated income tax return.
3 Q. Does the Consumer Advocate agree with the methodology used in calculating the
4 2006 test year DPAD at proposed rates?
5 A. Yes, the Consumer Advocate agrees with the methodology but has adjusted the
6 Company's calculated DPAD and federal income tax benefit.
7 Q. What is the difference between the Company's and the Consumer Advocate's
8 estimate of DPAD?
9 A. The Company allocated its production revenues, at proposed rates, and certain
10 expenses based on its 2006 test year production cost of service, as adjusted for
11 purchase power revenues. However, certain expenses such as fuel cost,
12 production asset depreciation and State ITC were directly attributed to the
13 production activity as these amounts were specifically related to the generation
14 activity; i.e., no allocation factor was applied. The Consumer Advocate's
15 adjustment to DPAD was erroneously calculated by applying an adjustment factor
16 to estimated total taxable income from generation (CA-T-1, Exhibit CA-101,
17 Schedule C-20, Line 6), to effectuate its proposed lower 2006 "weighted cost of
18 equity capital." Direct costs attributable to the production activity, such as fuel
19 and production asset depreciation, should not be subject to this adjustment factor.
20 The Company estimates that if it applied the Consumer Advocate's adjustment
21 factor to the appropriate amounts in the DPAD calculation, there would be a
22 significant reduction in DPAD for the 2006 test year under proposed rates.
23 However, the Company has agreed to the Consumer Advocate's DPAD
24 adjustment in proposed rates, for this rate case only, to minimize the number of
25 issues in this proceeding.

1 Q. Does the Company agree with the Consumer Advocate's application of the same
2 DPAD to present rates?
3 A. No, the Company does not agree that the same DPAD calculation at proposed
4 rates should be applied to present rates. The Company's DPAD calculation used
5 by the Consumer Advocate in its adjustment to present rates was based on
6 proposed rates. Consequently, the federal income tax benefit of DPAD (based on
7 production income at proposed rates) is overstated. The resulting lower federal
8 income tax expense at present rates understates the Company's revenue
9 deficiency. However, the Company has agreed to the Consumer Advocate's
10 DPAD adjustment in present rates, for this rate case only, to minimize the number
11 of issues in this proceeding.
12 Q. Prior to settlement discussions, what was the difference between the Company's
13 estimate of income tax expense for the 2006 test year and the Consumer
14 Advocate's estimates?
15 A. The Company's estimate of income tax expense under present rates for the 2006
16 test year of $3,624,000 was less than the Consumer Advocate's estimate by
17 $1,046,000. The Company's estimated income tax expense under proposed rates
18 for the 2006 test year of $12,324,000 was greater than the Consumer Advocate's
19 estimate by $1,760,000. Refer to HELCO-R-1302.
20 Q. What was the reason for the remaining difference between the Company's
21 estimate of income tax expense and the Consumer Advocate's estimate of income
22 tax expense for the 2006 test year?
23 A. The remaining difference was primarily the result of differences in estimated
24 revenues and expenses used to determine pre-tax operating income.

1 Q. Have the Company and the Consumer Advocate reached an agreement on the
2 resulting 2006 test year settlement amount for income taxes at present rates?
3 A. Yes. Although the Company does not agree with the Consumer Advocate's
4 calculation of its DPAD adjustment and its application to present rates, the
5 Company has agreed to the Consumer Advocate's ($160,000) adjustment for the
6 purpose of minimizing issues in this proceeding. Refer to CA-T-1, Exhibit
7 CA-101, Exhibit C-20, Line 8. The Company and the Consumer Advocate agree
8 with the resulting 2006 test year settlement amount of $3,624,000 for income
9 taxes at present rates, as shown on HELCO-R-1302.
10 Q. Are there any remaining issues related to income tax expense at present rates in
11 dispute between the Company and the Consumer Advocate?
12 A. No.
13 Unamortized Net SFAS 109 Regulatory Asset
14 Q. What is the revised ending balance of the unamortized net SFAS 109 regulatory
15 asset for the 2006 test year?
16 A. The revised 2006 test year balance for the net unamortized SFAS 109 regulatory
17 asset is $10,655,000. See HELCO-R-1305.
18 Q. Why did HELCO revise its 2006 test year estimates?
19 A. The balance was revised to reflect the recorded balance as of the end of 2006.
20 Q. What is the Consumer Advocate's position on the unamortized net SFAS 109
21 regulatory asset balances for the 2006 test year?
22 A. The Consumer Advocate has not proposed an adjustment.
23 Q. Have the Company and the Consumer Advocate reached an agreement on the
24 2006 average test year balance for the unamortized net SFAS 109 regulatory
25 asset?

A. Yes. The Company and the Consumer Advocate agree on the 2006 average test year balance of $10,772,000, as shown on HELCO-R-1305.

Unamortized Investment Tax Credits

Q. What is the revised 2006 test year unamortized investment tax credit balances?

A. The revised 2006 beginning and ending estimated unamortized investment tax credit balances for the 2006 test year are $11,247,000 and $11,877,000, respectively. See HELCO-R-1303.

Q. Why did the Company revise its beginning 2006 test year unamortized investment tax credit balance?

A. The Company revised its beginning 2006 test year unamortized investment tax credit balance to reduce the 2005 beginning balance and related state ITC amortization associated with the Keahole writedown. This change reduces the beginning 2006 test year balance by $308,000. Refer to HELCO-RWP-1303.

Q. Why did the Company revise its ending 2006 test year unamortized investment tax credit balance?

A. The Company revised its ending 2006 test year unamortized investment tax credit balance to carry forward the revised beginning 2006 test year unamortized state ITC balance and to reduce the 2006 state ITC amortization associated with the Keahole writedown. Refer to HELCO-RWP-1303. This adjustment reduces the ending 2006 test year by $298,000. The Company also revised its estimate of the Hawaii Capital Goods Excise Tax Credit to reflect recorded 2006 test year plant additions.

Q. What is the Consumer Advocate's position on unamortized investment tax credit balance for the 2006 test year?

1 A. The Company and the Consumer Advocate have agreed to reduce the 2006 test
2 year unamortized investment tax credit balance and state ITC amortization related
3 to the Keahole writedown. The Consumer Advocate has also accepted the
4 Company's revised estimate of plant additions.
5 Q. Are there any remaining issues related to 2006 average test year unamortized
6 investment tax credit balance in dispute between the Company and the Consumer
7 Advocate?
8 A. No.
9 Q. Have the Company and the Consumer Advocate reached an agreement on the
10 resulting 2006 average test year unamortized tax credit balance?
11 A. Yes. The Company and the Consumer Advocate agree on the 2006 average test
12 year balance of $11,562,000 for unamortized investment tax credits, as shown on
13 HELCO-R-1303.
14 Accumulated Deferred Income Taxes
15 Q. What is the revised estimated 2006 test year accumulated deferred income tax
16 balances?
17 A. The revised beginning and ending estimated accumulated deferred income tax
18 ("ADIT") balances for the 2006 test year are $26,108,000 and $25,631,000,
19 respectively. See HELCO-R-1304.
20 Q. Why did the Company revise its 2005 and 2006 test year estimates of ADIT?
21 A. The Company revised its estimates of ADIT to: 1) update ADIT to recorded
22 balances as of December 31, 2006, 2) exclude certain ADIT accounts that the
23 Company identified and agreed should be excluded as summarized in our
24 response to CA-IR-447 (T-13), 3) exclude the deferred tax amounts associated
25 with bad debt, 4) adjust beginning 2006 test year balances to include the deferred

1 tax amounts associated with the "true-up of recorded ADIT for 2005 tax return",
2 5) adjust 2006 beginning test year balances to include IRS examination
3 adjustments to deferred tax amounts, 6) exclude the deferred tax amounts
4 associated with IRP, DSM and energy services, as proposed by the Consumer
5 Advocate in CA-T-1, CA-101, Schedule B-3, lines 19-21, for the purpose of
6 minimizing issues in this proceeding, and 7) exclude the deferred income tax
7 amounts associated with the Keahole writedown of $12,898,000.
8 Q. Prior to settlement discussions, what were the differences between the Company's
9 revised 2006 test year ADIT balances and the Consumer Advocate's balances?
10 A. The Company's revised ADIT balance at the beginning of the 2006 test year is
11 $26,108,000, which was $393,000 less than the Consumer Advocate's estimate
12 and the revised ADIT balance at the end of the 2006 test year is $25,631,000,
13 which was $564,000 less than the Consumer Advocate's estimate. See HELCO-
14 R-1304.
15 Q. Prior to settlement discussions, what was the difference between the Company's
16 2006 test year beginning ADIT balance and the Consumer Advocate's balance?
17 A. The differences between the Company's ADIT balance and the Consumer
18 Advocate's balance at the beginning of 2006 test year were as follows:
19 1) The Consumer Advocate made a mathematical error in calculating the
20 exclusion on the gain on the Mililani ADIT (CA-T-1, Exhibit CA-101,
21 Schedule B-3, Line 10). The Consumer Advocate agreed to the correction in
22 its response to HELCO/CA-IR-103. The result of this change was to reduce
23 the beginning of year ADIT by $2,000.
24 2) The Consumer Advocate erroneously excluded the deferred tax amounts
25 associated with the amortization of revenue bond interest differential and the

revenue bond redemption/premium costs (CA-T-1, Exhibit CA-101, Schedule B-3, lines 22-23) from rate base. The unamortized investment income differential (refer to the Company's response to CA-IR-470) and unamortized issuance and redemption costs are a component in the calculation of cost of capital. As such, it was erroneous to exclude the related deferred tax amounts from rate base. The Consumer Advocate has reconsidered and conceded its adjustment in its response to HELCO/CA-IR-106. The result of this change was to increase the beginning of year ADIT by $382,000.

3) The Consumer Advocate, in its response to HELCO/CA-IR-101, contended that it was proper to restate the 12/31/05 ADIT balance for adjustments ("post year end adjustments") arising from the finalization of the 2005 income tax returns. The Consumer Advocate's rationale for restating the 12/31/05 recorded balance for post year end adjustments was "to improve upon the accuracy of previously recorded estimated ADIT balances of as December 31, 2005..." However, this position was not consistent with the Consumer Advocate's treatment of the deferred tax adjustment booked by the Company in 2006, related to the settlement of IRS audits and amended returns. In the Company's response to CA-IR-283, the Company explained that it booked a $400,000 deferred tax asset related to the settlements noted above. However, the Consumer Advocate did not propose an adjustment to restate the 12/31/05 balance for this adjustment. Under the Consumer Advocate's rationale stated above, the 12/31/05 balance should include these adjustments because these ADIT adjustments relate to prior years. The Consumer Advocate has agreed with this change. The result of this agreement was to reduce the beginning of year ADIT by $400,000.

4) The Company and the Consumer Advocate have agreed to reduce the 2006 beginning test year ADIT related to tax accelerated depreciation associated with the $12,898,000 writedown in Keahole costs. The Company and the Consumer Advocate have agreed that it is appropriate to exclude the accumulated deferred tax liabilities associated with accelerated depreciation. In addition, as discussed above, the unamortized state ITC related to the Keahole costs was also adjusted. Therefore, the deferred tax amounts related to the unamortized state ITC should also be excluded. The result of this agreement was to reduce the beginning of year ADIT by $375,000. Refer to HELCO-R-1304.

Q. Prior to settlement discussions, what was the difference between the Company's 2006 test year ending balance and the Consumer Advocate's balance?

A. The differences between the Company's ADIT balance and the Consumer Advocate's balance at the end of 2006 test year were as follows:

1) The Consumer Advocate erroneously double counted the exclusion of the deferred tax amount relating to supplemental pension and executive life insurance in the ending 2006 test year balance (already included in the preliminary actual balance in CA-SIR-18, p. 4). The Consumer Advocate agreed to the correction in its response to HELCO/CA-IR-102. The result of this change was to reduce the end of year ADIT by $339,000.

2) The Consumer Advocate erroneously excluded the deferred tax amounts associated with the amortization of revenue bond interest differential and the revenue bond redemption/premium costs (CA-T-1, Exhibit CA-101, Schedule B-3, lines 22-23) from rate base. As discussed above, the Consumer Advocate has reconsidered and conceded its position in its response to

HELCO/CA-IR-106. The result of this change was to increase the end of year ADIT by $363,000.

3) The Company and the Consumer Advocate have agreed to reduce the 2006 test year ending ADIT for deferred tax balances related to accelerated depreciation associated with the $12,898,000 writedown in Keahole costs and the related unamortized state ITC. The result of this agreement was to reduce the end of year ADIT by $563,000. Refer to HELCO-R-1304.

4) The remaining difference is primarily attributed to the Company's update of its end of year ADIT to reflect recorded balances as of December 31, 2006. The Consumer Advocate's end of year ADIT balances reflected preliminary year end ADIT balances provided by the Company in its response to CA-SIR-18. The Company noted in its response that it was providing preliminary actual balances as the books were not closed as of the date of the response.

Q. Have the Company and the Consumer Advocate reached an agreement on the average 2006 test year balance for accumulated deferred income taxes?

A. Yes. Although the Company does not agree with all of the Consumer Advocate's adjustments to ADIT, for the purposes of settlement, the Company and the Consumer Advocate agree on an average 2006 test year balance of $25,870,000 for accumulated deferred income taxes, as shown on HELCO-R-1304.

Q. Are there any remaining issues related to 2006 average test year accumulated deferred income taxes in dispute between the Company and the Consumer Advocate?

A. No.

1 UPDATE ON SIMPLIFIED SERVICE COST METHOD CHANGE

2 Q. What is the Consumer Advocate's position regarding the potential adjustment for
3 the change in accounting method for determining the deduction for mixed service
4 costs?

5 A. The Consumer Advocate did not propose an adjustment because the amount of the
6 adjustment was not determinable at the time the Company's direct testimony was
7 filed.

8 Q. What is the status of the application to the Internal Revenue Service for a change
9 in accounting method related to the overhead costs allocated to self-constructed
10 assets—i.e., the simplified service cost method?

11 A. On February 9, 2007, the Company received a letter from the Internal Revenue
12 Service (IRS) granting permission to change its method of accounting to the
13 simplified service cost method, subject to the guidance in Revenue Ruling 2005-
14 53 and any other administrative guidance or directives subsequently issued by the
15 IRS.

16 Q. How does the receipt of this consent to change affect HELCO?

17 A. The IRS has granted HELCO permission to change its accounting method of
18 allocating overhead costs, and this would prompt the filing of amended returns for
19 2001. However the permission was subject to the guidance in Revenue Ruling
20 2005-53, and any amended return filed under the new method will be subject to
21 examination by the IRS. As described in my previously filed testimony (HELCO
22 T-13, pps. 21-22), this ruling defined qualifying self-constructed assets to include
23 only short-lived assets (three years or less). Substantially all of HELCO's utility
24 assets are long-lived assets and as such, would not qualify for the new method.
25 Consequently, without further guidance, the IRS consent to change should have

1 no impact on the 2006 test year. The IRS is expected to issue further guidance,
2 but the timing of issuance and the form of this future guidance remains unclear.
3 Q. What other information on this issue has the Company received from its
4 consultants (Deloitte & Touche LLP)?
5 A. The consultants have indicated that a few test cases have been settled with the
6 taxpayer sustaining a portion of the benefits claimed.
7 Q. How does this impact the Company?
8 A. The Company will have to file amended return claims for an amount, not yet
9 determined, generally based on the amounts settled for in the test cases. However,
10 any amounts claimed are subject to examination and the ultimate outcome cannot
11 be determined at this time.
12 Q. How does this impact the 2006 test year ADIT?
13 A. Based on the IRS published guidance to date and the indeterminate status of a
14 potential claim by the Company, HELCO's estimated 2006 test year ADIT should
15 not include any adjustment if the potential impact cannot be determined. In
16 addition, the new regulations require that any prior year tax return benefits derived
17 from the change in accounting method be reversed and paid back by the tax year
18 ending December 31, 2006. Thus, any potential deferred income taxes related to
19 the accelerated deductions would be completely reversed as of December 31,
20 2006.
21 Q. Does this conclude your testimony?
22 A. Yes, it does.

HAWAII ELECTRIC LIGHT COMPANY, INC.
TAXES OTHER THAN INCOME TAXES CHARGED TO OPERATIONS
2006

($ Thousands)

		At present rates			
		HELCO Direct	Consumer Advocate	HELCO / CA Settlement Test Year 2006	Reference
	PAYROLL TAXES				
1	F.I.C.A. Taxes	1,442	1,350	1,362	HELCO-RWP-1301, p. 1
2	Federal Unemployment Taxes	15	14	14	HELCO-RWP-1301, p. 1
3	State Unemployment Taxes	73	66	66	HELCO-RWP-1301, p. 1
4	Total Payroll Taxes	1,530	1,430	1,442	
	REVENUE TAXES				
5	Public Service Company Taxes	19,073	18,793	19,049	HELCO-RWP-1301, p. 2
6	Public Utility Fees	1,620	1,596	1,618	HELCO-RWP-1301, p. 2
7	Franchise Royalty Taxes	8,070	7,960	8,069	HELCO-RWP-1301, p. 2
8	Total Revenue Taxes	28,763	28,349	28,736	
9	Total Taxes Other Than Income Taxes	30,293	29,779	30,178	HELCO-R-1302

		At proposed rates			
		HELCO Direct	Consumer Advocate	HELCO / CA Settlement Test Year 2006	
	PAYROLL TAXES				
1	F.I.C.A. Taxes	1,442	1,350	1,362	HELCO-RWP-1301, p. 1
2	Federal Unemployment Taxes	15	14	14	HELCO-RWP-1301, p. 1
3	State Unemployment Taxes	73	66	66	HELCO-RWP-1301, p. 1
4	Total Payroll Taxes	1,530	1,430	1,442	
	REVENUE TAXES				
5	Public Service Company Taxes	20,834	19,771	20,493	HELCO-RWP-1301, p. 2
6	Public Utility Fees	1,770	1,679	1,741	HELCO-RWP-1301, p. 2
7	Franchise Royalty Taxes	8,816	8,375	8,678	HELCO-RWP-1301, p. 2
8	Total Revenue Taxes	31,420	29,825	30,912	
9	Total Taxes Other Than Income Taxes	32,950	31,255	32,354	HELCO-R-1302

HAWAII ELECTRIC LIGHT COMPANY, INC.
COMPUTATION OF INCOME TAX EXPENSE
2006
(In Thousands)

		At present rates			
		HELCO Direct	Consumer Advocate	HELCO / CA Settlement Test Year 2006	Reference
1	Total Operating Revenues	324,089	319,724	324,073	HELCO-R-2101
	Operating Expenses:				
2	Fuel Oil and Purchased Power	196,143	191,964	195,793	HELCO-R-2101
3	Other Operation & Maint Exp	50,335	47,303	50,042	HELCO-R-2101
4	Depreciation & Amortization	29,374	28,285	28,772	HELCO-R-2101
5	Amort of State ITC	(501)	(501)	(490)	HELCO-R-2101
6	Taxes Other Than Income Taxes	30,293	29,778	30,178	HELCO-R-1301
7	Other Interest, Net	56	56	56	HELCO-R-2101
8	Total Operating Expenses	305,700	296,885	304,351	
9	Operating Income Before Taxes	18,389	22,839	19,722	
	Tax Adjustments:				
10	Interest Expense	(10,438)	(10,438)	(10,021)	HELCO-RWP-1302, p. 1
11	Meals & Entertainment	12	12	24	HELCO-RWP-1302, p. 2
12	Total Tax Adjustments	(10,426)	(10,426)	(9,997)	
13	Taxable Income for Rate-Making	7,963	12,413	9,725	
14	Income Tax Expense Before Adjustments (At Composite Rate of 38.9097744%)	3,098	4,830	3,784	
15	Less: Tax Benefit of Domestic Production Activities Deduction		(160)	(160)	Exh. CA-101, Sch. C-20, Line 8
16	TOTAL INCOME TAX EXPENSE	3,098	4,670	3,624	

		At proposed rates			
		HELCO Direct	Consumer Advocate	HELCO / CA Settlement Test Year 2006	
17	Total Operating Revenues	354,020	336,367	348,638	HELCO-R-2101
	Operating Expenses:				
18	Fuel Oil and Purchased Power	196,143	191,964	195,793	HELCO-R-2101
19	Other Operation & Maint Exp	50,371	47,323	50,071	HELCO-R-2101
20	Depreciation & Amortization	29,374	28,285	28,772	HELCO-R-2101
21	Amortization of State ITC	(501)	(501)	(490)	HELCO-R-2101
22	Taxes Other Than Income Taxes	32,950	31,254	32,354	HELCO-R-1301
23	Other Interest, Net	56	56	56	HELCO-R-2101
24	Total Operating Expenses	308,393	298,381	306,556	
25	Operating Income Before Taxes	45,627	37,986	42,082	
	Tax Adjustments:				
26	Interest Expense	(10,438)	(10,438)	(10,021)	HELCO-RWP-1302, p. 1
27	Meals & Entertainment	12	12	24	HELCO-RWP-1302, p. 2
28	Total Tax Adjustments	(10,426)	(10,426)	(9,997)	
29	Taxable Income for Rate-Making	35,201	27,560	32,085	
30	Income Tax Expense Before Adjustments (At Composite Rate of 38.9097744%)	13,697	10,724	12,484	
31	Less: Tax Benefit of Domestic Production Activities Deduction	-	(160)	(160)	Exh. CA-101, Sch. C-20, Line 8
32	TOTAL INCOME TAX EXPENSE	13,697	10,564	12,324	

HAWAII ELECTRIC LIGHT COMPANY
STATE CAPITAL GOODS EXCISE TAX CREDIT
TEST YEAR 2006

(In Thousands)

		HELCO Direct	Consumer Advocate	HELCO Before Settlement	Keahole Settlement Adjustment		HELCO / CA Settlement Test Year 2006
BALANCE AT 12/31/05							
1	Beginning Balance	9,967	9,967	9,967	(319)	(a)	9,648
2	Amortization of State ITC	(447)	(447)	(447)	11	(a)	(436)
3	Additions	2,035	2,035	2,035			2,035
4	Ending Balance	11,555	11,555	11,555	(308)		11,247
2006 CHANGES, NET							
5	Amortization of State ITC	(501)	(501)	(501)	11	(a)	(490)
6	Additions	981	1,121	1,121			1,121
		480	620	620	11		631
BALANCE AT 12/31/06		12,035	12,175	12,175	(298)		11,877
AVERAGE BALANCE		**11,795**	**11,865**	**11,865**	**(303)**		**11,562**

(a) Refer to HELCO-RWP-1303 for calculation of change in 2005 state ITC additions and amortization of state ITC.

NOTE: Totals may not add exactly due to rounding.

HAWAII ELECTRIC LIGHT COMPANY
DEFERRED INCOME TAX BY INDIVIDUAL ITEMS
AND YEAR END BALANCES
TEST YEAR 2006

(In Thousands)		HELCO Direct	Consumer Advocate	HELCO Before Adjustment	Keahole Settlement Adjustment		HELCO/CA Settlement Test Year 2006
BALANCE AT 12/31/05							
	Accelerated Depreciation over Straight Line						
1	Federal	(19,032)	(19,096)	(18,761)	418	(a)	(18,343)
2	State	(2,377)	(2,389)	(2,324)	76	(b)	(2,248)
3	Subtotal	(21,408)	(21,485)	(21,085)	495		(20,590)
	All Other Items						
4	Federal	(3,177)	(4,210)	(4,530)	(101)	(a)	(4,631)
5	State	(660)	(806)	(868)	(19)	(b)	(887)
6	Subtotal	(3,837)	(5,016)	(5,398)	(120)		(5,518)
7	Total	(25,245)	(26,501)	(26,483)	375		(26,108)
2006 ADDITIONS AND ADJUSTMENTS							
	Accelerated Depreciation over Straight Line						
8	Federal	445	544	208	156		364
9	State	4	26	(39)	28		(11)
10	Subtotal.	449	570	169	184		353
	All Other Items						
11	Federal	90	(217)	109	3		112
12	State	7	(47)	11	1		12
13	Subtotal	97	(264)	120	4		124
14	Total	546	306	289	188		477
BALANCE AT 12/31/06							
	Accelerated Depreciation over Straight Line						
15	Federal	(18,587)	(18,552)	(18,553)	574	(c)	(17,979)
16	State	(2,373)	(2,363)	(2,363)	105	(d)	(2,258)
17	Subtotal	(20,960)	(20,915)	(20,916)	679		(20,237)
	All Other Items						
18	Federal	(3,087)	(4,427)	(4,421)	(98)	(c)	(4,519)
19	State	(653)	(853)	(857)	(18)	(d)	(875)
20	Subtotal	(3,740)	(5,280)	(5,278)	(116)		(5,394)
21	Total	(24,699)	(26,195)	(26,194)	563		(25,631)
AVERAGE BALANCE		**(24,972)**	**(26,348)**	**(26,339)**	**469**		**(25,870)**

Amoutn Agreed To By HELCO and the
Consumer Advocate (Before Keahole Settlement) **(1,367)**

(a) Refer to HELCO-RWP-1304a, p. 2
(b) Refer to HELCO-RWP-1304b, p. 2
(c) Refer HELCO-RWP-1304a, p. 4
(d) Refer HELCO-RWP-1304b, p. 4

NOTE: Totals may not add exactly due to rounding.

HAWAII ELECTRIC LIGHT COMPANY, INC.
SFAS 109 RECONCILIATION
REGULATORY ASSETS AND LIABILITIES

(In Thousands)

	BALANCES AT 12/31/05	HELCO Direct	CA	HELCO Adjusted Test Year 2006	Reference
1	CWIP Equity Transition	102	102	102	HELCO-RWP-1305
2	SFAS 109 Flow Through	759	759	759	HELCO-RWP-1305
3	Plant Transition	1,751	1,751	1,751	HELCO-RWP-1305
4	CWIP Equity Ongoing	9,101	9,101	9,101	HELCO-RWP-1305
5	Federal ITC	(725)	(725)	(725)	HELCO-RWP-1305
6	Excess Def'd Taxes	(399)	(399)	(399)	HELCO-RWP-1305
7	Deficit Def'd Taxes	290	290	290	HELCO-RWP-1305
8	RAR 88-89	9	9	9	HELCO-RWP-1305
9	Total	10,888	10,888	10,888	

	BALANCES AT 12/31/06	HELCO Direct	CA	HELCO Adjusted Test Year 2006	
10	CWIP Equity Transition	96	96	96	HELCO-RWP-1305
11	SFAS 109 Flow Through	705	705	705	HELCO-RWP-1305
12	Plant Transition	1,626	1,626	1,626	HELCO-RWP-1305
13	CWIP Equity Ongoing	8,888	8,888	8,833	HELCO-RWP-1305
14	Federal ITC	(605)	(605)	(605)	HELCO-RWP-1305
15	Excess Def'd Taxes	(294)	(294)	(293)	HELCO-RWP-1305
16	Deficit Def'd Taxes	284	284	284	HELCO-RWP-1305
17	RAR 88-89	7	7	9	HELCO-RWP-1305
18	Total	10,707	10,707	10,655	
19	**AVERAGE BALANCE**	**10,798**	**10,798**	**10,772**	

HAWAII ELECTRIC LIGHT COMPANY, INC.
RECONCILIATION OF SFAS 109 REGULATORY ASSETS/LIABILITIES AND DEFERRED TAXES

(In Thousands)

HELCO DIRECT

	Description	Regulatory Asset/Liab Balance 12/31/2005	Federal Def Tax Balance 12/31/2005	State Def Tax Balance 12/31/2005	Other 12/31/2005	Total Def Tax Balance 12/31/2005
1	CWIP Equity Transition	102	(86)	(16)	0	(102)
2	SFAS 109 Flow Through	759	(642)	(117)	0	(759)
3	Plant Transition	1,751	(1,480)	(271)	0	(1,751)
4	CWIP Equity Ongoing	9,101	(7,694)	(1,407)	0	(9,101)
5	Federal ITC	(725)	613	112	-	725
6	Excess AccDep	(335)	110	20	204	334
7	Excess Deferred Taxes	(64)	21	4	39	63
8	Deficit AccDep	370	(121)	(22)	(226)	(370)
9	Deficit Deferred Taxes	(80)	2	4	74	80
10	RAR 88-89	9	(8)	(1)	-	(9)
11	Total	10,888	(9,285)	(1,694)	91	(10,888)

CA

	Description	Regulatory Asset/Liab Balance 12/31/2005	Federal Def Tax Balance 12/31/2005	State Def Tax Balance 12/31/2005	Other 12/31/2005	Total Def Tax Balance 12/31/2005
12	CWIP Equity Transition	102	(86)	(16)	0	(102)
13	SFAS 109 Flow Through	759	(642)	(117)	0	(759)
14	Plant Transition	1,751	(1,480)	(271)	0	(1,751)
15	CWIP Equity Ongoing	9,101	(7,694)	(1,407)	0	(9,101)
16	Federal ITC	(725)	613	112	-	725
17	Excess AccDep	(335)	110	20	204	334
18	Excess Deferred Taxes	(64)	21	4	39	63
19	Deficit AccDep	370	(121)	(22)	(226)	(370)
20	Deficit Deferred Taxes	(80)	2	4	74	80
21	RAR 88-89	9	(8)	(1)	-	(9)
22	Total	10,888	(9,285)	(1,694)	91	(10,888)

HELCO REBUTTAL

	Description	Regulatory Asset/Liab Balance 12/31/2005	Federal Def Tax Balance 12/31/2005 (A)	State Def Tax Balance 12/31/2005 (B)	Other 12/31/2005	Total Def Tax Balance 12/31/2005
23	CWIP Equity Transition	102	(86)	(16)	0	(102)
24	SFAS 109 Flow Through	759	(642)	(117)	0	(759)
25	Plant Transition	1,751	(1,480)	(271)	0	(1,751)
26	CWIP Equity Ongoing	9,101	(7,694)	(1,407)	0	(9,101)
27	Federal ITC	(725)	613	112	-	725
28	Excess AccDep	(335)	110	20	204	334
29	Excess Deferred Taxes	(64)	21	4	39	63
30	Deficit AccDep	370	(121)	(22)	(226)	(370)
31	Deficit Deferred Taxes	(80)	2	4	74	80
32	RAR 88-89	9	(8)	(1)	-	(9)
33	Total	10,888	(9,285)	(1,694)	91	(10,888)

(A) Refer to HELCO-R-1305.
(B) Refer to HELCO-RWP-1304a.
(C) Refer to HELCO-RWP-1304b.

HAWAII ELECTRIC LIGHT COMPANY, INC.
RECONCILIATION OF SFAS 109 REGULATORY ASSETS/LIABILITIES AND DEFERRED TAXES

(In Thousands)

HELCO DIRECT

	Description	Regulatory Asset/Liab Balance 12/31/2006	Federal Def Tax Balance 12/31/2006	State Def Tax Balance 12/31/2006	Other 12/31/2006	Total Def Tax Balance 12/31/2006
1	CWIP Equity Transition	96	(81)	(15)	0	(96)
2	SFAS 109 Flow Through	705	(596)	(109)	0	(705)
3	Plant Transition	1,626	(1,374)	(251)	-	(1,626)
4	CWIP Equity Ongoing	8,888	(7,515)	(1,374)	1	(8,888)
5	Federal ITC	(605)	512	94	-	605
6	Excess AccDep	(232)	76	14	141	231
7	Excess Deferred Taxes	(62)	21	4	38	62
8	Deficit AccDep	348	(115)	(21)	(213)	(348)
9	Deficit Deferred Taxes	(64)	(3)	3	65	65
10	RAR 88-89	7	(6)	(1)	-	(8)
11	Total	10,707	(9,082)	(1,657)	32	(10,707)

CA

	Description	Regulatory Asset/Liab Balance 12/31/2006	Federal Def Tax Balance 12/31/2006	State Def Tax Balance 12/31/2006	Other 12/31/2006	Total Def Tax Balance 12/31/2006
12	CWIP Equity Transition	96	(81)	(15)	0	(96)
13	SFAS 109 Flow Through	705	(596)	(109)	0	(705)
14	Plant Transition	1,626	(1,374)	(251)	-	(1,626)
15	CWIP Equity Ongoing	8,888	(7,515)	(1,374)	1	(8,888)
16	Federal ITC	(605)	512	94	-	605
17	Excess AccDep	(232)	76	14	141	231
18	Excess Deferred Taxes	(62)	21	4	38	62
19	Deficit AccDep	348	(115)	(21)	(213)	(348)
20	Deficit Deferred Taxes	(64)	(3)	3	65	65
21	RAR 88-89	7	(6)	(1)	-	(8)
22	Total	10,707	(9,082)	(1,657)	32	(10,707)

HELCO REBUTTAL

	Description	Regulatory Asset/Liab Balance 12/31/2006 (A)	Federal Def Tax Balance 12/31/2006 (B)	State Def Tax Balance 12/31/2006 (C)	Other 12/31/2006	Total Def Tax Balance 12/31/2006
23	CWIP Equity Transition	96	(81)	(15)	0	(96)
24	SFAS 109 Flow Through	705	(596)	(109)	0	(705)
25	Plant Transition	1,626	(1,374)	(251)	-	(1,626)
26	CWIP Equity Ongoing	8,833	(7,468)	(1,366)	1	(8,833)
27	Federal ITC	(605)	512	94	-	605
28	Excess AccDep	(231)	76	14	141	231
29	Excess Deferred Taxes	(62)	21	4	38	62
30	Deficit AccDep	348	(115)	(21)	(213)	(348)
31	Deficit Deferred Taxes	(64)	(3)	3	65	65
32	RAR 88-89	9	(8)	(1)	-	(9)
33	Total	10,655	(9,037)	(1,649)	32	(10,654)
						rounding

(A) Refer to HELCO-R-1305.
(B) Refer to HELCO-RWP-1304a.
(C) Refer to HELCO-RWP-1304b.