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

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August 29, 2005

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PUBLIC UTILITIES COMMISSION

William A. Bonnet
Vice President
Government & Community Affairs

The Honorable Chairman and Members of
the Hawaii Public Utilities Commission
Kekuanaoa Building
465 South King Street
Honolulu, Hawaii 96813

Dear Commissioners:

Subject: Docket No. 04-0113
HECO 2005 Test Year Rate Case

Attached are twelve sets (each set containing two binders) of HECO's responses to the

CA-RIR-1

Ref: RT- 4, Pages 2 – 3, Lines 21 – 27 and Line 1.

Please provide all of the P-MONTH Production Simulation Model input data files, for the test year period used in the HECO August 5, 2005 Rebuttal Testimony filing. Please provide this information in electronic spreadsheet format and hard copy format.

HECO Response:

Please see the attached files for the PMonth input file for HECO's Rebuttal Testimony production simulation run:

1. HE05TY1.ara
2. HE05TY1.rfc
3. HE05TY1.stu
4. HE05TY1.TRF
5. HE05TY1.uba
6. HE05TY1.ucs
7. HE05TY1.upf
8. HE05TYM1.umt
9. HE05TYR1.fcl
10. HE05TYR1.plt
11. HE05TYR1.sfu
12. HE05TYR2.eei
13. heco00.qlp
14. heco00.rl2
15. ptn1.hcp
16. ptn2.hcp
17. ptn3.hcp
18. pnt4.hcp
19. ptn5.hcp
20. ptn6.hcp
21. rdlc1.spn

These input files do not translate well to a hard copy. Please work with the attached input files that are provided.

CA-RIR-2

Ref: RT- 4, Pages 2 – 3, Lines 21 – 27 and Line 1.

Please provide all P-MONTH Production Simulation Model output reports, for the test year period in support of the August 5, 2005 Rebuttal Testimony filing, in electronic format and hard copy. This information should include dispatch costs (fuel and variable O&M) and energy generated by each resource in each month of the test year.

HECO Response:

Please see the attached file "HECO Rate Case Rebuttal Old Maint Sched Results 07052005.xls"

for the PMonth report for HECO's Rebuttal Testimony production simulation run results

CA-RIR-3

Ref: RT- 4, Pages 2 – 3, Lines 21 – 27, and Line 1.

Please provide the P-Month Production Simulation Model hourly and monthly energy output for each HECO unit, including the Kalaeloa and AES units that was calculated in support of the HECO August 5, 2005 Rebuttal Testimony Filing in electronic spreadsheet format and hard copy.

HECO Response:

Please see the following attached files for the PMonth output files for HECO's Rebuttal

Testimony production simulation run:

1. he05tyr2.c01
2. he05tyr2.c02
3. he05tyr2.dgn
4. he05tyr2.hec
5. he05tyr2.hr
6. he05tyr2.log
7. he05tyr2.mgc
8. he05tyr2.mo
9. he05tyr2.uc
10. he05tyr2.yr

These output files do not translate well to a hard copy. Please work with the attached output files that are provided.

CA-RIR-4

Ref. RT- 5, Page 2, Lines 10 – 17.

Please provide a copy of the power dispatch schedules for H-Power, in support of the August 5, 2005 Rebuttal Testimony filing, as modeled in the P-Month Production Simulation Model.

HECO Response:

Please see HECO's response to CA-RIR-1. The "ptn1.hcp" file is HPOWER's input file for the PMonth program's Rebuttal Testimony production simulation run. HPOWER is run at 90% of its capacity to reflect the 90% Availability Factor. HPOWER is run at 50% of its capacity during a single boiler maintenance outage.

CA-RIR-5

Ref. RT- 5, Page 2, Lines 10 – 17.

Please provide the specific dates for the maintenance schedule for H-Power in support of the August 5, 2005 Rebuttal Testimony filing, as modeled in the P-Month Production Simulation Model.

HECO Response:

Please see the "ptnl.hcp" file submitted in HECO's response to CA-RIR-1. The same input file that defines the dispatch schedules for HPOWER also defines the maintenance schedule.

CA-RIR-6

Ref: RT-21, pages 5-10.

Please provide an update to the responses to CA-IR-102 (reports of rating agencies that evaluate HECO and/or HEI).

HECO Response:

See the attached articles, as well as excerpts of the S&P article dated 7/6/2005 filed in the response to CA-IR-8 and the S&P report dated 5/31/05 which was presented as HECO-R-1614 in Ms. Sekimura's rebuttal testimony for available reports by rating agencies that evaluate HECO and/or HEI for the period 2004 to the present which were not included in the response to CA-IR-102.

Note: Most (if not all) of the information requested is copyrighted. The attached copy is being provided under the "fair use" exception to the copyright laws. Any copies made of the attachment are subject to the copyright laws.

STANDARD
&POOR'S

U.S. Utility Upgrades Beat Downgrades In Second Quarter, But Negative Watch Listings Grew

Primary Credit Analyst(s):
Barbara A Eiseman, New York (1) 212-438-7666;
barbara_eiseman@standardandpoors.com
Secondary Credit Analyst(s):
Brendan Dalton, New York;
brendan_dalton@standardandpoors.com

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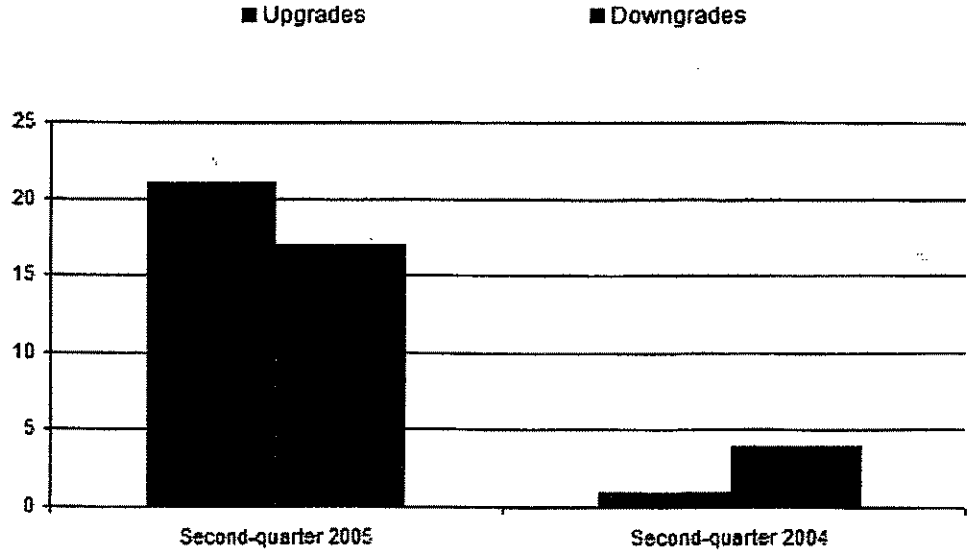
Recent Ratings Stability

Ratings activity in the U.S. investor-owned utility industry (electric, gas, pipeline, and water companies) picked up during the second quarter of 2005, with upside rating actions exceeding downgrades, a departure from the negative bias of recent years. Since Jan. 1, 2005, Standard & Poor's Ratings Services recorded 26 upgrades and 24 downgrades of holding companies and operating subsidiaries. In the second quarter alone, there were 21 upgrades and 17 downgrades. In contrast, there were only five upgrades and seven downgrades in the year-earlier quarter and 21 downgrades versus three upgrades during the first half of 2004 (see chart 1). However, there were numerous new negative CreditWatch listings and negative outlooks compared with just a couple of companies cited with upward credit improvement.

Chart 1

Rating Changes



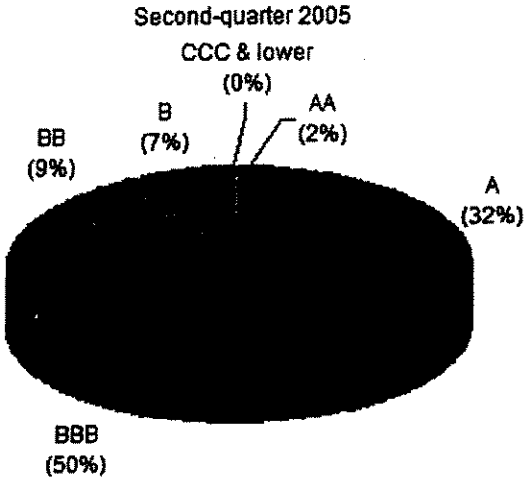
This past quarter's improved creditworthiness can be traced to various factors, including reduced exposure to riskier unregulated activities, stronger balance sheets, increasing free cash flow, enhanced liquidity, expectations of sustained profitability, improving regulatory relationships, better business profiles, the filing of a delayed 2004 Form 10-K, and credit-supportive actions by management. Despite the flurry of positive rating actions since April 1, 2005, a note of caution is warranted. The upgrades of El Paso Corp. and Allegheny Energy Inc. accounted for 11 of the 21 upgrades and were also from very low ratings, and are therefore not necessarily indicative of any industrywide momentum. In addition, CreditWatch listings and rating outlooks are good indicators of prospective rating actions and given the numerous new and existing negative CreditWatch listings and negative credit outlooks, any upturn in overall ratings quality is unlikely over the intermediate term.

The downside rating actions since April 1 are attributable to overall deterioration in bondholder protection measures, onerous construction programs, unrecovered investments, unresponsive rate decisions, a focus on shareholder enhancement, and more aggressive growth strategies.

The outlook for regulated utilities remains reasonably stable. Much of the industry has been

Chart 2

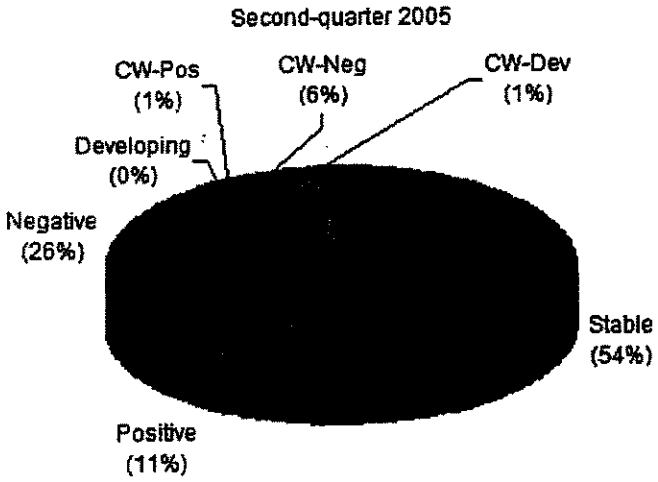
Utility Ratings Distribition



Despite moderation in the pace and severity of downside rating actions, any notable upturn in ratings quality is unlikely in the near term given the still large number of negative outlooks (79) and negative CreditWatch listings (18) (see chart 3). Any acceleration in merger and acquisition activity would also weigh heavily on creditworthiness over the intermediate term. Therefore, Standard & Poor's does not expect that the industry as a whole will deviate from the current mid 'BBB' category.

Chart 3

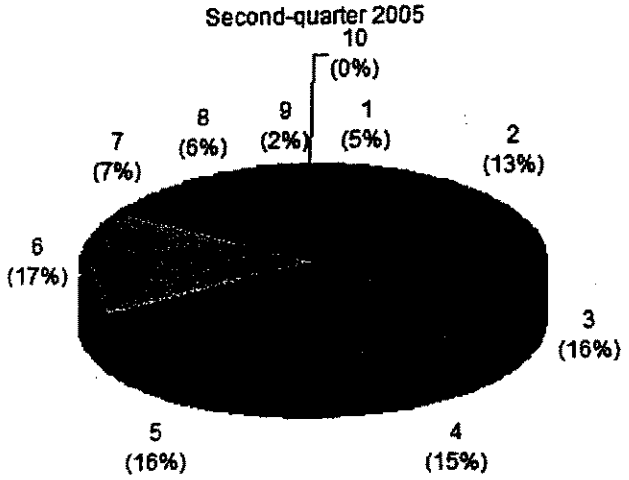
Utility Outlook Distribution



The U.S. power sector is relatively highly rated, certainly compared with the average 'BB' category for U.S. industrial companies. This is a function of the large percentage of firms (about 84%) carrying business profiles of '6' (considered satisfactory) and stronger. A firm's business profile is assessed on a '1' to '10' scale, where '1' represents "excellent" (see chart 4). It incorporates an analysis of the qualitative factors of management, competitive positioning, operations, markets, and regulation (if appropriate), as well as nonregulated businesses, typically merchant generation and energy trading and marketing.

Chart 4

[redacted]



Business profiles are scored on a 10-point scale, where '1' is considered "excellent" and '10' is "vulnerable."

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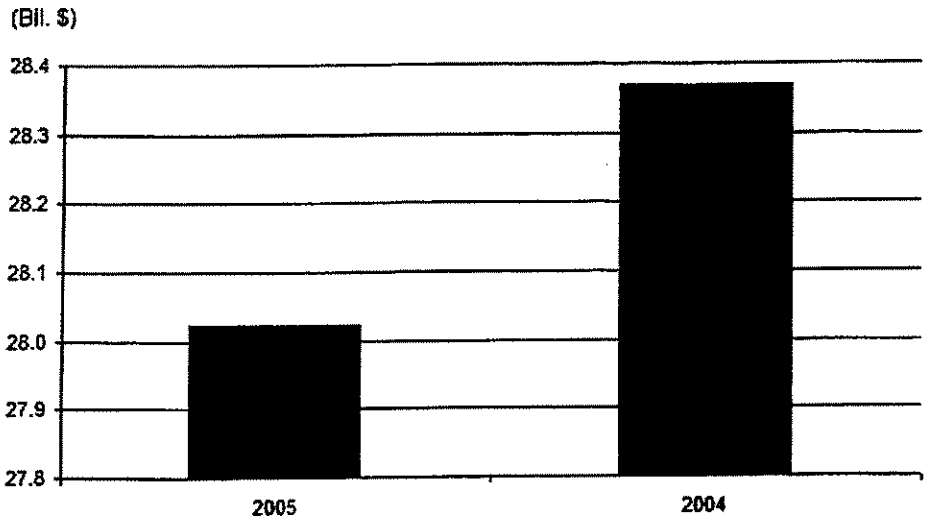
Capital Market Update

Financing activity for the U.S. power industry has stabilized in the past 12 months. The amount of medium- to long-term debt and preferred stock issued during the first half of this year was about $28 billion, which closely mirrors the $28.3 billion issued during the six months of 2004 (see chart 5). The leveling off of external financing can be traced to the significant amount of refinancing completed in early 2004 and Pacific Gas & Electric Co.'s massive $6.7 billion financing related to its emergence from bankruptcy in early 2004. Although interest rates are expected to continue to gradually rise, debt financing could increase later this year as many companies install new generating facilities, expand transmission and distribution facilities, are required to make new environmental modifications at coal-fired plants, and if merger and acquisition activity continues to

Chart 5

Debt Issuance

Second-quarter 2005



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Credit Protection Measures Gradually Improving

[redacted]

Chart 6

Adjusted FFO Interest Coverage

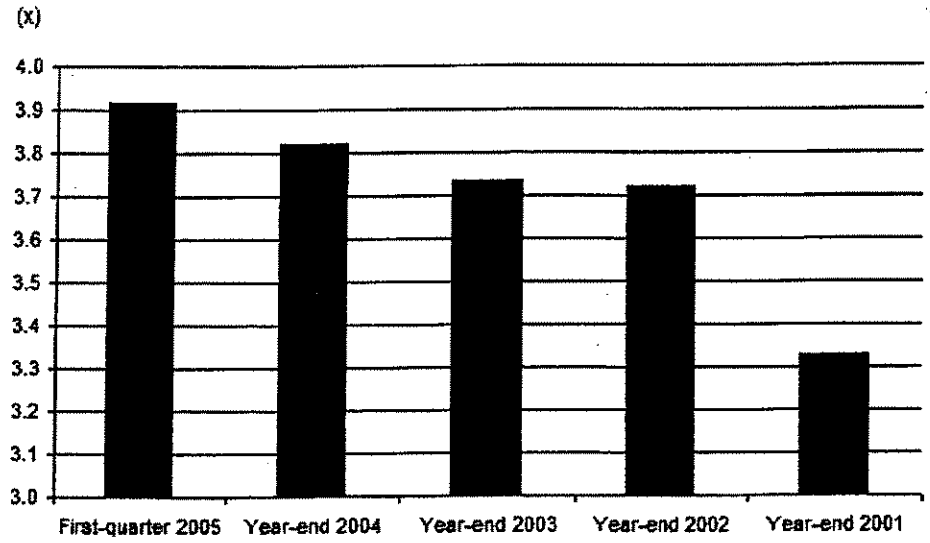


Chart 7

Adjusted FFO/Avg. Total Debt

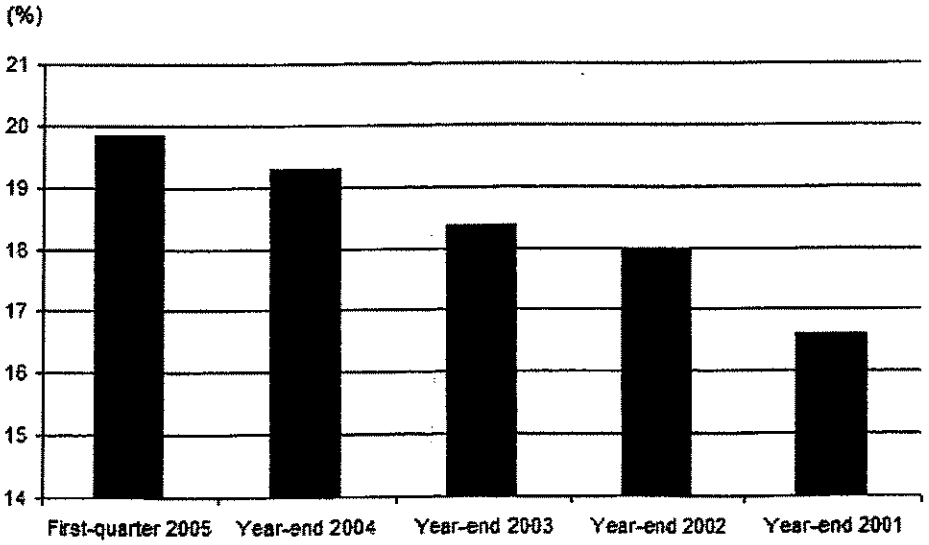


Chart 8

Adj. Total Debt/Total Capitalization

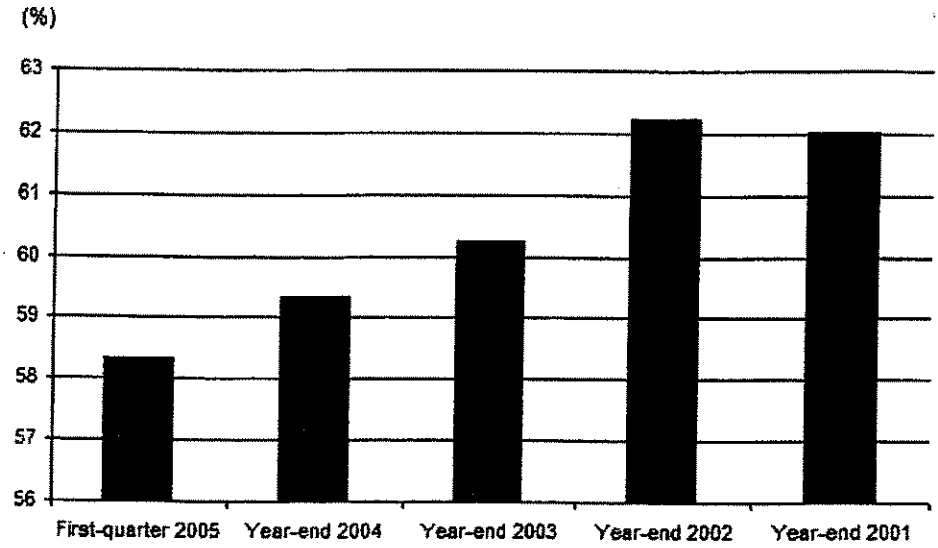
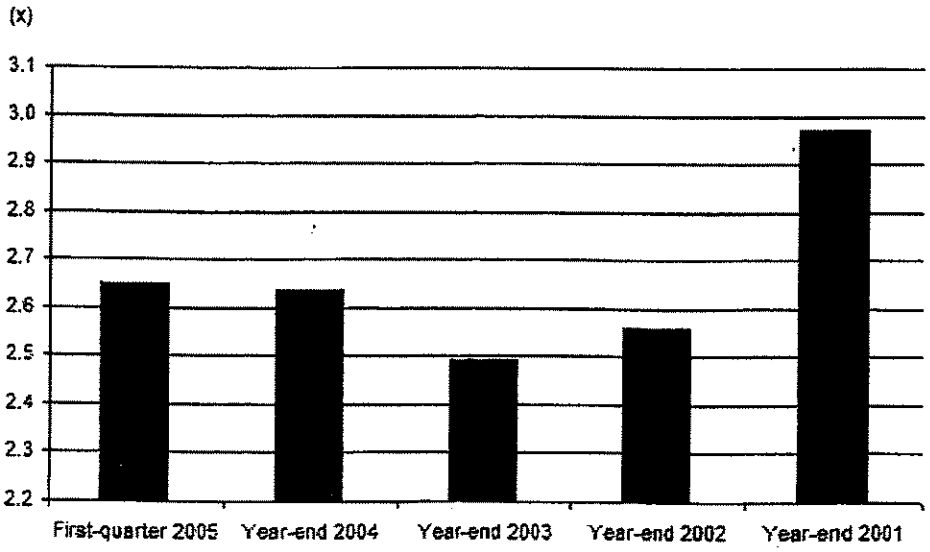


Chart 9

Adjusted EBIT/Interest Coverage



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Looking Ahead

The percentage of stable utility rating outlooks stood at 54%, closely mirroring the 56% level posted at the prior year's second quarter. This relatively high level of ratings stability is attributable mainly to the substantial number of ratings that had carried a negative outlook or CreditWatch listing and that have since been lowered. Although negative outlooks (26%) have declined from nearly 34% at June 30, 2004, they still overshadow positive outlooks, which stand at about 11%. This negative bias results mostly from deteriorating financial profiles, weak competitive positioning, investment in unregulated activities, regulatory uncertainty, a volatile wholesale power market, and acquisitions of financially weaker companies. CreditWatch listings stand at about 8%, and the predisposition is still overwhelmingly negative. A CreditWatch placement is typically driven by events such as mergers and acquisitions, or the vulnerability of an issuer to a potentially unsupportive regulatory decision. Of all the companies on CreditWatch, 72% carry a negative listing, 16% are developing (which indicates that a rating may be raised, lowered, or affirmed), and just 12% are positive.

Standard & Poor's expects the industry as a whole to retain its solid investment-grade characteristics. Traditional nondiversified utilities should remain relatively stable, with little

'B-', with the exception of El Paso Energy Credit Corp. (B+/Positive/--), whose rating was raised to 'B+' from 'B'. The upgrades recognize the progress the company has made in reducing exposure to unregulated operations and improving liquidity. Proceeds from asset sales and the issuance of $750 million of convertible preferred stock put the company in a much-improved position to meet its challenging near-term maturities, although refinancing risk remains a material concern. The exploration and production (E&P) business, where serious underperformance is a continuing cause for concern, has stabilized somewhat as shown by leveling production declines. Continued progress toward improving the financial profile and an improvement in E&P operations would result in another upgrade. The positive outlook reflects the assessment that El Paso is in an improved position to meet its looming debt maturities and that progress on its restructuring plan will allow management to focus on core businesses. Further ratings improvement would require additional progress on debt reduction, combined with stabilization of the upstream business. Similarly, failure to execute these plans would likely result in a stable outlook, and if the company's liquidity position were to significantly deteriorate, a downgrade could occur.

The ratings on NorthWestern Corp. (BB/Watch Neg/--) were raised because the new management has taken steps to improve regulatory relations, resolve litigation, and to strengthen the company. However, subsequently, on July 1 the ratings were placed on CreditWatch with negative implications pending clarity on Montana Public Power Inc.'s June 30, 2005 offer to buy NorthWestern for $1.18 billion plus the assumption of $825 million in debt. The CreditWatch listing reflects Standard & Poor's lack of information about Montana Public Power and the financing and legal structure of its bid for NorthWestern. Montana Public Power has indicated that it would use debt financing, which could harm NorthWestern's credit metrics. Should the offer be rejected or withdrawn, it is likely that Standard & Poor's will affirm ratings and assign a positive outlook. However, if the bid is approved, the ratings could be lowered or withdrawn, depending on the actions of the new owners.

The ratings on Texas-New Mexico Power Co. (BBB/Stable/--) were raised two notches and removed from CreditWatch with positive implications. The upgrade followed the closing of PNM Resources Inc.'s (BBB/Stable/A-2) acquisition of TNP Enterprises Inc., the previous parent of Texas-New Mexico Power. The rating on Texas-New Mexico Power now mirrors the corporate credit rating on PNM Resources and its electric and gas subsidiary, Public Service Co. of New Mexico (BBB/Stable/A-2). The stable outlook indicates that PNM Resources will finance the TNP Enterprises acquisition with a sufficient amount of common equity and mandatory convertible debt to maintain the 'BBB' corporate credit rating. This view takes into account the fact that proceeds from the remarketing of convertible debt in 2008 will be used to pay down $300 million of debt, while the capital structure is further strengthened by the issuance of $350 million of common equity. Upside rating potential may be limited by PNM Resources' growth strategy, which incorporates additional acquisitions. The possibility of lower ratings is mitigated by the Global Electric Agreement in New Mexico, which allows Public Service New Mexico to pursue its wholesale power strategy only if all debt ratings remain investment grade. A lower corporate credit rating would result in noninvestment-grade debt ratings at the holding company.

The ratings on DPL Inc. (BB/Positive/--) and its regulated subsidiary Dayton Power & Light Co. (BB/Positive/--) were raised and removed from CreditWatch with positive implications. The rating action follows the company's filing with the SEC of its audited financial statements 2004 Form 10-K with relatively minimal and immaterial restatements, and the completed sale of a significant portion of DPL's investment portfolio for net cash proceeds of about $520 million. The sale of a sizable portion of its higher-risk investment portfolio, combined with the fact that the company plans to use such proceeds toward debt reduction, bolsters DPL's creditworthiness by enhancing its business profile and should further improve its financials. The business profile score on DPL was improved to

'6' from '8' due to the sale and the expectations that the company will ultimately liquidate its remaining interest in its investment portfolio. The positive outlook incorporates new management's commitment to reconcile the company's former weak internal controls and corporate governance, combined with the utility's generation of sufficient cash flow and further reduction of DPL's debt. Upside rating action will be strongly correlated with the actual timing of the sale of its remaining interest in the investment portfolio assets and use of proceeds toward debt reduction and reinvestment needs in its core operations. Conversely, failure to reduce debt and improve cash flow would result in an outlook revision and/or downgrade.

The ratings on Allegheny Energy Inc. (BB-/Stable/B-2) were raised due to the company's progress in debt reduction using proceeds from asset sales and free cash flow, and through accelerated debt to equity conversion. Also supporting the upgrade is management's proactive approach in seeking regulatory relief and implementing cost reduction and reliability improvement initiatives. The positive outlook reflects the expectation that Allegheny will continue to execute its plan to pay down $1.5 billion or

The ratings on Questar Pipeline Co. (A-/Stable/--) and Questar Gas Co. (A-/Stable/--) were lowered two notches and the short-term ratings on parent Questar Corp. (BBB+/Stable/--) were lowered to 'A-2' from 'A-1'. The corporate credit rating on Questar Market Resources Inc. (QMR) was affirmed. The actions reflect Standard & Poor's reassessment of the relationships that exist among regulated and nonregulated entities at Questar. The intracompany relationships among the Questar family are marked by a generally free flow of funds and services. While affiliation with QMR serves Pipeline and Questar Gas well in the current market with oil and gas prices at a cyclical high, Standard & Poor's recognizes that, over the long term, affiliation with QMR exposes the regulated entities to cyclical pressures that are inconsistent with the previous ratings. The rating action on Questar's short-term rating reflects QMR's increasing use of the parent's commercial paper. Continued delays in contracting the western segment of the Southern Trails pipeline and the FERC's order mandating a credit to shippers of proceeds from Pipeline's sale of natural gas liquids resulting from the processing of wet gas also pressure Pipeline's stand-alone business risk profile. The Utah Commission's order that Questar Gas refund certain intracompany gas-processing costs previously recovered in rates also points to a moderate (negative) shift in the regulatory environment. Ratings stability reflects expectations that the company will maintain its current business risk profile and that financial performance will continue to benefit from strong oil and gas prices over the short term. Should internal funds fall short of the company's operating and capital needs, ratings could be lowered if the company uses higher levels of debt to fund nonregulated oil and gas E&P projects.

The ratings on Central Vermont Public Service Corp. (BB+/Stable/--) were lowered and removed from CreditWatch with negative implications. The downgrade is in response to a Vermont Public Service Board rate order requiring Central Vermont to provide refunds to customers of about $6 million in June 2005 and to cut rates by 2.75% effective April 1, 2005. The order represents an adverse shift in the regulatory climate, which heightens the company's business risk. The refund and rate limit the company's ability to generate positive discretionary cash flow, which is a material difference from previous years. Ratings stability reflects the expectation that the company's financial profile will not erode beyond current projections. Should FFO fall short of projections, the outlook may be revised to negative. Furthermore, should the company pursue additional discretionary capital projects or provide additional financial support for nonregulated projects, the outlook could be revised to negative. While Standard & Poor's considers it unlikely that the company will obtain substantive rate relief before 2007, should the company file for and obtain substantive rate relief before then, the outlook could be revised to positive.

The ratings on TXU Corp. (BBB-/Stable/--) and its units were lowered and removed from CreditWatch with negative implications. The 'BBB-' rating on TXU Electric Delivery Co.'s senior unsecured debt is in anticipation that the company will exercise its right to eliminate the "fall-away" lien on the secured bonds. The business risk profile on the company was changed to '7' from '5'. The rating actions reflect Standard & Poor's views that even though TXU's disposal of its nonperforming assets and restructuring of its debt over the past year and a half are highly beneficial to all stakeholders, TXU's willingness to use debt leverage to bolster its stock price and its strong earnings per share growth targets may be a source of continued tension with lenders' interests. Given the company's heavy focus on equity holders, Standard & Poor's current opinion is that a 'BBB-' rating is more appropriate for the company. The stable outlook incorporates the expectation that the company may continue to issue more debt to buy back stock and expand into higher-risk businesses, but only to a point shy of triggering a rating action. A fall in gas prices during the next two years is not likely to result in a rating action unless the ramifications on the retail business are beyond current expectations.

The ratings on TEPPCO Partners L.P. (BBB-/Stable/--) and TE Products Pipeline Co. L.P.

were lowered and removed from CreditWatch with negative implications following Standard & Poor's review of the ownership structure, corporate governance, and proposed funding after affiliates of EPCO Inc. acquired TEPPCO's general partner interest in early 2005. EPCO, a private company, is unrated. The ratings on TEPPCO reflect expectations that the partnership will likely pursue a more aggressive growth strategy under its new owner to increase incentive payments to the general partner. This is particularly so because the acquisition price paid to acquire the general partner is a relatively high multiple of general partner cash flow and is entirely debt-funded. The ratings also reflect TEPPCO's weak distribution coverage and high leverage relative to other energy master limited partnerships. Standard & Poor's expectation for more aggressive growth and also production declines in the Val Verde coal-bed methane system has resulted in a weakening in TEPPCO's business profile score to '5' from '4'. These weaknesses are mitigated to an extent by TEPPCO's other assets that generate relatively stable cash flows, a diverse customer mix, and limited commodity risk. The stable outlook reflects expectations that the company will produce earnings and cash flow sufficient to maintain its current financial profile. However, the ratings could fall should the effects of double leverage at the parent result in a change in the company's growth strategy and the partnership takes on riskier projects to increase distributions to its owner.

The ratings on Energen Corp. (BBB+/Stable/--) and its subsidiary Alabama Gas Corp. (Alagasco) were lowered, reflecting Energen's increasing exposure to the oil and gas E&P sector through the company's unit, Energen Resources Corp. (ERC). ERC has been and continues to be the company's primary growth vehicle. Alagasco, Energen's regulated gas distribution subsidiary, serves a mature market with limited opportunities for growth. Over the past two years, ERC has accounted for about 80% of the company's total capital expenditures. Prospectively, the unit is expected to account for 85% of capital outlays. Participation in the oil and gas sector increases the company's exposure to a competitive and cyclical industry with large capital requirements. Above-average business risk

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The Latest Negative CreditWatch Listings

The ratings on ONEOK Inc. (BBB+/Watch Neg/A-2) were placed on CreditWatch with negative implications following the company's announcement that it is acquiring the natural gas liquids business owned by several Koch Industries companies for about $1.35 billion. Standard & Poor's will resolve the CreditWatch in the coming weeks as it obtains more details on the acquired assets and the company's financing strategy.

The ratings on Regency Gas Services LLC (B+/Watch Neg/--) were placed on CreditWatch with negative implications following the company's announcement that it will incur $125 million in capital expenditures to expand and extend its existing intrastate gas pipeline in northern Louisiana. The largely debt-financed expansion is expected to be completed before the end of 2005 and will pressure overall credit metrics. While the expansion could eventually lead to an improved business mix due to an increased

benefit from operating and regulatory diversity, generally supportive regulatory regimes, and an increased asset base with competitive power costs.

Nevertheless, Standard & Poor's notes that the nonregulated operations, particularly electricity and gas trading and marketing, could become a significant user of liquidity, including cash on hand and available credit facilities, under certain adverse market and credit conditions. Furthermore, the merged companies could be challenged to fully exploit the targeted synergies among the merchant generation assets in the Midwest.

The rating action on Cinergy reflects Standard & Poor's preliminary assessment that when the transaction closes, the company's credit quality will be assessed on a consolidated basis, indicating lack of regulatory insulation or meaningful restrictions on the flow of cash within the company. As a result, Standard & Poor's expects that the ratings on Cinergy will likely be equalized with those on Duke Energy, reflecting the same level of default risk.

Standard & Poor's expects to resolve the CreditWatch listing on the companies as additional details of the merged company become available, including clarity on the strategic direction of the potential separation of the regulated utility and pipeline assets, specific information on the timing of the necessary merger approvals, and a final corporate structure.

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Mixed CreditWatch Listings

The ratings on PacifiCorp (A-/Watch Neg/A-2) were placed on CreditWatch with negative implications and the ratings on MidAmerican Energy Holdings Co. (MEHC; BBB-/Watch Pos/--) were placed on CreditWatch with positive implications. The rating actions follow the announcement by Scottish Power PLC (A-/Stable/A-2) that it has agreed to sell PacifiCorp to MEHC for $9.4 billion, including $5.1 billion in cash, and the assumption of $4.3 billion in net debt and preferred stock. In addition, Standard & Poor's placed its 'A-' rating on Northern Natural Gas Co. on CreditWatch with positive implications, reflecting the fact that Northern Natural's rating is capped at a level three notches above the rating on MEHC, and that it can support an 'A' rating on a stand-alone basis.

The CreditWatch listing reflects the fact that the current 'A-' corporate credit rating on PacifiCorp is based on ScottishPower's consolidated credit profile, whose solid financial performance has compensated for the U.S. utility's weaker stand-alone metrics. The positive CreditWatch listing for MEHC reflects Standard & Poor's expectation that the

including a master limited partnership, IPO, sale, or other unspecified alternatives for the pipeline subsidiary. Standard & Poor's expects to resolve the CreditWatch listing after reviewing the company's decision on its course of action, including potential changes in governance, strategic direction, financial profile, or other credit metrics, and their ultimate effect on credit quality.

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Recent Negative Outlooks

The outlook on Hawaiian Electric Industries Inc. (HEI; BBB/Negative/A-2) and subsidiary Hawaiian Electric Co. Inc. (BBB+/Negative/A-2) was changed to negative from stable. The revision reflects a declining trend in HEI's financial condition, despite the strong Hawaii economy and efforts in recent years to strengthen capital structure balance. The company's financial metrics have been pressured owing to rising operating expenses, unrecovered investments, and the long-term lack of rate relief. Absent a supportive rate order in Hawaiian Electric's pending rate case, prospective bondholder protection measures may not support a financial profile that is commensurate with the current ratings. Although there are no time restrictions for the Hawaii Public Utilities Commission to issue a final order, an interim decision is possible by the fourth quarter of 2005. Failure to strengthen financial parameters, especially cash flow coverage of debt, a slump in the Hawaii economy, a punitive rate order, and/or erosion in HEI subsidiary American Savings Bank's creditworthiness could lead to lower ratings. Conversely, credit supportive actions by HEI, as well as responsive rate treatment that would enable the company to produce FFO to total debt in the lower to mid-20s percentage range would lead to ratings stability.

The ratings on Duquesne Light Holdings Inc. (DLH; BBB/Negative/--) and subsidiary Duquesne Light Co. (BBB/Negative/--) were affirmed and removed from CreditWatch, reflecting DLH's filing of its 2004 10-K after the company initially delayed the filing due to restatements for earlier years. After reviewing the filed 10-K, Standard & Poor's determined that the restatement is consistent with its expectations and reflects the removal of discontinued operations (including asset proceeds) from cash flow from operations, an adjustment that Standard & Poor's has been making for some time. The negative outlook reflects multiple challenges confronting DLH that could result in lower ratings. Although projected financials support a mid-'BBB' rating, ratings could be affected if additional state taxes must be paid for the Pennsylvania tax liability, DLH incurs a loss of operating fees after an unfavorable IRS audit, or remaining supply risk causes the company to be unable to meet its forecast financial performance. Also, expiration of the synthetic fuel tax credits after 2007 could challenge DLH to find a replacement for the lost cash flow associated with these operations. Conversely, the outlook could be changed to stable if pending issues related to the state tax liability and synthetic fuel operations are favorably resolved.

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Recent Ratings Stability

The outlook on Puget Energy Inc. (Puget; BBB-/Stable/--) and its unit Puget Sound Energy Inc. (PSE) was revised to stable from positive. The 'BBB-' corporate credit ratings on Puget and PSE reflect the credit profile of principal subsidiary PSE, a regulated electric and gas utility. Puget's nonregulated construction subsidiary, InfrastruX, is not a primary credit factor, given Puget's plans to monetize the unit and focus on PSE as its sole major investment. Ratings stability reflects Standard & Poor's expectation of moderate rate relief at PSE consistent with the Washington Utilities and Transportation Commission's latest general rate case decision. Credit stability will also depend on adequate and timely equity infusions to support capital investment needs and PSE's 43% equity target. The outlook assumes that PSE's power cost cap will remain in effect through mid-2006 and that

resource acquisitions by PSE will be prudently financed. The outlook also assumes that Puget will monetize in a timely fashion its unregulated subsidiary InfrastruX. Consideration of a positive rating outlook will depend on more favorable rate relief in future years, consistently strong cash flow coverage metrics, and Puget's ability to improve its equity capitalization. Alternatively, a negative outlook could result due to several factors, including additional commodity cost disallowances, inadequate regulatory treatment of capital additions, or a disproportionate reliance on financing to meet its capital needs.

The outlook on Energy East Corp. (BBB+/Stable/A-2) and its subsidiaries was revised to stable from negative owing to an improving financial profile and a reduction in business risk from the sale of the Ginna nuclear power plant and various unregulated subsidiaries. In addition, the rating on New York State Electric & Gas Corp.'s (NYSEG) unsecured bonds was raised to 'BBB+' from 'BBB' because the unsecured bonds are now the most senior debt at NYSEG. Also, the ratings on Southern Connecticut Gas Co.'s first mortgage bonds were lowered to 'BBB+' from 'A-' because the collateral is not sufficient to warrant a higher rating than the 'BBB+' corporate credit rating.

The stable outlook reflects a financial profile that is adequate for the rating and is improving toward a solid 'BBB+'. Bondholder protection measures are expected to strengthen following the implementation of the approved rate settlement and the use of Ginna sale proceeds to reduce debt. Standard & Poor's expects FFO to debt to improve to 14% and debt to total capital to improve to 56% over the next few years. An outlook revision to positive is unlikely in the near term given the current financial forecast. Debt reduction would have to significantly exceed the forecast to warrant a higher rating. A significant increase in debt or significantly lower operating cash could cause a change in the outlook to negative.

The outlook on Pinnacle West Capital Corp. (PWCC; BBB/Stable/A-2) and subsidiary Arizona Public Service Co. (APS) was revised to stable from negative, reflecting the resolution of APS' general rate case. The Arizona Corporation Commission (ACC) adopted with few changes a negotiated settlement, thereby resolving many of the issues

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STANDARD &POOR'S UTILITIES

ation date: 31-May-2005Primary Credit Analyst(s): Barbara A Eiseman, New York (1) 212-438-7666;
ara_eiseman@standardandpoors.com
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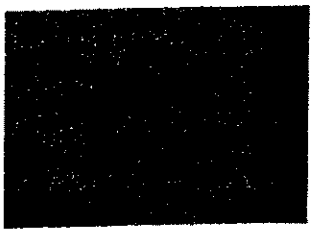
Hawaiian Electric Industries Inc.



ISSUER CREDIT RATINGS	
Hawaiian Electric Industries Inc.	
Corporate Credit Rating	BBB/Negative/A-2
American Savings Bank, FSB, Honolulu HI	
Corporate Credit Rating	BBB-/Stable/A-3
Hawaii Electric Light Company, Inc.	
Corporate Credit Rating	BBB+/Negative/--
Hawaiian Electric Company, Inc.	
Corporate Credit Rating	BBB+/Negative/A-2
Maui Electric Company, Ltd.	
Corporate Credit Rating	BBB+/Negative/--

AFFIRMED RATINGS	
Hawaiian Electric Industries Inc.	
Sr unsecd debt	
Local currency	BBB
CP	
Local currency	A-2
Pfd stk	
Local currency	BB+
American Savings Bank, FSB, Honolulu HI	
Certificate Of Deposit	
Local currency	BBB-/A-3
Hawaii Electric Light Company, Inc.	
Sr unsecd debt	
Local currency	BBB+
Hawaiian Electric Company, Inc.	
Sr unsecd debt	
Local currency	BBB+
CP	
Local currency	A-2
Pfd stk	
Local currency	BBB-
Maui Electric Company, Ltd.	
Sr unsecd debt	
Local currency	BBB+
ASB Realty Corp.	
Pfd stk	
Local currency	BB

Business profile:

Financial policy:
Moderate

Debt maturities:
2005 $37 mil.
2006 $110 mil.
2007 $10 mil.
2008 $50 mil.
2008-2010 $0
Thereafter $207 mil.
Hawaiian Electric Co. Inc. has no maturing long-term debt until 2012. Scheduled maturities are $57.5 million in 2012, $11.4 million in 2014, and $50 million in 2018. Remaining maturities of $636.5 million occur in 2020 and beyond.

Corporate credit rating history:

Feb. 9, 1993	BBB/A-1
Nov. 16, 1990	BBB+

Major Rating Factors

Strengths:

- Generally responsive regulatory climate with an excellent fuel clause,
- Limited competitive threats due to the lack of interconnections and wheeling capability,
- Cultivation of strong customer relationships with emphasis on the military,
- Little asset concentration risk,
- Exemption from acid rain provisions of the Clean Air Act, and
- Steady banking operations.

Weaknesses:

- Dependence on a supportive rate decision to strengthen financial condition,
- An undiversified economy, heavily reliant on the federal government, military, and tourism, which can be significantly affected by world events,
- Large purchased-power obligations,
- Dependence on imported fuel oil,
- High electric rates,
- Ownership of somewhat riskier banking operations, and
- Subpar financial metrics.

Rationale

The ratings on Hawaiian Electric Industries Inc. (HEI) are based on the consolidated credit profile of HEI's family of companies, which include the regulated electric utility, Hawaiian Electric Co. Inc. and its two island utility subsidiaries (81% of core revenues and 64% of operating income as of Dec. 31, 2004) and the riskier financial services operations of American Savings Bank FSB, which contributed 19% of core revenues and 39% of operating income as of Dec. 31, 2004. Standard & Poor's does not accord any credit uplift to American Savings Banks as a result of its affiliation with HEI.

HEI's consolidated financial condition has declined despite the strong Hawaii economy and the company's efforts in recent years to strengthen its capital structure. Consolidated financial metrics have been pressured owing to the long-term lack of rate relief and rising operating expenses. Absent a supportive rate decision in Hawaiian Electric's pending rate case, prospective key financial metrics may not support a financial profile that is commensurate with the current ratings.

HEI and Hawaiian Electric have satisfactory business profiles of '6' and '5', respectively, (business profiles are ranked from '1' (strong) to '10' (weak)) and weak financial measures. HEI's business position is characterized by limited competitive threats due to the utility's geographic isolation, nominal stranded-asset risk, an excellent fuel clause, and steady banking operations. American Savings Bank's consistent earnings are driven by net interest income from its low-cost deposit funding and low-risk earning-asset base. These strengths are tempered by Hawaii's undiversified economy, dependence on fuel oil, significant purchased-power obligations, and support of the somewhat riskier banking businesses. Hawaiian Electric is spared the competitive threat of wholesale competition, but its market share for direct kilowatt-hour sales could contract over time because of inroads from demand-side management (currently recovered through a surcharge on customer bills), competitive bidding, and nonutility generators, including distributed generation. Hawaiian Electric's business profile is slightly stronger than that of the parent due to the absence of nonutility operations.

A responsive rate order from the Hawaii Public Utilities Commission with regard to Hawaiian Electric's pending rate case for a $98.6 million (9.9%) gross rate hike is crucial to help lift the company's key financial measures to more appropriate levels for the ratings. Although there are no time restrictions for the commission to issue a final order, an interim decision is expected by the fourth quarter of 2005. Rate relief is needed to recover the costs of reliability investments made since 1995, which have included a number of transmission upgrades, the costs associated with an additional 29 MW of firm capacity from a purchased-power contract, a new fuel oil pipeline, and energy efficiency and conservation programs.

Hawaii's economy has been growing modestly during the past several years and is expected to grow by 3.1% after inflation in 2005 and 2.7% in 2006. Military and federal government spending remains strong as the U.S. Department of Defense has moved military assets to Hawaii. The visitor industry is also a significant component of the Hawaii economy, second only to the federal government. In 2004, visitor days exceeded 2003 by 7% and the record set in 2000 by 2%. Domestic arrivals were well above record levels set in 2000 and international arrivals are starting to increase as the Japanese economy has improved. Strength in key nontourism sectors, particularly real estate and the growing military commitment, coupled with low interest rates, have resulted in solid construction and real estate sales activity although future growth in real estate may slow with rising interest rates. Hawaii's economic growth is expected to be tied primarily to the rate of expansion in the mainland U.S. and Japan economies and increased military spending, yet remains vulnerable to uncertainties in the world's geopolitical environment.

Internal cash covered nearly 70% of HEI's consolidated capital program in 2004. Assuming no new unplanned capacity additions, which may eventually be necessary to meet load growth on Oahu, internally generated funds should satisfy the bulk of construction expenditures for the next five years. Prospective construction outlays will focus predominantly on additions and improvements to transmission facilities and, to a lesser extent, on generation projects as well as energy solutions and customer-choice technologies.

HEI's bondholder protection metrics are subpar for the current ratings. Although total debt to capital (adjusted for off-balance-sheet obligations, such as purchased-power contracts, and Hawaiian Electric's $50 million trust-originated preferred securities) declined to roughly 56% as of Dec. 31, 2004 from about 58% at the end of 2003, it is still liberal for a mid 'BBB' rating. Adjusted funds from operations (FFO) interest coverage is only 3.1x, which is at the lower end of the 'BBB' category benchmark. Adjusted FFO to total debt is just 16.1%, which is commensurate with noninvestment-grade guideposts. However, with rate relief, tight cost controls, improved earnings from continued expansion of Hawaii's economy, and HEI's other credit supportive actions, the company's overall financial condition should improve.

Short-term credit factors

The short-term corporate credit and commercial paper ratings on HEI and Hawaiian Electric are 'A-2', incorporating solid liquidity and the ability to internally fund the bulk of dividends and capital expenditures in nearby years. HEI faces a manageable maturity schedule, with $37 million due in 2005, the bulk of which matures in December. Hawaiian Electric has no maturing long-term debt until 2012. As of March 31, 2005, HEI had $14 million of cash and cash equivalents (excluding American Savings Bank's cash and cash equivalents). HEI and Hawaiian Electric had bank lines totaling $80 million and $140 million, respectively, at the end of March 2005.

Covenants in HEI's and Hawaiian Electric's lines require Hawaiian Electric to maintain a consolidated equity capitalization ratio (exclusive of short-term debt) of at least 35%. As of March 31, 2005, Hawaiian Electric's consolidated common equity to capitalization ratio was 56%. Certain HEI lines of credit totaling $20 million and $45 million require the company to maintain a consolidated net worth, exclusive of intangible assets, of at least $900 million and $850 million, respectively, which at the end of March 2005 was $1.1 billion. The line of credit agreements do not contain interest coverage ratio requirements. None of HEI's or Hawaiian Electric's lines contains material adverse change clauses or rating triggers that affect access to the facilities.

Consolidated capital outlays are expected to decline to about $193 million in 2005 from around $215 million in 2004. Roughly 75% of the 2005 construction program is expected to be internally funded. Importantly, ongoing growth in the Hawaii economy should allow the electric utility to generate relatively stable cash flows and the bank to maintain normal cash dividend levels (50% of its earnings) while still supporting its own business growth.

HEI has $150 million of debt capacity remaining under a Rule 415 shelf registration. As of March 31, 2005, proceeds of approximately $11 million from a previous sale of special purpose revenue bonds issued by the State of Hawaii's Department of Budget and Finance for the benefit of Hawaiian Electric remained undrawn.

Outlook

The negative outlook on HEI reflects its declining financial performance. Failure to strengthen key financial parameters, especially cash flow coverage of debt, a slump in the Hawaii economy, a punitive rate order, and/or an erosion in American Savings Bank's creditworthiness could lead to lower ratings. Conversely, credit supportive actions by the company as well as responsive rate treatment that would enable the company to produce consolidated FFO to total debt in the lower to mid-20% range would lead to ratings stability.

Accounting

HEI reports its financial statements in accordance with U.S. GAAP. Recently adopted or pending adoption of new accounting standards did not nor are expected to have a

material effect on the company's financial statements. Importantly, there was no material weakness identified by the management in its internal control over financial reporting as of Dec. 31, 2004, under Section 404 of the Sarbanes-Oxley Act.

A few of the independent power producers (IPPs) that supply power to Hawaiian Electric have declined to provide the information necessary for Hawaiian Electric to determine the applicability of FIN 46R related to the consolidation of variable interest entities (VIES). Hence, the company was unable to apply FIN 46R to these IPPs. Hawaiian Electric's other IPPs are either not VIES or outside the purview of FIN 46R.

Standard & Poor's has made certain analytical adjustments to HEI's reported financial information to reflect off-balance-sheet obligations (OBS), such as purchased power commitments and operating leases, when calculating its adjusted financial ratios.

As of Dec. 31, 2004, Hawaiian Electric had purchased power arrangements for 529.6 MW of firm capacity. To analyze the financial impact of purchased power contracts, Standard & Poor's employs the following methodology: the net present value of future annual capacity payments (discounted at 10%) represents a potential debt equivalent—the OBS obligation that a utility incurs when it enters into an intermediate- to long-term purchased power agreement. Standard & Poor's adds to the balance sheet only a portion of this amount, recognizing that such contractual arrangements are not entirely the equivalent of debt. The percentage that is added (the risk factor) is a function of Standard & Poor's qualitative analysis of the specific contracts and the extent to which market, operating, and regulatory risks are borne by the utility. Standard & Poor's has assigned a risk factor of 30% to Hawaiian Electric's take-and-pay contracts, which translates into a debt equivalent of $290.9 million.

The present value of the company's operating leases is determined using a 6% discount rate and is treated as a debt equivalent. Operating lease interest expense and depreciation expense are also computed. The amounts relating to operating leases that were included in HEI's adjusted ratios for 2004 were $59.8 million for OBS debt, $3.6 million for imputed interest, and $15.4 million for depreciation.

Standard & Poor's also makes an analytical adjustment for allowance for funds used during construction (AFUDC) charges capitalized by the company and treats the charges as a part of operating expenses. The AFUDC charge is backed out to arrive at cash flows from operations. Adjustments for AFUDC debt and equity in 2004 were nominal at about $2.5 million and $5.8 million, respectively.

Table 1 Hawaiian Electric Industries Inc. Peer Comparison

	--Average of past three fiscal years--			
	Hawaiian Electric Industries	Portland General Electric Co.	El Paso Electric Co.	PNM Resources Inc.
Rating	BBB/Negative/A-2	BBB+/Developing/A-2	BBB/Stable/--	BBB/Stable/A-2
(Mil. $)				
Sales	1,786.4	1,687.0	687.7	1,409.8
Net income from cont. oper.	114.7	71.3	28.3	70.0

Hawaiian Electric Industries Inc.

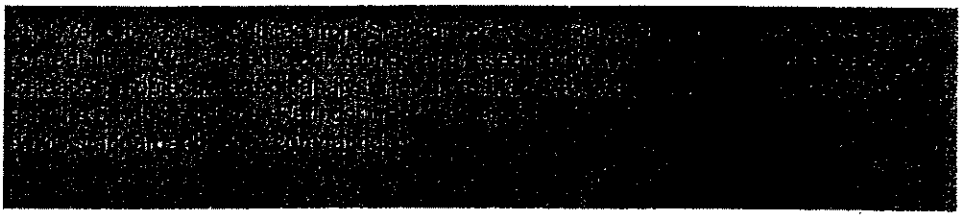
Funds from oper. (FFO)	270.1	296.3	146.5	266.2
Capital expenditures	167.7	175.3	87.9	184.9
Total debt	1,271.3	974.7	633.3	1,108.6
Preferred stock	34.4	9.0	0.0	12.4
Common equity	1,115.4	1,195.0	494.9	1,050.3
Total capital	2,421.2	2,178.7	1,128.2	2,175.2
Ratios				
Adj. EBIT interest coverage (x)	2.6	2.4	1.9	2.4
Adj. FFO interest coverage (x)	3.3	4.1	3.7	4.2
Adj. FFO/avg. total debt (%)	17.6	24.5	22.5	19.8
Net cash flow/capital expenditures (%)	112.9	162.5	169.8	127.9
Adj. total debt/capital (%)	58.1	49.8	56.3	57.3
Return on common equity (%)	10.1	6.0	5.1	6.4
Common dividend payout (%)	70.5	0	0	52.0

Table 2 Hawaiian Electric Industries Inc. Financial Summary

	--Years ended Dec. 31--				
	2004	2003	2002	2001	2000
Rating	BBB/Stable/A-2	BBB/Stable/A-2	BBB/Stable/A-2	BBB/Negative/A-2	BBB/Negative/A-2
(Mil. $)					
Sales	1,924.1	1,781.3	1,653.7	1,727.3	1732.3
Net income from cont. oper.	107.7	118.0	118.2	107.7	109.3
Funds from oper. (FFO)	239.3	268.2	302.8	258.5	245.9
Capital expenditures	212.1	162.9	128.1	126.3	134.6
Total debt	1,243.3	1,264.4	1,306.3	1,345.8	1393.1

Hawaiian Electric Industries Inc.

Preferred stock	34.4	34.4	34.4	34.4	34.4
Common equity	1,210.9	1,089.0	1,046.3	929.7	839.1
Total capital	2,488.7	2,387.9	2,387.0	2,309.8	2267.4
Ratios					
Adj. EBIT interest coverage (x)	2.8	2.5	2.5	2.3	2.4
Adj. FFO interest coverage (x)	3.2	3.3	3.6	3.0	2.9
Adj. FFO/avg. total debt (%)	16.0	17.8	19.0	15.9	15.1
Net cash flow/capital expenditures (%)	68.6	118.5	179.1	151.6	113.6
Adj. total debt/capital (%)	56.1	58.7	59.6	62.4	65.4
Return on common equity (%)	8.6	10.5	11.4	11.4	9.1
Common dividend payout (%)	87.1	63.6	62.1	62.2	80.8



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The McGraw-Hill Companies

Moody's Investors Service

Global Credit Research
Credit Opinion
30 DEC 2004

Credit Opinion: Hawaiian Electric Company, Inc.

Hawaiian Electric Company, Inc.

Honolulu, Hawaii, United States

Ratings

Category	Moody's Rating
Outlook	Stable
Issuer Rating	Baa1
Preferred Stock	Baa3
Bkd Commercial Paper	P-2
Parent: Hawaiian Electric Industries, Inc.	
Outlook	Stable
Senior Unsecured	Baa2
Bkd Commercial Paper	P-2

Contacts

Analyst	Phone
A.J. Sabatelle/New York	1.212.553.1653
Laura Schumacher/New York	
Daniel Gates/New York	

Key Indicators

Hawaiian Electric Company, Inc.

	3Q04 LTM	2003	2002	2001
Adjusted Funds from Operations / Adjusted Debt [1][2]	21.0%	22.0%	22.3%	21.2%
Retained Cash Flow / Adjusted Debt [2]	18.1%	15.5%	17.3%	16.9%
Common Dividends / Net Income Available for Common	29.8%	73.1%	48.9%	41.1%
Funds from Operations - Capitalized Interest + Adjusted Interest / Adjusted Interest [1][3]	4.77	4.55	4.58	4.08
Adjusted Debt / Adjusted Capitalization [2][4]	47.6%	47.3%	47.6%	47.8%
Net Income Available for Common / Common Equity	9.0%	8.4%	9.8%	10.1%

[1] Preferred dividends have been deducted from FFO [2] Adjusted debt includes quarterly income preferred securities (QUIPS) [3] Interest is adjusted to include preferred dividends [4] Adjusted capitalization reflects the adjustments made to debt

Note: For definitions of Moody's most common ratio terms please see the accompanying User's Guide.

Opinion

Credit Strengths

Credit strengths for HECO's rating includes:

The company's role as the predominant provider of electricity within the state of Hawaii.

The company's emphasis on relationship building particularly with the large customer segment such as the military.

A stable regulatory environment that emphasizes traditional cost of service techniques.

Strong cash flows and a manageable level of capital expenditures.

Credit Challenges

Credit challenges facing HECO include:

The cash flow volatility that is associated with an economic base that has a significant reliance on tourism for incremental growth.

A strong environmental lobby that not only extends the time frames over which large scale construction projects can be completed but leads to increased costs.

The growth in distributed generation alternatives increases the competitive environment particularly for large, geographically concentrated customers, such as hotels.

[redacted]

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Moody's Investors Service

Global Credit Research
Liquidity Risk Assessment
14 JUL 2004

Liquidity Risk Assessment: Hawaiian Electric Industries, Inc.

Hawaiian Electric Industries, Inc.

Honolulu, Hawaii, United States

Broad Industry:	Public Utility
Specific Industry:	Utility/Diversified Holding Company
Short Term Rating:	P-2 (Backed)

Contacts

Analyst	**Phone**
A. J. Sabatelle/ Jersey City	1 212 553 1653

[redacted]

Opinion

Support for Hawaiian Electric Industries, Inc. (HEI) Prime-2 short-term rating for commercial paper is primarily derived from the stability of the company's core businesses operated under Hawaiian Electric Company (HECO) and American Savings Bank (ASB) as well as the strategic emphasis throughout the organization on cost controls and capital management.

HECO's utility operations have traditionally benefited from the relative absence of competition due to Hawaii's geographic isolation as well as a generally supportive regulatory environment that is cognizant of the importance of a financially viable utility base. While revenues continue to expand, rising pension expenses reduced margins with a corresponding impact on cash flows. Net income was $79 million in 2003 compared with $90 million in 2002. Even with this pressure cash from operations in 2003 at $206 million was 20% higher than the year earlier figure.

HEI and HECO utilize short-term debt, principally commercial paper, to support normal operations and for other temporary requirements, and from time to time, HECO also borrows short-term from HEI for itself and on behalf of its subsidiary utility company, Hawaiian Electric Light Company, Inc. (HELCO) and Maui Electric Company (MECO). Under the intercompany arrangements, HECO can also borrow from or loan to HELCO and MECO on a short-term basis. At March 31, 2004, HECO had $16 million and $18 million of short-term borrowings from HEI and MECO, respectively, and HELCO had $16 million of short-term borrowings from HECO. HEI had no commercial paper borrowings during the first three months of 2004. HECO had an average outstanding balance of commercial paper for the first three months of 2004 of $13 million and had $23 million of commercial paper outstanding at March 31, 2004.

loans to HECO, to assist the utility subsidiary in redeeming $50 million aggregate principal amount of 7.30% Cumulative Quarterly Income Preferred Securities and for other general corporate purposes. It is anticipated that HECO will repay the short-term loans by the end of 2004.

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CA-RIR-7

Ref: RT-21, pages 5-10.

Please provide an update to the responses to CA-IR-103 (reports by security analysts that evaluate HECO and/or HEI).

HECO Response:

Attached are reports by security analysts that evaluate HEI for the period 2004 to the present that we are aware of and were not included in the response to CA-IR-103. The information is voluminous. One copy of the voluminous information will be provided to the Consumer Advocate, Department of Defense and the Commission under separate transmittal.

Note: Most (if not all) of the information requested is copyrighted. The attached copy is being provided under the "fair use" exception to the copyright laws. Any copies made of the attachment are subject to the copyright laws.

Due to the voluminous nature of the information, one copy (pages 2 to 184) will be provided to the Consumer Advocate, Department of Defense and the Public Utilities Commission under separate transmittal.

CA-RIR-8

Ref: RT-21, page 8.

Please provide copy of all S&P publications relied upon in making statement on lines 10-11.

HECO Response:

While no specific rating agency reports were relied upon in making this statement S&P does make mention of this point in various reports. Based on S&P's current reports, the impending rate filing decision does impact the financial metrics by which the Company is measured and which S&P factors into their credit ratings and credit outlooks. The Company's negative outlook is attributed to its financial metrics which have been negatively impacted by the "long-term lack of rate relief".

Please see S&P Research Update dated 4/22/05 and filed on 4/27/05 in HECO's response to DOD/HECO-IR-3-5. Also, please see S&P report dated 5/31/05 filed as HECO-R-1614. S&P states that the "financial metrics have been pressured owing to the long-term lack of rate relief...". S&P also says "Absent a supportive rate decision in Hawaiian Electric's pending rate case, prospective key financial metrics may not support a financial profile that is commensurate with the current ratings". In addition "...responsive rate treatment that would enable the company to produce FFO to total debt in the lower to mid-20s percentage range would lead to ratings stability." Also, "A responsive rate order from the Hawaii Public Utilities Commission with regard to Hawaiian Electric's pending rate case for a $98.6 million (9.9%) gross rate hike is crucial to help lift the company's key financial measures to more appropriate levels for the ratings."

In a recent S&P report dated 7/6/05 (excerpts attached in pages 2-5) S&P goes on to say that "Regulatory rulings have once again become a dominant factor in companies' credit

[redacted]

implications in the near future."

STANDARD &POOR'S
Credit Ratings - Commentary & News

Credit Ratings

Print

Industry Report Card: U.S. Electric/Water/Gas

Primary Credit Analyst(s):
Richard W Cortright, Jr., New York (1) 212-438-7665;
richard_cortright@standardandpoors.com

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Rating Changes
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Commentary/Key Trends

Standard & Poor's Ratings Services expects rating activity in the regulated U.S. utility (electric, gas, pipeline, and water) and merchant power sectors to continue to be relatively modest through at least the remainder of the year.

Regulatory rulings have once again become a dominant factor in companies' credit quality. These decisions will be critical for utilities in many states that are nearing the end of multiyear transition periods and for those that will be making significant capital investment in infrastructure. Efforts to reward shareholders through share repurchases or dividend increases are also a development that weighs on credit quality. These actions are especially significant for companies whose financial profiles are already somewhat weak for their ratings, leaving them susceptible to negative rating actions.

Credit outlooks, which are a leading indicator of rating trends, show that there are nearly twice as many stable outlooks as negative outlooks. Only about 11% of outlooks are positive. Therefore, there should be more rating stability over the near to intermediate term, with somewhat of a negative bias in rating actions.

Since the last report card (see "Industry Report Card: U.S. Electric/Water/Gas" published on RatingsDirect May 3, 2005), four families of companies were upgraded (representing 13 individual ratings) and six families of companies were downgraded (representing 15 individual ratings). Rating actions have been largely due to various factors, most prominently changing financial profiles, both improving (Allegheny Energy Inc.) and weakening (Northeast Utilities), and negative regulatory actions or uncertainty (Central Vermont Public Service Corp., Middlesex Water Co.).

Rate filings and rulings on rate proceedings in Florida, Hawaii, Illinois, Kansas, Maryland, Massachusetts, Missouri, and Wisconsin could have rating implications in the near future. Factors that are driving the need for regulatory approval include the considerable capital expenditures required by many utilities to satisfy environmental requirements, construction of new generation facilities, and efforts to pass through or recover unanticipated costs. Developments in FERC policy, particularly regarding transmission and market power, bear watching. The opposing views of certain state regulatory bodies and the FERC on issues, such as restructuring the regional transmission systems and incorporating certain merchant plants of affiliated companies in the rate base, add to the importance of the regulatory treatment for the industry.

Despite meaningful improvement in financial measures over the past few years, many companies have negative outlooks because of weak credit metrics. This weakness results primarily from high debt levels and cash flow stress associated with unsuccessful forays into more competitive businesses. Moreover, despite the current industry trend of getting

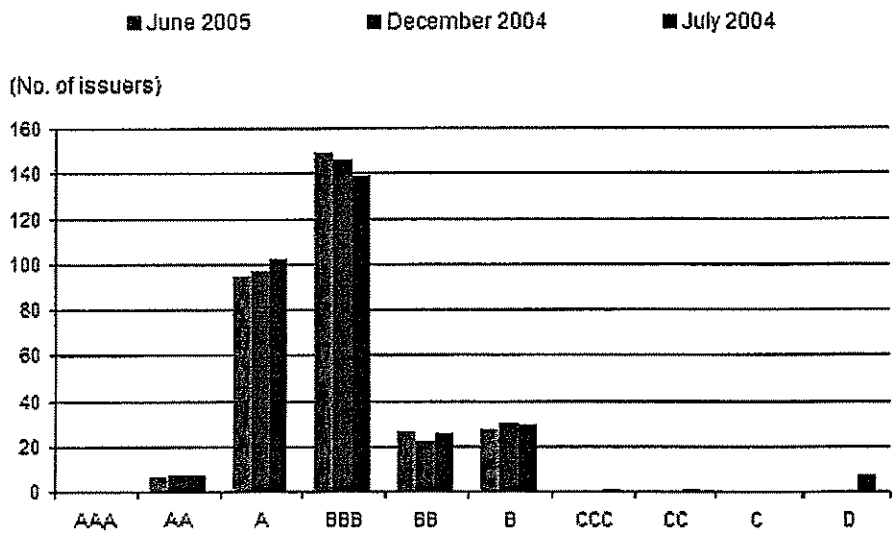
"back to basics," Standard & Poor's remains vigilant to, and skeptical of, nonregulated business pursuits outside of the core competencies of utility management. Inevitably, competition for capital and investor interest will embolden companies to embrace growth strategies that could erode credit quality.

Credit trends in the merchant energy segment of the electric power industry have not changed very much over the past six months, although there have been a few rating upgrades and positive outlook revisions. Most of the credit improvement has come from successful refinancings and completion of strategic asset sales and not from improved industry fundamentals. Utilities with merchant exposure continue to experience volatile cash flows and regulatory uncertainty.

The operating environment for the merchant energy sector remains challenging. Faced with the prospect of stagnant power markets in many regions, cash flow measures are likely to remain weak until wholesale electricity margins materially improve. Since electric industry deregulation has come to a halt, market opportunities in merchant generation are few, although existing assets continue to change ownership, particularly as private equity becomes a larger player.

Chart 1

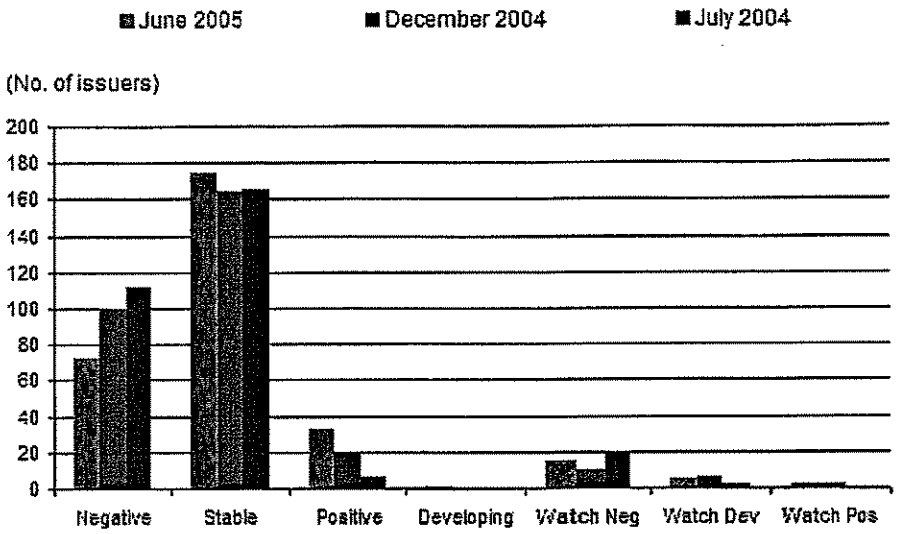
U.S. Utilities Long-Term Ratings Distribution*



*Dates represent current and previously published report card data.

Chart 2

U.S. Utilities Outlook/CreditWatch Distribution*



*Dates represent current and previously published report card data.

↑back to top

Issuer Review

Table 1 U.S. Electric/Gas/Water

Issuer	Corporate credit rating*	Analyst	Comment
The AES Corp.	B+/Positive/--	Taylor	Standard & Poor's expects AES to continue on its path of parent level debt reduction and, if Standard & Poor's becomes comfortable that AES can meet its goal of lowering parent level debt to about $4.5 billion by early next year, an upgrade to 'BB-' is likely. Fairly sizable distributions from developing economies such as Venezuela, Nigeria, and Argentina, in 2004 were helpful, but expectations of continuing dividends from these economies present risk. Standard & Poor's expects continued equity investment in new projects, especially in the wind sector.
Indianapolis Power & Light Co.	BB+/Positive/--	Eiseman	See The AES Corp.
IPALCO Enterprises Inc.	BB+/Positive/--	Eiseman	See The AES Corp.
AGL Resources Inc.	A-/Negative/A-2	Messer	On June 10, 2005, Atlanta Gas Light Co. reached a rate settlement with the Georgia Public Service Commission that Standard & Poor's considers neutral for credit quality. Standard & Poor's views positively the roughly $30 million annual increase in discretionary cash flow through 2008 expected to result from the extension of AGL's pipeline-replacement program, as well as the commission's decision to only modestly

			balance sheet that would normally be excluded from rate base. Moreover, regulators recognize that Green Mountain is exposed to material customer concentration risk. As such, they allow the company to earn a higher allowable ROE (10.5%) than Central Vermont (10%).
Hawaiian Electric Industries Inc.	BBB/Negative/A-2	Eiseman	The negative outlook on Hawaiian Electric Industries reflects the declining trend in the company's consolidated financial condition, despite the strong Hawaii economy and the company's efforts in recent years to strengthen capital structure balance. The company's financial metrics have been pressured owing to rising operating expenses, yet-to-be recovered investments, and the long-term lack of rate relief. Absent credit supportive measures by the company and a responsive decision in Hawaiian Electric's pending rate case, prospective key financial metrics may not support a financial profile that is commensurate for the current ratings. Although there are no time restrictions for the commission to issue a final order, an interim decision is possible by the fourth quarter of 2005.
Hawaiian Electric Co. Inc.	BBB+/Negative/A-2	Eiseman	See Hawaiian Electric Industries Inc.
IDACORP Inc.	BBB+/Stable/A-2	Venkataraman	With the issuance of $115 million in common stock in December 2004, IDACORP's financial profile is expected to be commensurate with expectations for a 'BBB+' rating from 2005 forward. IDACORP has more than $600 million in capital requirements in the next two years but external funding needs are expected to be modest. The stable outlook reflects expectations for stable cash generation from the utility and the absence of any significant unregulated businesses. Two key issues that would determine future ratings movement are water flows in the Snake River, which are currently weak, and future rate case rulings by the commission.
Idaho Power Co.	BBB+/Stable/A-2	Venkataraman	See IDACORP Inc.
			The Iroquois Gas Transmission System is a limited partnership of gas distribution utilities, electric generators, and pipeline companies. The company is substantially contracted for firm ship-or-pay contracts

CA-RIR-9

Ref: RT-21, page 9, lines 6-25.

Please provide the actual HECO debt coverage, as computed by S&P and including imputed debt, for the five years prior to the 1995 rate proceeding and for the five years prior to the present rate proceeding.

HECO Response:

Please see attached for the debt coverage ratios and imputed debt for HECO (consolidated) for the years 1990-1994 and 2000-2003 from accessible S&P publications. For 2004, the FFO Interest Coverage is approximately 3.8 and FFO to Total Debt is approximately 20% with imputed debt of $290.9 million. Information for 2004 was obtained from the S&P report dated 5/31/05 filed as HECO-R-1614 (pages 4 & 5).

It is difficult to compare the two time periods given all the reasons that were reflected in HECO T-21 and HECO RT-21 that indicate circumstances have changed in the industry. During the 90's time period, before a major utility had declared bankruptcy (an unheard of thought at that time), S&P and Moody's were much more lenient in allowing a company to have financial ratios that did not exactly match with the target ranges. They are much stricter now (which is also why we have had to increase our equity levels) and the ranges themselves have also changed.

		A				B	C			
Description	2004	2003	2002	2001	2000	1994	1993 **	1992	1991	1990
FFO Int Coverage	*	4.0	4.3	4.0	3.7	3.1	3.8	3.7	3.8	3.4
FFO/Avg Tot Debt	*	21.9	22.8	21.1	20.6	17.7	20.7	20.3	22.2	19.9
Off Balance Sheet Obligations	*	***	***	***	***	147.1	***	***	***	***

* Please see discussion on 2004 ratios on page 1.

** 12 months ended 6/30

*** Information was not presented in respective S&P publication

Note: Ratios are "adjusted" by S&P in 1994 and 2000-2003 for off balance sheet obligations.
1990-1993 are unadjusted

Source:

A - 7/9/04 Hawaiian Electric Industries, Inc. Filed 2/15/05 in response to CA-IR-102 pages 9 - 21.

B - September 1999 Utility Credit Report. Excerpt attached as pages 3-4.

C - 10/11/93 S&P Creditweek. Filed in Docket No. 7766 in response to DOD-IR-K-72.
Excerpt attached as page 5.

[redacted]

Financial Statistics—Hawaiian Electric Co.Inc.

	—Year ended Dec. 31—				
	1998	1997	1996	1995	1994
Income statement (mil. $)					
Gross revenues	1,008.9	1,098.8	1,071.4	982.0	907.3
Operating expenses (excl. DD&A)	752.4	852.9	833.0	760.9	712.4
Depreciation and amortization	85.7	82.0	73.5	67.6	63.8
Pretax operating income	170.9	163.8	165.0	153.4	131.1
Gross interest expense	43.7	48.8	47.5	47.1	40.2
Pretax income	149.9	137.7	141.4	123.6	105.5
AFUDC and deferrals	18.0	17.1	17.6	15.3	13.1
Income taxes	54.7	52.8	56.2	50.7	43.8
Net income from continuing operations	95.2	84.9	85.2	72.9	61.6
Earnings protection					
Pretax interest coverage (x)	4.12	3.53	3.66	3.36	3.37
Adjusted pretax interest coverage (x)	3.33	2.93	3.02	2.77	2.73
Preferred dividend coverage (x)	3.27	2.93	3.27	2.95	2.90
EBITDA interest coverage (x)	6.08	5.21	5.21	4.79	4.96
AFUDC and deferred income/earnings (%)	16.8	20.1	20.7	21.0	21.3
Return on common equity (nominal) (%)	9.2	8.0	8.8	8.0	7.0
Common dividend payout (%)	90.7	74.7	70.1	55.4	49.7
Annual O&M growth (%)	(6.4)	2.0	5.7	9.8	N.A.
Annual expense growth (excl. DD&A) (%)	(11.8)	2.4	9.5	6.8	N.A.
O&M/revenues (%)	18.5	18.1	18.2	18.6	18.5
Total operating expenses (excl. DD&A)/revenues (%)	74.6	77.6	77.7	77.5	78.5
Balance sheet (mil. $)					
Cash and equivalents	54.8	1.7	0.8	0.0	10.7
Gross plant	2,924.8	2,797.8	2,674.4	2,483.0	2,293.5
Net plant	1,942.7	1,863.1	1,845.5	1,720.2	1,590.6
Total assets	2,311.3	2,212.3	2,166.5	2,016.3	1,889.1
Short-term debt	139.4	128.2	141.2	170.5	141.2
Long-term debt	622.0	597.6	589.2	487.3	468.7
Preferred stock	181.0	131.5	84.5	88.2	93.1
Common equity	786.6	769.2	751.3	696.9	633.8
Total capitalization	1,729.0	1,626.5	1,566.2	1,442.9	1,336.9
Total off-balance-sheet obligations	149.1	151.2	153.0	154.5	147.1
Balance sheet ratios (%)					
Short-term debt/total capital	8.1	7.9	9.0	11.8	10.6
Long-term debt/total capital	36.0	36.7	37.6	33.8	35.1
Preferred stock/total capital	10.5	8.1	5.4	6.1	7.0
Common equity/total capital	45.5	47.3	49.0	48.3	47.4

HAWAIIAN ELECTRIC CO.

S&P Contact: Barbara A. Eiseman (212) 208-1656

RATINGS AFFIRMED

OUTLOOK: NEGATIVE

SENIOR DEBT HISTORY

1992	A-
1991	A-
1990	A-
1989	A
1988	A

OUTSTANDING RATINGS

Senior secured debt	BBB+
Senior unsecured debt	BBB
Preferred stock	BBB
Commercial paper	A-2

RATIONALE Hawaiian Electric Co.'s (HECO) relatively healthy electric sales growth prospects, cost containment initiatives, and the absence of nuclear challenges are important strengths for this oil-dependent utility. Generating reserve margins should remain adequate based on purchased power arrangements. An efficient fuel clause mitigates risks associated with higher oil prices, but unstable oil prices poses a challenge as do elevated levels of construction spending to meet growth demands and ensure service reliability. Cash construction spending will likely be less than 50% internally funded and will average a huge 15% of capitalization during the next several years. In addition to significant general rate relief requirements, responsive regulation is also needed for timely and economic cost recovery of payments to energy suppliers. Parent Hawaiian Electric Industries Inc.'s aggressive diversification activities—in financial services, freight transportation, and real estate development (representing around 20% of total earnings)—have intensified consolidated financial risk. In view of parent debt financing, the utility is not fully insulated from higher-risk affiliates. Hawaiian Insurance Group, a property/casualty insurance affiliate had large losses as a result of the September 1992 hurricane that struck the island of Kauai. In view of large policyholder claims, Hawaiian Electric Industries decided to exit the insurance business.

OUTLOOK:NEGATIVE Downward pressure on credit quality reflects a very large utility construction program, sizable external funding needs, related significant regulatory risk, and huge off-balance-sheet obligations in the form of purchased-power contracts. In the absence of continuing supportive rate relief, financials will weaken. The financial and political consequences associated with the parent company's decision to exit the insurance business also adds risk.

Hawaiian Electric Co. financial statistics (Mil. $)	1993*	1992	1991	1990	1989
			—Year ended Dec. 31—		
Revenues	850.9	776.9	739.6	704.9	605.0
Interest incurred	34.2	33.0	33.2	30.9	30.0
Net income from cont. operations	55.6	53.7	46.2	48.5	52.8
Pretax interest coverage (x)	3.28	3.22	3.03	3.24	3.52
Preferred dividend coverage (x)	2.54	2.46	2.30	2.41	2.86
Return on avg. equity (nominal) (%)	10.6	10.5	10.3	12.3	15.0
AFDC & deferred income/earnings (%)	18.7	18.1	12.7	13.5	10.2
Common dividend payout (%)	45.1	46.9	66.0	74.9	40.1
Funds from operations (FFO)	97.3	91.4	91.8	78.0	83.6
Common dividends	23.1	23.0	27.5	32.8	20.0
Preferred dividends	4.5	4.5	4.6	4.7	3.1
Net cash flow (NCF)	69.7	63.8	59.8	40.5	60.5
Capital expenditures (Capex)	206.1	172.7	124.0	89.8	112.7
Capex/avg. total capital (%)	19.9	17.2	13.7	10.7	15.1
FFO interest coverage (pretax) (x)	4.63	4.47	4.52	4.22	4.74
FFO interest coverage (aftertax) (x)	3.76	3.68	3.80	3.44	3.85
FFO/avg. total debt (%)	20.7	20.3	22.2	19.9	24.7
NCF/Capex (%)	33.8	37.0	48.2	45.0	53.7
Total capital	1,083.1	1,062.1	927.5	881.0	791.7
Short-term debt (%)	13.4	13.0	3.9	9.6	5.1
Long-term debt (%)	31.5	33.1	39.3	38.9	39.8
Preferred stock (%)	7.7	7.7	9.3	9.9	11.3
Common equity (%)	47.4	46.2	47.5	41.5	43.8
Cash and marketable securities	0.1	30.9	0.4	1.4	3.5

*For 12 months ended June 30 (unaudited).

CA-RIR-10

Ref: RT-21, page 10, lines 5-7.

Please reconcile the statement on the cited lines with regard to CA-413, which reflects purchase power "debt equivalent" for HECO.

HECO Response:

Upon further review of CA-413, the Consumer Advocate has reflected the purchase power "debt equivalent" of $243,404,000 and related interest expense at 10% in its calculation as a separate line item whereas the DOD has not. The derived pre-tax coverage ratio does remain quite low in the BBB range and would reflect a BBB- credit rating by Standard and Poor's (two ratings lower) versus the Company's current BBB+ rating which would require a ratio in the upper portion of the range.

CA-RIR-11

Ref: RT-21, page 12, lines 22-24.

Please provide copy of S&P report cited.

HECO Response:

Please see HECO's response to DOD-IR-3-5 which was filed on 4/27/05 for a copy of this S&P report dated 4/22/05.

CA-RIR-12

Ref: RT-21, page 14, lines 9-11.

Please indicate if Mr. Von Gnechten agrees that, in several HECO subsidiary cases since 1994, the Consumer Advocate's proposed DCF results have been used in part by the Commission in setting the fair cost of equity.

HECO Response:

Yes, in prior proceedings the Commission has used in part the Consumer Advocate's DCF results. The point is, however, that the Commission has previously recognized the limitations of the DCF model and when it provided a result that was too low (and unfairly skewed the results) decided to eliminate it from its calculations in deriving the final authorized return on equity that would allow the company to earn a fair and reasonable return. To the Company's knowledge, it is not aware of any other model that was eliminated due to low results.

CA-RIR-13

Ref: RT-21, page 16, lines 13-14.

Please provide copies of all documentation relied upon in making this statement.

HECO Response:

The basis of this statement is personal discussions that Mr. von Gnechten had with the rating agencies and financial analysts during his tenure as Financial Vice President of Hawaiian Electric Company. Standard and Poor's negative outlook reaffirms this position. Please see response to CA-RIR-8 and Ms. Sekimura's RT-16 testimony for further discussion and documentation on this matter.

CA-RIR-14

Ref: RT-16, page 63

Please provide a copy of any slides or other materials used by HECO in the "Company's annual visit, on May 17, 2005" with S&P.

HECO Response:

HECO objects to providing its May 2005 presentation to the rating agencies on the grounds that the presentation contains privileged commercial and financial information (including earnings forecast information), which is maintained by HECO and its subsidiaries and the rating agencies as non-public, confidential information. HECO is willing to make non-confidential portions of the May 2005 presentation relating to the utilities available for inspection, and to make select confidential portions of the presentations relating to the utilities available for inspection pursuant to an appropriate protective order. HECO, however, objects to making available information related to forecast earnings and forecast return, which disclosure might trigger requirements under the rules and guidelines of the Securities and Exchange Commission and/or the New York Stock Exchange even under the protective order (see discussion below) .

The disclosure of forecast information related to income and earnings could trigger requirements under the rules and guidelines of the Securities and Exchange Commission ("SEC") and/or the New York Stock Exchange that information that would be meaningful to an investor (such as earnings estimates) be released to all investors, if the information is disclosed beyond a limited number of "insiders". Forecasts of earnings, etc. are the types of information that, if selectively released, could violate such requirements.

The Company is considering whether it can provide such information under a separate confidentiality agreement that meets the requirements of SEC Regulation FD (see attached) for purposes of settlement discussions.

Regulation FD - Fair Disclosure

Rule 100. General Rule Regarding Selective Disclosure.

(a) Whenever an issuer, or any person acting on its behalf, discloses any material nonpublic information regarding that issuer or its securities to any person described in paragraph (b)(1) of this section, the issuer shall make public disclosure of that information as provided in Rule 101(e):

(1) Simultaneously, in the case of an intentional disclosure; and

(2) Promptly, in the case of a non-intentional disclosure.

(b)(1) Except as provided in paragraph (b)(2) of this section, paragraph (a) of this section shall apply to a disclosure made to any person outside the issuer:

(i) Who is a broker or dealer, or a person associated with a broker or dealer, as those terms are defined in Section 3(a) of the Securities Exchange Act of 1934;

(ii) Who is an investment adviser, as that term is defined in Section

(iv) In connection with a securities offering registered under the Securities Act, other than an offering of the type described in any of Rule 415(a)(1)(i)-(vi).

Rule 101. Definitions.

This section defines certain terms as used in Regulation FD (Rule 100 through Rule 103).

(a) *Intentional.* A selective disclosure of material nonpublic information is "intentional" when the person making the disclosure either knows, or is reckless in not knowing, that the information he or she is communicating is both material and nonpublic.

(b) *Issuer.* An "issuer" subject to this regulation is one that has a class of securities registered under Section 12 of the Securities Exchange Act of 1934, or is required to file reports under Section 15(d) of the Securities Exchange Act of 1934, including any closed-end investment company (as defined in Section 5(a)(2) of the Investment Company Act of 1940), but not including any other investment company or any foreign government or foreign private issuer, as those terms are defined in Rule 405 under the Securities Act.

(c) *Person acting on behalf of an issuer.* "Person acting on behalf of an issuer" means any senior official of the issuer (or, in the case of a closed-end investment company, a senior official of the issuer's investment adviser), or any other officer, employee, or agent of an issuer who regularly communicates with any person described in Rule 100(b)(1)(i), (ii), or (iii), or with holders of the issuer's securities. An officer, director, employee, or agent of an issuer who discloses material nonpublic information in breach of a duty of trust or confidence to the issuer shall not be considered to be acting on behalf of the issuer.

(d) *Promptly.* "Promptly" means as soon as reasonably practicable (but in no event after the later of 24 hours or the commencement of the next day's trading on the New York Stock Exchange) after a senior official of the issuer (or, in the case of a closed-end investment company, a senior official of the issuer's investment adviser) learns that there has been a non-intentional disclosure by the issuer or person acting on behalf of the issuer of information that the senior official knows, or is reckless in not knowing, is both material and nonpublic.

(e) *Public disclosure.*

(1) Except as provided in paragraph (e)(2) of this section, an issuer shall make the "public disclosure" of information required by Rule 100(a) by furnishing to or filing with the Commission a Form 8-K disclosing that information.

(2) An issuer shall be exempt from the requirement to furnish or file a Form 8-K if it instead disseminates the information through another method (or combination of methods) of disclosure that is reasonably designed to provide broad, non-exclusionary distribution of the information to the public.

(f) *Senior official.* "Senior official" means any director, executive officer (as defined in Rule 3b-7 of this chapter), investor relations or public relations officer, or other person with similar functions.

(g) *Securities offering.* For purposes of Rule 100(b)(2)(iv):

[redacted]

CA-RIR-15

Ref: RT-16, page 65

Please provide copy of any slides or other materials used by HECO in the May, 2005 annual visit with Moody's.

HECO Response:

Please see HECO's objections and response to CA-RIR-14.

CA-RIR-16

Ref: RT-20, page 7.

Please provide a copy of the source document cited in table on this page.

Dr. Morin's Response:

The AUS Report is attached.

Note: Most (if not all) of the information requested is copyrighted. The attached copy is being provided under the "fair use" exception to the copyright laws. Any copies made of the attachment are subject to the copyright laws.

LATEST ISSUE - AUS MONTHLY REPORT
JULY 2005
REPORT PAGES

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ELECTRIC COMPANIES

ST	PER SHARE DATA ($)					PERCENT (2)					
ITHS NGS ABLE	EARNINGS	CURRENT ANNUAL DIVIDEND	BOOK VALUE (1)	STOCK PRICE 6/20	COMMON SHARES O/S MILL	DIV PAYOUT	DIV YIELD	MKT/ BOOK	DIV/ BOOK (2)	PRICE EARN MULT
5	0.14	1.26	20.72	49.93	29.8	NM	2.5	241	6.1	NM
5	3.09	1.40	22.47	35.90	383.9	45	3.9	160	6.2	11.6
5	0.68	0.92	17.60	19.30	12.2	135	4.8	110	5.2	28.4
5	1.23	0.90	10.88	21.33	49.9	73	4.2	196	8.3	17.3
5	1.65	0.96	8.32	27.48	127.8	58	3.5	330	11.5	16.7
5	1.30	1.00	7.79	18.86	81.4	77	5.3	242	12.8	14.5
5	0.97	1.00	18.72	38.31	325.8	103	2.6	205	5.3	39.5
5	0.74	0.00	11.24	20.95	47.7	0	0.0	186	NM	28.3
5	0.78	1.28	14.79	24.17	25.7	164	5.3	163	8.7	31.0
5	2.56	1.65	26.14	46.83	329.8	64	3.5	179	6.3	18.3
5	2.42	1.42	21.73	41.27	372.4	59	3.4	190	6.5	17.0
5	2.23	1.66	15.33	32.05	74.6	74	5.2	209	10.8	14.4
5	1.94	1.00	18.59	29.18	6.0	52	3.4	157	5.4	15.0
5	1.26	1.24	14.66	27.20	80.7	98	4.6	185	8.5	21.6
5	1.94	1.20	24.13	29.94	42.2	62	4.0	124	5.0	15.4
5	0.62	1.00	30.62	24.50	1.6	161	4.1	80	3.3	39.5
5	1.67	1.33	14.02	28.64	90.2	80	4.6	204	9.5	17.1
5	1.61	1.12	14.93	27.31	29.1	70	4.1	183	7.5	17.0
5	2.50	1.90	32.61	44.51	91.8	76	4.3	137	5.8	17.8
5	3.08	2.36	30.78	44.62	249.0	77	5.3	145	7.7	14.5
5	2.04	1.49	13.99	34.08	744.0	73	4.4	244	10.7	16.7
5	-1.47	2.25	2.68	84.44	239.8	NM	2.7	NM	NM	NM
5	2.39	2.88	37.39	53.58	14.5	121	5.4	143	7.7	22.4
5	1.25	0.92	16.07	23.86	86.4	74	3.9	148	5.7	19.1
						82	4.0	181	7.5	20.6

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			(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)
			Electric Companies (continued)											
						NET				% RETURN ON				
			OPER			PLANT			COMMON	BOOK VALUE		REGULATION		
			REV	%	NET	PER $	S&P	MOODY'S	EQUITY	COMMON	TOTAL	ALLOWED	ORDER	
		COMPANY	$ MILL (1)	ELEC REV	PLANT $ MILL	REV (1)	BOND RATING	BOND RATING	RATIO (3)	EQUITY (4)	CAPITAL	ROE	DATE	
1	1	ALLETE, Inc. (NYSE-ALE)	1,179.8	48	880.8	0.75	A	Baa1	61	0.4	2.1	11.60	11/94	
2	2	American Electric Power Co. (NYSE-AEP)	13,603.0	78	22,599.0	1.66	BBB	Baa1	41	14.3	9.0	11.31	-	
3	3	Central Vermont Public Serv. Corp. (NYSE-CV)	293.7	77	297.3	1.01	BBB	NR	59	3.8	5.2	10.00	03/05	
4	4	Cleco Corporation (NYSE-CNL)	734.4	100	1,064.3	1.45	BBB+	A3	47	12.0	9.3	12.25	03/04	
5	5	DPL Inc.(NYSE-DPL)	1,204.6	99	2,531.3	2.10	BBB+	Baa2	33	20.3	10.5	-	09/00	
6	6	Duquesne Light Holdings Inc. (NYSE-DQE)	898.9	85	1,458.7	1.62	BBB+	Baa1	35	16.5	9.5	-	05/98	
7	7	Edison International (NYSE-EIX)	10,135.0	85	13,610.0	1.34	BBB+	A3	36	5.6	6.3	11.60	07/04	
8	8	El Paso Electric Company (ASE-EE)	712.0	99	1,275.8	1.79	BBB	Baa2	48	6.8	7.1	11.25	-	
9	9	Empire District Electric Co. (NYSE-EDE)	327.8	93	864.4	2.64	A-	Baa1	48	5.3	6.2	11.00	03/05	
10	10	FirstEnergy Corporation (NYSE-FE)	11,963.1	72	13,550.1	1.13	BBB	Baa1	43	10.0	7.5	9.75	-	
11	11	FPL Group, Inc. (NYSE-FPL)	10,628.0	83	21,471.0	2.02	A	Aa3	45	11.7	8.0	-	03/02	
12	12	Great Plains Energy (NYSE-GXP)	2,467.7	44	2,718.1	1.10	BBB	A2	46	15.5	10.0	-	-	
13	13	Green Mountain Power Corp. (NYSE-GMP)	223.9	100	232.8	1.04	BBB	Baa1	53	9.6	8.2	10.50	12/03	
14	14	Hawaiian Electric Industries, Inc. (NYSE-HE)	1,959.6	81	2,199.0	1.12	BBB+	Baa2	28	8.4	4.0	11.22	-	
15	15	IDACORP, Inc. (NYSE-IDA)	852.5	97	2,224.3	2.61	A-	A3	48	8.1	6.6	10.25	-	
16	16	Maine & Maritimes Corporation (ASE-MAM)	38.4	88	63.7	1.66	NR	NR	54	2.2	4.0	10.25	09/03	
17	17	OGE Energy Corp. (NYSE-OGE)	5,165.7	30	3,611.3	0.70	BBB +	Baa2	44	12.1	8.6	11.55	-	
18	18	Otter Tail Corporation (NDQ-OTTR)	915.8	29	683.0	0.75	BBB+	A2	56	11.2	8.7	12.00	-	
19	19	Pinnacle West Capital Corp. (NYSE-PNW)	2,959.3	69	7,561.5	2.56	BBB	Baa1	49	7.8	6.7	10.25	03/05	
20	20	Progress Energy Inc. (NYSE-PGN)	9,736.0	74	14,122.0	1.45	BBB	A2	41	9.9	7.6	12.75	-	
21	21	Southern Company (NYSE-SO)	12,036.3	92	28,539.2	2.37	A+	A1	41	15.1	9.0	12.20	-	
22	22	TXU Corp. (NYSE-TXU)	9,209.0	24	16,761.0	1.82	BBB-	Baa1	5	10.5	4.6	11.25	-	
23	23	UIL Holdings Corporation (NYSE-UIL)	1,130.4	64	565.7	0.50	NR	Baa2	51	6.7	5.3	10.45	08/04	
24	24	Westar Energy, Inc. (NYSE-WR)	1,460.7	100	3,914.7	2.68	BBB	Baa3	45	8.0	7.2	11.02	09/01	
25		AVERAGE							44	9.7	7.1	11.12		

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GAS COMPANIES

K S	COMMON SHARES O/S MILL	PERCENT (2) DIV PAYOUT	DIV YIELD	MKT/ BOOK	DIV/ BOOK (2)	PRICE EARN MULT
0	652.5	0	0.0	NM	NM	24.2
9	165.7	0	0.0	303	NM	30.7
8	115.9	84	3.8	127	4.8	22.3
9	195.8	88	4.7	183	8.5	18.9
	241.8	0	0.0	77	NM	NM
5	48.5	79	3.0	114	3.5	26.1
0	32.5	67	3.4	169	5.7	19.7
3	309.0	33	2.4	344	8.2	14.0
9	15.8	86	4.5	149	6.7	18.9
4	198.0	87	4.4	193	8.5	19.9
5	195.6	0	0.0	127	NM	9.9
2	242.5	97	5.0	156	7.7	19.5
5	177.4	40	2.4	195	4.7	16.3
3	340.5	72	3.6	236	8.5	19.8
1	174.2	91	4.4	148	6.5	20.7
8	928.0	53	3.8	164	6.2	14.2
3	146.9	59	3.7	155	5.7	16.2
5	216.8	56	2.9	201	5.8	19.4
5	668.5	55	3.3	336	11.0	16.7
5	4.0	53	3.3	162	5.3	16.2
9	118.2	39	2.5	200	5.1	15.4
5	20.4	96	3.8	218	8.2	25.4
5	271.7	59	3.7	135	5.1	15.7
7	151.2	NM	3.3	147	4.9	NM
8	35.7	6	3.1	142	4.4	1.9

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Electric + Gas Companies (Continued)										
.16	13.70	29.80	106.5	67	3.9	218	8.5	17.3		
.00	18.04	23.81	188.8	71	4.2	132	5.5	16.9		
.20	19.89	36.80	393.2	52	3.3	185	6.0	16.0		
.74	19.88	29.89	60.5	48	2.5	150	3.7	19.5		
.84	22.84	58.91	189.1	50	3.1	258	8.1	16.1		
.24	24.03	57.16	238.7	73	3.9	238	9.3	18.6		
.00	16.83	23.36	99.9	169	4.3	139	5.9	39.6		
.56	23.45	43.24	112.9	68	3.6	184	6.7	19.0		
.16	21.47	40.11	239.0	30	2.9	187	5.4	10.2		
.00	12.66	12.83	117.5	0	0.0	101	NM	NM		
.76	7.07	18.65	206.9	NM	4.1	264	10.8	NM		
.76	16.77	29.61	34.5	77	2.6	177	4.5	29.9		
.38	16.90	27.50	5.5	97	5.0	163	8.2	19.2		
.18	14.94	28.50	75.9	81	4.1	191	7.9	19.5		
.88	21.77	37.13	117.0	80	2.4	171	4.0	33.8		
.22	30.05	56.31	37.8	50	3.9	187	7.4	12.6		
.86	13.11	19.50	401.8	71	4.4	149	6.6	16.1		
				60	3.2	182	6.6	19.1		
GES				67	3.5	182	6.9	19.7		

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Combination Electric & Gas Companies (Continued)

	COMPANY	TOTAL REV $ MILL	% ELEC REV	NET PLANT $ MILL	NET PLANT PER $ REV (1)	S&P BOND RATING	MOODY'S BOND RATING	COMMON EQUITY RATIO (3)	% RETURN ON BOOK VALUE COMMON EQUITY (4)	% RETURN ON BOOK VALUE TOTAL CAPITAL	REGULATION ALLOWED ROE	REGULATION ORDER DATE
1	AES Corporation (NYSE-AES)	9,859.0	45	18,823.0	1.91	BBB-	Baa2	8	NM	10.8	-	06/96
2	Allegheny Energy, Inc. (NYSE-AYE)	2,822.9	92	6,287.3	2.23	BB	Ba1	23	8.6	8.2	10.85	-
3	Alliant Energy Corporation (NYSE-LNT)	3,014.8	72	4,697.8	1.56	A-	A2	48	5.8	6.3	11.50	-
4	Ameren Corporation (NYSE-AEE)	5,570.0	81	13,332.0	2.39	A-	A2	49	10.0	7.9	10.92	-
5	Aquila Inc. (NYSE-ILA)	1,808.8	43	2,804.5	1.55	B-	B2	32	NM	NM	11.33	-
6	Avista Corporation (NYSE-AVA)	1,167.6	54	2,026.9	1.74	BB+	Baa3	39	4.4	6.5	10.78	-
7	Black Hills Corporation (NYSE-BKH)	1,153.1	21	1,554.8	1.35	BBB	Baa1	47	7.5	7.4	-	-
8	CenterPoint Energy (NYSE-CNP)	9,287.6	17	8,201.0	0.88	BBB	Baa2	11	16.9	9.0	10.37	-
9	CH Energy Group, Inc. (NYSE-CHG)	814.6	54	751.4	0.92	A	A2	59	7.9	6.9	10.30	10/01
10	Cinergy Corp. (NYSE-CIN)	4,743.5	77	10,043.3	2.12	BBB-	Baa3	47	10.1	7.5	11.00	-
11	CMS Energy Corporation (NYSE-CMS)	5,563.0	46	8,798.0	1.58	BBB-	Baa3	20	14.0	8.4	11.20	-
12	Consolidated Edison, Inc. (NYSE-ED)	9,894.0	67	15,400.0	1.56	A	A1	48	8.3	7.2	11.08	-
13	Constellation Energy Group, Inc. (NYSE-CEG)	13,142.9	15	9,887.8	0.75	A	A1	48	12.8	9.0	11.05	-
14	Dominion (NYSE-D)	14,825.0	35	27,304.0	1.84	A-	A2	38	11.8	7.7	10.50	-
15	DTE Energy Company (NYSE-DTE)	7,365.0	18	10,524.0	1.43	BBB+	Baa2	40	7.2	7.3	11.00	-
16	Duke Energy Corporation (NYSE-DUK)	23,305.5	22	33,391.0	1.43	BBB	Baa2	44	13.1	8.8	11.83	-
17	Energy East Corporation (NYSE-EAS)	4,854.6	58	5,668.3	1.17	BBB+	A3	41	9.9	8.0	11.15	-
18	Entergy Corporation (NYSE-ETR)	10,192.1	78	18,778.1	1.84	A-	Baa2	49	10.3	6.4	11.03	-
19	Exelon Corporation (NYSE-EXC)	14,354.0	72	21,413.0	1.49	A-	A2	40	21.4	11.8	11.72	-
20	Florida Public Utilities Company (ASE-FPU)	114.8	38	120.0	1.05	NR	NR	45	10.3	8.9	11.28	-
21	MDU Resources Group, Inc. (NYSE-MDU)	2,808.1	6	2,622.0	0.93	A-	A2	64	13.6	10.8	11.83	-
22	MGE Energy, Inc. (NDQ-MGEE)	428.5	59	620.7	1.45	AA-	Aa3	60	9.2	7.3	11.50	12/04
23	NiSource Inc. (NYSE-NI)	6,876.3	16	9,357.5	1.36	BBB	Baa2	44	8.9	7.6	11.97	-
24	Northeast Utilities (NYSE-NU)	7,113.2	58	5,954.3	0.84	BBB+	A3	31	NM	3.5	9.87	-
25	Northwestern Corporation (NYSE-NWEC)	1,034.5	53	1,378.5	1.33	BB	Ba1	47	NM	NM	11.46	-

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			Combination		Electric + Gas		Companies			(Continued)				
33	26	NSTAR (NYSE-NST)	3,024.4	80	3,457.2	1.14	A	A1	33	13.0	7.0	11.63	-	
34	27	Pepco Holdings, Inc. (NYSE-POM)	7,262.5	67	7,210.4	0.99	A-	A3	37	7.9	6.6	10.76	-	
35	28	PG&E Corporation (NYSE-PCG)	11,027.0	66	19,068.0	1.73	BBB	Baa1	43	13.3	11.0	11.22	05/04	
36	29	PNM Resources, Inc. (NYSE-PNM)	1,593.2	70	2,340.2	1.47	BBB	Baa2	49	8.2	6.2	10.25	-	
37	30	PPL Corporation (NYSE-PPL)	5,894.0	67	11,008.0	1.87	A-	Baa1	35	17.8	10.1	10.70	-	
38	31	Public Service Enterprise Group (NYSE-PEG)	11,085.0	63	13,797.0	1.24	A-	A3	30	13.0	7.1	9.88	-	
39	32	Puget Energy, Inc. (NYSE-PSD)	2,571.0	56	4,289.4	1.67	BBB	Baa2	40	3.6	5.6	10.30	02/05	
40	33	SCANA Corporation (NYSE-SCG)	4,015.0	43	6,606.0	1.65	A-	A1	41	10.1	7.4	11.05	-	
41	34	SEMPRA Energy (NYSE-SRE)	9,742.0	48	11,245.0	1.15	A+	A1	50	20.0	12.8	10.90	-	
42	35	Sierra Pacific Resources (NYSE-SRP)	2,884.3	94	5,042.9	1.75	BB+	Ba2	26	4.6	6.5	10.25	-	
43	36	TECO Energy, Inc. (NYSE-TE)	2,800.2	60	4,556.1	1.63	BBB-	Baa2	27	NM	NM	11.25	-	
44	37	UniSource Energy Corporation (NYSE-UNS)	1,159.8	84	2,086.3	1.80	BBB-	Ba2	22	6.1	7.4	10.67	-	
45	38	Unitil Corporation (ASE-UTL)	214.6	85	204.8	0.95	NR	NR	40	8.6	6.6	10.00	-	
46	39	Vectren Corporation (NYSE-VVC)	1,721.6	22	2,161.5	1.26	A-	A3	47	9.9	7.9	11.03	-	
47	40	Wisconsin Energy Corporation (NYSE-WEC)	3,464.2	61	5,974.0	1.72	A-	A1	42	5.2	4.9	12.20	-	
48	41	WPS Resources Corporation (NYSE-WPS)	4,979.4	18	2,061.0	0.41	AA-	Aa2	50	15.4	10.6	11.50	12/04	
49	42	Xcel Energy Inc. (NYSE-XEL)	8,475.0	75	1,539.2	0.18	A-	A3	34	9.3	6.8	11.49	-	
50		AVERAGE							40	10.5	7.9	11.01		
51														
52		COMBINED ELECTRIC/COMBINATION ELECTRIC & GAS AVERAGES							41	10.2	7.6	11.05		

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NATURAL GAS DISTRIBUTION, TRANSMISSION AND INTEGRATED NATURAL GAS COMPANIES

			PER SHARE DATA ($)					PERCENT (2)					
		COMPANY	LATEST 12 MONTHS EARNINGS AVAILABLE	EARNINGS	CURRENT ANNUAL DIVIDEND	BOOK VALUE (1)	STOCK PRICE 6/20	COMMON SHARES O/S MILL	DIV PAYOUT	DIV YIELD	MKT/ BOOK	DIV/ BOOK (2)	PRICE EARN MULT
1													
2													
3													
4													
5													
6													
7													
8													
9	1	AGL Resources Inc. (NYSE-ATG)	3/05	2.43	1.24	18.85	37.29	76.7	51	3.3	198	6.6	15.3
10	2	Atmos Energy Corporation (NYSE-ATO)	3/05	1.79	1.24	20.43	28.59	79.9	69	4.3	140	6.1	16.0
11	3	Cascade Natural Gas Corporation (NYSE-CGC)	3/05	0.92	0.96	11.32	20.00	11.3	104	4.8	177	8.5	21.7
12	4	Chesapeake Utilities Corporation (NYSE-CPK)	3/05	1.70	1.14	14.37	30.54	5.8	67	3.7	213	7.9	18.0
13	5	Delta Natural Gas Company (NDQ-DGAS)	3/05	1.83	1.18	16.14	26.15	3.2	64	4.5	162	7.3	14.3
14	6	El Paso Corporation (NYSE-EP)	3/05	-1.05	0.16	5.17	11.41	642.9	NM	1.4	221	3.1	NM
15	7	Energen Corporation (NYSE-EGN)	3/05	1.71	0.40	10.90	35.01	73.3	23	1.1	321	3.7	20.4
16	8	Energy West Incorporated (NDQ-EWST)	3/05	0.23	0.00	5.80	10.08	2.6	0	0.0	174	NM	43.8
17	9	EnergySouth, Inc. (NDQ-ENSI)	3/05	1.66	0.86	13.04	27.23	7.8	52	3.2	209	6.6	16.4
18	10	Equitable Resources, Inc. (NYSE-EQT)	3/05	4.55	1.68	12.27	67.75	61.0	37	2.5	552	13.7	14.9
19	11	KeySpan Corp. (NYSE-KSE)	3/05	3.14	1.82	25.24	40.50	161.1	58	4.5	160	7.2	12.9
20	12	Kinder Morgan, Inc. (NYSE-KMI)	3/05	4.39	2.80	21.90	82.75	123.5	64	3.4	378	12.8	18.8
21	13	Laclede Group, Inc. (NYSE-LG)	3/05	1.76	1.38	18.15	31.07	21.1	78	4.4	171	7.6	17.7
22	14	National Fuel Gas Company (NYSE-NFG)	3/05	1.91	1.12	15.93	29.29	83.5	59	3.8	184	7.0	15.3
23	15	New Jersey Resources Corp. (NYSE-NJR)	3/05	2.77	1.36	18.84	46.89	27.4	49	2.9	249	7.2	16.9
24	16	NICOR Inc. (NYSE-GAS)	3/05	2.25	1.86	17.61	41.49	44.1	83	4.5	236	10.6	18.4
25	17	Northwest Natural Gas Co. (NYSE-NWN)	3/05	2.07	1.30	21.73	37.21	27.6	63	3.5	171	6.0	18.0
26	18	ONEOK, Inc. (NYSE-OKE)	3/05	2.23	1.12	15.38	31.99	102.2	50	3.5	208	7.3	14.3
27	19	Peoples Energy Corporation (NYSE-PGL)	3/05	1.92	2.18	22.97	43.89	38.2	114	5.0	191	9.5	22.9
28	20	Piedmont Natural Gas Co., Inc. (NYSE-PNY)	4/05	0.91	0.92	12.12	23.75	76.8	101	3.9	196	7.6	26.1
29	21	Questar Corporation (NYSE-STR)	3/05	2.88	0.90	16.68	66.45	84.4	31	1.4	398	5.4	23.1
30	22	RGC Resources, Inc. (NDQ-RGCO)	3/05	1.28	1.18	18.99	26.01	2.1	92	4.5	137	6.2	20.3
31	23	SEMCO Energy, Inc. (NYSE-SEN)	3/05	-0.22	0.30	5.89	5.85	28.4	NM	5.1	99	5.1	NM
32	24	South Jersey Industries, Inc. (NYSE-SJI)	3/05	1.62	0.85	13.26	30.29	27.8	52	2.8	229	6.4	18.7
33	25	Southern Union Company (NYSE-SUG)	3/05	0.92	0.00	18.30	24.65	104.8	0	0.0	135	NM	26.8
34	26	Southwest Gas Corporation (NYSE-SWX)	3/05	1.30	0.82	20.17	25.76	36.8	63	3.2	128	4.1	19.8
35	27	Southwestern Energy Company (NYSE-SWN)	3/05	1.50	0.00	6.07	44.60	72.9	0	0.0	NM	NM	29.7
36	28	UGI Corporation (NYSE-UGI)	3/05	1.83	0.68	8.86	26.13	115.2	37	2.6	295	7.6	14.3
37	29	WGL Holdings, Inc. (NYSE-WGL)	3/05	2.06	1.33	19.42	33.79	48.7	65	3.9	174	6.8	16.4
38	30	Williams Companies, Inc. (NYSE-WMB)	3/05	0.51	0.20	9.22	19.20	570.5	39	1.0	208	2.2	37.6
39		AVERAGE							56	3.1	218	7.0	20.3

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Natural Gas Distribution, Transmission and Integrated Natural Gas Companies (continued)

			(14)	(15)	(16)	(17)	(18)	(19)	(20)	(21)	(22)	(23)	(24)	(25)
						NET				% RETURN ON				
			TOTAL			PLANT			COMMON	BOOK VALUE		REGULATION		
			REV	%	NET	PER $	S&P	MOODY'S	EQUITY	COMMON	TOTAL	ALLOWED	ORDER	
		COMPANY	$ MILL (1)	GAS REV	PLANT $ MILL	REV (1)	BOND RATING	BOND RATING	RATIO (3)	EQUITY (4)	CAPITAL	ROE	DATE	
1	1	AGL Resources Inc. (NYSE-ATG)	2,093.0	56	3,224.0	1.54	A-	A3	46	14.3	9.7	10.81	-	
2	2	Atmos Energy Corporation (NYSE-ATO)	4,119.6	64	3,251.6	0.79	BBB	Baa3	42	11.4	8.6	11.86	-	
3	3	Cascade Natural Gas Corporation (NYSE-CGC)	316.1	100	341.2	1.08	BBB+	Baa1	42	8.2	7.5	11.75	-	
4	4	Chesapeake Utilities Corporation (NYSE-CPK)	192.0	71	178.4	0.93	NR	NR	55	12.4	10.1	-	-	
5	5	Delta Natural Gas Company (NDQ-DGAS)	85.6	63	115.7	1.35	NR	NR	46	11.9	9.2	-	12/99	
6	6	El Paso Corporation (NYSE-EP)	5,525.0	48	18,911.0	3.42	B-	B1	15	NM	3.7			
7	7	Energen Corporation (NYSE-EGN)	947.0	56	574.9	0.61	A-	A1	53	16.4	12.1	13.40	06/02	
8	8	Energy West Incorporated (NDQ-EWST)	76.0	58	38.9	0.51	NR	NR	37	3.8	7.6	12.63	-	
9	9	EnergySouth, Inc. (NDQ-ENSI)	120.9	96	203.5	1.68	NR	NR	53	13.6	10.8	13.60	10/01	
10	10	Equitable Resources, Inc. (NYSE-EQT)	1,230.9	61	1,999.1	1.62	A-	A2	42	NM	12.6	11.00	-	
11	11	KeySpan Corp. (NYSE-KSE)	6,783.2	66	7,097.2	1.05	A+	A2	48	13.0	8.7	10.20	-	
12	12	Kinder Morgan, Inc. (NYSE-KMI)	1,149.2	27	5,834.0	5.08	BBB	Baa2	40	20.1	10.1	-	-	
13	13	Laclede Group, Inc. (NYSE-LG)	1,461.8	64	661.5	0.45	A	A3	45	10.4	8.1	-	10/02	
14	14	National Fuel Gas Company (NYSE-NFG)	2,032.8	55	3,059.8	1.51	BBB+	Baa1	51	12.6	7.4	11.00	-	
15	15	New Jersey Resources Corp. (NYSE-NJR)	2,761.8	38	894.3	0.32	AA-	Aa3	55	15.5	10.8	11.50	01/94	
16	16	NICOR Inc. (NYSE-GAS)	2,803.8	86	2,557.4	0.91	AA	Aa3	59	13.0	10.3	-	11/99	
17	17	Northwest Natural Gas Co. (NYSE-NWN)	755.3	98	1,300.2	1.72	A+	A2	54	10.2	8.7	10.20	-	
18	18	ONEOK, Inc. (NYSE-OKE)	7,710.4	26	3,792.0	0.49	BBB+	Baa1	41	16.0	9.7	-	-	
19	19	Peoples Energy Corporation (NYSE-PGL)	2,497.7	66	1,909.2	0.76	A-	Aa3	49	8.2	6.8	11.20	-	
20	20	Piedmont Natural Gas Co., Inc. (NYSE-PNY)	1,617.1	77	1,882.4	1.16	A	A3	59	9.8	8.6	11.30	-	
21	21	Questar Corporation (NYSE-STR)	2,018.1	40	3,039.9	1.51	A-	A2	59	18.2	13.5	11.20	12/02	
22	22	RGC Resources, Inc. (NDQ-RGCO)	111.6	81	72.1	0.65	NR	NR	57	7.1	6.7	9.85	-	
23	23	SEMCO Energy, Inc. (NYSE-SEN)	527.1	93	559.9	1.06	BB-	Ba2	23	NM	6.1	11.78	-	
24	24	South Jersey Industries, Inc. (NYSE-SJI)	840.1	62	811.4	0.97	A	Baa1	51	13.0	9.4	10.00	07/04	
25	25	Southern Union Company (NYSE-SUG)	1,848.8	73	3,355.1	1.81	BB	Baa3	45	5.9	6.0	10.86	-	
26	26	Southwest Gas Corporation (NYSE-SWX)	1,546.5	86	2,353.4	1.52	BB	Baa2	36	6.9	6.9	10.80	-	
27	27	Southwestern Energy Company (NYSE-SWN)	518.4	77	1,044.1	2.01	BBB-	Ba1	59	NM	18.7	11.30	11/96	
28	28	UGI Corporation (NYSE-UGI)	3,918.8	19	1,819.6	0.46	BBB	Ba1	34	20.1	11.0	-	07/96	
29	29	WGL Holdings, Inc. (NYSE-WGL)	2,197.6	62	1,923.9	0.88	AA-	A2	57	10.9	8.7	10.62	-	
30	30	Williams Companies, Inc. (NYSE-WMB)	12,339.7	11	11,852.3	0.96	B+	Ba3	NM	6.4	16.3			
39		AVERAGE							47	11.9	9.5	11.28		

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TELEPHONE COMPANIES

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)
			PER SHARE DATA ($)					PERCENT (2)						
	COMPANY	LATEST 12 MONTHS EARNINGS AVAILABLE	EARNINGS	CURRENT ANNUAL DIVIDEND	BOOK VALUE (1)	STOCK PRICE 6/20	COMMON SHARES O/S MILL.	DIV PAYOUT	DIV YIELD	MKT/ BOOK	DIV/ BOOK (2)	PRICE EARN MULT		
1	ALLTEL Corporation (NYSE-AT)	3/05	3.76	1.52	23.95	60.96	302.3	40	2.5	255	6.3	16.2		
2	AT&T Corp. (NYSE-T)	3/05	-7.37	0.95	9.26	19.38	800.8	NM	4.9	209	10.3	NM		
3	BCE, Inc. (NYSE-BCE)	3/05	1.23	1.06	11.21	23.61	926.2	86	4.5	211	9.5	19.2		
4	BellSouth Corporation (NYSE-BLS)	3/05	1.61	1.08	12.93	27.22	1831.0	67	4.0	211	8.4	16.9		
5	CenturyTel, Inc. (NYSE-CTL)	3/05	2.44	0.24	25.85	34.95	132.4	10	0.7	135	0.9	14.3		
6	Cincinnati Bell Inc. (NYSE- CBB)	3/05	0.16	0.00	(2.55)	4.22	245.7	0	0.0	NM	NM	26.4		
7	Citizens Communications (NYSE-CZN)	3/05	0.19	1.00	3.90	13.46	340.6	NM	7.4	345	NM	70.8		
8	Commonwealth Telephone Ent. (NDQ-CTCO)	3/05	2.83	0.00	13.39	40.70	21.2	0	0.0	304	NM	14.4		
9	General Communication, Inc. (NDQ-GNCMA)	3/05	0.39	0.00	4.22	9.25	55.4	0	0.0	219	NM	23.7		
10	Qwest Communications International (NYSE-Q)	3/05	-0.80	0.00	(1.41)	3.69	1817.3	0	0.0	NM	NM	NM		
11	SBC Communications Inc. (NYSE-SBC)	3/05	1.23	1.29	12.24	24.07	3300.9	105	5.4	197	10.5	19.6		
12	Sprint Corporation (NYSE-FON)	3/05	-0.56	0.50	9.44	24.97	1474.8	NM	2.0	265	5.3	NM		
13	Telephone & Data Systems, Inc. (ASE-TDS)	3/05	0.36	0.35	27.88	40.83	114.9	96	0.9	146	1.3	NM		
14	US LEC Corp. (NDQ-CLEC)	3/05	-1.24	0.00	(7.07)	2.48	30.3	0	0.0	NM	NM	NM		
15	Verizon Communications (NYSE-VZ)	3/05	2.81	1.62	13.71	35.14	2769.7	58	4.6	256	11.8	12.5		
	AVERAGE							38	2.5	229	7.1	23.4		

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cs (continued)

T NT $ V	S&P BOND RATING	MOODY'S BOND RATING	COMMON EQUITY RATIO (3)	% RETURN ON BOOK VALUE COMMON EQUITY (4)	% RETURN ON BOOK VALUE TOTAL CAPITAL	REGULATION ALLOWED ROE	REGULATION ORDER DATE
9	A	A2	56	16.3	11.7	-	-
8	BB+	Ba1	44	NM	NM	-	-
4	A-	A3	41	11.6	8.0		
7	A	A2	56	13.3	10.3	-	-
6	BBB+	Baa2	55	9.8	8.4	10.00	-
8	B+	Ba3	NM	NM	16.1	-	-
1	BB+	Ba3	24	5.0	7.6	-	-
1	NR	NR	46	25.2	12.9	-	05/02
9	NR	B2	33	10.2	7.6		
9	B+	B2	NM	NM	NM	11.11	-
0	A	A2	60	10.2	8.3	12.10	-
0	BBB+	A3	46	NM	0.4	12.27	-
9	A-	Baa1	42	1.4	3.3	-	-
2	NR	NR	NM	19.0	NM		
3	A+	A1	37	22.0	10.0	12.53	-
			45	13.1	8.7	11.60	

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GES

	(8)	(9)	(10)	(11)	(12)	(13)

PERCENT (2)

JT	DIV YIELD	MKT/ BOOK	DIV/ BOOK (2)	PRICE EARN MULT
46	3.7	136	5.0	12.6
53	3.1	126	4.0	17.0
79	5.7	62	3.6	31.3
17	0.9	155	1.4	19.0
81	5.7	335	19.1	14.3
59	3.9	331	12.8	15.4
M	4.1	148	6.1	NM
57	3.2	335	10.7	17.7
70	3.8	204	7.8	18.2

PERCENT (2)

IT	DIV YIELD	MKT/ BOOK	DIV/ BOOK (2)	PRICE EARN MULT
68	3.1	195	6.0	22.2
58	1.7	375	6.5	33.6
77	3.0	209	6.2	25.8
81	3.1	241	7.4	26.4
73	3.4	227	7.6	21.8
87	3.4	237	8.0	25.7
52	3.3	219	7.3	45.7
48	2.2	240	5.4	21.3
80	1.7	179	3.1	46.3
85	2.9	311	8.9	30.0
81	2.8	243	6.6	29.9

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Telephone Companies (Continued)

L	NET PLANT $ MILL.	NET PLANT PER $ REV (1)	S&P BOND RATING	MOODY'S BOND RATING	COMMON EQUITY RATIO (3)	% RETURN ON BOOK VALUE COMMON EQUITY (4)	% RETURN ON BOOK VALUE TOTAL CAPITAL	REGULATION ALLOWED ROE	REGULATION ORDER DATE
39	98.5	1.15	NR	NR	77	11.4	12.1		
56	207.0	1.26	NR	NR	75	7.7	7.3	-	-
91	182.1	1.04	NR	Ba3	44	2.3	4.3	-	-
58	38.5	1.23	NR	NR	48	9.2	6.6	-	-
50	112.5	1.24	NR	NR	25	24.7	8.8	-	-
27	77.4	0.71	NR	NR	75	22.7	18.2	-	-
53	372.2	1.74	NR	NR	68	0.6	1.1	-	-
45	41.3	1.43	NR	NR	76	19.4	16.0		
					61	12.2	9.3		

Companies (Continued)

?	NET PLANT $ MILL.	NET PLANT PER $ REV (1)	S&P BOND RATING	MOODY'S BOND RATING	COMMON EQUITY RATIO (3)	% RETURN ON BOOK VALUE COMMON EQUITY (4)	% RETURN ON BOOK VALUE TOTAL CAPITAL	REGULATION ALLOWED ROE	REGULATION ORDER DATE
38	602.7	2.60	A-	A2	48	9.1	7.9	10.00	4Q/99
34	1,805.7	3.96	AA-	NR	45	11.7	8.3	10.08	-
95	182.0	4.47	NR	NR	37	8.6	7.1	-	04/05
96	714.2	2.26	NR	A2	50	9.6	8.0	9.70	-
91	190.6	3.54	AA+	NR	54	10.9	8.2	12.70	-
86	238.2	3.31	A+	NR	42	9.8	6.8	10.04	-
85	67.0	2.90	NR	NR	46	4.7	6.8	10.00	03/02
97	435.8	2.58	NR	NR	56	11.8	9.4	9.90	08/04
37	217.4	1.11	NR	NR	49	3.8	5.1	9.84	05/03
95	141.6	6.06	NR	NR	48	11.2	9.6	-	11/04
					48	9.1	7.7	10.28	

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COMPOSITE INDEX

NATURAL GAS DISTRIBUTION COMPANIES

		DIVIDEND YIELD	PRICE EARNINGS MULTIPLE
	1995	5.6	15.3
	1996	4.9	14.9
	1997	4.7	15.2
	1998	4.3	17.9
	1999	4.4	19.5
	2000	4.3	19.0
	2001	4.1	16.6
	2002	4.3	17.3
	2003	4.0	16.2
	2004	3.3	17.0
TO DATE	2005	3.2	19.8
IST	2004	3.3	16.6
EMBER	2004	3.2	16.4
BER	2004	3.0	17.7
MBER	2004	3.1	17.0
MBER	2004	2.9	18.0
ARY	2005	3.0	18.4
UARY	2005	3.3	19.4
CH	2005	3.2	20.4
	2005	3.2	20.3
	2005	3.3	19.8
	2005	3.3	19.6
	2005	3.1	20.3

TELEPHONE COMPANIES

		DIVIDEND YIELD	PRICE EARNINGS MULTIPLE
YEAR	1995	3.6	15.9
YEAR	1996	3.2	19.6
YEAR	1997	3.0	17.6
YEAR	1998	2.0	24.4
YEAR	1999	1.5	28.2
YEAR	2000	0.9	27.9
YEAR	2001	0.9	26.3
YEAR	2002	1.4	21.1
YEAR	2003	1.7	21.6
YEAR	2004	2.3	21.5
YEAR TO DATE	2005	2.6	21.9
AUGUST	2004	2.7	21.5
SEPTEMBER	2004	2.8	20.6
OCTOBER	2004	2.6	21.6
NOVEMBER	2004	2.6	21.8
DECEMBER	2004	2.5	22.1
JANUARY	2005	2.5	22.1
FEBRUARY	2005	2.6	21.6
MARCH	2005	2.6	21.2
APRIL	2005	2.7	21.7
MAY	2005	2.8	20.8
JUNE	2005	2.5	22.8
JULY	2005	2.5	23.4

SMALL TELEPHONE COMPANIES

		DIVIDEND YIELD	PRICE EARNINGS MULTIPLE
YEAR	1995	NA	NA
YEAR	1996	NA	NA
YEAR	1997	NA	NA
YEAR	1998	NA	NA
YEAR	1999	NA	NA
YEAR	2000	2.4	24.4
YEAR	2001	2.8	20.0
YEAR	2002	2.6	20.1
YEAR	2003	2.8	21.7
YEAR	2004	2.6	19.3
YEAR TO DATE	2005	3.3	16.6
AUGUST	2004	2.8	14.7
SEPTEMBER	2004	2.8	15.6
OCTOBER	2004	2.6	16.3
NOVEMBER	2004	2.7	15.7
DECEMBER	2004	2.6	16.5
JANUARY	2005	2.7	16.5
FEBRUARY	2005	2.8	16.1
MARCH	2005	3.0	16.2
APRIL	2005	3.1	16.3
MAY	2005	3.5	15.5
JUNE	2005	3.9	17.5
JULY	2005	3.8	18.2

WATER COMPANIES

		DIVIDEND YIELD	PRICE EARNINGS MULTIPLE
YEAR	1995	6.5	12.9
YEAR	1996	5.9	14.2
YEAR	1997	5.2	15.1
YEAR	1998	4.4	17.2
YEAR	1999	3.7	19.7
YEAR	2000	3.5	21.4
YEAR	2001	3.4	21.4
YEAR	2002	3.1	22.2
YEAR	2003	3.2	23.2
YEAR	2004	3.1	27.9
YEAR TO DATE	2005	3.0	27.0
AUGUST	2004	3.3	27.1
SEPTEMBER	2004	3.2	27.7
OCTOBER	2004	3.1	28.3
NOVEMBER	2004	3.2	28.1
DECEMBER	2004	3.0	26.3
JANUARY	2005	2.9	26.7
FEBRUARY	2005	3.0	26.0
MARCH	2005	3.0	26.0
APRIL	2005	3.0	26.6
MAY	2005	3.1	25.2
JUNE	2005	2.9	28.5
JULY	2005	2.8	29.9

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AUS INDUSTRY RANKINGS

ELECTRIC COMPANIES

DIVIDEND YIELD

HIGH		LOW	
UIL Holdings Corporation (NYSE-UIL)	5.4	El Paso Electric Company (ASE-EE)	0.0
Duquesne Light Holdings Inc. (NYSE-DQE)	5.3	ALLETE, Inc. (NYSE-ALE)	2.5
Empire District Electric Co. (NYSE-EDE)	5.3	Edison International (NYSE-EIX)	2.6
Progress Energy Inc. (NYSE-PGN)	5.3	TXU Corp. (NYSE-TXU)	2.7
Great Plains Energy (NYSE-GXP)	5.2	FPL Group, Inc. (NYSE-FPL)	3.4
Central Vermont Public Serv. Corp. (NYSE-CV)	4.8	Green Mountain Power Corp. (NYSE-GMP)	3.4
Hawaiian Electric Industries, Inc. (NYSE-HE)	4.6	DPL Inc.(NYSE-DPL)	3.5
OGE Energy Corp. (NYSE-OGE)	4.6	FirstEnergy Corporation (NYSE-FE)	3.5
Southern Company (NYSE-SO)	4.4	American Electric Power Co. (NYSE-AEP)	3.9
Pinnacle West Capital Corp. (NYSE-PNW)	4.3	Westar Energy, Inc. (NYSE-WR)	3.9

MARKET/BOOK RATIO

HIGH		LOW	
DPL Inc.(NYSE-DPL)	330	Maine & Maritimes Corporation (ASE-MAM)	80
Southern Company (NYSE-SO)	244	Central Vermont Public Serv. Corp. (NYSE-CV)	110
Duquesne Light Holdings Inc. (NYSE-DQE)	242	IDACORP, Inc. (NYSE-IDA)	124
ALLETE, Inc. (NYSE-ALE)	241	Pinnacle West Capital Corp. (NYSE-PNW)	137
Great Plains Energy (NYSE-GXP)	209	UIL Holdings Corporation (NYSE-UIL)	143
Edison International (NYSE-EIX)	205	Progress Energy Inc. (NYSE-PGN)	145
OGE Energy Corp. (NYSE-OGE)	204	Westar Energy, Inc. (NYSE-WR)	148
Cleco Corporation (NYSE-CNL)	196	Green Mountain Power Corp. (NYSE-GMP)	157
FPL Group, Inc. (NYSE-FPL)	190	American Electric Power Co. (NYSE-AEP)	160
El Paso Electric Company (ASE-EE)	186	Empire District Electric Co. (NYSE-EDE)	163

Electric Companies (Continued)

PRICE/EARNINGS MULTIPLE

HIGH		LOW	
NYSE-EIX)	39.5	American Electric Power Co. (NYSE-AEP)	11.6
rporation (ASE-MAM)	39.5	Great Plains Energy (NYSE-GXP)	14.4
c Co. (NYSE-EDE)	31.0	Duquesne Light Holdings Inc. (NYSE-DQE)	14.5
c Serv. Corp. (NYSE-CV)	28.4	Progress Energy Inc. (NYSE-PGN)	14.5
ny (ASE-EE)	28.3	Green Mountain Power Corp. (NYSE-GMP)	15.0
ion (NYSE-UIL)	22.4	IDACORP, Inc. (NYSE-IDA)	15.4
stries, Inc. (NYSE-HE)	21.6	DPL Inc.(NYSE-DPL)	16.7
YSE-WR)	19.1	Southern Company (NYSE-SO)	16.7
n (NYSE-FE)	18.3	FPL Group, Inc. (NYSE-FPL)	17.0
Corp. (NYSE-PNW)	17.8	Otter Tail Corporation (NDQ-OTTR)	17.0

RETURN ON BOOK VALUE OF COMMON EQUITY

HIGH		LOW	
	20.3	ALLETE, Inc. (NYSE-ALE)	0.4
gs Inc. (NYSE-DQE)	16.5	Maine & Maritimes Corporation (ASE-MAM)	2.2
YSE-GXP)	15.5	Central Vermont Public Serv. Corp. (NYSE-CV)	3.8
YSE-SO)	15.1	Empire District Electric Co. (NYSE-EDE)	5.3
er Co. (NYSE-AEP)	14.3	Edison International (NYSE-EIX)	5.6
YSE-OGE)	12.1	UIL Holdings Corporation (NYSE-UIL)	6.7
SE-CNL)	12.0	El Paso Electric Company (ASE-EE)	6.8
E-FPL)	11.7	Pinnacle West Capital Corp. (NYSE-PNW)	7.8
(NDQ-OTTR)	11.2	Westar Energy, Inc. (NYSE-WR)	8.0
KU)	10.5	IDACORP, Inc. (NYSE-IDA)	8.1

LOW	
SE-AES)	0.0
(NYSE-AYE)	0.0
)	0.0
ion (NYSE-CMS)	0.0
s (NYSE-SRP)	0.0
YSE-CNP)	2.4
roup, Inc. (NYSE-CEG)	2.4
poration (NYSE-WEC)	2.4
, Inc. (NYSE-MDU)	2.5
NYSE-PNM)	2.5

LOW	
)	77
s (NYSE-SRP)	101
YSE-AVA)	114
on (NYSE-CMS)	127
ation (NYSE-LNT)	127
NYSE-POM)	132
NI)	135
SE-PSD)	139
ion (NYSE-NWEC)	142
SE-NU)	147

Combination Electric + Gas Companies (Continued)

PRICE/EARNINGS MULTIPLE

HIGH		LOW	
Puget Energy, Inc. (NYSE-PSD)	39.6	Northwestern Corporation (NYSE-NWEC)	1.9
Wisconsin Energy Corporation (NYSE-WEC)	33.8	CMS Energy Corporation (NYSE-CMS)	9.9
Allegheny Energy, Inc. (NYSE-AYE)	30.7	SEMPRA Energy (NYSE-SRE)	10.2
UniSource Energy Corporation (NYSE-UNS)	29.9	WPS Resources Corporation (NYSE-WPS)	12.6
Avista Corporation (NYSE-AVA)	26.1	CenterPoint Energy (NYSE-CNP)	14.0
MGE Energy, Inc. (NDQ-MGEE)	25.4	Duke Energy Corporation (NYSE-DUK)	14.2
AES Corporation (NYSE-AES)	24.2	MDU Resources Group, Inc. (NYSE-MDU)	15.4
Alliant Energy Corporation (NYSE-LNT)	22.3	NiSource Inc. (NYSE-NI)	15.7
DTE Energy Company (NYSE-DTE)	20.7	PG&E Corporation (NYSE-PCG)	16.0
Cinergy Corp. (NYSE-CIN)	19.9	PPL Corporation (NYSE-PPL)	16.1

RETURN ON BOOK VALUE OF COMMON EQUITY

HIGH		LOW	
Exelon Corporation (NYSE-EXC)	21.4	Puget Energy, Inc. (NYSE-PSD)	3.6
SEMPRA Energy (NYSE-SRE)	20.0	Avista Corporation (NYSE-AVA)	4.4
PPL Corporation (NYSE-PPL)	17.8	Sierra Pacific Resources (NYSE-SRP)	4.6
CenterPoint Energy (NYSE-CNP)	16.9	Wisconsin Energy Corporation (NYSE-WEC)	5.2
WPS Resources Corporation (NYSE-WPS)	15.4	Alliant Energy Corporation (NYSE-LNT)	5.8
CMS Energy Corporation (NYSE-CMS)	14.0	UniSource Energy Corporation (NYSE-UNS)	6.1
MDU Resources Group, Inc. (NYSE-MDU)	13.6	DTE Energy Company (NYSE-DTE)	7.2
PG&E Corporation (NYSE-PCG)	13.3	Black Hills Corporation (NYSE-BKH)	7.5
Duke Energy Corporation (NYSE-DUK)	13.1	CH Energy Group, Inc. (NYSE-CHG)	7.9
NSTAR (NYSE-NST)	13.0	Pepco Holdings, Inc. (NYSE-POM)	7.9

COMPANIES

LOW	
West Incorporated (NDQ-EWST)	0.0
rn Union Company (NYSE-SUG)	0.0
vestern Energy Company (NYSE-SWN)	0.0
ns Companies, Inc. (NYSE-WMB)	1.0
n Corporation (NYSE-EGN)	1.1
Corporation (NYSE-EP)	1.4
r Corporation (NYSE-STR)	1.4
ble Resources, Inc. (NYSE-EQT)	2.5
orporation (NYSE-UGI)	2.6
Jersey Industries, Inc. (NYSE-SJI)	2.8

LOW	
O Energy, Inc. (NYSE-SEN)	99
vest Gas Corporation (NYSE-SWX)	128
rn Union Company (NYSE-SUG)	135
Resources, Inc. (NDQ-RGCO)	137
Energy Corporation (NYSE-ATO)	140
an Corp. (NYSE-KSE)	160
Natural Gas Company (NDQ-DGAS)	162
e Group, Inc. (NYSE-LG)	171
vest Natural Gas Co. (NYSE-NWN)	171
West Incorporated (NDQ-EWST)	174

Natural Gas Dist. & Int. Gas Companies (Continued)

PRICE/EARNINGS MULTIPLE

HIGH		LOW	
Energy West Incorporated (NDQ-EWST)	43.8	KeySpan Corp. (NYSE-KSE)	12.9
Williams Companies, Inc. (NYSE-WMB)	37.6	UGI Corporation (NYSE-UGI)	14.3
Southwestern Energy Company (NYSE-SWN)	29.7	Delta Natural Gas Company (NDQ-DGAS)	14.3
Southern Union Company (NYSE-SUG)	26.8	ONEOK, Inc. (NYSE-OKE)	14.3
Piedmont Natural Gas Co., Inc. (NYSE-PNY)	26.1	Equitable Resources, Inc. (NYSE-EQT)	14.9
Questar Corporation (NYSE-STR)	23.1	National Fuel Gas Company (NYSE-NFG)	15.3
Peoples Energy Corporation (NYSE-PGL)	22.9	AGL Resources Inc. (NYSE-ATG)	15.3
Cascade Natural Gas Corporation (NYSE-CGC)	21.7	Atmos Energy Corporation (NYSE-ATO)	16.0
Energen Corporation (NYSE-EGN)	20.4	WGL Holdings, Inc. (NYSE-WGL)	16.4
RGC Resources, Inc. (NDQ-RGCO)	20.3	EnergySouth, Inc. (NDQ-ENSI)	16.4

RETURN ON BOOK VALUE OF COMMON EQUITY

HIGH		LOW	
Kinder Morgan, Inc. (NYSE-KMI)	20.1	Energy West Incorporated (NDQ-EWST)	3.8
UGI Corporation (NYSE-UGI)	20.1	Southern Union Company (NYSE-SUG)	5.9
Questar Corporation (NYSE-STR)	18.2	Williams Companies, Inc. (NYSE-WMB)	6.4
Energen Corporation (NYSE-EGN)	16.4	Southwest Gas Corporation (NYSE-SWX)	6.9
ONEOK, Inc. (NYSE-OKE)	16.0	RGC Resources, Inc. (NDQ-RGCO)	7.1
New Jersey Resources Corp. (NYSE-NJR)	15.5	Cascade Natural Gas Corporation (NYSE-CGC)	8.2
AGL Resources Inc. (NYSE-ATG)	14.3	Peoples Energy Corporation (NYSE-PGL)	8.2
EnergySouth, Inc. (NDQ-ENSI)	13.6	Piedmont Natural Gas Co., Inc. (NYSE-PNY)	9.8
KeySpan Corp. (NYSE-KSE)	13.0	Northwest Natural Gas Co. (NYSE-NWN)	10.2
NICOR Inc. (NYSE-GAS)	13.0	Laclede Group, Inc. (NYSE-LG)	10.4

TELEPHONE COMPANIES

DIVIDEND YIELD

HIGH		LOW	
Citizens Communications (NYSE-CZN)	7.4	Cincinnati Bell Inc. (NYSE- CBB)	0.0
SBC Communications Inc. (NYSE-SBC)	5.4	Commonwealth Telephone Ent. (NDQ-CTCO)	0.0
AT&T Corp. (NYSE-T)	4.9	General Communication, Inc. (NDQ-GNCMA)	0.0
Verizon Communications (NYSE-VZ)	4.6	Qwest Communications International (NYSE-Q)	0.0
BCE, Inc. (NYSE-BCE)	4.5	US LEC Corp. (NDQ-CLEC)	0.0

MARKET/BOOK RATIO

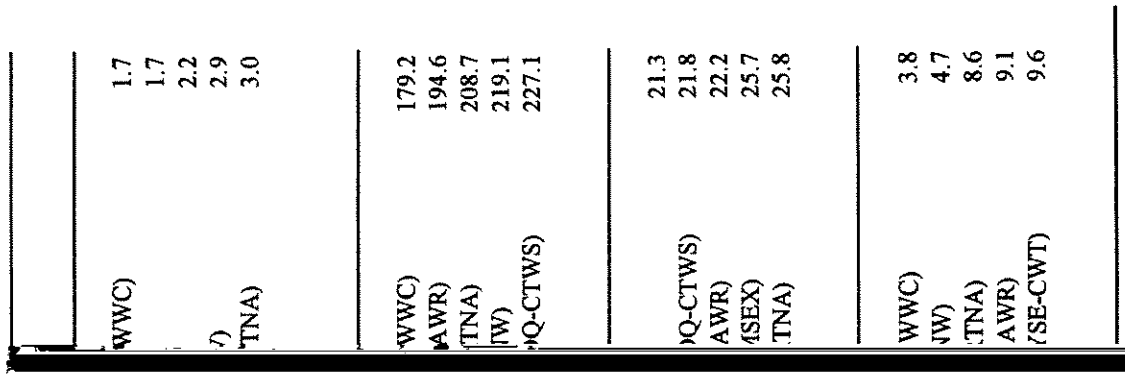
HIGH		LOW	
Citizens Communications (NYSE-CZN)	345	CenturyTel, Inc. (NYSE-CTL)	135
Commonwealth Telephone Ent. (NDQ-CTCO)	304	Telephone & Data Systems, Inc. (ASE-TDS)	146
Sprint Corporation (NYSE-FON)	265	SBC Communications Inc. (NYSE-SBC)	197
Verizon Communications (NYSE-VZ)	256	AT&T Corp. (NYSE-T)	209
ALLTEL Corporation (NYSE-AT)	255	BellSouth Corporation (NYSE-BLS)	211

PRICE/EARNINGS MULTIPLE

HIGH		LOW	
Citizens Communications (NYSE-CZN)	70.8	Verizon Communications (NYSE-VZ)	12.5
Cincinnati Bell Inc. (NYSE- CBB)	26.4	CenturyTel, Inc. (NYSE-CTL)	14.3
General Communication, Inc. (NDQ-GNCMA)	23.7	Commonwealth Telephone Ent. (NDQ-CTCO)	14.4
SBC Communications Inc. (NYSE-SBC)	19.6	ALLTEL Corporation (NYSE-AT)	16.2
BCE, Inc. (NYSE-BCE)	19.2	BellSouth Corporation (NYSE-BLS)	16.9

RETURN ON BOOK VALUE OF COMMON EQUITY

HIGH		LOW	
Commonwealth Telephone Ent. (NDQ-CTCO)	25.2	Telephone & Data Systems, Inc. (ASE-TDS)	1.4
Verizon Communications (NYSE-VZ)	22.0	Citizens Communications (NYSE-CZN)	5.0
US LEC Corp. (NDQ-CLEC)	19.0	CenturyTel, Inc. (NYSE-CTL)	9.8
ALLTEL Corporation (NYSE-AT)	16.3	SBC Communications Inc. (NYSE-SBC)	10.2
BellSouth Corporation (NYSE-BLS)	13.3	General Communication, Inc. (NDQ-GNCMA)	10.2


WWC)
TNA)
1.7
1.7
2.2
2.9
3.0
WWC)
AWR)
TNA)
IW)
Q-CTWS)
179.2
194.6
208.7
219.1
227.1
Q-CTWS)
AWR)
ISEX)
TNA)
21.3
21.8
22.2
25.7
25.8
WWC)
IW)
TNA)
AWR)
SE-CWT)
3.8
4.7
8.6
9.1
9.6

CA-RIR-17

Ref: RT-20, page 38.

Please provide copy of survey cited in footnote 1.

Dr. Morin's Response:

The Bruner survey article is attached.

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CASE 12

"Best Practices" in Estimating the Cost of Capital: Survey and Synthesis

In recent decades, theoretical breakthroughs in such areas as portfolio diversification, market efficiency, and asset pricing have converged into compelling recommendations about the cost of capital to a corporation. By the early 1990s, a consensus had emerged prompting such descriptions as "traditional . . . textbook . . . appropriate," "theoretically correct" and "a useful rule of thumb and a good vehicle."[1] Beneath this general agreement about cost of capital theory lies considerable ambiguity and confusion over how the theory can best be applied. The issues at stake are sufficiently important that differing choices on a few key elements can lead to wide disparities in estimated capital cost. The cost of capital is central to modern finance touching on investment and divestment decisions, measures of economic profit, performance appraisal and incentive systems. Each year in the United States, corpo-

practices against best-practice peers. Third, the evidence sheds light on the accuracy with which capital costs can be reasonably estimated, enabling executives to use the estimates more wisely in their decision making. Fourth, it enables teachers to answer the inevitable question, "How do companies really estimate their cost of capital?"

The paper is part of a lengthy tradition of surveys of industry practice. Among the more relevant predecessors, Gitman and Forrester (1977) explored "the level of sophistication in capital budgeting techniques" among 103 large, rapidly growing businesses, finding that the internal rate of return and the payback period were in common use. Although the authors inquired about the level of the firm's discount rate, they did not ask how the rate was determined. Gitman and Mercurio (1982) surveyed 177 Fortune 1000 firms about "current practice in cost of capital measurement and utilization," concluding that "the respondents' actions do not reflect the application of current financial theory." Moore and Reichert (1983) surveyed 298 Fortune 500 firms on the use of a broad array of financial techniques, concluding among other things, that 86 percent of firms surveyed use time-adjusted capital budgeting techniques. Bierman (1993) surveyed 74 Fortune 100 companies reporting that all use some form of discounting in their capital budgeting and 93 percent use a weighted-average cost of capital. In a broad-ranging survey of 84 Fortune 500 large firms and Forbes 200 best small companies, Trahan and Gitman (1995) report that 30 percent of respondents use the capital asset pricing model.

This paper differs from its predecessors in several important respects. Existing published evidence is based on written, closed-end surveys sent to a large sample of firms, often covering a wide array of topics and commonly using multiple-choice or fill-in-the-blank questions. Such an approach often yields response rates as low as 20 percent and provides no opportunity to explore subtleties of the topic. Instead, we report the result of a telephone survey of a carefully chosen group of leading corporations and financial advisers. Another

A standard means of expressing a company's cost of capital is the weighted average of the cost of individual sources of capital employed. In symbols, a company's weighted-average cost of capital (or WACC) is

$$\text{WACC} = (W_{\text{debt}}(1 - t)K_{\text{debt}}) + (W_{\text{preferred}}K_{\text{preferred}}) + (W_{\text{equity}}K_{\text{equity}}) \qquad (1)$$

where:

K = Component cost of capital
W = Weight of each component as percent of total capital
t = Marginal corporate tax rate

For simplicity, this formula includes only three sources of capital; it can be easily expanded to include other sources as well.

Finance theory offers several important observations when estimating a company's WACC. First, the capital costs appearing in the equation should be current costs reflecting current financial market conditions, not historical, sunk costs. In essence, the costs should equal the investors' anticipated internal rate of return on future cash flows associated with each form of capital. Second, the weights appearing in the equation should be market weights, not historical weights based on often arbitrary, out-of-date book values. Third, the cost of debt should be after corporate tax, reflecting the benefits of the tax deductibility of interest.

Despite the guidance provided by finance theory, use of the weighted-average expression to estimate a company's cost of capital still confronts the practitioner with a number of difficult choices.[2] As our survey results demonstrate, the most nettlesome component of WACC estimation is the cost of equity capital; for unlike readily available yields in bond markets, no observable counterpart exists for equities. This forces practitioners to rely on more abstract and indirect methods to estimate the cost of equity capital.

II. SAMPLE SELECTION

This paper describes the results of a telephone survey of leading practitioners. Believing that the complexity of the subject does not lend itself to a written questionnaire, we wanted to solicit an explanation of each firm's approach told in the practitioner's own words. Though our interviews were guided by a series of questions, these were sufficiently open-ended to reveal many subtle differences in practice.

Since our focus is on the gaps between theory and application rather than on average or typical practice, we aimed to sample practitioners who were leaders in the field. We began by searching for a sample of corporations (rather than investors or financial advisers) in the belief that they had ample motivation to compute WACC carefully and

[2]Even at the theoretical level, Dixit and Pindyck (1994) point out that the use of standard net present value (NPV) decision rules (with, for instance, WACC as a discount rate) does not capture the option value of being able to delay an irreversible investment expenditure. As a result, a firm may find it better to delay an investment even if the current NPV is positive. Our survey does not explore the ways firms deal with this issue; rather we focus on measuring capital costs.

to resolve many of the estimation issues themselves. Several publications offer lists of firms that are well regarded in finance;[3] of these, we chose a research report, *Creating World-Class Financial Management: Strategies of 50 Leading Companies* (1992), which identified firms,

> selected by their peers as being among those with the best financial management. Firms were chosen for excellence in strategic financial risk management, tax and accounting, performance evaluation and other areas of financial management. . . . The companies included were those that were mentioned the greatest number of times by their peers.[4]

From the 50 companies identified in this report, we eliminated 18 headquartered outside North America.[5] Of those remaining, five declined to be interviewed, leaving a sample of 27 firms. The companies included in the sample are given in **Exhibit 1.** We approached the most senior financial officer first with a letter explaining our research, and then with a telephone call. Our request was to interview the individual in charge of estimating the firm's WACC. We promised our interviewees that, in preparing a report on our findings, we would not identify the practices of any particular company by name—we have respected this promise in the presentation that follows.

In the interest of assessing the practices of the broader community of finance practitioners, we surveyed two other samples:

- *Financial advisers.* Using a "league table" of merger and acquisition advisers presented in *Institutional Investor* issues of April 1995, 1994, and 1993, we drew a sample of 10 of the most active[6] advisers. We applied approximately[7] the same set of questions to representatives of these firms' merger and acquisition departments. We wondered whether the financial advisers' interest in promoting deals might lead them to lower WACC estimates than those estimated by operating companies. This proved not to be the case. If anything, the estimating techniques most often used by financial advisers yield higher, not lower, capital cost estimates.
- *Textbooks and trade books.* From a leading textbook publisher we obtained a list of the graduate level textbooks in corporate finance having the greatest unit sales in 1994. From

[3]For instance, *Institutional Investor* and *Euromoney* publish lists of firms with the best CFOs, or with special competencies in certain areas. We elected not to use these lists because special competencies might not indicate a generally excellent finance department, nor might a stellar CFO.

[4]*Creating World-Class Financial Management: Strategies of 50 Leading Companies,* Research Report No. 1-110, Business International Corporation, New York, 1992 (238 pages), pages vii–viii. This survey was based upon a written questionnaire sent to CEOs, CFOs, controllers, and treasurers, followed up by a telephone survey.

[5]Our reasons for excluding these firms were the increased difficulty of obtaining interviews, and possible difficulties in obtaining capital market information (such as betas and equity market premiums) that might preclude using American practices. The enlargement of this survey to firms from other countries is a subject worthy of future study.

[6]*Activity* in this case was defined as four-year aggregate deal volume in mergers and acquisitions. The sample was drawn from the top 12 advisers, using their *average* deal volume over the 1993–95 period. Of these 12 firms, 2 chose not to participate in the survey.

[7]... with capital budgeting matters and

these, we selected the top four. In addition, we drew on three trade books that discuss the estimation of WACC in detail.

Names of advisers and books included in these two samples are shown in Exhibit 1.

III. SURVEY FINDINGS

The detailed survey results appear in Exhibit 2. The estimation approaches are broadly similar across the three samples in several dimensions:

- Discounted cash flow (DCF) is the dominant investment-evaluation technique.
- WACC is the dominant discount rate used in DCF analyses.
- Weights are based on *market*, not book, value mixes of debt and equity.[8]
- The after-tax cost of debt is predominantly based on *marginal* pretax costs, and *marginal* or *statutory* tax rates.
- The capital asset pricing model (CAPM) is the dominant model for estimating the cost of equity. Some firms mentioned other multifactor asset pricing models (e.g., arbitrage pricing theory), but these were in the small minority. No firms cited specific modifications of the CAPM to adjust for any empirical shortcomings of the model in explaining past returns.[9]

These practices differ sharply from those reported in earlier surveys.[10] First, the best-practice firms show much more alignment on most elements of practice. Second, they base their practice on financial economic models rather than on rules of thumb or arbitrary decision rules.

On the other hand, disagreements exist within and among groups on how to apply the CAPM to estimate cost of equity. The CAPM states that the required return (K) on any asset can be expressed as

$$K = R_f + \beta(R_m - R_f) \qquad (2)$$

where:

R_f = Interest rate available on a risk-free bond
R_m = Return required to attract investors to hold the broad market portfolio of risky assets
β = the relative risk of the particular asset

[8]The choice between target and actual proportions is not a simple one. Because debt and equity costs clearly depend on the proportions of each employed, it might appear that the actual proportions must be used. However, if the firm's target weights are publicly known and if investors expect the firm soon to move to these weights, then observed costs of debt and equity may anticipate the target capital structure.

[9]For instance, even research supporting the CAPM has found that empirical data are better explained by an intercept higher than a risk-free rate and a price of beta risk less than the market risk premium. Ibbotson (1994) offers such a modified CAPM, in addition to the standard CAPM and other models, in its cost of capital service. Jagannathan and McGrattan (1995) provide a useful review of empirical evidence on the CAPM.

[10]Gitman and Forrester (1977), and Gitman and Mercurio (1982).

According to CAPM, then, the cost of equity, K_{equity}, for a company depends on three components: returns on risk-free bonds (R_f); the stock's equity beta, which measures risk of the company's stock relative to other risky assets ($\beta = 1.0$ is average risk); and the market risk premium ($R_m - R_f$) necessary to entice investors to hold risky assets generally versus risk-free bonds. In theory, each of these components must be a forward-looking estimate. Our survey results show substantial disagreements on all three components.

Comments on Risk-Free Rates

Some of our best-practice companies noted that their choice of a bond market proxy for a risk-free rate depended specifically on how they were proposing to spend funds. We asked, "What do you use for a risk-free rate?" and heard the following:

- "Ten-year Treasury bond or other duration Treasury bond if needed to better match project horizon."
- "We use a three- to five-year Treasury note yield, which is the typical length of our company's investment. We match our average investment horizon with maturity of debt."

The Risk-Free Rate of Return

As originally derived, the CAPM is a single-period model, so the question of which interest rate best represents the risk-free rate never arises. But in a many-period world typically characterized by upward-sloping yield curves, the practitioner must choose. Our results show the choice is typically between the 90-day T-bill yield and a long-term Treasury bond yield. (Because the yield curve is ordinarily relatively flat beyond 10 years, the choice of which particular long-term yield to use is not a critical one.)[11] The difference between realized returns on the 90-day T-bill and the 10-year T-bond has averaged 150 basis points over the long run; so choice of a risk-free rate can have a material effect on the cost of equity and WACC.[12]

The 90-day T-bill yields are more consistent with the CAPM as originally derived and reflect truly risk-free returns in the sense that T-bill investors avoid material loss in value from interest rate movements. However, long-term bond yields more closely reflect the

[11] In early January 1996, the differences between yields on the 10- and 30-year T-bonds was about 35 basis points. Some aficionados will argue that there *is* a difference between the 10- and 30-year yields. Ordinarily the yield curve declines just slightly as it reaches the 30-year maturity—this has been explained to us as the result of life insurance companies and other long-term buy-and-hold investors who are said to purchase the long bond in significant volume. It is said that these investors command a lower liquidity premium than the broader market, thus driving down yields. If this is true, then the yields at this point of the curve may be due not to some ordinary process of rational expectations, but rather to an anomalous supply–demand imbalance, which would render these yields less trustworthy. The counterargument is that life insurance companies could be presumed to be rational investors too. As buy-and-hold investors, they will surely suffer the consequences of any irrationality and therefore have good motive to invest for yields "at the market."

[12] This was estimated as the difference in arithmetic mean returns on long-term government bonds and U.S. Treasury bills over the years 1926 to 1994, given in Ibbotson Associates (1995).

default-free holding period returns available on long-lived investments and thus more closely mirror the types of investments made by companies.

Our survey results reveal a strong preference on the part of practitioners for long-term bond yields. Of both corporations and financial advisers, 70 percent use Treasury-bond yield maturities of 10 years or greater. None of the financial advisers and only 4 percent of the corporations used the Treasury-bill yield. Many corporations said they matched the term of the risk-free rate to the tenor of the investment. In contrast, 43 percent of the books advocated the T-bill yield, while only 29 percent used long-term Treasury yields.

Beta Estimates

Finance theory calls for a forward-looking beta, one reflecting investors' uncertainty about the future cash flows to equity. Because forward-looking betas are unobservable, practitioners are forced to rely on proxies of various kinds. Most often this involves using beta estimates derived from historical data and published by such sources as Bloomberg, Value Line, and Standard & Poor's.

The usual methodology is to estimate beta as the slope coefficient of the market model of returns:

$$R_{it} = \alpha_i + \beta_i(R_{mt}) \tag{3}$$

where:

R_{it} = Return on stock i in time period (e.g., day, week, month) t
R_{mt} = Return on the market portfolio in period t
α_i = Regression constant for stock i
β_i = Beta for stock i

In addition to relying on historical data, use of this equation to estimate beta requires a number of practical compromises, each of which can materially affect the results. For instance, increasing the number of time periods used in the estimation may improve the statistical reliability of the estimate, but risks the inclusion of stale, irrelevant information. Similarly, shortening the observation period from monthly to weekly, or even daily, increases the size of the sample but may yield observations that are not normally distributed and may introduce unwanted random noise. A third compromise involves choice of the market index. Theory dictates that R_m is the return on the market portfolio, an unobservable portfolio consisting of *all* risky assets, including human capital and other nontraded assets, in proportion to their importance in world wealth. Beta providers use a variety of stock market indices as proxies for the market portfolio on the argument that stock markets trade claims on a sufficiently wide array of assets to be adequate surrogates for the unobservable market portfolio.

The following table shows the compromises underlying the beta estimates of three prominent providers and their combined effect on the beta estimates of our sample companies. Note, for example, that the mean beta of our sample companies according to Bloomberg is 1.03, while the same number according to Value Line is 1.24. **Exhibit 3** provides a complete list of sample betas by publisher.

Compromises Underlying Beta Estimates and Their Effect on Estimated Betas of Sample Companies

	Bloomberg*	Value Line	Standard & Poor's
[illegible]	102	260	60

Because expected future returns are unobservable, all survey respondents extrapolated historical returns into the future on the presumption that past experience heavily conditions future expectations. Where respondents chiefly differed was in their use of *arithmetic* versus *geometric* average historical equity returns and in their choice of realized returns on T-bills versus T-bonds to proxy for the return on riskless assets.

The arithmetic mean return is the simple average of past returns. Assuming the distribution of returns is stable over time and that periodic returns are independent of one another, the arithmetic return is the best estimator of expected return.[13] The geometric mean return is the internal rate of return between a single outlay and one or more future receipts. It measures the compound rate of return investors earned over past periods. It accurately portrays historical investment experience. Unless returns are the same each time period, the geometric average will always be less than the arithmetic average and the gap widens as returns become more volatile.[14]

Based on Ibbotson Associates' (1995) data from 1926 to 1995, the matrix below illustrates the possible range of equity market risk premiums depending on use of the geometric as opposed to the arithmetic mean equity return and on use of realized returns on T-bills as opposed to T-bonds.[15] Even wider variations in market risk premiums can arise when one changes the historical period for averaging. Extending U.S. stock experience back to 1802, Siegel (1992) shows that historical market premiums have changed over time and were typically lower in the pre-1926 period. Carleton and Lakonishok (1985) illustrate considerable variation in historical premiums using different time periods and methods of calculation even with data since 1926.

The Equity Market Risk Premium ($R_m - R_f$)

	T-Bill Returns	T-Bond Returns
Arithmetic mean return	8.5%	7.0%
Geometric mean return	6.5%	5.4%

Of the texts and trade books in our survey, 71 percent support use of the arithmetic mean return over T-bills as the best surrogate for the equity market risk premium. For long-[illegible] advocates forecasting the T-bill rate and using a different cost of [illegible] equity risk pre-

mium of 7.97 percent, which is most consistent with the arithmetic mean and T-bills. A minority view is that of Copeland, Koller, and Murrin (1990, pp. 193–94) writing on behalf of the Corporate Financial Practice at McKinsey & Company: "We believe that the geometric average represents a better estimate of investors' expected returns over long periods of time." Ehrhardt (1994) recommends use of the geometric mean return if one believes stockholders are "buy-and-hold" investors.

Half of the financial advisers queried use a premium consistent with the arithmetic mean and T-bill returns, and many specifically mentioned use of the arithmetic mean. Cor- [redacted] evidenced more diversity of opinion and tend to fa-

erationalize the theoretical call for a market risk premium. A glaring result is that few respondents specifically cited use of any forward-looking method to supplement or replace reading the tea leaves of past returns.[16]

IV. THE IMPACT OF VARIOUS ASSUMPTIONS FOR USING CAPM

To illustrate the effect of these various practices, we estimated the hypothetical cost of equity and WACC for Black & Decker, which we identified as having a wide range in estimated betas, and for McDonald's, which has a relatively narrow range. Our estimates are "hypothetical" in that we do not adopt any information supplied to us by the companies but rather apply a range of approaches based on publicly available information as of late 1995. **Exhibit 4** gives Black & Decker's estimated costs of equity and WACCs under various combinations of risk-free rate, beta, and market risk premiums. Three clusters of practice are illustrated, each in turn using three betas as provided by S&P, Value Line, and Bloomberg (unadjusted). The first approach, as suggested by some texts, marries a short-term risk-free rate (90-day T-bill yield) with Ibbotson's arithmetic mean (using T-bills) risk premium. The second, adopted by a number of financial advisers, uses a long-term risk-free rate (30-year T-bond yield) and a risk premium of 7.2 percent (the modal premium mentioned by financial advisers). The third approach also uses a long-term risk-free rate but adopts the modal premium mentioned by corporate respondents of 5.5 percent. We repeated these general procedures for McDonald's.

The resulting ranges of estimated WACCs for the two firms are as follows:

	Maximum WACC	Minimum WACC	Difference in Basis Points
Black & Decker	12.80%	8.50%	430
McDonald's	11.60%	9.30%	230

The range from minimum to maximum is large for both firms, and the economic impact is potentially stunning. To illustrate this, the present value of a level perpetual annual stream of $10 million would range between $78 million and $118 million for Black & Decker, and between $86 million and $108 million for McDonald's.

Given the positive but relatively flat slope of the yield curve in late 1995, most of the variation in our illustration is explained by beta and the equity market premium assumption. Variations can be even more dramatic, especially when the yield curve is inverted.

[16]Only two respondents (one advisor and one company) specifically cited forward-looking estimates, although others cited use of data from outside sources (e.g., a company using an estimate from an investment bank) where we cannot identify whether forward-looking estimates were used. Some studies using financial analyst forecasts in dividend growth models suggest market risk premiums average in the 6 to 6.5 percent range and change over time with higher premiums when interest rates decline. See for instance, Harris and Marston (1992). Ibbotson (1994) provides industry-specific cost-of-equity estimates using analysts' forecasts in a growth model.

V. RISK ADJUSTMENTS TO WACC

Finance theory is clear that a single WACC is appropriate only for investments of broadly comparable risk: A firm's overall WACC is a suitable benchmark for a firm's average risk investments. Finance theory goes on to say that such a company-specific figure should be adjusted for departures from such an average risk profile. Attracting capital requires payment of a premium that depends on risk.

We probed whether firms use a discount rate appropriate to the risks of the flows being valued in questions on types of investment (strategic vs. operational), terminal values, synergies, and multidivisional companies. Responses to these questions displayed in Exhibit 3 do not display much apparent alignment of practice. When financial advisers were asked how they value parts of multidivision firms, all 10 firms surveyed reported that they use different discount rates for component parts (item 17). However, only 26 percent of companies always adjust the cost of capital to reflect the risk of individual investment opportunities (item 12). Earlier studies (summarized in Gitman and Mercurio (1982) reported that between a third and a half of firms surveyed did *not* adjust for risk differences among capital projects. These practices stand in stark contrast to the recommendations of textbooks and trade books: The books did not explicitly address all subjects, but when they did, they were uniform in their advocacy of risk-adjusted discount rates.

A closer look at specific responses reveals the tensions as theory based on traded financial assets is adapted to decisions on investments in real assets. Inevitably, a fine line is drawn between use of financial market data versus managerial judgments. Responses from financial advisers illustrate this. As shown in Exhibit 2, all advisers use different capital costs for valuing parts (e.g., divisions) of a firm (item 17); only half ever select different rates for synergies or strategic opportunities (item 18); only 1 in 10 state any inclination to use different discount rates for terminal values and interim cash flows (item 16). Two simplistic interpretations are that (1) advisers ignore important risk differences or (2) material risk differences are rare in assessing factors such as terminal values. Neither of these fits; our conversations with advisers reveal that they recognize important risk differences but deal with them in a multitude of ways. Consider comments from two prominent investment banks who use different capital costs for valuing parts of multidivision firms. When asked about risk adjustments for prospective merger synergies, these same firms responded as follows:

- "We make these adjustments in cash flows and multiples rather than in discount rates."
- "Risk factors may be different for realizations of synergies, but we make adjustments to cash flows rather than the discount rate."

While financial advisers typically value existing companies, corporations face further challenges. They routinely must evaluate investments in new products and technologies. Moreover, they deal in an administrative setting that melds centralized (e.g., calculating a WACC) and decentralized (e.g., specific project appraisal) processes. As the next box of comments illustrates, these complexities lead to a blend of approaches for dealing with risk. A number of respondents mentioned specific rate adjustments to distinguish between divi-

sional capital costs, international versus domestic investments, and leasing versus nonleasing situations. In other instances, however, these same respondents favored cash-flow adjustments to deal with risks.

Why do practitioners risk-adjust discount rates in one case and work with cash-flow adjustments in another? Our interpretation is that risk-adjusted discount rates are more likely used when the analyst can establish relatively objective financial market benchmarks for what rate adjustments should be. At the business (division) level, data on comparable companies provide cost-of-capital estimates. Debt markets provide surrogates for the risks in leasing cash flows. International financial markets shed insights on cross-country differences. When no such market benchmarks are available, practitioners look to other methods for dealing with risks. Lacking a good market analog from which to glean investor opinion (in the form of differing capital costs), the analyst is forced to rely more on internal focus. Practical implementation of risk-adjusted discount rates thus appears to depend on the ability to find traded financial assets that are comparable in risk to the cash flows being valued and then to have financial data on these traded assets.

Comments Regarding Adjustments for Project Risk

When asked whether they adjusted discount rates for project risk, companies provided a wide range of responses:

- "No, it's difficult to draw lines between the various businesses we invest in, and we also try as best we can to make adjustments for risk in cash-flow projections rather than in cost of capital factors. . . . We advocate minimizing adjustments to cost of capital calculations and maximizing understanding of all relevant issues (e.g., commodity costs and international/ political risks)." At another point the same firm noted that "for lease analysis only the cost of debt is used."
- "No [we don't risk adjust cost of capital]. We believe there are two basic components: (1) projected cash flows, which should incorporate investment risk, and (2) discount rate." The same

The pragmatic bent of application also comes to the fore when companies are asked how often they reestimate capital costs (item 13, Exhibit 2). Even for those firms that reestimate relatively frequently, the next box of comments shows that they draw an important distinction between estimating capital costs and policy changes about the capital cost figure used in the firm's decision making.

Firms consider administrative costs in structuring their policies on capital costs. For a very large venture (e.g., an acquisition), capital costs may be revisited each time. On the other hand, only large material changes in costs may be fed into more formal project evaluation systems. Firms also recognize a certain ambiguity in any cost number and are willing to live with approximations. While the bond market reacts to minute basis-point changes in investor return requirements, investments in real assets, where the decision process itself is time-consuming and often decentralized, involve much less precision. To paraphrase one of our sample companies, we use capital costs as a rough yardstick rather

VI. CONCLUSIONS

terviews of leading corporations and financial advisers. Given the huge annual expenditure on capital projects and corporate acquisitions each year, the wise selection of discount rates is of material importance to senior corporate managers.

The survey revealed broad acceptance of the WACC as the basis for setting discount rates. In addition, the survey revealed general alignment in many aspects of the estimation of WACC. The main area of notable disagreement was in the details of implementing the capital asset pricing model (CAPM) to estimate the cost of equity. This paper outlined the varieties of practice in CAPM use, the arguments in favor of different approaches, and the practical implications.

In summary, we believe that the following elements represent "best current practice" in the estimation of WACC:

- Weights should be based on *market-value* mixes of debt and equity.
- The after-tax cost of debt should be estimated from *marginal* pretax costs, combined with *marginal* or *statutory* tax rates.
- CAPM is currently the preferred model for estimating the cost of equity.
- Betas are drawn substantially from published sources, preferring those betas using a long interval of equity returns. Where a number of statistical publishers disagree, best practice often involves judgment to estimate a beta.
- Risk-free rate should match the tenor of the cash flows being valued. For most capital projects and corporate acquisitions, the yield on the U.S. government Treasury bond of 10 or more years in maturity would be appropriate.

need additional tools for sharpening their assessment of relative risk. The variation in company-specific beta estimates from different published sources can create large differences in capital cost estimates. Moreover, use of risk-adjusted discount rates appears limited by lack of good market proxies for different risk profiles. We believe that appropriate use of averages across industry or other risk categories is an avenue worth exploration. Second, practitioners could benefit from further research on estimating equity market risk premiums. Current practice displays large variations and focuses primarily on averaging past data. Use of expectational data appears to be a fruitful approach. As the next generation of theories gradually sharpen our insights, we feel that research attention to implementation of existing theory can make for real improvements in practice.

Finally, our research is a reminder of the old saying that too often in business we measure with a micrometer, mark with a pencil, and cut with an ax. Despite the many advances in finance theory, the particular "ax" available for estimating company capital costs remains a blunt one. Best-practice companies can expect to estimate their weighted-average cost of capital with an accuracy of no more than plus or minus 100 to 150 basis points. This has important implications for how managers use the cost of capital in decision making. First, do not mistake capital budgeting for bond pricing. Despite the tools available, effective capital appraisal continues to require thorough knowledge of the business and wise business judgment. Second, be careful not to throw out the baby with the bath water. Do not reject the cost of capital and attendant advances in financial management because your finance people are not able to give you a precise number. When in need, even a blunt ax is better than nothing.

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EXHIBIT 1
Three Survey Samples

Company Sample	Adviser Sample	Textbook/Trade Book Sample
Advanced Micro Devices	CS First Boston	**Textbooks**
Allergan	Dillon, Read	Brealey and Myers
Black & Decker	Donaldson, Lufkin, Jenrette	Brigham and Gapenski
Cellular One	J. P. Morgan	Gitman
Chevron	Lehman Brothers	Ross, Westerfield & Jaffe
Colgate-Palmolive	Merrill Lynch	**Trade Books**
Comdisco	Morgan Stanley	Copeland, Koller & Murrin
Compaq	Salomon	Ehrhardt
Eastman Kodak	Smith Barney	Ibbotson Associates
Gillette	Wasserstein Perella	
Guardian Industries		
Henkel		
Hewlett-Packard		
Kanthal		
Lawson Mardon		
McDonald's		
Merck		
Monsanto		
PepsiCo		
Quaker Oats		
Schering-Plough		
Tandem		
Union Carbide		
U.S. West		
Walt Disney		
Weyerhauser		
Whirlpool		

Note: For the full titles of textbooks and trade books, please see the preceding list of references.

EXHIBIT 2
General Survey Results

	Corporations	Financial Advisers	Textbooks/Trade Books
1. Do you use DCF techniques to evaluate investment opportunities?	89% Yes, as a primary tool 7% Yes, only as a secondary tool 4% No	100% rely on DCF, comparable companies multiples, comparable transactions multiples. Of these, 10% DCF is primary tool. 10% DCF is used mainly "as a check." 80% Weight the three approaches depending on purpose and type of analysis.	100% Yes
2. Do you use any form of a cost of capital as your discount rate in your DCF analysis?	89% Yes 7% Sometimes 4% N/A	100% Yes	100% Yes
3. For your cost of capital, do you form any combination of capital cost to determine a WACC?	85% Yes 4% Sometimes 4% No 7% N/A	100% Yes	100% Yes
4. What weighting factors do you use? *a.* target vs. current debt/equity? *b.* market vs. book weights?	*Target/Current* 52% Target 15% Current 26% Uncertain 7% N/A *Market/Book* 59% Market 15% Book 19% Uncertain 7% N/A	*Target/Current* 90% Target 10% Current *Market/Book* 90% Market 10% Book	*Target/Current* 86% Target 14% Current/Target *Market/Book* 100% Market
5. How do you estimate your before tax cost of debt?	52% Marginal cost 37% Current average 4% Uncertain 7% N/A	60% Marginal cost 40% Current average	71% Marginal cost 29% No explicit recommendation
6. What tax rate do you use?	52% Marginal or statutory 37% Average historical 4% Uncertain 7% N/A	60% Marginal or statutory 30% Average historical 10% Uncertain	71% Marginal or statutory 29% No explicit recommendation
7. How do you estimate your cost of equity? (If you do not use CAPM, skip to question 12).	81% CAPM 4% Modified CAPM 15% N/A	80% CAPM 20% Other (including modified CAPM)	100% Primarily CAPM Other methods mentioned: dividend-growth model arbitrage pricing model
8. As usually written, the CAPM version of the cost of equity has three terms: a risk-free rate, a volatility or beta factor, and a market risk premium. Is this consistent with your company's approach?	85% Yes 0% No 15% N/A	90% Yes 10% N/A	100% Yes

EXHIBIT 2 *(continued)*

	Corporations	Financial Advisers	Textbooks/Trade Books
9. What do you use for the risk-free rate?	4% 90-day T-bill 7% 3–7 year Treasuries 33% 10-year Treasuries 4% 20-year Treasuries 33% 10–30 year Treasuries 4% 10 yrs. or 90-day; depends 15% N/A (Many said they match the term of the risk-free rate to the tenor of the investment)	10% 90-day T-bill 10% 5–10 year Treasuries 30% 10–30 year Treasuries 40% 30-year Treasuries 10% N/A	43% T-bills 29% LT Treasuries 14% Match tenor of investment 14% Don't say
10. What do you use as your volatility or beta factor?	52% Published source 3% Financial adviser's estimate 30% Self-calculated 15% N/A	30% Fundamental beta (e.g., BARRA) 40% Published source 20% Self-calculated 10% N/A	100% mention availability of published sources
11. What do you use as your market risk premium?	11% Use fixed rate of 4–4.5% 37% Use fixed rate of 5–6% 4% Use geometric mean 4% Use arithmetic mean 4% Use average of historical and implied 15% Use financial adviser's estimate 7% Use premium over Treasuries 3% Use Value Line estimate 15% N/A	10% Use fixed rate of 5% 50% Use 7–7.4% (Similar to arithmetic) 10% LT arithmetic mean 10% Both LT arithmetic and geometric mean 10% spread above Treasuries 10% N/A	71% Arithmetic historical mean 15% Geometric historical mean 14% Don't say
12. Having estimated your company's cost of capital, do you make any further adjustments to reflect the risk of individual investment opportunities?	26% Yes 33% Sometimes 41% No	Not asked	86% Adjust beta for investment risk 14% Don't say
13. How frequently do you reestimate your company's cost of capital?	4% Monthly 19% Quarterly 11% Semiannually 37% Annually 7% Continually/every investment 19% Infrequently 4% N/A (Generally, many said that in addition to scheduled reviews, they reestimate as needed for significant events such as acquisitions and high-impact economic events)	Not asked	100% No explicit recommendation
14. Is the cost of capital used for purposes other than project analysis in your	51% Yes 44% No 4% N/A	Not asked	100% No explicit discussion

EXHIBIT 2 *(concluded)*

	Corporations	Financial Advisers	Textbooks/Trade Books
company? (For example, to evaluate divisional performance?)			
15. Do you distinguish between strategic and operational investments? Is cost of capital used differently in these two categories?	48% Yes 48% No 4% N/A	Not asked	29% Yes 71% No explicit discussion
16. What methods do you use to estimate terminal value? Do you use the same discount rate for the terminal value as for the interim cash flows?	Not asked	30% Exit multiples only 70% Both multiples and perpetuity DCF model 70% Use same WACC for TV 20% No response 10% Rarely change	71% Perpetuity DCF model 29% No explicit discussion 100% No explicit discussion of separate WACC for terminal value
17. In valuing a multidivisional company, do you aggregate the values of the individual divisions, or just value the firm as a whole? If you value each division separately, do you use a different cost of capital for each one?	Not asked	100% Value the parts 100% Use different WACCs for separate valuations	100%: Use distinct WACC for each division
18. In your valuations do you use any different methods to value synergies or strategic opportunities (e.g., higher or lower discount rates, options valuation)?	Not asked	30% Yes 50% No 20% Rarely	29%: Use distinct WACC for synergies 71% No explicit discussion
19. Do you make any adjustments to the risk premium for changes in market conditions?	Not asked	20% Yes 70% No 10% N/A	14% Yes 86% No explicit discussion
20. How long have you been with the company? What is your job title?	Mean: 10 years All senior, except one	Mean: 7.3 years 4 MDs, 2 VPs, 4 associates	N/A

EXHIBIT 3
Betas for Corporate Survey Respondents

	Bloomberg Betas				
	Raw	Adjusted	Value Line Betas	S&P Betas	Range Maximum–Minimum
Advanced Micro	1.20	1.13	1.70	1.47	0.57
Allergan	0.94	0.96	1.30	1.36	0.42
Black & Decker	1.06	1.04	1.65	1.78	0.74
Cellular One			Not listed		
Chevron	0.70	0.80	0.70	0.68	0.12
Colgate-Palmolive	1.11	1.07	1.20	0.87	0.33
Comdisco	1.50	1.34	1.35	1.20	0.30
Compaq Computer	1.26	1.18	1.50	1.55	0.37
Eastman Kodak	0.54	0.69	NMF	0.37	0.32
Gillette	0.93	0.95	1.25	1.30	0.37
Guardian Industries			Not listed		
Henkel			Not listed		
Hewlett-Packard	1.34	1.22	1.40	1.96	0.74
Kanthal			Not listed		
Lawson Mardon			Not listed		
McDonald's	0.93	0.96	1.05	1.09	0.16
Merck	0.73	0.82	1.10	1.15	0.42
Monsanto	0.89	0.93	1.10	1.36	0.47
PepsiCo	1.12	1.08	1.10	1.19	0.11
Quaker Oats	1.38	1.26	0.90	0.67	0.71
Schering-Plough	0.51	0.67	1.00	0.82	0.49
Tandem Computers	1.35	1.23	1.75	1.59	0.52
Union Carbide	1.51	1.34	1.30	0.94	0.57
U.S. West	0.61	0.74	0.75	0.53	0.22
Walt Disney	1.42	1.28	1.15	1.22	0.27
Weyerhauser	0.78	0.85	1.20	1.21	0.43
Whirlpool	0.90	0.93	1.55	1.58	0.68
Mean	1.03	1.02	1.24	1.18	0.42
Median	1.00	1.00	1.20	1.21	0.42
Standard deviation	0.31	0.21	0.29	0.41	0.19

Note:
1. Bloomberg's adjusted beta is $\beta_{adj} = (.66)\beta_{raw} + (.33)1.00$

EXHIBIT 4
Variations in Cost-of-Capital (WACC) Estimates for Black & Decker Using Different Methods of Implementing the Capital Asset Pricing Model*

1. Short-term rate plus arithmetic average historical risk premium (recommended by some texts)
   R_f = 5.36%, 90-day T-bills
   $R_m - R_f$ = 8.50%, Ibbotson arithmetic average since 1926

Beta Service	Cost of Equity (K_e)	Cost of Capital (WACC)
Bloomberg, β = 1.06	14.40%	9.70%
Value Line, β = 1.65	19.40%	12.20%
S&P, β = 1.78	20.50%	12.80%

2. Long-term rate plus risk premium of 7.20% ("modal" practice of financial advisers surveyed)
   R_f = 6.26%, 30-year T-bonds
   $R_m - R_f$ = 7.20%, modal response of financial advisers

Beta Service	Cost of Equity (K_e)	Cost of Capital (WACC)
Bloomberg, β = 1.06	13.90%	9.40%
Value Line, β = 1.65	18.10%	11.60%
S&P, β = 1.78	19.10%	12.10%

3. Long-term rate plus risk premium of 5.50% ("modal" practice of corporations surveyed)
   R_f = 6.26%, 30-year T-bonds
   $R_m - R_f$ = 5.50%, modal response of corporations

Beta Service	Cost of Equity (K_e)	Cost of Capital (WACC)
Bloomberg, β = 1.06	12.10%	8.50%
Value Line, β = 1.65	15.30%	10.20%
S&P, β = 1.78	16.10%	10.50%

*In all cases the CAPM is used to estimate the cost of equity, the cost of debt is assumed to be 7.81 percent based on a Baa rating, the tax rate is assumed to be 38 percent, and debt is assumed to represent 49 percent of capital.

CA-RIR-18

Ref: RT-20, page 42.

Please provide copy of article cited in footnote 2.

Dr. Morin's Response:

The Dimson, Marsh, Staunton article is attached.

Note: Most (if not all) of the information requested is copyrighted. The attached copy is being provided under the "fair use" exception to the copyright laws. Any copies made of the attachment are subject to the copyright laws.

TRIUMPH OF THE OPTIMISTS

101 Years of Global Investment Returns

Elroy Dimson

Paul Marsh

Mike Staunton

Princeton University Press

Princeton, New Jersey and Oxford

Chapter 12 The equity risk premium

Investment in equities over the 101 years from 1900–2000 has proved rewarding but, as we have seen, has been accompanied by correspondingly greater risks. In this chapter we examine the historical rewards that investors have enjoyed for bearing this risk.

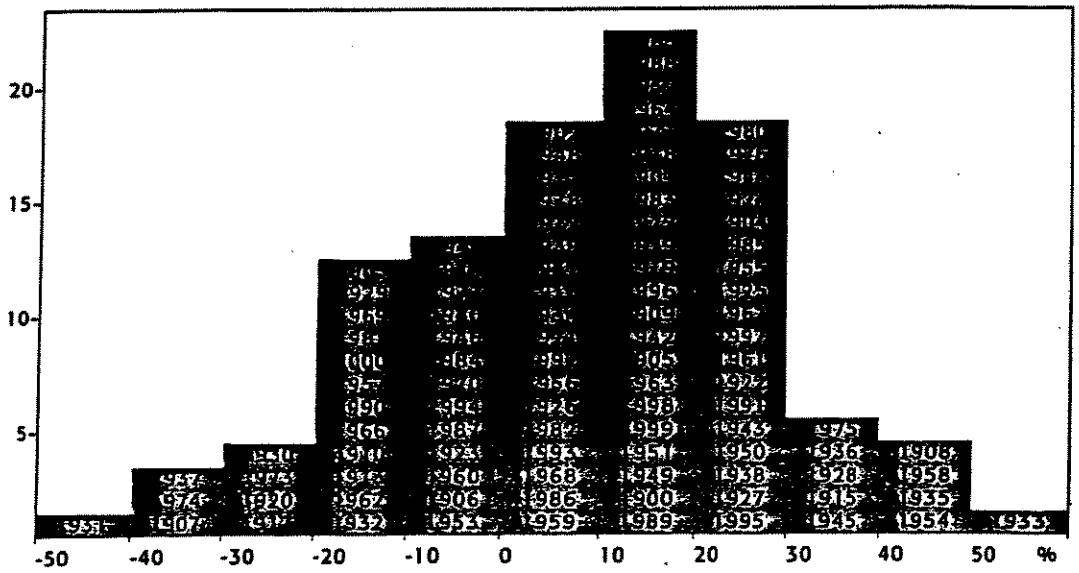
Clearly, investors do not like volatility—at least on the downside—and will be prepared to invest in equities only if there is some expected compensation for their risk exposure. We can measure the reward for risk that they have received in the past by comparing the return on equities with the return from risk free investments. The difference between these two returns is called the equity risk premium. The risk premium is typically measured relative to

Whether the premium is defined relative to bills or to bonds, we measure it by taking the geometric difference between the equity return and the risk free return. The formula is *1 + Equity rate of return* divided by *1 + Riskless return*, minus *1*. For example, if shares with a one-year return of 21 percent were being evaluated relative to treasury bills yielding 10 percent, the equity risk premium would be 10 percent. This is because $(1 + {}^{21}/_{100})$ divided by $(1 + {}^{10}/_{100})$ is equal to $(1 + {}^{10}/_{100})$. The difference between the equity return of 21 percent and the treasury bill return of 10 percent could also be estimated by subtracting one return from another and the result (11 percent) would be similar.

These measures of the risk premium have no obvious numeraire in terms of currency since the equity risk premium, measured relative to bill or bond returns, is a ratio. It is hence unaffected by whether returns are computed in dollars or (say) pounds, or whether returns are computed in nominal or real (inflation adjusted) terms.

Figure 12-1 shows the year-by-year US risk premium relative to bills. The distribution of outcomes was wide, with the lowest and highest premia occurring, as might be expected, in the worst and best years for stocks. The lowest premium was -45 percent in 1931, when equities returned -44 percent and treasury bills 1.1 percent, while the highest was 57 percent in 1933, when equities gave 57.6 percent and bills 0.3 percent. Figure 12-1 shows that the distribution of annual premia is roughly symmetrical, resembling a normal distribution. The mean is 7.7 percent and the standard deviation is 19.6 percent. On average, therefore, US investors received a positive—and quite large—reward for exposure to equity market risk.

Figure 12-1: Histogram of US equity risk premium relative to treasury bills, 1900–2000



Because the range of premia that are encountered on a year-to-year basis is very broad, it can be misleading to label these as "risk premia." Investors clearly cannot have expected, let alone required, a negative risk premium from investing in equities, otherwise they would simply have avoided them. All the negative and many of the very low premia shown in Figure 12-1 must therefore reflect nasty surprises. Equally, investors could not have "required" the very high premia, such as the 57 percent in 1933. Such numbers are implau-

[redacted]

Figure 12-2 shows that even over intervals of a decade, there were periods when the *ex post* US risk premium was negative, most recently in the 1970s and early 1980s. There can be major performance surprises, even over a ten-year interval. It follows that we need very long periods to infer investors' expectations about the reward for exposure to equity market risk. Even then, inference can be problematic, as we will see in chapter 13.

12.2 Worldwide risk premia relative to bills

We have seen that US investors enjoyed a large, positive risk premium relative to bills with a 101-year arithmetic mean of 7.7 percent and a geometric mean of 5.8 percent. The US economy has been especially successful, however, and so we need to set the US record in context.

Figure 12-3 shows the annualized, geometric mean risk premia relative to bills for all sixteen countries over the full 101-year period. The bars plot the equity risk premia relative to bills, while the line plot overlay shows the real rate of return on equities. The chart also shows the "world" risk premium, based on our sixteen-country world equity index, calculated in US dollars, with risk premia and real returns computed relative to US bills and US inflation.

Figure 12-3 shows that while the equity risk premium varies across countries, the 101-year averages fall within a fairly narrow range. The US premium of 5.8 percent, while above average, is not the largest, with five other countries enjoying higher premia. France led the field with a premium of 7.4 percent, while the lowest premium was the 1.8 percent for Denmark. The UK risk premium of 4.8 percent was just below the figure of 4.9 percent on the world index, which, in turn, was 0.9 percent below the premium for the United States.

Figure 12-3: Worldwide annualized real equity returns and risk premia relative to bills, 1900–2000

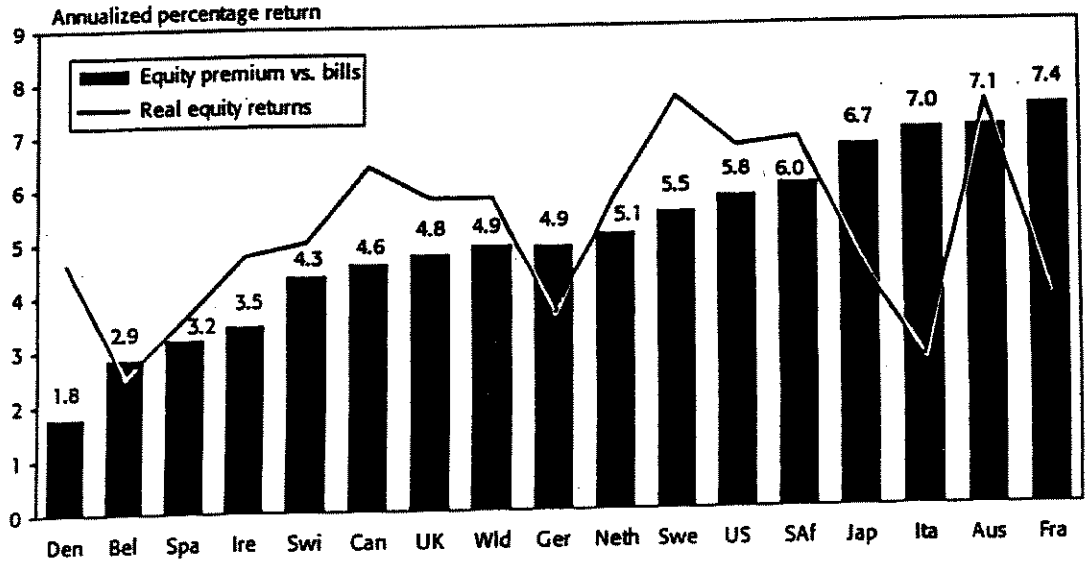


Figure 12-3 shows that the relationship between equity risk premia relative to bills and real equity returns can be complex. In most countries, real equity returns exceeded the risk premium, but in some cases, such as Italy, an above-average risk premium is associated with below-average real returns. The reason for this was identified in chapter 5. In countries like Italy, the returns on cash fell short of investors' *ex ante* expectations due to unexpectedly high inflation. It is therefore possible for an equity market that performs poorly (perhaps also as a consequence of inflation) to have a large *ex post* premium relative to bills.

The equity risk premia relative to bills for the sixteen countries and for the world index are listed in Table 12-1. Note that for Germany the calculations are based on 99, rather than 101 years, since we have excluded 1922–23. While we can calculate a continuous, 101-year real return series for German equities, calculating risk premia is more problematic. The hyperinflation of 1922–23 decimated bill and bond returns, resulting in -100 percent real returns in 1923. We therefore obtain more meaningful statistics by omitting these years.

The first six columns of Table 12-1 provide statistics on the annual risk premia. The geometric means in the first column provided the plotting data for the bars in Figure 12-3. The next five columns show the arithmetic means, standard errors, standard deviations, and maximum and minimum premia. We commented earlier that the distribution of annual risk premia for the United States—displayed in Figure 12-1—was very wide. The standard deviation figures in the fourth column of Table 12-1 show that the dispersion was even greater than in the United States in all but four of the other countries.

Table 12-1: Worldwide equity risk premia relative to bills, 1900–2000

	Annual equity risk premium relative to treasury bills						Ten year risk premium		
Country	Geometric mean	Arithmetic mean	Standard error	Standard deviation	Minimum return	Maximum return	Geometric mean	Arithmetic mean	Standard deviation
Australia	7.1	8.5	1.7	17.2	-30.2	49.4	6.9	7.0	4.2
Belgium	2.9	5.1	2.3	23.5	-38.1	120.6	2.8	3.0	5.4
Canada	4.6	5.9	1.7	16.7	-34.7	49.1	4.6	4.7	4.8
Denmark	1.8	3.4	1.9	19.4	-32.7	87.0	1.4	1.5	3.4
France	7.4	9.8	2.4	23.8	-33.4	78.7	7.5	7.7	7.4
Germany	4.9	10.3	3.5	35.3	-87.2	165.3	8.1	8.3	8.2
Ireland	3.5	5.4	2.1	20.6	-51.1	73.6	3.2	3.3	4.4
Italy	7.0	11.0	3.2	32.5	-48.6	150.3	6.8	7.2	10.0
Japan	6.7	9.9	2.8	27.9	-48.3	108.6	7.1	7.4	8.7
[illegible]	5.1	7.1	2.2	22.2	-31.3	126.7	4.7	4.9	6.4

Note that even with 101 years of data, the standard errors around the risk premia estimates are high, ranging from 1.6–1.7 percent (for the world index, Australia, and Canada) to 3.5 percent (for Germany). The standard error for both the United States and the United Kingdom is 2.0 percent. Strictly, these standard errors relate to the arithmetic mean, but as an approximate guide, we can apply them to the geometric mean. This means that while the US figure of 5.8 percent remains our best estimate, we can be only 68 percent confident that the true geometric mean lies within one standard error of this, that is, within the range 5.8 ± 2 percent, or 3.8 to 7.8 percent. Note that the historical geometric mean risk premia of all but four of our sixteen countries fall within this range.

Political and economic conditions have varied over the last 101 years for every country. Some analysts prefer to emphasize recent data since it reflects the current environment. Others recommend using the longest possible data series since this is more likely to encapsulate unusual events that may have current or future relevance. Parallels have been drawn, for example, between the technology and communications revolution of the late twentieth century and the electricity and the automobile innovations of the early twentieth century; or between the nineteenth century railway bubble and the recent internet bubble; or between the 1990 invasion of Kuwait and ensuing Gulf War of 1991 and the September 11, 2001 attacks on the United States and the subsequent "War on Terrorism." All market analysts agree, however, that repetition of certain historical events is so implausible that the past must be interpreted with care. Extreme hyperinflation is widely regarded as something that will not again afflict major economies, and a world war would be of a different nature if it were to happen in the future.

For these, or perhaps for less dramatic reasons, many people wish to review risk premia over shorter intervals than 101 years. We have selected decades as our intermediate time frame, which although arbitrary, is nevertheless a common choice. The final three columns of Table 12-1 present annualized statistics on premia that have been calculated over ten-year intervals. With 101 years of data, there are ninety-two (overlapping) decades for which we can compute premia. Table 12-1 shows the geometric means, arithmetic means, and standard deviations of these ten-year premia. By definition, the arithmetic mean always exceeds the geometric mean, but the difference between them is small when the measurement interval is as long as a decade. Note that, as with measures based on annual data, the United States ranks sixth while the United Kingdom falls in the middle of the distribution of premia for the countries in our sample.

The last column of Table 12-1 shows that over a ten-year horizon, the dispersion of returns is reduced. This is because there is diversification over time: one poor year is not necessarily followed by another. This gives rise to annualized returns that have a tighter distribution (a smaller standard deviation) than the underlying single-year returns. In the United States, for example, the single-year risk premia have a standard deviation of 19.6 percent while the ten-year premia have an annualized standard deviation of 5.4 percent. Assuming that ten-year annualized risk premia are approximately normally distributed, then in about two decades out of three, the annualized ten-year premium lies within ±5.4 percent of the mean.

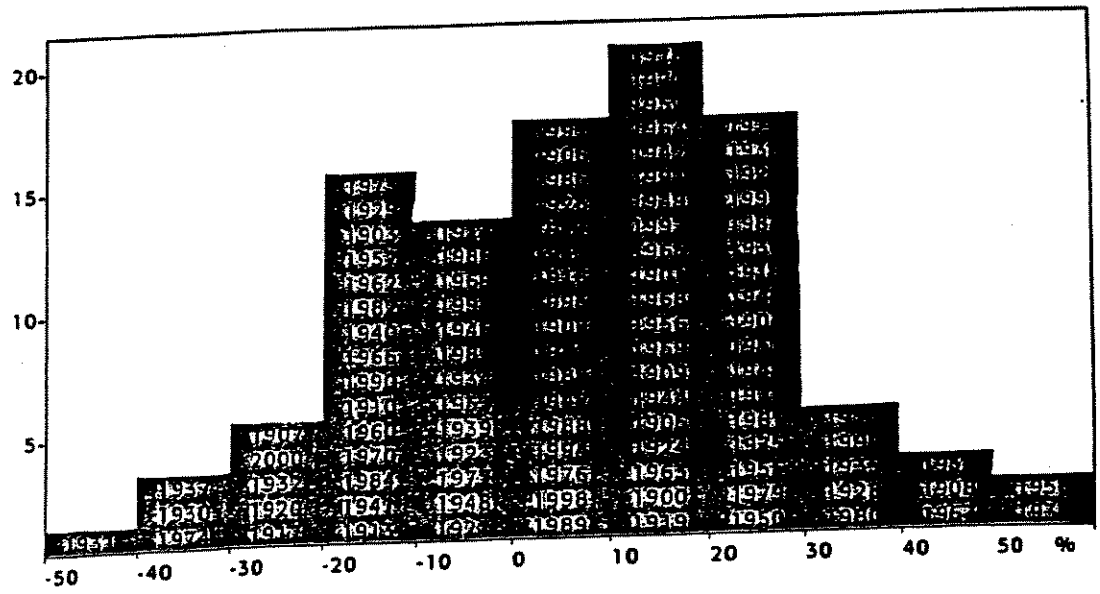
12.3 US risk premia relative to bonds

We can also estimate the equity risk premium relative to long-term bonds. As with bills, we take the risk premium relative to bonds as the geometric difference between the equity return and the bond return over the same period. Since by definition the risk premium is the difference between the equity return and the risk free return, we are implicitly assuming here that bonds can be regarded as a risk free asset. This is harder to justify than for bills since long-term government bonds are risk free only in the sense that they normally offer a fixed income, and the likelihood of default is very small. In all other respects, they are appreciably riskier than bills since bond prices are sensitive both to changes in real interest rates and to inflationary expectations. Since bonds are riskier than bills, we would expect the equity risk premium relative to bonds to be lower than the premium relative to bills.

Long-term bonds do have one advantage as a benchmark in that their yields reflect not only today's short-term interest rate but also future expected interest rates. Thus for valuing shares or projects with cash flows extending many years into the future, the promised return on long bonds will encapsulate the expected sequence of returns on short-dated bills over the remaining term of the bond. The corresponding disadvantage is that long-bond prices will also encapsulate a maturity risk premium, the magnitude of which is hard to measure.

With these considerations in mind, we therefore compute both one- and ten-year equity risk premia relative to bonds. In addition, we also compute the average premium relative to bonds over the full 101-year period. The histogram in Figure 12-4 shows the distribution of

Figure 12-4: Histogram of US equity risk premium relative to bonds, 1900–2000

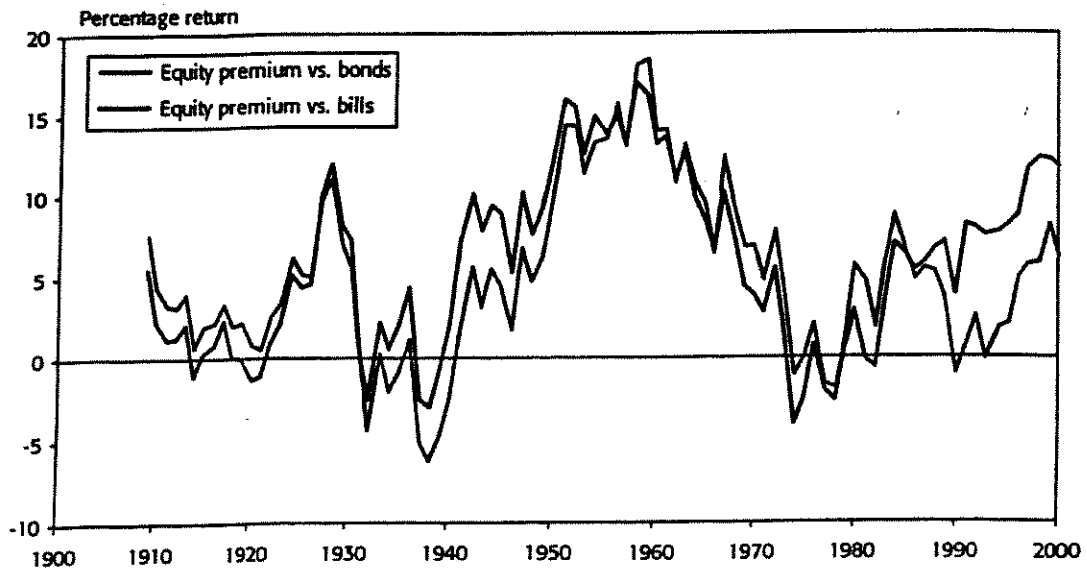


the one-year risk premia relative to bonds for the United States over the 101 years from 1900–2000. The average premium was 5.0 percent, which is below the figure of 5.8 percent relative to bills. The reason for this is that, as discussed in chapter 6, over this 101-year period the return on long-term US government bonds exceeded the return on treasury bills by 0.7 percent. Figure 12-4 shows that there is again a wide dispersion of year-by-year risk premia.

While the one-year equity risk premia in Figure 12-4 summarize historical returns over short periods, it is again helpful to look at longer-term premia. Figure 12-5 plots the rolling ten-year US risk premia relative to bonds over the 101 years from 1900–2000, contrasting this with the equivalent ten-year premia relative to bills. Obviously, over periods when bonds performed poorly, the equity premium relative to bonds has tended to exceed the premium relative to bills, and vice versa. This is especially noticeable over the second half of the twentieth century. During the higher inflation period in the United States from the mid-1950s through until the early 1980s, bond-based premia were consistently higher than bill-based premia. Subsequently, bonds have generally performed well, and from the mid-1980s the ten-year risk premium relative to bonds has been below that on bills.

Note that as with the risk premium relative to bills, there have been periods when the rolling ten-year US risk premium relative to bonds has been negative. Most recently, this occurred in 1990 and 1993. At first sight, this seems surprising since US equities have performed well in recent decades. But over the ten years until the end of 1990, although US equities returned a creditable 12.6 percent per year, US bonds gave an even higher annualized return of 13.7 percent.

Figure 12-5: Rolling ten-year US equity risk premia relative to bonds and to bills, 1909–2000



A similar situation has arisen recently in the United Kingdom. By 2000, the rolling ten-year UK risk premium relative to bonds had fallen to just under 2 percent. This led many UK market professionals to conclude that investors now required a risk premium of just 2 percent, and this was frequently used as a justification for the high stock prices at the turn of the millennium. While it may be true that required premia had become low (we address this issue in the next chapter), we cannot infer this from the recent ten-year historical premium relative to bonds. The main reason the ten-year premium is so low is that, over the decade ending in 2000, UK long bonds performed exceptionally well, almost certainly exceeding investors *ex ante* expectations. Over the same period in the United States, the historical ten-year risk premium relative to bonds was 6.1 percent per year, and yet US stocks were if anything more highly rated than their UK counterparts.

The problem that lies at the source of these confusions is that over many periods, even when we look at ten-year returns, the *ex post* returns on bonds appear to have differed markedly from *ex ante* expectations. One option would be to adjust bond returns for unexpected shocks in the bond market, such as unanticipated decreases or increases in inflation. Approximate adjustments might involve computing equity premia relative to each year's starting yield-to-redemption on bonds, or calculating premia relative to the income yield on bonds (excluding capital gains or losses). Although these computations become possible with the availability of our new data series, it can be misleading to compute premia after adjusting bond returns for shocks such as inflation increases or decreases, without also considering the impact of such shocks or other unexpected events on equity prices. The latter is far more challenging, as we will show in the next chapter.

Nevertheless, the experience of the 1980s and 1990s makes it obvious that we should not draw inferences about the expected future risk premium from periods as short as a decade. This is especially true when we have strong reasons to believe that during the decade in question, investors fared much better or worse than they had expected in advance. During the 1930s or mid-1970s, for example, it would have been extremely foolish to conclude that investors required a negative risk premium for investing in equities. These periods when the historical risk premia turned negative simply reflect the poor performance of equities over the previous decade. While less immediately obvious, interpreting the post-1980 era has been equally problematic, since this was a period that turned out to be particularly rewarding for both bond and equity investors.

12.4 Worldwide risk premia relative to bonds

Once again, it is important to set the US findings in their worldwide context. The bars and the line plot in Figure 12-6 show the geometric mean risk premia calculated both relative to bonds (the bars) and to bills (the line plot) over the full 101 years for all sixteen countries plus the world index. This chart shows that for all countries other than Germany, Denmark, and Belgium, the risk premium relative to bonds was lower than the premium relative to bills, consistent with our expectations, given that bonds are higher risk than bills. Figure 12-6 also

Figure 12-6: Worldwide annualized equity risk premia relative to bonds and bills, 1900–2000

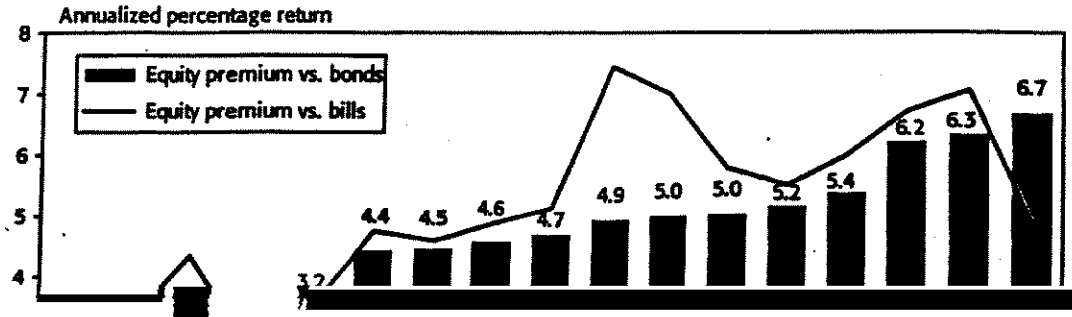


Table 12-2: Worldwide equity risk premia relative to long bond returns, 1900–2000

	Annual equity risk premium relative to long-term bonds						Ten year risk premium		
Country	Geometric mean	Arithmetic mean	Standard error	Standard deviation	Minimum premium	Maximum premium	Geometric mean	Arithmetic mean	Standard deviation
Australia	6.3	8.0	1.9	18.9	-30.6	66.3	6.3	6.4	4.6
Belgium	2.9	4.8	2.1	20.7	-35.1	76.6	3.0	3.2	5.1
Canada	4.5	6.0	1.8	17.8	-36.8	54.7	4.6	4.7	5.4
Denmark	2.0	3.3	1.7	16.9	-35.9	74.9	1.8	1.9	4.1
France	4.9	7.0	2.1	21.6	-32.7	83.7	4.9	5.1	6.8
Germany *	6.7	9.9	2.9	28.4	-38.6	117.6	8.2	8.5	9.1
Ireland	3.2	4.6	1.7	17.4	-37.0	73.3	3.0	3.2	4.8
Italy	5.0	8.4	3.0	30.0	-39.6	152.2	5.0	5.4	9.2
Japan	6.2	10.3	3.3	33.2	-43.3	193.0	6.7	7.2	11.5
The Netherlands	4.7	6.7	2.1	21.4	-43.9	107.6	4.3	4.5	6.5
South Africa	5.4	7.1	2.0	19.7	-29.2	70.9	6.2	6.3	5.0
Spain	2.3	4.2	2.0	20.3	-34.0	69.1	2.2	2.3	5.5
Sweden	5.2	7.4	2.2	22.1	-38.3	87.8	4.8	5.0	7.7
Switzerland†	2.7	4.2	1.9	17.9	-34.4	52.2	2.0	2.1	5.1
United Kingdom	4.4	5.6	1.7	16.7	-38.0	80.8	4.8	4.9	4.5
United States	5.0	7.0	2.0	20.0	-40.8	57.7	4.9	5.0	5.2
World	4.6	5.6	1.4	14.5	-31.2	37.4	4.6	4.7	4.8

* All statistics for Germany exclude 1922–23. † Premia for Switzerland are from 1911.

In this table, the first six columns give summary statistics for the annual premia, while the last three columns relate to rolling ten-year premia. The first column shows the geometric means that were plotted as bars in Figure 12-6. The fourth column shows the standard deviations. The 20.0 percent figure for the United States is close to the 19.6 percent standard deviation for the premia relative to bills shown earlier in Table 12-1. For some countries, however, the distribution of premia relative to bonds is narrower than relative to bills. For the United Kingdom, for example, the standard deviation is 16.7 percent, compared with 19.9 percent relative to bills. This is because, in the United Kingdom, there was a fairly high correlation between annual equity returns and long bond returns (0.56), while the correlation between equities and bills was lower (0.29). This propensity for good bond years to coincide with good equity years, and vice versa, has tended to lower the annual difference between equity and bond returns in the United Kingdom. This was particularly marked in the best and worst years on record for UK equities, namely, 1975 and 1974 respectively.

12.5 Summary

In this chapter, we have used 101 years of stock market history for sixteen different countries and for the world index to take a fresh look at the equity risk premium. In the past, the historical evidence for the US market, and to a lesser extent for the United Kingdom, has heavily influenced views about the magnitude of the risk premium. For the United States, the most widely cited source is Ibbotson Associates (2000), who estimate a geometric risk premium of

7.3 percent relative to bills for the period 1926–99. Before the publication of the research for this book, the most widely cited sources for the United Kingdom were Barclays Capital (1999) and CSFB (1999), which both started in 1919. Over the period 1919–98, there had been a UK risk premium relative to bills of 6.2 percent.

In recent years, both practitioners and researchers have grown increasingly uneasy about how to interpret these widely cited estimates, largely because they seemed too high. Apart from biases in index construction—a possibility that had not previously been thought important, but which we saw in section 3.2 is material in relation to the UK figure—the finger of suspicion has pointed mainly at success and survivorship bias among countries. The concern over success bias is that inferences about risk premia worldwide were being heavily influenced by the US experience, yet the United States has been an unusually successful economy. The closely related worry over survivorship bias is that previous attempts to place the experience of other countries like the United Kingdom alongside that of the United States may still have overstated the risk premium since they have focused on just a few selected markets that have survived, typically with continuous trading, over a long period.

To provide better estimates of the equity risk premium we therefore need to focus on the experience of all countries, not just the United States and the United Kingdom. If we look at all markets, then survivorship bias ceases to be an issue. Our sample of sixteen countries is by no means comprehensive. However, it does represent a large proportion by value of the world's stock markets in 1900. Fortunately, we are also able to compute total returns, including reinvested dividends, for this remarkably large sample of countries over a full 101-year period. This has allowed us to estimate long-run risk premia over an extended and uniform research period, thus overcoming another important but overlooked factor in previous studies, namely, easy data bias (see section 3.4). In other words, we mitigate the easy-data tendencies of previous researchers who measure a market's performance after a period of growth or recovery, omitting earlier periods of market turmoil.

We have found that from 1900–2000 the annualized equity risk premium relative to bills was 5.8 percent for the United States and 4.8 percent for the United Kingdom. Across all sixteen countries covered by this study, the cross-sectional (unweighted) average risk premium was 5.0 percent, while the risk premium on our size-weighted world equity index was 4.9 percent. Relative to long bonds, the story is similar. The annualized US equity risk premium relative to bonds was 5.0 percent, and the corresponding figure for the United Kingdom was 4.4 percent. Across all sixteen countries, the cross-sectional average risk premium relative to bonds was 4.5 percent, while for the world index it was 4.6 percent.

These figures are, of course, just long-run averages, and this chapter has also highlighted their high standard errors, the wide dispersion of annual equity risk premia, and how premia fluctuate over time as well as across markets. It has also reminded us that premia relative to

[and, by implication, UK] equities appears to be the exception rather than the rule." While the United States and the United Kingdom have indeed performed well, especially the United States, there is no indication that they are hugely out of line with other countries. The big differences in long-term stock market performances are between the best and worst countries. The United States and the United Kingdom have experienced somewhat similar long-run equity risk premia, both to each other and to the global average. While US equities have performed very well, and the US risk premium was above the global average, it ranked only sixth out of sixteen countries. The United Kingdom is near the middle of the distribution of worldwide equity premia. Concerns about success and survivorship bias, while legitimate, may therefore have been somewhat overstated. In this sense, investors may not have been materially misled by a focus on the United States and, to a lesser extent, UK experience.

The second important conclusion is that the risk premia estimated in this study and reported in this chapter are around 1½ percent lower than those that have been reported in previous studies of long-term US and UK stock market performance. The differences here arise from previous biases in index construction (for the United Kingdom) and (for both countries) from the use of a rather longer time frame, extending back to 1900.

Chapter 13 The prospective risk premium

In chapter 12, our focus was on the historical risk premium, namely, the premium that investors in different countries have obtained in the past from investing in equities, rather than in less risky assets such as treasury bills or government bonds. In this chapter, we switch from the past to the future, and to the prospective risk premium that investors can reasonably expect to obtain over future years and decades.

In the run-up to the millennial year, there was a series of books with titles like *Dow 36,000*, *Dow 40,000*, and even *Dow 100,000* (see; for example, Elias, 2000, and Kadlec, 1999). Glassman and Hassett (2000), in their book *Dow 36,000*, presented their case for why they believe equities are undervalued. Their view was that investors had come to require an extremely low rate of return on equity investments, and that this required return could get lower still. In short, they agreed that among investors, it was optimists who triumphed—investors in risky securities did well—but Glassman and Hassett believe that, historically, these investors should have done even better. Since stocks therefore remain underpriced in relation to what those authors consider the "perfectly reasonable price," there are further gains still to come. Accordingly, they regard it as likely that in the future optimists will continue to triumph.

Investors' views on the risk premium can be thought of as a tug-of-war. Glassman and Hassett are at one end of the rope. At the other end is Shiller (2000). Shiller's view is essentially that the equity investors triumphed beyond what might reasonably have been expected: they benefited from the stock market moving to irrationally high levels. Shiller and his colleagues are the pessimists.

[redacted]

pessimist, the market would collapse right away. The consensus represents an equilibrium between optimists and pessimists. In estimating the consensus of the market, we therefore have to balance the arguments that are put forward by each side in the tug-of-war. We need

risk premia appear to be lower than previously believed, we argue that experts might now wish to revise downward their long-term future risk premium forecasts.

We then look in section 13.6 at how using our historical analysis may more deeply inform us about likely future premia. We argue both that twentieth century equity returns almost certainly exceeded investors' *ex ante* risk premium requirements, and that the required risk premium itself fell over time. In section 13.7, by decomposing the historical risk premium into the contribution from unanticipated cash flow increases and the impact of a decline in [redacted] to infer the likely magnitude of the equity premium. In our

It is clear that given projected dividend growth, the correct value for the Dow depends on the return that investors expect from common stocks. The relationship is shown in Figure 13-1 which shows how the discount rate, which is the return expected by investors, influences the valuation given by the Gordon model. With dividends growing in real terms at 3 percent, valuations vary from infinity (if the expected return, like the dividend growth rate, is also 3 percent in real terms), through 36,000 (when the expected return is close to 3.4 percent) and 10,000 (if the expected return is 4.4 percent), to just 1,000 (if the expected return is 17 percent in real terms) or less. Values depend on the discount rate.

[redacted] a tiny move of just half a percent in the return cur-

well over 4 percent as recently as late 2000. To the risk free interest rate we may add some additional reward that is expected by investors as compensation for equity market risk. Clearly, the risk premium is the major determinant of asset values. If it is close to zero, the Glassman-Hassett optimists are correct; and if it is large, the Shiller pessimists are correct. This is why most finance professionals and financial economists regard the equity risk premium as the single most important number in finance.

To measure the equity market premium and to establish the reward for risk, we need to look at the markets where equity risk is traded, not only the United States but also other major global stock markets. That was the focus of chapter 12. An unbiased estimate of the *ex ante* risk premium required by investors tells us what equity market returns we can expect in the future relative to bills or bonds. A small risk premium automatically implies higher valuations but lower returns expected in the future from equities; a large risk premium automatically implies lower valuations but higher future returns from equities. If this were not the case, then, as we explained at the start of this chapter, the highly competitive conditions prevailing in the world's leading stock markets would ensure that share prices rapidly rise or fall until promised returns are aligned with required returns.

13.2 How big should the risk premium be?

We have explained the central role that the equity premium plays in determining stock prices. Other things being equal, the higher the required risk premium, the lower the value placed on a stream of cash flows. So when the required risk premium goes up, the realized, or *ex post*, risk premium is reduced over the transition period. Conversely, when the required premium goes down, the historical, *ex post* risk premium will be larger over the transition period. Once transition is complete, of course, equity returns will have an expected return that reflects the new required risk premium. Since transition from a high to a lower required risk premium may occupy many years, the historical, *ex post* premium may overstate consensus expectations. It is therefore important not to extrapolate unadjusted, historical equity premia into the future. Rather, one should use history as a means of informing the quest for a sensible estimate of the *ex ante*, forward looking premium.

We might wish to start with a direct estimate of the prospective risk premium. Unfortunately, we cannot *measure* the prospective risk premium since it relates to the unknown future. The prospective premium is the reward investors require for taking on risk. We could in principle simply ask investors. Indeed, we refer below to the results of investor surveys, but mostly they provide a source of amusement rather than useful information. Private investors' opinions appear to reflect what has happened in the recent past, or even sheer fantasy. Professional money managers seem (at best) to provide answers that reproduce, with some noise, the evidence from long-run historical studies. That approach is unlikely to inform us about the market's expectations.

An alternative approach involves analyzing the earnings, dividend, or cash flow projections of security analysts. The premium is inferred from the discount rate that equates these

future cash flows to ruling security prices. This approach, which we discuss in section 13.6, is also fraught with difficulty since there is no evidence that analysts' forecasts are unbiased predictors of the future.

In practice, therefore, we typically measure the historical risk premium, and use this as our starting point for inferences about the future. But to guide us, it is helpful to think about plausible magnitudes for the risk premium. This involves a brief detour into theory.

The starting point is, of course, the capital asset pricing model (CAPM), first formulated by Sharpe (1964). The CAPM was for most of the last three decades the method of choice among finance experts for estimating expected returns. The CAPM asserts that the expected return on a risky asset is the risk free rate of interest plus a risk premium. The latter is equal to the equity market risk premium, scaled up or down by the asset's beta. Beta measures the risk of the asset relative to the market portfolio, and beta estimates are widely available in most stock markets. The average beta for all stocks in a market is, by definition, equal to one. The equity market risk premium is fundamental in determining CAPM expected returns.

As one might expect, there are competing theories that suggest differing magnitudes for the risk premium (see Cornell (1999) for a review). Though some writers may give another impression, there is no single figure for the risk premium that theory says is "correct." Stewart (1991) writes: "Is there any fundamental reason why [the] market risk premium should be 6 percent? Not that I can figure. The question is a little like asking why did God make pi the number 3.14159... Don't ask. Just memorize it." If you are not convinced that theory provides a unique constant for you to commit to memory, then you too will wish to read the entrails of capital market history. In the following section, we therefore revert to deeper examination of the historical evidence.

13.3 Measuring the premium

We define the risk premium relative to either bills or bonds. For the sake of concreteness, this chapter emphasizes historical and prospective equity risk premia calculated relative to bills. We select bills because they are the more commonly used basis for defining the equity premium—reflecting the fact that only treasury bills can really be considered close to risk free. Nearly all of our discussion, however, applies equally well to premia relative to bonds. Where it is helpful, we supplement our analysis with premia estimated relative to bonds.

The risk premia reported in chapter 12 were computed as geometric means. This has intuitive appeal from an investment perspective. It corresponds to the annualized performance figures you see every day for mutual funds, for indexes, and for pension plans. When past performance is being considered, the geometric mean summarizes the annualized rate of return over a historical period. Computing the geometric mean requires us to calculate the product of *1 + First return* multiplied by *1 + Second return* and so on up to the nth *return*. We then compute the nth root of this product and deduct *1*. The resulting geometric mean measures the annualized rate of return that equates the initial investment to the final value of a portfolio. The geometric mean risk premium has a similar interpretation. It is the incremental reward from investing in equities in preference to government securities.

We can simplify calculation of the geometric mean return over n years. In practice, all we require is two numbers, the final and the initial values of the portfolio. The geometric mean involves calculating the nth root of *Final value* divided by *Initial value*, and then deducting the value *1*. Think of a portfolio that appreciates over a period, such as 101 years, from $1,000 to (say) $10,000. It will have precisely the same annualized return regardless of whether the intermediate prices are stable or wildly volatile. By construction, the annualized return is the same over every one of the n years for which it has been calculated. We cannot meaningfully talk of the volatility of the geometric mean return. Volatility is a characteristic of the intermediate, year-by-year returns within our 101-year interval.

The year-by-year returns clearly experience considerable variability over time. We can capture this by estimating the average around which returns fluctuate, and the range of these fluctuations, that is, the arithmetic mean and the standard deviation of the annual returns. The arithmetic mean over n periods is the sum of all n returns, divided by n. The arithmetic

mean answers the question: If I chose a year at random, what return should I expect? The arithmetic mean may be calculated for premia as well as for raw returns.

The arithmetic mean of a sequence of different returns is always larger than the geometric mean. To see this, consider equally likely returns of +25 and -20 percent. Their arithmetic mean is 2½ percent, since (25 – 20)/2 = 2½. Their geometric mean is zero, since $(1 + {}^{25}/_{100}) \times (1 - {}^{20}/_{100}) - 1 = 0$. But which mean is the right one for discounting risky expected future cash flows? For forward-looking decisions, the arithmetic mean is the appropriate measure.

To verify that the arithmetic mean is the correct choice, we can use the 2½ percent required return to value the investment we just described. A $1 stake would offer equal probabilities of receiving back $1.25 or $0.80. To value this, we discount the cash flows at the arithmetic mean rate of 2½ percent. The present values are respectively $1.25/1.025 = $1.22 and $0.80/1.025 = $0.78, each with equal probability, so the value is $1.22 × ½ + $0.80 × ½ = $1.00. If there were a sequence of equally likely returns of +25 and -20 percent, the geometric mean return will eventually converge on zero. The 2½ percent forward-looking arithmetic mean is [illegible] for the [illegible] to year volatility of returns.

The more volatile or risky the sequence of returns, the greater will be the difference between the two means. This is confirmed in Table 12-1. The arithmetic and geometric equity premia differ in the relatively low-volatility United States and the United Kingdom by less than 2 percent. The least volatile equity market has been Canada, whose annual risk premium, relative to bills, had a standard deviation since 1900 of 16.7 percent. The most volatile market was Germany with an annual standard deviation of 35.3 percent. For stable assets, the arithmetic mean risk premium is only slightly above its geometric counterpart; for very volatile assets the arithmetic mean premium can be much higher than the geometric mean. Canada has the smallest gap between its arithmetic and geometric means; Germany, the largest.

A reasonable approximation is that the arithmetic mean will exceed the geometric mean by one-half of the variance of annual returns. The variance is the square of the standard deviations presented in Table 12-1 (and also Table 12-2). The difference between arithmetic and geometric real returns therefore varies from Canada's 1.3 percent (which is very close to ½ × .167²) to Germany's 5.4 percent (fairly close to ½ × .353²). This approximation is very accu-

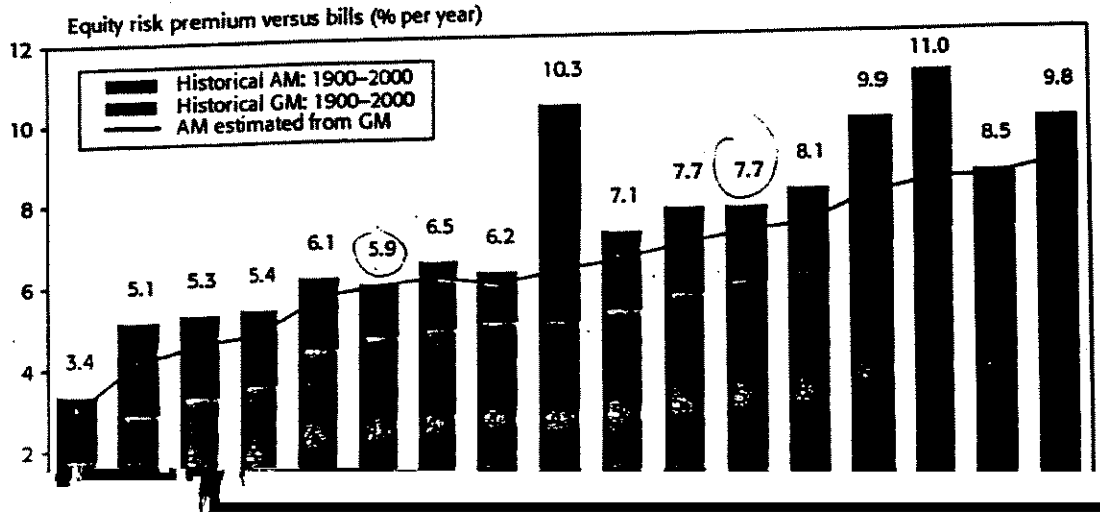
best estimate of 7.7 percent, we can be only two-thirds confident that the true mean lies within one standard error of this, namely, within the range 7.7 ± 2 percent, or 5.7 to 9.7 percent. These high standard errors are the reason why conventional wisdom prescribes that the longest possible series of stock market data should be used to estimate risk premia.

As we explained earlier, one of the key uses of the equity risk premium is to determine investors' required returns, and hence the cost of equity capital. This is used, for instance, as a crucial input when estimating the discount rate for valuing shares, projects and other claims on uncertain future cash flows. In Tables 12-1 and 12-2, we report the historical arithmetic means, and associated standard deviations, for risk premia around the world. To build on that analysis, we now turn to expectations for the future.

13.4 Arithmetic and geometric premia

A crude estimate of the expected equity risk premium is the arithmetic mean of the one-year historical premia. In Figure 13-2, the full height of the bars shows the historical arithmetic mean premium relative to bills over the last 101 years for each of the sixteen countries. The US and UK premia are 7.7 and 6.5 percent, respectively, while the world equity risk premium is 6.2 percent. As we would expect, the arithmetic mean premia are noticeably higher than the geometric mean premia. Further, the arithmetic mean is at its largest, both in absolute terms and relative to the geometric mean, for the countries that suffered the greatest turmoil and hence volatility of returns over the last century (see the rightmost bars in Figure 4-14).

Figure 13-2: Arithmetic mean and geometric mean equity risk premia, 1900–2000



The historical arithmetic means in Figure 13-2 are thus clearly influenced by past levels of stock market volatility (among other factors). However, as demonstrated in chapter 8, estimates of the long-term historical standard deviation are not necessarily the best predictors of future volatility. We observed in chapter 12 that repetition of certain historical events is so unlikely that the past must be used with care as a guide to the future. There will be new uncertainties, but we know not what they will be. We therefore need estimates of expected future arithmetic risk premia, conditional on current predictions for market volatility.

It is not clear how investors should ideally adjust historical estimates of the equity risk premium to reflect today's judgments about stock market volatility. The approach we follow is to recalculate the arithmetic means, assuming current projections of early twenty-first century levels of volatility. To do this, we use the result that with lognormally distributed returns, the geometric and arithmetic means are linked by the standard deviation of returns, as described in section 13.3. We bypass some statistical assumptions that underpin our calculations, and which are discussed in Cooper (1996) and Dimson and Marsh (2001). We therefore recalculate the arithmetic mean premium for each country, replacing the historical difference between the arithmetic and geometric means with a difference based on risk estimates that are more contemporary.

For our estimates of arithmetic premia, we illustrate the approach using the same volatility for all national markets. That cannot be correct since markets inevitably expose investors to differing levels of risk. Nevertheless, for simplicity we assume a current volatility level for all sixteen national markets of 16 percent, and for the world index of 14 percent. It follows that our prediction of the difference between the arithmetic and geometric means is ½ × variance $= ½ \times 0.16^2 = .0128 = 1.28$ percent for each country and $½ \times 0.14^2 \approx 1$ percent for the world index. At this stage, we adjust the historical record only for volatility changes relative to the past.

Clearly, the volatility of one stock market is not in reality the same as another. Different stock markets have had differing risk levels in the past, and projections for the future should not be uniform. Chapters 4 and 8 show that national stock market risks differ in ways that relate to fundamental attributes, as well as to the impact of political and military history. Some countries are natural resource-based; others are more driven by technology. Some are more highly leveraged; others, less so. Some are concentrated in a narrow range of business activities; others are large, diversified markets which naturally tend to have a lower variability for the risk premium. It is impossible for us to make country-by-country risk predictions that will appear reasonable for the lifetime of this book. We therefore stress that assuming the same projected volatility for all premia is an expositional device, no more.

Given our predicted standard deviation for each country's risk premium, what, then, are our estimates of the arithmetic mean premia? These premia, measured relative to treasury bills, are represented graphically by the line-plot in Figure 13-2. The US equity risk premium is estimated at 7.1 percent, and that for the United Kingdom is 6.0 percent. Arithmetic mean

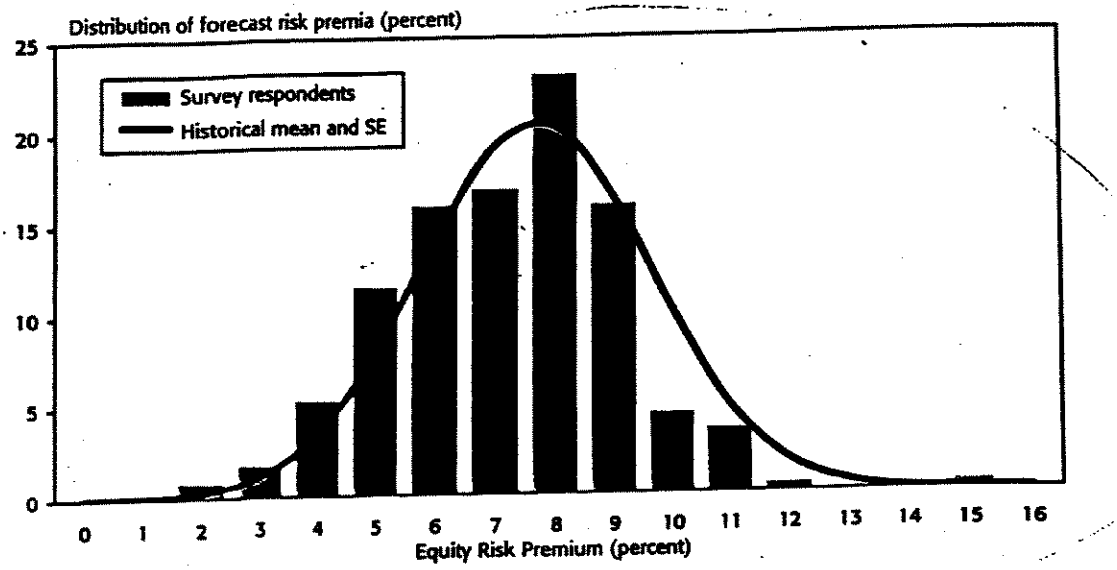
premia range from 3.1 percent (Denmark) to 8.7 percent (France); the worldwide arithmetic mean premium, relative to bills, is 6.2 percent.

The estimates of the adjusted arithmetic mean equity risk premia, relative to government bonds, are not displayed graphically. They are mostly somewhat lower. The US equity premium relative to bonds is estimated at 6.3 percent, and that for the United Kingdom is 5.7 [illegible] from 3.3 percent (Denmark) to 7.6 percent (Australia) or higher (Ger-

[redacted]

To obtain an estimate of expected equity market returns, we require a forecast of the future arithmetic risk premium. For those who seek to extrapolate from the long-run series of historical premia, the numbers illustrated by the line plot in Figure 13-2 are the ones to use. For our world index, the adjusted arithmetic mean risk premium is 5.9 percent. Hence, the [illegible] risk free rate of interest, plus a premium of 5.9 percent. However, we

Figure 13-3: Financial economists' risk premium forecasts compared with US capital market history

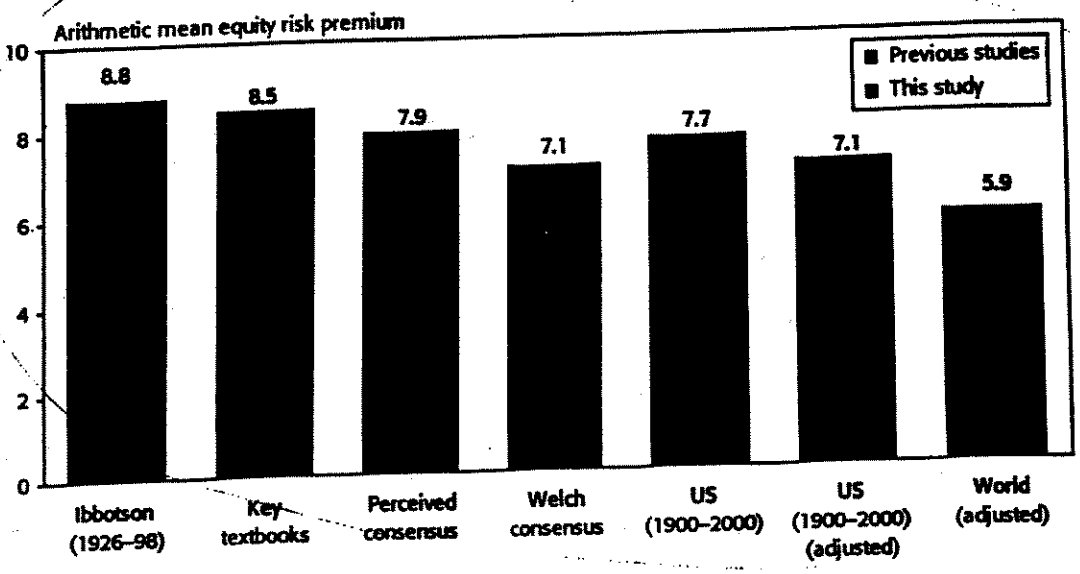


Most respondents to the Welch survey would have regarded the Ibbotson Associates' *Stocks, Bonds, Bills, and Inflation Yearbook* as the definitive study of the historical US risk premium. The first bar of Figure 13-4 shows that, at the time, the most recent long-run arithmetic risk premium computed from Ibbotson data from 1926–98 was 8.8 percent per year. The second bar shows that the key finance textbooks were on average suggesting a premium of 8.5 percent, a little below the Ibbotson figure. The textbook authors may have based their views on earlier, slightly lower, Ibbotson estimates, or else they were shading the Ibbotson estimates downward. The Welch survey mean is in turn lower than the textbook figure, but since respondents claimed to lower their forecasts when the equity market rises, this difference is probably explained by the market's strong performance in the 1990s. Interestingly, the third and fourth bars of the chart show that the survey respondents also perceived the profession's consensus to be higher than it really was. That is, they thought the mean was 0.5 to 1 percent higher than the average revealed in the Welch survey.

These survey and textbook figures represent what is being taught in the world's leading business schools and economics departments. As such, they are also widely used by finance professionals and corporate executives. Similarly, they are cited by regulators and in rate-of-return regulation disputes. Their influence extends from the classroom, to the boardroom, to the dealing room, to the courtroom.

Whether the Welch survey mean of 7.1 percent is appropriate is quite another matter. A large number of the survey respondents were clearly calibrating their forecasts relative to the longest-run historical benchmark available from Ibbotson, and then shading the historical number down based on subjective factors, including their judgment of the impact of recent

Figure 13-4: Alternative estimates of the arithmetic mean risk premium, relative to bills



strong market performance in the late 1990s. The Ibbotson Associates risk premium estimates are based on data from the Center for Research in Securities Prices (CRSP) data that starts in 1926. In the spirit of using the longest possible series of historical data, the fifth bar in Figure 13-4 shows that the arithmetic mean risk premium over the period 1900–2000, as estimated in this current study, is 7.7 percent.

The inclusion of twenty-six years of extra data from the start of the twentieth century (plus adding in 1999 and 2000) lowers the estimated premium by 1.1 percent. To the extent that their forecasts were anchored in long-run historical data, the Welch survey respondents might now wish to make a corresponding further downward revision in their forecasts of the equity risk premium. Welch (2001) is now updating his survey. If his new respondents were to make a full 1.1 percent reduction in their mean, the revised arithmetic mean would fall to 6.0 percent.

Of course, the 101-year mean of 7.7 percent shown in the fifth bar in our chart is the unadjusted historical mean. We argued above that we are likely to obtain more plausible estimates of the future arithmetic mean risk premium if we adjust the historical estimates downward to reflect today's current levels of equity market volatility. The sixth and seventh bars of Figure 13-4 portray the results of making such an adjustment for the United States and the world index. The adjusted US figure is 7.1 percent, while the world index provided a risk premium of 5.9 percent. To the extent that the Welch survey respondents were not already making an adjustment of this kind, this suggests that, in responding to the Welch (2001) survey, they should further lower their forecasts of the risk premium. This assumes, of course, that they still wish to use historical means as the anchor for their future forecasts.

13.6 History as a guide to the future

Financial economists may be reluctant to diverge markedly from the historical mean. Decision-makers, on the other hand, need to go beyond using only the past record, and to identify the market's implicit expectation for future performance. This is by no means easy. Recently, a number of researchers have sought to infer expected risk premia from surveys of the financial community, including Claus and Thomas (2001), Fraser (2001), Graham and Harvey (2001a), and Harris and Marston (2001). Unfortunately, such surveys are difficult to interpret. Graham and Harvey find that financial executives underestimate stock market risk substantially, while Brav and Lehavy (2001) and earlier researchers find that investment professionals are over-optimistic about the likely course of stock prices. Despite their wide dispersion, the responses to Welch's (2000) survey are about as usable as any.

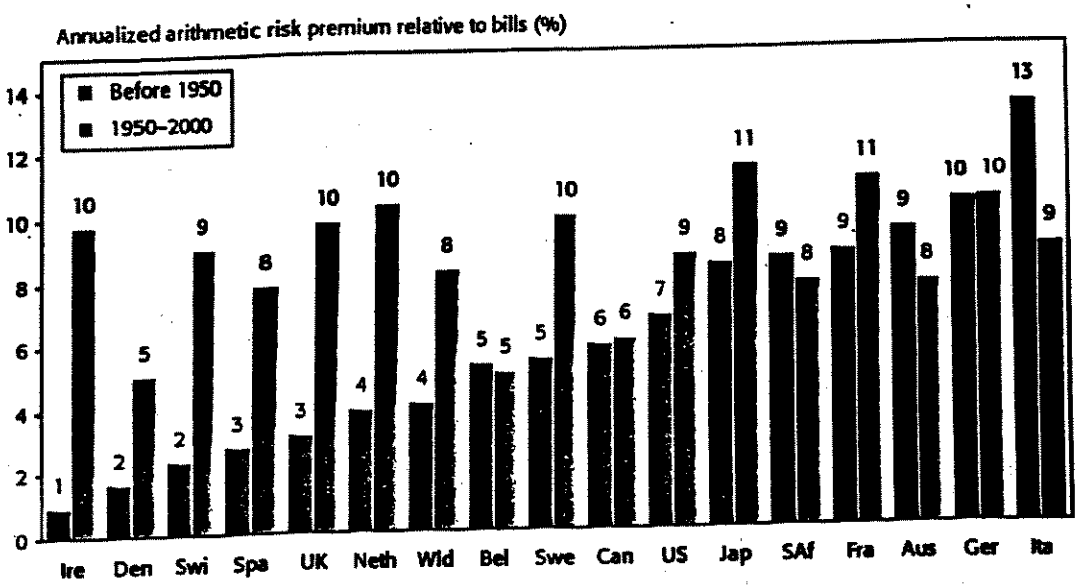
The wide dispersion of views reinforces the case for basing estimates on the historical record. However, since history may have been kind to (or harsh on) stock market investors, there are coherent arguments for going beyond raw historical estimates. First, the whole idea of using the achieved risk premium to forecast the required risk premium depends on having a long enough period to iron out good and bad luck. Yet as we noted in section 13.3, even with 101 years of data, standard errors remain high and our estimates of the average are imprecise.

Second, the expected equity risk premium could change over time. This might be because the underlying risk of equity investment has fluctuated, particularly as the variety of exchange-listed sectors has broadened out over the last century (see chapter 2). The corporate sector as a whole may have become more or less risky. The risks faced by investors have been transformed through reduced dealing costs and the advent of pooled investment vehicles. Enhanced diversification opportunities became available, both domestically and internationally. And as many households became wealthier, there may have been systematic changes in investors' levels of risk aversion.

Third, we must take account of the fact that stock market outcomes are influenced by many factors. Some that were important in the past (removal of barriers to international investment, for example) may be non-repeatable. If so, projections of the future risk premium should deviate from the past. The financial history of our sixteen stock markets has been so variable over time that it is worth exploring this argument further.

A comparison between the first and second halves of our 101-year period makes the point. Over the first half of the twentieth century, the arithmetic average US equity risk premium relative to bills was 6.7 percent, whereas over the period 1950–2000, it was 8.6 percent. As is clear from Figure 13-5, this pattern is common to most of the sixteen countries covered in this book, with Australia, Italy, Belgium, and South Africa being the exceptions. The cross-sectional mean for all countries in the first half of the twentieth century was an arithmetic average risk premium of 6.0 percent, versus 8.6 percent for the sixteen-country mean in the next fifty-one years. The corresponding averages for the equity premium relative to bonds are not shown here, but the pattern is similar: a pre-1950 mean of 5.5 percent as compared to 7.5 percent over the following fifty-one years.

Figure 13-5: The equity premium relative to bills: first half-century versus next fifty-one years

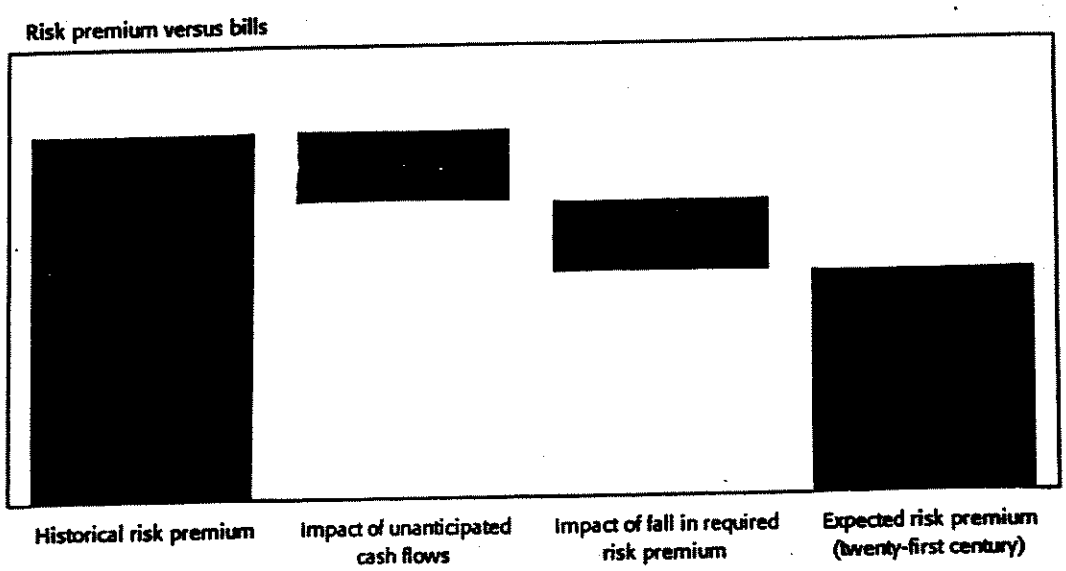


The large risk premia achieved during the second half of the twentieth century are attributable to two factors. First, there was unprecedented growth in productivity and efficiency, acceleration in the pace of technological change, and substantial enhancements to the quality of management and corporate governance. As Europe, North America, and the Asia-Pacific region emerged from the turmoil of the Second World War, expectations for improvement were limited to what could be imagined. Reality almost certainly exceeded investors' expectations. Corporate cash flows grew faster than investors anticipated, and this higher growth is now known to the market and built into higher stock prices.

Second, as noted by Bernstein (1997) and others, stock prices have doubtless also risen because of a fall in the required rate of return due to diminished investment risk. The economic and political lessons of the twentieth century have surely been learned, international trade and investment flows have increased, and the Cold War has ended, leading to a more secure business environment. A further factor that must surely have lowered required returns is that investors now have much more opportunity to diversify, both domestically and internationally, than they had a century ago. Diversification allows investors to lower their risk exposure without detriment to expected return. Transaction costs are also lower now than a century ago. Factors such as these, which led to a reduction in the required risk premium, have contributed further to the upward re-rating of stock prices.

To convert from a pure historical estimate of the risk premium into a forward-looking projection, we need to reverse-engineer the factors that drove up stock markets over the last 101 years. The simplest idea would be to use the Gordon Model (from section 13.1) to infer the

Figure 13-6: *Ex post* and *ex ante* equity risk premia



illustrated conceptually in Figure 13-6. The left-hand bar in the chart portrays the historical risk premium on the equity market. This includes the contribution from unanticipated growth in cash flows and the gain from falls in the required risk premium. We therefore deduct the impact of these two factors. What remains in the right-hand bar of this chart is an estimate of the prospective risk premium demanded by investors as they look ahead to the remainder of the twenty-first century. The key qualitative point is that this is lower than the raw historical risk premium.

13.7 Expectations of the risk premium

To apply this framework, we need some notion of when cash flows (proxied here by equity dividends) have exceeded or fallen short of expectations. What dividends might investors expect each year? There are a variety of possible approaches (see, for example, Ibbotson and Chen, 2001). Perhaps the simplest approach is one that is commonly used today for forecasting the long-run dividend growth rate, namely, to extrapolate from previous long-term [illegible]. The long-term dividend-growth rate is then used to project future real

We assume that at every December 31, investors compare the year's real dividend growth to the real growth rate that would have been projected as at January 1 of that year. The difference is defined as *1 + Annual dividend growth* divided by *1 + Projected growth*, minus *1*. This error in projecting dividend growth may be thought of as a naive measure of the unanticipated growth rate in dividends. The unanticipated changes in dividend growth are compounded together to produce an estimate of their annualized impact over the last century. This is clearly a rather unsophisticated measure of unanticipated real dividend growth, but it suffices to illustrate the general idea.

Defined this way, the impact in the United States of unanticipated dividend growth amounts to 0.2 percent per year over the period from 1900 to 2000. For the United Kingdom, the impact of unanticipated dividend growth is 1.7 percent per year. This large difference is explained in chapter 11 and reflects two factors. First, in the early decades of the last century, the United States generated more favorable growth expectations than did the United Kingdom; consequently, there was less scope in the United States for a favorable surprise. Second, over the last quarter-century in the United States, dividends became less important than in the United Kingdom as a result of growing rates of repurchases; this further reduced the scope for unanticipated dividend growth.

Since 1900, there has also been a dramatic change in the valuation basis for equity markets. The price/dividend ratio (the reciprocal of the dividend yield) is much higher now than it was in 1900. In the United Kingdom, for example, the price/dividend ratio at the start of 2001 was 42, as compared to 23 a century earlier. Undoubtedly, this change is in part a reflection of expected future growth in real dividends, so we could in principle decompose the impact of this valuation change into both an element that reflects changes in required rates of return, and an element that reflects enhanced growth expectations. To keep things simple, we assume that the increase in the price/dividend ratio is attributable solely to a long-term fall in the required risk premium for equity investment. Given this assumption, the fall in the required risk premium since 1900 is 1.4 and 0.6 percent per year for the United States and the United Kingdom, respectively. These amounts—which arise from the change in the price/dividend ratio—need to be deducted from the historical risk premium to obtain a measure of investors' *ex ante* expectations.

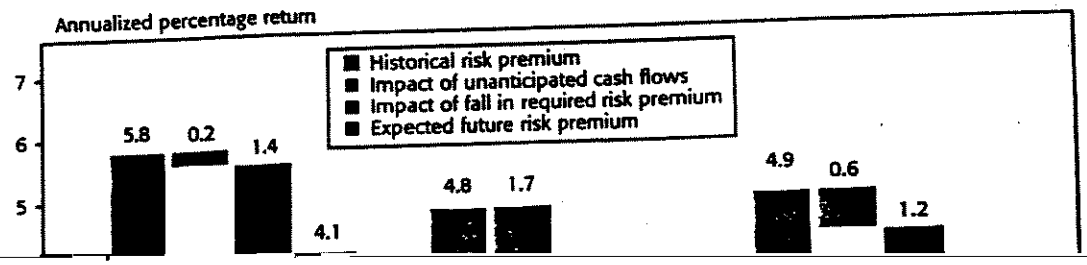
The remainder of the annualized risk premium represents the expected reward for equity investment. Even though we are deviating from some of its underlying assumptions, we can think of the risk premium in terms of the Gordon model for equity valuation. The Gordon model asserts that the expected equity return is equal to the prospective dividend yield plus the projected long-term dividend growth rate. We have already abstracted for the dividend yield, so for a given yield the Gordon model equates the expected return to the long-term dividend growth rate. It follows that the expected risk premium, measured relative to the riskless interest rate, is the projected dividend growth rate, also measured relative to the real interest rate. That is, *1 + Projected dividend growth* divided by *1 + Riskless rate of interest*, minus *1*. Linking together these premia for each year after 1900, the expected US and UK equity risk premia are respectively 4.1 and 2.4 percent per year.

More complex decompositions of the historical risk premium are possible; see, for example, Arnott and Bernstein (2001) and Ibbotson and Chen (2001). These analyses, however, all point in the same direction. So using our simplistic decomposition of the backward-looking risk premium, we can now show how the historical premium can be broken down into a series of elements. For the United States, United Kingdom and for our sixteen-country world index, the risk premium estimates are depicted in Figure 13-7.

The differences between the estimates for each index should not be taken too seriously, especially since US corporations pay such low levels of dividends that computations based on dividend growth must be interpreted with care (see section 11.2). We acknowledge that our dividend projections are simplistic, and the reader should not put too much weight on cross-country differences. The key point is that the expected equity risk premium, based on the last century, should be lower than our backward-looking, historical averages suggest.

Our estimates indicate a geometric mean premium for the United States of 4.1 percent, for the United Kingdom of around 2.4 percent, and for our sixteen-country world index of about 3.0 percent. This is similar to the Fama and French (2002) estimate for the United States using a related approach. Also based on dividend yields and dividend growth estimates, Fama and French use the Gordon model to compute the US equity premium from 1872–1999. They find a premium of 3.8 percent before 1949, and a premium of 3.4 percent for the subsequent period. They argue that the difference between these estimates and the larger *ex post* risk premium based on historical realized returns is attributable to a reduction, since 1949, in investors' required rate of return. Our analysis is consistent with their assertions.

Figure 13-7: *Ex post* and *ex ante* equity risk premia for selected indexes



If they are to be used as a prospective risk premium, our annualized figures need to be converted into arithmetic means, as outlined in section 13.4. Using a projected standard deviation for US and UK equities of 16 percent, the prospective *arithmetic* risk premium is 5.4 percent for the United States and 3.7 percent for the United Kingdom. With a slightly lower standard deviation for the world index of 14 percent, the prospective *arithmetic* risk premium for the world index is 4.0 percent. In fact, whichever country one focuses on, our forward-looking predictions for the equity risk premium are lower than the historically based projections reviewed in section 13.4.

There is scope to finesse our estimates of the expected risk premium. Some of the opportunities to enhance our estimates are the following: First, as explained in chapters 18–33, for many countries we use index series that are spliced together, and this presents difficulties when estimating dividend growth rates. Second, we ignore changes in the tax treatment of dividend income, both cross-sectionally and over time. Third, we estimate annual dividends from annual index returns and capital appreciation, rather than using more frequent (say, monthly) data. Fourth, we use a simplified decomposition of equity risk premia that could easily be enriched. Fifth, and very importantly, we use a naive model of investors' dividend expectations, an issue that merits further research (some of which we present elsewhere; see Dimson and Marsh, 2001). We leave these enhancements as a task for future researchers.

Finally, note that the use of historical averages as indicators of current required returns suggests that France may have a higher equity risk premium, while Denmark's risk premium may be lower (see Figure 13-2). There are obviously differences in risk between markets, but this is unlikely to account for cross-sectional differences in historical premia. Indeed, much of the cross-country variation in historical equity premia is attributable to country-specific historical events that will not recur. When making future projections, there is a strong case, particularly given the increasingly international nature of capital markets, for taking a global rather than a country-by-country approach to determining the cost of capital.

13.8 Summary

The equity premium is the difference between the return on risky stocks and the return on safe bonds. The equity market premium is central to investment, financing, and saving decisions. It is often described as the most important number in finance. Yet it is not clear how big the equity premium is today, or how large it has been in the past.

Survey evidence on best practice by corporations and financial advisors, such as Bruner, Eades, Harris, and Higgins (1998), reveals that nearly all respondents estimate the equity risk premium by averaging past data. However, there is considerable variation in their choice of time period and in their method of averaging, whether arithmetic or geometric. Their judgments are usually underpinned by knowledge of one, or at most two, national exchanges: respondents invariably focus on their domestic and/or the US stock market. In this chapter we use evidence from the past to provide a guide to what might be expected in the future.

The chapter addresses four questions: Which historical equity risk premium should one use as the starting point? Why has it typically been so high? What is a good forward-looking predictor for the future? How can one use variables such as the dividend yield to improve forecasts of the risk premium?

We stress the central role in finance of the equity premium. The historical premium is often summarized in the form of an annualized rate of return. This is a geometric mean. It provides information on past performance. For the future, what is required is the arithmetic mean of the distribution of equity premia, which is larger than the geometric mean. For markets that have been particularly volatile, the arithmetic mean of past equity premia may exceed the geometric mean premium by several percentage points. We adjust the arithmetic mean for (i) the differences between the variability of the stock market over the last 101 years, and the variability that we might anticipate today, and (ii) the impact of unanticipated cash flows and of declines in the required risk premium. The result is a forward-looking, *geometric* mean risk premium for the United States, United Kingdom and world of around 2½ to 4 percent and an *arithmetic* mean risk premium for US, UK, and world equities that falls within a range from a little below 4 to a little above 5 percent.

These equity risk premia are lower than those cited in surveys of finance academics. They are also lower than frequently quoted historical averages, such as those from Ibbotson Associates, which cover a somewhat briefer interval. We show that the historical risk premium, even if it embraces countries that have been less successful than the United States, is supported by two factors. Over the second half of the last century, equity cash flows almost certainly exceeded expectations, and the required rate of return doubtless fell as investment risk declined and the scope for diversification increased. Stock markets rose, in both the United States and other countries, for reasons that are unlikely to be repeated. Even after the setbacks of 2001, the prospective risk premium is markedly lower than the historical risk premium.

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Please provide copy of articles cited in footnotes 3 and 4.

Dr. Morin's Response:

The Harris, Marston, Mishra, article is attached. Dr. Morin does not have access to the Journal of Business Welch surveys. This article is available at most university libraries.

Note: Most (if not all) of the information requested is copyrighted. The attached copy is being provided under the "fair use" exception to the copyright laws. Any copies made of the attachment are subject to the copyright laws.

Ex Ante Cost of Equity Estimates of S&P 500 Firms: The Choice Between Global and Domestic CAPM

Robert S. Harris, Felicia C. Marston, Dev R. Mishra, and Thomas J. O'Brien*

We estimate ex ante expected returns for a sample of S&P 500 firms over the period 1983-1998. The ex ante estimates show a better overall fit with the domestic version of the single-factor CAPM than with the global version, but the difference is small. This finding has no trend in time and is consistent across groups formed on the basis of relative foreign sales. The findings suggest that for estimating the cost of equity, the choice between the domestic and global CAPM may not be a material issue for many large US firms.

The estimation of a firm's cost of equity capital remains one of the most critical and challenging issues faced by financial managers, analysts, and academicians. Although theory provides several broad approaches, recent survey evidence reports that among large US firms and investors, the capital asset pricing model (CAPM) is by far the most widely used model.

Among the variety of decisions to be made in implementing the CAPM is the choice between a domestic or global index for the market portfolio. Although theory suggests that using a domestic market index is appropriate only for an asset traded in a closed, national market, empirical research has thus far failed to establish whether a global or domestic pricing model performs better with US stocks.

We study the choice between the global and domestic CAPM by examining which of the two models provides the better fit with a sample of *ex ante* expected equity return estimates for large US companies. In contrast to many prior studies that use realized returns, we estimate implied expected returns based on the theory's call for a forward looking measure. The question we ask is whether the domestic or the global version of the single-factor CAPM provides the better fit with the dispersion of the *ex ante* expected return estimates for a sample of S&P 500 equities. Our study period covers 1983 to 1998.

We find that the domestic US CAPM fits the *ex ante* expected return estimates better than does the global CAPM. This result shows no trend over time. We also find that except for a few years in the early 1990s, the better fit of the domestic CAPM holds consistently across subsamples formed on the basis of the relative levels of the firms' foreign sales. However, the difference in fit of the two versions of the CAPM is small.

We also find a positive and significant empirical relation between *ex ante* risk premium estimates and systematic risk estimates. Moreover, we find that the *ex ante* risk premium estimates for

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Robert S. Harris is Professor and Dean at the University of Virginia. Felicia C. Marston is an Associate Professor at University of Virginia. Dev R. Mishra is an Assistant Professor at Memorial University of Newfoundland in St. John's, NF, Canada. Thomas J. O'Brien is Professor of Finance at the University of Connecticut.

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broad industry groups have a high correlation with the corresponding Fama-French (1997) estimates from the CAPM, but not with the estimates from their three-factor model.

The study's practical implications are based on the widespread use of the CAPM in cost of capital estimation by large US firms and investors, where the traditional use of the S&P 500 index as the "market portfolio" continues to be the standard. Our findings support the use of the domestic CAPM to estimate the cost of equity of large US firms. However, finding a relatively small difference in the overall fit of the two CAPM versions suggests that the choice between applying the domestic CAPM and the global CAPM may not be a critical issue for many large US firms.

The paper is organized as follows. Section I reviews related literature. This review includes the domestic and global versions of the single-factor CAPM and why the two models are theoretically likely to result in different expected rates of return for a given asset. Section II discusses the methodology and data for the empirical analysis. Section III reports the results of the empirical comparison of the *ex ante* expected return estimates with the estimates of the two CAPM versions and with corresponding measures of risk. Section IV provides a brief summary and conclusion.

I. Review of Related Literature

Recent survey evidence (Bruner, Eades, Harris, and Higgins, 1998) and Graham and Harvey, 2001) reports that the capital asset pricing model (CAPM) is widely used by large US firms and investors. The CAPM also continues to have wide popularity in academic textbooks and applied articles (e.g., Kaplan and Peterson, 1998 and Ruback, 2002).

These applications use the traditional domestic CAPM, $k_i = r_f + \beta_{iD}[k_{MD} - r_f]$; where k_i is the equilibrium expected rate of return for asset i; r_f is the risk-free rate; β_{iD} is the beta of asset i against the domestic market portfolio returns; k_{MD} is the equilibrium required rate of return on the domestic market portfolio; and $k_{MD} - r_f$ is the risk premium on the domestic market portfolio.

A. Global CAPM and Domestic CAPM

Stehle (1977) and Stulz (1995a, 1995b, 1999) argue that using a domestic market index is only appropriate for an asset traded in a closed, national financial market. Although equilibrium international asset pricing models are multifactor in general, if the purchasing power parity (PPP) condition holds, then the single-factor CAPM equation can be adapted to a international context for assets in the global market portfolio, as discussed in Stulz (1995c). We emphasize the difference between the domestic and global CAPMs by Equation (1).

$$k_i = r_f + \beta_{iG}[k_{MG} - r_f] \qquad (1)$$

where k_i is the equilibrium expected rate of return for asset i in a specific pricing currency, r_f is the nominal rate of return on an asset that is risk-free and denominated in the pricing currency, β_{iG} is the beta of asset i's returns against the unhedged global market index returns, with returns computed in the pricing currency, k_{MG} is the equilibrium required rate of return in the pricing currency on the unhedged global market portfolio, and $k_{MG} - r_f$ is the risk premium on the unhedged global market portfolio. As in Grauer, Litzenberger, and Stehle (1976), under the assumption of logarithmic utility the global CAPM in Equation (1) holds

with any numeraire currency. Ross and Walsh (1983) show that when log utility is not assumed, Equation (1) holds for at most one currency. We assume that currency is the US dollar.

Karolyi and Stulz (2003) point out that only in the special case in which β_{iG} equals $\beta_{iD}\beta_{DG}$ does the global CAPM result in the same expected return as the domestic CAPM, i.e., when an asset's global beta is equal to its domestic beta times the global beta of the domestic market portfolio. Generally, this condition does not hold. Instead, when β_{iG} is greater than $\beta_{iD}\beta_{DG}$, the domestic CAPM is likely to underestimate the asset's expected return relative to the global CAPM, because there is more global systematic risk in the asset's returns than is accounted for by the domestic market index. Similarly, when β_{iG} is less than $\beta_{iD}\beta_{DG}$, the domestic CAPM is likely to overestimate the asset's expected return relative to the global CAPM, because the asset has less global systematic risk in its returns than is accounted for by the domestic market index.

Stehle (1977) reports empirical support for the global CAPM over the domestic version in realized returns for US stocks from 1956 to 1975. Harvey's (1991) study provides further empirical support of global pricing of US equities. Black (1993) asserts that the issue of whether a global or domestic index should be used in CAPM applications is not yet settled. However, given the significant globalization of the world financial markets, Stulz (1995a, 1995b, 1999) advocates the use of the global version. In contrast to Stehle's (1977) findings, Griffin (2002) reports that for the period between 1981 and 1995, a three-factor (Fama-French) domestic model had lower pricing errors for US firms than did an analogous three-factor world version. His results indicate that a domestic pricing model is a better fit with realized return data than a global pricing model.

Campbell's (1996) empirical analysis of a multifactor domestic pricing model finds that the single-factor domestic "... CAPM is a good approximate model for stock and bond prices," since the additional factors (returns to human capital and changes in expected market return) are highly correlated with the market index returns. Ng (2003) reaches a similar conclusion in the context of the global CAPM, with the additional factors of FX risk and shifts in both expected market returns and expected FX changes. Therefore, we only examine the two single-factor CAPMs. Griffin (2002) does not report results on domestic compared to world single-factor (market index) models. However, in private correspondence after our study was completed, Griffin reported to us that the domestic version of the single-factor model had lower pricing errors than did the world model.

For large US companies like those in the S&P 500, there are arguments why choosing a domestic or a global index for CAPM applications could be a non-issue. One argument is that a US index will closely track a global index, especially as markets have become more integrated and since the market value of US stocks is a substantial proportion of the market value of a global index. However, the data show that the beta of the S&P 500 compared to the MSCI World Index has been substantially less than one in the past. Another argument is that S&P 500 companies are often global in scope, which makes the S&P 500 something of a global index in its own right. However, Jacquillat and Solnik (1978) and Christophe and McFnally (2000) report evidence that a portfolio of US multinationals is an ineffective vehicle

A domestic index could be the preferred benchmark for US investors with a significant "home bias", as in the Cooper and Kaplanis (2000) model of partially integrated world markets. However, we do not know whether the popularity of the domestic CAPM among US firms is for this reason.

B. *Ex Ante* Expected Return Estimates

Empirical tests comparing global to domestic pricing models usually rely on realized returns. However, Elton (1999) points out that *ex ante* estimates of expected returns are more desirable. We obtain *ex ante* expected return estimates through analysts' growth forecasts and discounted cash flow (DCF) models, as in a number of prior studies, including Claus and Thomas (2001), Fama and French (2002), and others discussed below.

In contrast to research that uses realized returns, almost all of the studies using *ex ante* expected return estimates find an empirical relation between expected return and beta risk, despite differences in approaches and time periods. For example, using the constant dividend growth model, Harris and Marston (1992) and Marston and Harris (1993) report a significant relation between *ex ante* expected return estimates and (domestic) betas for a sample of US stocks in the 1982-1987 period. At the same time they confirm the findings of previous empirical studies of no significant relation between realized returns and betas.

When they apply a DCF model to 51 highly leveraged transactions (mostly management buyouts) in the period 1980-1989, Kaplan and Ruback (1995) find that implied costs of capital estimates are related to beta but not to the size and book-to-market factors. Using IBES forecasts, Gordon and Gordon (1997) and Gode and Mohanram (2003) also observe a significant relation between *ex ante* expected equity return estimates and domestic US betas. Gordon and Gordon use a finite horizon dividend discount model and the time period 1985-1991. Gode and Mohanram use the Ohlson-Juettner (2000) valuation model for the period 1984-1998. Also, Brav, Lehavy, and Michaely (2003) find a positive empirical association between analysts' direct return forecasts and beta for US stocks, but not between the return forecasts and the size and book-to-market factors.

The results of Gebhardt, Lee, and Swaminathan (2001) provide the only exception that we know of to a positive empirical relation between *ex ante* expected return and beta risk estimates. Their study, which uses IBES forecasts and a clean-surplus residual income valuation model, reports no significant association between their *ex ante* expected return estimates and domestic betas for a sample of US stocks from the period 1979-1995.

There is some controversy about IBES forecasts. La Porta (1996) asserts that analysts' growth forecasts tend to be too extreme, but Lee, Myers, and Swaminathan (1999) find that IBES forecasts improve their intrinsic value estimates over forecasts based on a time series model.

II. Methodology and Data

In this section, we discuss our approach for estimating *ex ante* expected returns using the constant dividend growth model and the consensus of financial analysts' five-year earnings growth forecasts available through IBES. In addition, we explain our criteria for comparing the global and domestic CAPMs.

A. *Ex Ante* Expected Return Estimation

For each month from January 1983 through August 1998, we calculate an *ex ante* expected

return estimate for each dividend-paying US stock in the S&P 500 index for which data are available. We eliminate a firm in a given month if there are fewer than three analysts' forecasts, if the standard deviation around the mean forecast exceeds 20%, or if there are not sufficient historical returns for the prior 60 months to perform beta estimations. The analysis comprises 65,154 expected return estimates for the months from January 1983 to August 1998. We

We estimate *ex ante* expected rates of return by using the constant dividend growth model.

$$k_i^e = \frac{D_{1i}}{P_{0i}} + g_i \qquad (2)$$

where k_i^e is the *ex ante* expected rate of return (cost of equity) estimate for company i, D_{1i} is the dividend per share expected to be received at time 1, P_{0i} is the current price per share, and g_i the expected long term growth rate in dividends per share, which we assume is equal to the consensus of the analysts' growth forecasts. See Timme and Eisemann (1989) for a review of the benefits of analysts' forecasts over historical growth estimates.

We recognize that our study, like any study of asset pricing relations, is a joint "test" of the underlying model and the empirical constructs used. Therefore, like other studies, we cannot conclude whether rejection is due to failure of the model or of the empirical proxies. With this standard caveat, our method for estimating *ex ante* expected returns, which uses IBES growth forecasts and the dividend growth model, has several strengths. First and foremost, theory suggests that measures of return should be those that investors expect to prevail over some future time horizon. Although many empirical tests rely on realized returns, there is no necessary relation between the investors' expected returns suggested by theory and subsequently realized returns, except under strong assumptions.

returns in US dollars from January 1978 through August 1998 from the CRSP files. We obtain T-bond returns from the website of the Federal Reserve Bank of St. Louis. We use the S&P 500 Index as the domestic US index. (We also use the CRSP Value-Weighted Index in a robustness check.) We use the Morgan Stanley Capital International (MSCI) World Index with gross dividend reinvestment as the global market index. The monthly data for the global index is from the website of MSCI: www.mscidata.com. This index is unhedged and thus, when reported in US dollars, reflects exchange rate changes in currencies against the US dollar.

The question we investigate is which of the two CAPM versions, if we assume that version is the "correct" model, has less variation in its fit with the *ex ante* expected return estimates for the individual firms. To implement this investigation, we "back out" the estimated *market* risk premia (domestic and global) for each month from the *ex ante* expected returns of the individual stocks. To do so, for a given month, we first turn each stock's *ex ante* expected return estimate into an *ex ante* risk premium estimate by subtracting the yield on the 20-year T-bond. Then we aggregate the stocks' *ex ante* risk premia estimates with value weighting, producing an *ex ante* portfolio risk premium estimate for the month. For the domestic CAPM, we value-weight the firms' domestic beta estimates into a portfolio domestic beta estimate for the month. Since the portfolio risk premium should be equal to the portfolio beta times the market risk premium, the domestic market risk premium estimate for the month is found

[redacted]

estimate. For example, if the value-weighted portfolio of eligible stocks has an *ex ante* risk

estimates for which the DCAPM provides a closer fit than the GCAPM. In the third metric, we compare the results of cross-sectional OLS of *ex ante* risk premium estimates for the individual stocks against both the estimated domestic betas and the estimated global betas. Whichever regression has the higher r-squared indicates the better-fitting CAPM version with this approach. We also examine the regression results for relative consistency with the theory: an intercept of zero and a positive slope.

Further, we investigate whether the fit of the *ex ante* estimates with those of the two CAPM versions is related to the ratio of foreign sales to total sales, which we use here as a proxy for international exposure. Although we understand that the relative level of foreign sales does not completely capture a firm's international exposure, its use is standard in many empirical studies, including Fatemi (1984), Jorion (1990), Miller and Reuer (1998), and Doidge, Griffin, and Williamson (2002), who contend that a good rationale for using relative foreign sales as a proxy for international exposure is the high correlation with other measures of firms' international operations.

Of the 489 firms used in the study, 253 firms have a reported foreign sales entry (including 76 firms reporting zero foreign sales) for the period 1994 to 1998. The overall average ratio of foreign to total sales is approximately 20% for the 253 firms. Using the eligibility criteria discussed above, we use the data for the 253 firms from 1983 to 1998 to construct a subsample of 36,580 observations (out of the 65,154 total observations), an average of about 194 firms per month. Of these observations, 11,053 involve a firm reporting zero foreign sales during 1994-1998, an average of about 59 firms per month. We divide the remaining observations, involving firms reporting non-zero foreign sales during 1994-1998, into three equal-sized

Table I. Summary of Risk Premium Differences For DCAPM and GCAPM

The columns show, respectively, the average number of firms per month (#Firms), the value-weighted averages of the estimated *ex ante* risk premia (*Ex Ante*), average domestic beta estimates (β_{iD}), the average domestic market risk premium estimates (RP_D), the average absolute differences between the *ex ante* estimates and those of the DCAPM (*Ex*-D), the average global beta estimates (β_{iG}), the average global market risk premium estimates (RP_G), the average absolute differences between the *ex ante* estimates and those of the GCAPM (*Ex*-G), and the percentage of cases in which the *ex ante* estimate is closer to the DCAPM estimate than to GCAPM estimate (%DCAPM Closer). The numbers in parenthesis are corresponding *t*-statistics.

Year	#Firms	*Ex Ante*	β_{iD}	RP_D	*Ex*-D	β_{iG}	RP_G	*Ex*-G	%DCAPM Closer
1983	285	0.066	0.883	0.075	0.030	0.864	0.077	0.031	0.573(8.489)***
1984	300	0.053	0.915	0.058	0.026	0.897	0.059	0.027	0.581(9.777)***
1985	314	0.057	0.925	0.062	0.026	0.915	0.062	0.028	0.561(7.524)***
1986	320	0.074	0.985	0.075	0.028	0.890	0.084	0.030	0.580(9.931)***
1987	327	0.061	1.024	0.060	0.024	0.941	0.065	0.027	0.618(14.76)***
1988	335	0.064	1.000	0.064	0.024	0.969	0.066	0.026	0.589(11.28)***
1989	352	0.066	0.982	0.067	0.023	0.890	0.073	0.025	0.601(13.08)***
1990	357	0.071	0.972	0.073	0.025	0.797	0.089	0.026	0.531(4.108)***
1991	363	0.075	0.976	0.077	0.027	0.723	0.104	0.027	0.482(-2.409)**
1992	370	0.078	0.990	0.079	0.030	0.723	0.109	0.028	0.440(-8.002)***
1993	374	0.082	1.018	0.080	0.029	0.576	0.142	0.029	0.490(-1.299)
1994	375	0.073	1.038	0.070	0.025	0.576	0.126	0.026	0.515(2.012)**
1995	370	0.077	1.039	0.074	0.028	0.579	0.133	0.031	0.538(5.118)***
1996	379	0.078	1.008	0.077	0.027	0.604	0.129	0.035	0.632(17.83)***
1997	383	0.082	1.005	0.081	0.029	0.650	0.127	0.037	0.616(15.73)***
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
Avg.	349	0.072	0.986	0.073	0.027	0.774	0.097	0.029	0.556(28.57)***

***Significant at the 0.01 level.
**Significant at the 0.05 level.

similar results (not reported here) when we use the CRSP Value-Weighted Index instead of the S&P 500 Index for the domestic US market portfolio.

We make two observations about the magnitudes of the market risk premium estimates. First, the global market risk premium estimates are higher than the local US market risk premium estimates. Although this observation may seem counterintuitive, it is a logical consequence of the fact that the global beta of the US market has historically been less than one. (See, for example, Karolyi and Stulz, 2003). Our second observation is that market risk premium estimates are higher than those reported in studies by Claus and Thomas (2001) and Fama and French (2002), but have a similar magnitude to that observed by Kaplan and

B. Cross-Section Regressions On Systematic Risk

Table II reports the results of the cross-section regression of the firms' *ex ante* risk premium estimates on the beta estimates. Overall, the cross-section regressions provide further evidence that consistently throughout the time period 1983-1998, the *ex ante* estimates have a better fit with those of the DCAPM than with the GCAPM. Table II shows that the r-squares of all of the regressions are higher when we use the domestic beta as the independent variable than with the global beta. Moreover, the DCAPM regression results are consistently better aligned with the theory. The regression intercepts are closer to zero for the DCAPM than for the GCAPM, and the *t*-statistics on the slope coefficients are more significant for the DCAPM than for the GCAPM. These observations apply to the entire period, to all four individual sub-periods, and to each of the 16 years covered in the study.

The findings of significant, positive slope coefficients in each of the 16 years' cross-section regressions appear to strongly confirm the basic asset pricing theory prediction that expected returns are positively related to beta risk. We note that we are using individual stock parameters, not portfolios, and we use no control variables in the cross-section regressions. However, the positive regression intercepts suggest the possible omission of risk factor(s) or systematic optimism in the analysts' growth forecasts. Further exploration of this issue is beyond the scope of this study and is a topic for future research.

Together, Tables I and II lead us to conclude that using all three metrics (average absolute differences, percentage of cases with the better fit, and cross-section regression results), the domestic CAPM fits the dispersion of *ex ante* risk premium estimates better than does the global CAPM. This finding surprised us, in light of the continuing integration of world financial markets and international diversification by investors. However, this finding is consistent with the Cooper and Kaplanis (2000) model of partially segmented global capital markets and home bias.

C. Impact of Foreign Sales

We hypothesize that the global CAPM provides the better fit for companies with a relatively higher level of foreign sales, or that at least we observe a trend toward this relation over time. Table III shows this expectation is not the case. Only in the 1990-1994 period the GCAPM is the better fit for the high and medium foreign sales groups, and the DCAPM is the better fit for the low and zero foreign sales groups. However, after 1994, the pattern is generally the same for all four foreign sales groups, and there is no longer a better fit by the GCAPM for firms in the high and medium relative foreign sales groups.

Looking at all the years together, the average absolute differences between the *ex ante* risk premium estimates for the individual stocks and those of the two CAPM versions are about the same for each foreign sales level group, and the DCAPM estimates are slightly closer to the *ex ante* estimates in all four groups. Thus, we conclude that the relative level of foreign sales does not indicate when the *ex ante* expected returns are more closely related to the GCAPM than the DCAPM, except possibly during times when the US and global economies are not in sync.

D. Risk Premium Estimates and Differences by Industry

Given the potential for measurement error at the company level, there are benefits from looking at industry aggregates. Table IV breaks down the full-period risk premium estimates by broad industry groups. The results weight each firm in the industry equally. We obtain similar results

Table II. Cross-Section Regressions

The table presents the results of cross-section regressions of *ex ante* risk premium estimates and systematic risk estimates for individual firms. We use ordinary least squares, with *ex ante* risk premium estimates as the dependent variable and firm beta against indicated market portfolio as independent variable. The numbers in parenthesis are the corresponding *t*-statistics.

	Versus Domestic Beta			Versus Global Beta			
Year	Intercept	Slope	R-Sq	Intercept	Slope	R-Sq	#Obs
1998	0.062 (35.07)***	0.025 (13.73)***	0.065	0.065 (38.39)***	0.025 (12.45)***	0.054	2718
1997	0.059 (46.08)***	0.020 (15.45)***	0.050	0.067 (62.89)***	0.026 (10.99)***	0.026	4590
1996	0.053 (43.91)***	0.023 (19.79)***	0.079	0.063 (65.33)***	0.021 (14.87)***	0.046	4544
1995	0.053 (45.99)***	0.020 (20.74)***	0.088	0.059 (57.29)***	0.027 (17.04)***	0.061	4439
1994	0.043 (35.78)***	0.026 (25.85)***	0.129	0.05 (40.52)***	0.037 (18.69)***	0.072	4503
1993	0.048 (38.14)***	0.028 (25.43)***	0.126	0.056 (44.79)***	0.039 (18.99)***	0.074	4489
1992	0.041 (27.73)***	0.027 (20.57)***	0.087	0.042 (28.77)***	0.037 (20.38)***	0.086	4437
1991	0.036 (22.29)***	0.031 (21.99)***	0.100	0.043 (27.05)***	0.034 (17.61)***	0.067	4357
1990	0.035 (20.00)***	0.033 (20.86)***	0.092	0.047 (28.44)***	0.026 (13.99)***	0.044	4287
1989	0.039 (25.59)***	0.025 (17.87)***	0.070	0.049 (35.32)***	0.017 (11.97)***	0.038	4222
1988	0.039 (24.17)***	0.023 (15.60)***	0.057	0.048 (31.53)***	0.016 (11.29)***	0.031	4015
1987	0.037 (23.05)***	0.024 (16.90)***	0.068	0.048 (32.75)***	0.016 (10.88)**	0.029	3929
1986	0.057 (42.63)***	0.017 (14.19)***	0.050	0.065 (49.90)***	0.011 (8.33)***	0.018	3835
1985	0.045 (40.69)***	0.012 (12.06)***	0.037	0.051 (45.47)***	0.007 (6.96)***	0.013	3770
1984	0.045 (38.79)***	0.008 (7.27)***	0.015	0.05 (43.15)***	0.003 (2.67)***	0.002	3605
1983	0.053 (45.93)***	0.011 (10.23)***	0.030	0.057 (50.04)***	0.007 (6.87)***	0.014	3414
1995-1998	0.058 (88.77)***	0.020 (32.61)***	0.061	0.063 (113.76)***	0.023 (29.25)***	0.050	16,291
1991-1994	0.042 (61.55)***	0.028 (46.34)**	0.108	0.054 (82.29)***	0.027 (29.93)***	0.048	17,786
1987-1990	0.038 (46.83)***	0.026 (35.09)***	0.070	0.051 (68.49)***	0.016 (21.31)***	0.027	16,453
1983-1986	0.049 (79.50)***	0.013 (22.82)***	0.034	0.057 (92.38)***	0.006 (10.27)***	0.007	14,624
1983-1998	0.049 (138.64)***	0.020 (64.27)***	0.059	0.065 (215.79)***	0.006 (18.81)***	0.005	65,154

***Significant at the 0.01 level.

Table III. Impact of Foreign Sales

The table displays the results of our analysis of the average absolute risk premium differences for individual firms for four groups, sorted by the ratio of foreign sales to total sales. The average ratio of foreign-to-total sales for the HIGH (MEDIUM, LOW) Foreign Sales Group is 53% (28%, 7%), respectively. Each group shows three columns, the average absolute differences between the *ex ante* estimates and those of the DCAPM (*Ex*-D), the average absolute differences between the *ex ante* estimates and those of the GCAPM (*Ex*-G), and the percentage of cases in which the *ex ante* estimate is closer to the DCAPM estimate than to GCAPM estimate (%DCAPM Closer). The numbers in parenthesis are corresponding *t*-statistics.

	High Foreign Sales			Medium Foreign Sales		
Year	*Ex*-D	*Ex*-G	%DCAPM Closer	*Ex*-D	*Ex*-G	%DCAPM Closer
1983	0.025	0.029	0.707(9.76)***	0.029	0.031	0.585(3.73)***
1984	0.021	0.024	0.723(10.69)***	0.027	0.028	0.620(5.36)***
1985	0.021	0.023	0.571(3.14)***	0.027	0.027	0.513(0.58)
1986	0.023	0.026	0.613(5.14)***	0.028	0.029	0.517(0.72)
1987	0.021	0.022	0.605(4.75)***	0.027	0.029	0.574(3.47)***
1988	0.023	0.024	0.561(2.76)***	0.027	0.028	0.560(2.84)***
1989	0.023	0.024	0.571(3.30)***	0.026	0.028	0.555(2.65)***
1990	0.024	0.024	0.476(-1.12)	0.028	0.027	0.519(0.89)
1991	0.031	0.030	0.443(-2.71)***	0.028	0.028	0.549(2.33)**
1992	0.029	0.026	0.353(-7.38)***	0.029	0.029	0.487(-0.62)
1993	0.028	0.024	0.405(-4.74)***	0.032	0.030	0.525(1.22)
1994	0.024	0.020	0.409(-4.55)***	0.027	0.024	0.499(-0.04)
1995	0.027	0.028	0.464(-1.79)*	0.026	0.029	0.544(2.058)**
1996	0.022	0.032	0.664(8.50)***	0.025	0.040	0.702(10.42)***
1997	0.025	0.037	0.664(8.57)***	0.025	0.047	0.788(16.91)***
1998	0.026	0.034	0.627(5.28)***	0.029	0.041	0.749(11.44)***
Average	0.025	0.027	0.546(8.55)***	0.028	0.031	0.578(14.51)***
	Low Foreign Sales			Zero Foreign Sales		
Year	*Ex*-D	*Ex*-G	%DCAPM Closer	*Ex*-D	*Ex*-G	%DCAPM Closer
1983	0.036	0.036	0.499(-0.04)	0.027	0.029	0.518(0.88)
1984	0.029	0.028	0.530(1.27)	0.025	0.026	0.54(2.01)**
1985	0.028	0.030	0.639(6.31)***	0.029	0.031	0.585(4.48)***
1986	0.032	0.032	0.532(1.41)	0.028	0.032	0.649(8.11)***
1987	0.027	0.027	0.579(3.59)***	0.026	0.031	0.682(10.27)***
1988	0.025	0.026	0.511(0.49)	0.024	0.027	0.611(6.01)***
1989	0.026	0.027	0.579(3.82)***	0.022	0.024	0.579(4.19)***
1990	0.027	0.028	0.559(2.80)***	0.026	0.027	0.482(-0.97)
1991	0.025	0.027	0.533(1.59)	0.026	0.025	0.414(-4.66)***
1992	0.029	0.030	0.526(1.24)	0.026	0.025	0.484(-0.85)
1993	0.030	0.031	0.542(2.04)**	0.026	0.032	0.551(2.80)***
1994	0.025	0.024	0.503(0.17)	0.024	0.029	0.57(3.92)***
1995	0.026	0.027	0.506(0.29)	0.031	0.036	0.634(7.55)***
1996	0.026	0.027	0.554(2.66)***	0.033	0.040	0.611(6.19)***
1997	0.027	0.031	0.557(2.80)***	0.034	0.038	0.534(1.89)*
1998	0.030	0.032	0.512(0.49)	0.033	0.033	0.526(1.22)
Average	0.028	0.029	0.541(7.67)***	0.027	0.030	0.561(12.99)***

***Significant at the 0.01 level.
**Significant at the 0.05 level.
*Significant at the 0.10 level.

Table IV. Risk Premium Estimates and Differences by Industry

The table shows the breakdown of the full-period risk premium estimates by broad industry groups. The reported results weight each firm in the industry equally. Columns two to nine, respectively, show the total number observations (#Obs), the average *ex ante* risk premia (*Ex Ante*), the average domestic beta estimates (β_{iD}), the average global beta estimates (β_{iG}), the average DCAPM industry risk premium estimate (RP_D), the average GCAPM industry risk premium estimate (RP_G), the average absolute differences between the *ex ante* estimates and those of the DCAPM (*Ex*-D), and the average absolute differences between the *ex ante* estimates and those of the GCAPM (*Ex*-G), and the percentage of cases in which the *ex ante* estimate is closer to the DCAPM estimate than to GCAPM estimate (%DCAPM Closer). The numbers in parenthesis are the corresponding *t*-statistics. Rows in italics indicate *Ex*-G lower than *Ex*-D.

Industry	#Obs	*Ex Ante*	β_{iD}	β_{iG}	RP_D	RP_G	*Ex*-D	*Ex*-G	%DCAPM Closer

with value weighting. Also, the DCAPM industry risk premium estimates with the CRSP Value-Weighted Index are very close to the estimates we report for the S&P 500 Index.

Since the DCAPM provides the better overall fit, the DCAPM will have the better fit for many industries. The GCAPM provides a slightly better fit for a few of the industry groups, Banks, Construction, Finance, Health, and Wholesale. For industry groups such as Computers, Food, Machines, Retail, and Toys, the DCAPM provides a significantly better overall fit with the *ex ante* estimates than does the GCAPM.

E. Further Analysis of Industry Risk Premium Estimates

Table V reports the results of cross-section regressions using the industry risk premium estimates for the period 1983-1998, and estimates obtained from other approaches by Fama and French (1997) and Gebhardt et al. (2001). We excluded the Ships and Fun industries, which only had one firm each in our sample.

The most striking result in Table V is that the *ex ante* industry risk premium estimates have an r-square of 31.6% (a correlation of about 0.56) with the Fama-French DCAPM estimates. The Fama-French DCAPM industry estimates even outperform our own DCAPM industry estimates in explaining our *ex ante* industry estimates, even though the Fama-French time span is different, 1963-1994. Perhaps the explanation has to do with investors using more than five years of realized returns as the basis for expectations, or viewing the one-month Treasury bill (used by Fama and French) as the risk-free security instead of the 20-year T-bond used in this study. Both of the DCAPM industry estimates outperform the GCAPM industry estimates.

The r-square of the *ex ante* industry risk premium estimates and the Fama-French (1997) industry risk premium estimates for the 3-Factor Model is only 5.79% (a correlation coefficient of 0.24). Thus, the *ex ante* industry risk premium estimates have a much better fit with the Fama-French DCAPM industry estimates than with those of the 3-Factor Model. This finding is consistent with similar findings reported by Kaplan and Ruback (1995) and Brav et al. (2003). The results with the CRSP Value-Weighted Index as the DCAPM benchmark are very close to those reported with the S&P 500 Index.

Gebhardt et al. (2001) determined their *ex ante* risk premium estimates by using the residual income model from the full period 1979-1995, with the ten-year T-bond serving as the risk-free security. The Gebhardt-Lee-Swaminathan industry risk premium estimates have a very low correlation with our DCAPM and GCAPM estimates, with the Fama-French (1997) DCAPM and 3-Factor Model estimates, and with our *ex ante* industry estimates.

IV. Conclusion

We compare *ex ante* expected return estimates, which are implicit in share prices, analysts' growth forecasts, and the dividend growth model, with expected return estimates from the global CAPM and the domestic (US) CAPM. We use the MSCI World Index as the market benchmark for computing betas for the global CAPM, and both the S&P 500 Index and the CRSP Value-Weighted Index as the market benchmark for computing betas for the domestic CAPM. Our sample comprises S&P 500 companies over the period 1983-1998. We find that the domestic CAPM has a better fit with the dispersion of *ex ante* expected return estimates, overall and for all subsamples, based on the ratio of foreign sales to total sales. We observe no trend in this fit over time. While the domestic model provides a better fit of our data, the relatively small empirical difference between the models suggests that for estimating the

Table V. Cross-Section Regressions with Industry Risk Premium Estimates

Panel A displays the results of cross-section regressions. We use our industry *ex ante* risk premium estimates for the period 1983-1998 compared to industry average risk premium estimates from the DCAPM, the GCAPM, and estimates reported in Fama and French (1997) and Gebhardt, Lee, and Swaminathan (2001). Panel B shows the results of cross-section regressions using the Gebhardt, Lee, and Swaminathan (2001) *ex ante* risk premium estimates (from the residual income model for the overall time period 1979-1995) compared to industry average risk premium estimates from the DCAPM, the GCAPM, and estimates reported in Fama and French (1997). The numbers in parenthesis are the corresponding *t*-statistics.

Panel A. Dependent Variable: Ex Ante Industry Risk Premium Estimate

Independent Variable	Intercept	Slope	R- Square
Industry Risk Premium Estimates:			
--Our DCAPM	4.442(4.51)***	0.370(2.92)***	19.58%
--GCAPM	4.775(3.73)***	0.325(1.96)**	9.99%
--Our Fama-French DCAPM	2.861(2.58)***	0.773(4.02)***	31.60%
--Fama-French 3-Factor	8.218(11.86)***	-0.154(-1.47)	5.79%
--Gebhardt-Lee-Swaminathan	7.241(17.03)***	0.005(0.04)	0.00%

Panel B. Dependent Variable: Industry Risk Premium Estimate of Gebhardt-Lee-Swaminathan

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CA-RIR-20

Ref: RT-20, page 50.

Please provide copy of articles cited in footnotes 6-10

Dr. Morin's Response:

The Chan-Lakonishok, Kothari-Shanken-Sloan, Kim and Jagannathan-Wang articles are enclosed as pages 2 to 115 of this response. The articles are voluminous and therefore only one copy will be provided to the Consumer Advocate, Department of Defense, and the Commission. Dr. Morin does not have access to the Black article. This article is available at most university libraries.

Note: Most (if not all) of the information requested is copyrighted. The attached copy is being provided under the "fair use" exception to the copyright laws. Any copies made of the attachment are subject to copyright laws.

Due to the voluminous nature of the information, one copy (pages 2 to 115) will be provided to the Consumer Advocate, Department of Defense and the Commission under separate transmittal.

CA-RIR-21

Ref: RT-20, page 67.

Please indicate the dates for each allowed ROE decision cited on this page.

Dr. Morin's Response:

See document provided in response to CA-RIR-16.

CA-RIR-22

Ref: RT-20, page 74-75.

Please indicate if Dr. Morin is aware of any academic or other studies that demonstrate that all investors rely exclusively on analysts' forecasts in making investment decisions. Please identify and provide copy of any studies cited.

Dr. Morin's Response:

Extensive academic research in the past two decades has documented and confirmed repeatedly the overwhelming superiority of analysts' earnings forecasts over the uni-variate time-series forecasts. This latter category includes many ad hoc forecasts from statistical models, ranging from the naive methods of simple averages, moving averages, etc. to the sophisticated time-series techniques such as the Box-Jenkins modeling techniques.

In other words, this literature suggests that analysts' earnings forecasts incorporate all the public information available to the analysts and the public at the time the forecasts are released. Furthermore, these forecasts are statistically more accurate than forecasts solely based on historical earnings, dividends, book value equity, and the like.

This finding is based on research on data from 1950s to 1980s. Important papers include Brown and Rozeff (1978), Cragg and Malkiel (1982), Harris (1986), Vander Weide and Carleton (1988), and Lys and Sohn (1990). The Brown-Rozeff and Vander Weide – Carleton papers are attached. The cited sources were consulted by Dr. Morin at the university library and are available from most university libraries. A summary of these papers follows.

Summary of Papers Reviewed

Lawrence D. Brown and Michael S. Rozeff, 1978, **The Superiority of Analyst Forecasts as Measures of Expectations: Evidence from Earnings**, Journal of Finance, Vol. XXXIII, No. 1, pp. 1 to 16

Using data (1951 to 1975) from 50 non-utility firms, the authors compared forecasting errors between forecasts reported in Value Line Investment Survey and forecasts from a sophisticated time-series methodology (Box-Jenkins). They concluded that "Value Line Investment Survey consistently makes significantly better earnings forecasts than the BJ [Box-Jenkins] and naive time series models." (p.13)

J. Cragg and B. G. Malkiel, Expectations and the Structure of Share Prices, National Bureau of Economic Research, University of Chicago Press, 1982

See quotation below from Harris (1986).

Robert S. Harris, 1986, **Using Analysts' Growth Forecasts to Estimate Shareholder Required Rates of Return**, Financial Management, Spring 1986, pp. 58 - 67

The main focus of this paper was to derive required return on equity using expected rather than historical earnings growth rates. Harris used IBES consensus earnings forecasts as a proxy for investor expectation. In his review of the literature on financial analysts' forecasts (FAF), Harris wrote:

> Moreover, a growing body of knowledge shows that analysts' earnings forecasts are indeed reflected in stock prices. Such studies typically employ a consensus measure of FAF calculated as a simple average of forecasts by individual analysts. Elton, Gruber, and Gultekin show that stock prices react more to changes in analysts' forecasts of earnings than they do to changes in earnings themselves, suggesting the usefulness of FAF as a surrogate for market expectations. In an extensive NBER study using analysts' earnings forecasts, Cragg and Malkiel conclude "the expectations formed by Wall Street professionals

> get quickly and thoroughly impounded into the prices of securities. Implicitly, we have found that the evaluations of companies that analysts make are the sorts of ones on which market valuation is based." (p.59, footnote omitted)

James H. Vander Weide and Willard T. Carleton, 1988, **Investor Growth Expectations: Analysts vs. History**, The Journal of Portfolio Management, Spring 1988, pp. 78 - 82

This paper updated the study by Cragg and Malkiel (1982), which suggests that the stock valuation process embodies analysts' forecasts rather than historically based growth figures such as the ten-year historical growth in dividends per share or the five-year growth in book value per share. (The Cragg and Malkiel study is based on data for the 1960s).

In this paper, the authors used data from 1971- 1983 for approximately sixty-five utility firms. They "found overwhelming evidence that the consensus analysts' forecasts of future growth is superior to historically oriented growth measures in predicting the firm's stock price." Their results "also are consistent with the hypothesis that investors use analysts' forecasts, rather than historically oriented growth calculations, in making stock buy-and-sell decisions." (p. 81)

Thomas Lys and Sungkyu Sohn, 1990, **The Association between Revisions of Financial Analysts' Earnings Forecasts and Security-Price Changes**, Journal of Accounting and Economics, vol. 13, pp. 341 - 363

Using virtually all publicly available analyst earnings forecasts for a sample of 58 companies in the 1980 - 86 period (over 23,000 individual forecasts by 100 analyst firms), the authors showed that stock returns responded to individual analyst earnings

forecasts, even when they were closely preceded by earnings forecast made by other analysts or by corporate accounting disclosures.

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The Journal of FINANCE

VOL. XXXIII MARCH 1978 NO. 1

THE SUPERIORITY OF ANALYST FORECASTS AS MEASURES OF EXPECTATIONS: EVIDENCE FROM EARNINGS

LAWRENCE D. BROWN AND MICHAEL S. ROZEFF*

ACCURATE MEASUREMENT OF EARNINGS expectations is essential for studies of firm valuation, cost of capital and the relationship between unanticipated earnings and stock price changes. Under the rational expectations hypothesis [23], market earnings expectations should be measured by the best available earnings forecasts. Univariate time series forecasts are often used for this purpose ([1], [3], [4], [5], [12], [13], [14], [16], [18], [20]) instead of direct measures of earnings expectations such as security analysts' forecasts. Univariate time series forecasts neglect potentially useful information in other time series and therefore do not generally provide the most accurate possible forecasts [24]. Since security analysts process substantially more data than the time series of past earnings, their earnings forecasts *should* be superior to time series forecasts and provide better measures of market earnings expectations.

However, the mere existence of analysts as an employed factor in long run equilibrium means that analysts *must* make forecasts superior to those of time series models. To reach this conclusion, one need only assume that participants in the market for forecasts act in their own best interests and that both forecast producers and consumers demand forecasts solely on the basis of their predictive ability.[1] Since analysts' forecasts cost more than time series forecasts, the continued employment of analysts by profit-maximizing firms implies that analysts' forecasts must be superior to those of the lower cost factor, time series models.

Past comparisons of analysts' forecasts to sophisticated time series models conclude that analysts' forecasts are not more accurate than time series forecasts (Cragg and Malkiel (CM) [9]; Elton and Gruber (EG) [11]). This evidence plainly conflicts with basic economic theory. Hence, the predictive accuracy of analysts' forecasts is re-examined in this paper. In contrast with other studies, the results overwhelmingly favor the superiority of analysts over time series models.

Part I considers statistical tests and experimental design. Part II contains the empirical results. Summary and implications appear in Part III.

*College of Business Administration, The University of Iowa, Iowa City.

1. We assume that forecast purchasers do not derive nonmonetary benefits from forecasts.

I. Experimental Design

A. *Statistical Evaluation of Forecast Methods*

Without direct information on the costs of imperfect forecasts to forecast users, comparative forecast accuracy is usually evaluated by comparing the error distributions of different forecast methods statistically. However, statistical comparisons in past studies ([9], [11]) utilize test statistics improperly, particularly Theil's U [25] and Student's t. In this section, after discussing the defects of these statistics for evaluating two or more forecast methods, the alternative statistical methods used in this study are introduced.[2]

Theil's U-statistic (applied to earnings) is the square root of

$$U_{ij}^2 = \frac{\sum_{t=1}^{T} (\dot{P}_{ijt} - \dot{A}_{it})^2}{\sum_{t=1}^{T} \dot{A}_{it}^2},$$

where $\dot{A}_{it}$ = change in actual earnings per share of firm i from $t-1$ to t,
$\dot{P}_{ijt}$ = predicted change in earnings per share of firm i from $t-1$ to t by forecast method j, and
T = total number of time series observations.

For its computation, it requires *time series* data on a firm's earnings *changes*.[3] Given forecast method j and earnings time series data on firm i, Theil's U compares the forecast accuracy of method j to that of a naive, no change, earnings forecast model.[4,5] Since analysts' earnings forecasts are currently available only in short time series, use of Theil's U for comparative forecast evaluation necessarily relies on small samples.[6] Larger sample sizes are possible by testing forecast methods on a cross-section of firms. Finally, no procedure is available with tests of significance which uses Theil's U to compare two forecast methods when neither is a no-change method. Direct hypothesis tests are preferable to inferences drawn from ranking the U statistics of different forecast methods.

For hypothesis tests of two forecast methods, an appropriate design is a one-sample or matched pairs case with self-pairing by firm. The members of each pair

2. Past studies also contain experimental biases: CM compare analysts' five-year forecasts with realizations over three and four-year horizons; EG compare analysts' forecasts with the "best" of nine time series models selected from the same time period in which comparisons with analysts' forecasts are made. This procedure introduces *ex post* selection bias.

3. EG computed "Theil's U" using earnings *levels* rather than *changes*. This statistic has unknown sampling properties.

4. $\dot{P}_{ijt} = \dot{A}_{it}$ and $U_{ij} = 0$ if prediction is perfect in every period. If no change is predicted in each period (i.e., $\dot{P}_{ijt} = 0$), $U_{ij} = 1$; $0 < U_{ij} < 1$ if prediction is less than perfect but better than the no-change prediction and $U_{ij} > 1$ if forecast method j is less accurate than the no-change prediction.

5. CM used *cross-sectional* rather than temporal data. This "Theil's U" statistic has unknown sampling properties because each error is drawn from a different error distribution, one for each firm.

6. EG's sample size in computing Theil's U varied between two and six.

are the errors from the two methods; the matched pair is reduced to a single observation by taking the difference in the errors. The usual parametric test of the mean difference is the paired t-test [17]. An alternative non-parametric test of the median difference is the Wilcoxon Signed Ranks test [8].

The parametric paired t-test is inappropriate for testing mean error differences of forecast methods applied to cross-section earnings data. If applied to error measures stated in level form (e.g., $|P_{ijt} - A_{it}|$, where P_{ijt} = firm i's forecasted earnings per share for period t by method j and A_{it} = firm i's actual earnings per share in period t), the test's assumption that paired differences are drawn from the same population is violated since each error difference depends upon each firm's earnings per share level. If applied to error measures stated in ratio form (e.g., $|P_{ijt} - A_{it}|/|A_{it}|$), the distributional assumptions of the paired t-test are also unlikely to be fulfilled since ratio measures applied to earnings per share data are dominated by outliers because actual earnings per share are often close to zero.[7]

Meaningful pairwise comparisons require test statisties which are insensitive to error definition and outliers. We adopt the Wilcoxon Signed Ranks test which meets these requirements and has power comparable to the parametric paired t-test [8, p. 213].

For tests of several forecast methods, the generalization of the paired t-test, two-way analysis of variance, is inapplicable.[8] The Friedman test [8], which is based on two-way analysis of variance by ranks and is independent of error definition, is used instead.

For an error measure, we choose relative error ignoring sign, $|P_{ijt} - A_{it}|/|A_{it}|$, a metric which is likely to be of interest to forecast purchasers.[9] In any event, the Wilcoxon test statistic is insensitive to error definition (see fn. 16).

B. *Forecast Horizon*

Because economic theory provides no guidance concerning the association of analyst superiority with a particular forecast horizon, several horizons should be investigated.[10] Our choice of horizons reflects the following considerations: (i) micro-level information obtained by analysts often concerns earnings of the following several quarters or fiscal year; (ii) current fiscal and monetary policies affect earnings of the subsequent one to five quarters; (iii) published forecasts are available mainly for short horizons. We thus investigate point estimates of quarterly earnings per share for forecast horizons of one to five quarters. We also examine annual earnings forecasts. The basic time series data are quarterly primary

7. EG's cross-section parametric t-test is inappropriate. Their use of an error measure stated in terms of levels squared (mean square error) appears to compound the inherent difficulty in applying the paired t-test to cross-section earnings data (see fn. 16).

8. Preliminary tests indicated serious violation of the homogeneity of variances and additivity assumptions, basically because of error outliers. Violation of the ANOVA assumptions also prevents application below of a factorial design with sample year and forecast horizon as factors, forecast method as treatment and firm as replication.

9. For a discussion of the deficiencies of using $|P_{ijt}|$ or $|P_{ijt} + A_{it}|/2$ in the denominator see [25].

10. The forecast horizons studied in the past have been five years (CM) and one year (EG).

earnings per share before extraordinary items, adjusted for stock splits, stock dividends and other capitalization changes for the years 1951–1975.

Ex ante conditional predictions of all forecast methods are determined as follows for a sample of 50 firms for each of the four years 1972–1975. Starting with third quarter 1971 earnings (III/1971), conditional earnings per share predictions for the ith firm by the jth method are obtained for the individual quarters of 1972. The forecasts of 1972 quarterly earnings, conditional on III/1971, are denoted P_{ij}(I/1972|III/1971), P_{ij}(II/1972|III/1971), P_{ij}(III/1972|III/1971) and P_{ij}(IV/1972|III/1971). Moving ahead one quarter, predictions are again obtained for each of the four quarters of 1972 made conditional upon IV/1971 earnings data. Again moving ahead one quarter, predictions are obtained for the last three quarters of 1972 conditional upon knowledge of I/1972 earnings, etc. Table 1 shows the set of 1972 predictions so obtained. With these conditional predictions, relative forecast errors ignoring sign are computed for each forecast method j over five distinct quarterly forecast horizons for use in the quarterly error comparisons. Annual earnings forecasts for 1972 are the sum of the forecasts P_{ij}(I/1972|IV/1971), P_{ij}(II/1972|IV/1971), P_{ij}(III/1972|IV/1971), and P_{ij}(IV/1972|IV/1971), that is, the one to four period ahead point forecasts made conditional upon knowledge of the prior year's fiscal earnings.[11] After obtaining analogous forecasts for the years 1973, 1974 and 1975, quarterly and annual comparisons are repeated for these years.

TABLE 1

SUMMARY OF PREDICTIONS BY FORECAST HORIZON FOR 1972[a,b]

1 Quarter Ahead	2 Quarters Ahead	3 Quarters Ahead	4 Quarters Ahead	5 Quarters Ahead[c]
P_{ij}(I/1972|IV/1971)	P_{ij}(I/1972|III/1971)			
P_{ij}(II/1972|I/1972)	P_{ij}(II/1972|IV/1971)	P_{ij}(II/1972|III/1971)		
P_{ij}(III/1972|II/1972)	P_{ij}(III/1972|I/1972)	P_{ij}(III/1972|IV/1971)	P_{ij}(III/1972|III/1971)	
P_{ij}(IV/1972|III/1972)	P_{ij}(IV/1972|II/1972)	P_{ij}(IV/1972|I/1972)	P_{ij}(IV/1972|IV/1971)	P_{ij}(IV/1972|III/1971)

[a] Predictions missing from the table (e.g., P_{ij}(I/1972|II/1971), P_{ij}(II/1972|II/1971) are absent because our source of analyst data does not contain these forecasts.

[b] i and j refer to firm i and method j, respectively.

[c] Five quarter ahead are available for BJ and V only.

C. *Time Series Models and Analysts' Forecasts*

Within the class of univariate time series models, Box and Jenkins (BJ) [6] models are highly regarded for their ability to make the most efficient use of the time series data. The BJ modelling technique enables one to select the most appropriate time series model consistent with the process generating each firm's time series of quarterly earnings per share data. BJ models, by not making *a priori* assumptions about the processes generating the data, subsume

11. Beaver [1] concludes that a quarterly approach to predicting annual earnings is at least as good as an annual approach to predicting annual

moving average and mixed models as special cases.[12] Forecasts of individually fitted BJ models should, therefore, perform better than forecasts of a particular class of time series models applied to all firms' time series data. We adopt the BJ modelling technique in this paper. Two other time series models are also included, a "seasonal martingale" (denoted M) and a "seasonal submartingale" (S). These models have been used as standards of comparison in the earnings forecast literature and are available for forecast producers and users at minimal cost.

As a source of analysts' forecasts we choose the Value Line Investment Survey since it contains one to five quarter ahead earnings forecasts which can be accurately dated and measured. Value Line makes earnings forecasts for 1,600 firms in contrast with institutional research firms which provide fewer, more expensive forecasts. Our hypothesis test thus compares a relatively sophisticated time series model with an "average" source of analysts' forecasts.

BJ conditional forecasts are obtained by standard methods after identifying and estimating each firm's appropriate model [6].[13] Value Line's conditional forecasts are taken directly from individual issues of the Value Line Investment Survey. The Survey, published weekly, makes quarterly earnings predictions four times a year for each firm included.

To define conditional forecasts of the naive models for each firm i, let A_{it} denote the tth actual quarterly earnings per share for firm i, where $t = 1,\ldots,96$ (I/1951–IV/1974).

Seasonal submartingale (S) conditional one to four quarter ahead forecasts at time t are

one quarter ahead	$A_{it-3}+(A_{it}-A_{it-4})$
two quarters ahead	$A_{it-2}+(A_{it}-A_{it-4})$
three quarters ahead	$A_{it-1}+(A_{it}-A_{it-4})$
four quarters ahead	$A_{it}\quad+(A_{it}-A_{it-4})$.

Seasonal martingale (M) conditional one to four quarter ahead forecasts made in period t are A_{it-3}, A_{it-2}, A_{it-1}, and A_{it}. M's forecasts for a given quarter do not change as actual earnings per share data become available. S modifies M's forecasts with the change of the latest period's quarter over that of the previous year.

Actual quarterly earnings data are announced for most firms approximately five to six weeks into the subsequent quarter. Time series forecasts then become

12. The *ad hoc* time series models used in previous studies at a time when BJ techniques were unavailable are special cases of BJ models.

13. Recent research by Froeschle [15] and diagnostic tests of Dent and Swanson [10] were helpful in identifying the BJ models in addition to the standard diagnostic tests. As an aid to identifying the BJ models, most of which had multiplicative seasonal components, theoretical autocorrelation and partial autocorrelation functions for many quarterly multiplicative seasonal models were obtained. The coefficients of the BJ models, estimated with data through IV/1974, were not re-estimated with less data for earlier periods or more data for later periods. Foster [13] has shown that coefficient re-estimation of BJ quarterly earnings models is unnecessary due to its negligible effect on forecast errors. In any event, our procedure (no re-estimation) favors BJ in nearly all comparisons with Value Line.

possible and Value Line forecasts are published, on average, forty to fifty days later.[14]

The pattern of forecasts for all models is summarized in Table 1. Note that models *M* and *S* are not used to generate five quarter ahead forecasts.

II. Empirical Results

A. *Sample Selection*

Fifty firms were randomly selected from Moody's Handbook of Common Stocks. Each firm has complete quarterly earnings data available from 1951, is included in the Value Line Investment Survey since 1971 and has a December fiscal year. The resulting sample (Appendix A) is representative of the New York Stock Exchange firms included in Moody's and Value Line. Utilities were excluded due to insufficient quarterly earnings data. Sample sizes are reduced in those rare instances when the Value Line conditional forecasts are unavailable.

B. *Annual Comparisons*

The error distributions of relative annual forecast errors are shown in Table 2 for each of the years 1972–75 using the four forecast methods, seasonal martingale (*M*), seasonal submartingale (*S*), Box-Jenkins (BJ) and Value Line (*V*). Table 2 also contains Friedman test statistics (Chi-square with 3 degrees of freedom) and Wilcoxon test statistics (Student's t with $N-1$ degrees of freedom where N is sample size). The Friedman test statistic examines the null hypothesis that *all four* error distributions are identically distributed; the Wilcoxon statistic tests the null hypothesis that the median error difference of *two* methods being compared exceeds zero.

Using the Friedman test, the null hypothesis is rejected at the 1% level in 1972, 1973 and 1975. In the 12 pairwise hypothesis tests of *V*'s errors against those of *M*, *S*, and BJ, the sign of the Wilcoxon test statistic favors Value Line in every instance. Statistical significance occurs 8 times; 6 times at the 1% level and twice at the 5% level. Thus, *V* generally produces smaller annual errors than the three time series models suggesting that Value Line annual earnings forecasts are superior to those of time series models.

As argued earlier, BJ forecasts should be superior to forecasts of *ad hoc* time series models. The annual comparisons show that the BJ models generally yield smaller forecast errors than the other time series models studied. In 8 comparisons with *M* and *S*, the Wilcoxon test favors BJ 7 times with statistical significance 3 times. These findings suggest that BJ's forecasts are superior to those of *ad hoc* naive time series models.

While the annual results provide strong support for the hypothesis of analyst superiority, they use only a fraction of the data. More powerful tests are achieved using the larger sample sizes of the quarterly data and many more comparative tests can be performed with these data. We turn next to quarterly comparisons.

14. The time interval from announcement to forecast varies from approximately 7 to 70 days for our sample firms. The fact that the Investment Survey, published in 13 installments, makes forecasts for different firms each week accounts for the variation.

TABLE 2

WILCOXON AND FRIEDMAN TEST STATISTICS AND ERROR DISTRIBUTIONS, ANNUAL COMPARISONS OF VALUE LINE AND TIME SERIES MODEL PREDICTION ERRORS, 1972–1975[c]

1972
Error Distribution[d]

	< .05	.05 – .10	.10 – .25	.25 – .50	.50 – .75	.75 – 1.00	> 1.00
M	3	7	14	17	4	3	2
S	11	6	12	10	3	1	7
BJ	10	6	12	12	4	1	5
V	13	7	17	12	0	0	1

SAMPLE SIZE = 50
Friedman Statistic = 27.10[a]
Wilcoxon Statistics[e]

	S	BJ	*V*
M	−.55	.24	4.46[a]
S		.46	3.50[a]
BJ			3.45[a]

1973
Error Distribution[d]

	< .05	.05 – .10	.10 – .25	.25 – .50	.50 – .75	.75 – 1.00	> 1.00
M	2	6	16	18	6	0	2
S	11	8	14	9	4	1	3
BJ	8	6	15	16	3	0	2
V	10	9	13	16	0	0	2

SAMPLE SIZE = 50
Friedman Statistic = 33.19[a]
Wilcoxon Statistics[e]

	S	BJ	*V*
M	3.15[a]	2.51[a]	4.61[a]
S		−1.89[b]	0.34
BJ			2.17[b]

1974
Error Distribution[d]

	< .05	.05 – .10	.10 – .25	.25 – .50	.50 – .75	.75 – 1.00	> 1.00
M	8	6	12	15	4	1	4
S	12	3	11	12	6	2	4
BJ	5	8	16	13	4	0	4
V	6	7	15	13	5	0	4

SAMPLE SIZE = 50
Friedman Statistic = 4.68
Wilcoxon Statistics[e]

	S	BJ	*V*
M	−.21	2.37[a]	2.23[b]
S		1.24	1.44
BJ			0.61

TABLE 2 (*continued*)

	1975 Error Distribution[d]						
	< .05	.05 – .10	.10 – .25	.25 – .50	.50 – .75	.75 – 1.00	> 1.00
M	4	7	13	10	2	3	11
S	3	5	12	7	9	4	10
BJ	7	3	13	12	2	3	10
V	7	5	18	5	3	3	9

SAMPLE SIZE = 50
Friedman Statistics = 12.84[a]
Wilcoxon Statistics[c]

	S	BJ	*V*
M	−1.77[b]	0.86	3.29[a]
S		2.99[a]	3.11[a]
BJ			1.28

[a]Significant at the 1% level, one-tailed test.

[b]Significant at the 5% level, one-tailed test.

[c]*V* = Value Line, *M* = Seasonal Martingale, *S* = Seasonal Submartingale, BJ = Box-Jenkins.

[d]Each entry below designates the number of observations for a given model whose relative error ignoring sign is within the stated fractiles.

[e]Each Wilcoxon test statistic below results from comparing the method at the top with the method on the side. Thus, positive Wilcoxon statistics indicate superiority of model on top.

C. *Quarterly Comparisons*

In each year, 1972 to 1975, quarterly forecasts are obtained for the forecast methods in the manner shown in Table 1. Relative forecast errors of all four methods are compared over 1–4 quarter forecast horizons; BJ and *V* are also compared over 5 quarter horizons. In each of the four years, sample sizes are approximately 200 for the 1 and 2 quarter ahead comparisons, 150 for the 3 quarter ahead comparisons, and 100 for the 4 quarter ahead comparisons. Test results over all horizons appear in Table 3 and are summarized in Table 4.

With minor exceptions (3 and 4 quarter horizons in 1974), the Friedman statistics are highly significant when the four methods are tested as a group; the null hypothesis of identically distributed distributions is rejected in 14 of the 16 Friedman tests. Using Wilcoxon test statistics, *V*'s errors are tested pairwise against *M*'s and *S*'s errors 16 times each and against BJ's errors 20 times. The resulting 52 hypothesis tests of *V* against *M*, *S* and BJ are summarized in Table 4A. In the 34 instances of significant Wilcoxon test statistics, *V* is statistically superior 33 times. In the remaining 18 tests, the sign of the *t*-statistic favors *V* 12 times. In total, *V* is favored 45 times out of 52, revealing an overwhelming dominance of *V* over the time series models.

The data are also summarized in Table 4 by the mean Wilcoxon *t*-value ($\bar{t}$), the estimated standard deviation of the mean *t*-value ($s(\bar{t})$) and the ratio $\bar{t}/s(\bar{t})$. The latter ratio is itself a *t*-statistic only if each *t*-value being averaged is drawn from the same distribution. Since the distribution of *t*-values is likely to depend upon the horizon, model and/or year that the experiment is conducted, we refrain from

TABLE 3

AN TEST STATISTICS, QUARTERLY COMPARISONS OF VALUE LINE AND SERIES MODEL PREDICTION ERRORS, 1972–1975[c,d]

	Forecast Horizon								
	Two Quarter		Three Quarter			Four Quarter			Five Quarter
	BJ	V	S	BJ	V	S	BJ	V	V
9	5.41[a]	6.87[a]	−1.09	2.50[a]	5.77[a]	−3.09[a]	1.41	5.22[a]	—
-	4.62[a]	5.57[a]	—	3.03[a]	5.42[a]	—	3.38[a]	5.30[a]	—
-	—	2.51[a]	—	—	4.09[a]	—	—	3.93[a]	3.11[a]
	mple Size = 200		Sample Size = 150			Sample Size = 100			Sample Size = 50
	iedman Stat. = 60.54[a]		Friedman Stat. = 41.14[a]			Friedman Stat. = 43.43[a]			
	BJ	V	S	BJ	V	S	BJ	V	V
1[a]	6.41[a]	8.70[a]	4.81[a]	3.52[a]	6.31[a]	2.55[a]	1.69[b]	4.63[a]	—
-	−1.83[b]	1.04	—	−3.57[a]	−0.02	—	−1.59	1.04	—
-	—	3.47[a]	—	—	3.34[a]	—	—	2.79[a]	1.66
	mple Size = 200		Sample Size = 150			Sample Size = 100			Sample Size = 50
	iedman Stat. = 119.91[a]		Friedman Stat. = 75.22[a]			Friedman Stat. = 29.12[a]			
S	BJ	V	S	BJ	V	S	BJ	V	V
34	4.88[a]	3.78[a]	−0.25	2.59[a]	1.29	−2.69[a]	1.41	0.29	—
-	2.31[b]	1.50	—	1.53	0.97	—	2.67[a]	2.80[a]	—
-	—	−1.45	—	—	−1.04	—	—	−0.92	−2.20[b]
	mple Size = 199		Sample Size = 149			Sample Size = 100			Sample Size = 50
	iedman Stat. = 22.63[a]		Friedman Stat. = 5.40			Friedman Stat. = 2.92			
S	BJ	V	S	BJ	V	S	BJ	V	V
64[a]	3.63[a]	5.29[a]	−4.49[a]	2.93[a]	2.95[a]	4.89[a]	−0.78	−0.05	—
-	6.02[a]	6.14[a]	—	6.13[a]	5.14[a]	—	3.62[a]	3.28[a]	—
-	—	1.62	—	—	−0.22	—	—	0.08	0.45
	mple Size = 199		Sample Size = 149			Sample Size = 100			Sample Size = 50
	riedman Stat. = 44.49[a]		Friedman Stat. = 33.25[a]			Friedman Stat. = 15.66[b]			

test.

test.

gale, S = Seasonal Submartingale, BJ = Box-Jenkins.

in the table results from comparing method at the top with method on the side. Thus, riority of model on top.

SUMMARY OF WILCOXON TEST COMPARISONS

A: Value Line vs. Time Series Models[a]

Forecast Horizon					Forecast Model			Year			
Total	1Q	2Q	3Q	4Q	5Q	M	S	BJ	1972	1973	1974	1975
52	12	12	12	12	4	16	16	20	13	13	13	13
45	12	11	9	10	3	15	15	15	13	12	9	11
33	10	8	7	7	1	13	10	10	13	8	4	8
1	0	0	0	0	1	0	0	1	0	0	1	0
3.25	4.86	3.75	2.83	2.37	.76	5.27	3.40	1.51	4.84	3.67	1.18	3.29
8.27	5.45	4.51	3.81	3.72	.67	5.65	6.24	3.48	9.98	4.18	1.81	4.24

B: BJ vs. Naive Time Series Models

Forecast Horizon					Forecast Model			Year			
Total	1Q	2Q	3Q	4Q	M	S	1972	1973	1974	1975	
32	8	8	8	8	16	16	8	8	8	8	
27	7	7	7	6	15	12	8	4	8	7	
24	7	7	6	4	13	11	7	4	6	7	
2	0	1	1	0	0	2	0	2	0	0	
3.15	4.87	3.93	2.33	1.48	3.97	2.34	3.98	1.63	3.00	4.00	
6.37	4.70	4.16	2.41	2.25	6.23	3.25	6.46	1.05	4.99	4.96	

Martingale, S = Seasonal Submartingale, BJ = Box-Jenkins.
Wilcoxon statistic in Table 3 is positive.
avorable if Wilcoxon statistic in Table 3 is positive and significant at the 5% level or

using the number of comparisons in each column of the Table.

hypothesis tests on $\bar{t}$ and present $\bar{t}$ and $\bar{t}/s(\bar{t})$ without formal tests of significance. For the 52 comparisons involving V, the mean Wilcoxon test statistic is 3.25 and $\bar{t}/s(\bar{t})$ is 8.27.

Table 4A also decomposes the 52 comparisons of V with the time series models by forecast horizon, model and year.[15] The data show that Value Line's forecast superiority holds over all horizons studied with a tendency for its superiority to decline as horizon lengthens. V's predominance model-by-model is, as hypothe-

are not confined to particular models, horizons, or years. The very general character of Value Line's superiority in predicting earnings, evidenced over all models, horizons, and years in 64 separate hypothesis tests involving sample sizes averaging 125, lends extraordinary support to the hypothesis of analyst superiority.

D. *Further Analysis*

The superiority of Value Line over time series models follows from the rational behavior of forecast producers and consumers and should be generalizable to other sources of analyst forecasts and other time periods. As a preliminary test of the sensitivity of our results to choice of analyst, we obtained predictions of 1975 annual earnings per share made by the Standard and Poor's Earnings Forecaster (SP) for each firm included in the 1975 annual earnings sample.[17] Wilcoxon tests of SP against M, S, and BJ favored SP, yielding t-statistics of 3.18, 2.85 and 1.45 respectively. These results are remarkably similar to those using Value Line.[18] This evidence suggests that Value Line's forecast superiority over time series models is not unique.

To ascertain whether the sample period posed unusual difficulties for time series earnings forecasting, a BJ model was fitted to the Quarterly Earnings Index of the Dow Jones Industrial Average over the 1951–1975 time period.[19] Average quarterly percentage errors ignoring sign produced by the BJ model for 1972–1975 were 7.31%, 6.61%, 9.99%, and 15.47% respectively. Since the mean and standard deviation of average percentage forecast errors over the 1951–1975 period were 10.14% and 4.38%, it appears that the 1972–1975 period was not a particularly difficult one in which to predict earnings. Indeed, from this standpoint, the 1972–1975 period is comparable to the "stable" years of the sixties, 1962–1967, studied by CM and EG.[20]

These results indicate that if appropriate hypothesis tests are applied to other analysts and time periods, the results are likely to parallel those using Value Line and the 1972–1975 time period.

E. *A Brief Investigation of Value Line Superiority*

To produce forecasts superior to time series models, Value Line must utilize information not contained in the time series of quarterly earnings. During the period between the most recent quarterly earnings announcement and the subsequent Value Line prediction, Value Line acquires incremental information which, if an important part of its total information set, may explain Value Line's

17. SP, published weekly, contains annual predictions made by Standard and Poor's and other investment firms. The SP prediction for each firm is that made by Standard and Poor's on the date closest to the Value Line prediction date.

18. V's t-statistics versus M, S, and BJ were 3.29, 3.11, and 1.28 respectively (See Table 2). A direct Wilcoxon test between V and SP favored V ($t = .77$).

19. The sample period, 1972–1975, may appear "unusual" since it includes peacetime wage and price controls, high inflation and inventory profits, large changes in employment and new accounting requirements. If events arising during the sample period caused the earnings generating process to change, the forecast ability of the BJ modelling technique may be hampered, unintentionally favoring the analyst.

20. The average percentage errors were 12.67%, 10.71%, 7.03%, 4.93%, 6.08% and 5.26%, respectively for 1962–1967.

superiority. Information arising during this interval is likely to be most important for predicting next quarter's earnings. Assuming that the generation of this incremental information is positively related to the passage of time, earnings should be relatively easier to predict the further Value Line's prediction date is from the most

forecasts than by those of time series models are consistent with our evidence and with market rationality.

The hypothesis of analyst superiority versus univariate time series models is derived from basic economic theory and is not limited to the case of earnings. It is therefore applicable to all types of [illegible]

Pan American World Airways, Inc.
Pepsico, Inc.
Phelps Dodge Corporation
Phillips Petroleum Co.
Pullman, Incorporated
Raybestos-Manhattan, Inc.
Republic Steel Corporation
Standard Brands, Inc.
Standard Oil Company of Indiana
Sterling Drug, Incorporated
St. Regis Paper Company
Timken Company
United States Gypsum Company
United States Steel Corporation
United Technologies Corp.
Wrigley (W. M.) Jr. Company

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Investor growth expectations: Analysts vs. history

Analysts' growth forecasts dominate past trends in predicting stock prices.

James H. Vander Weide and Willard T. Carleton

For the purposes of implementing the Discounted Cash Flow (DCF) cost of equity model, the analyst must know which growth estimate is embodied in the firm's stock price. A study by Cragg and Malkiel (1982) suggests that the stock valuation process embodies analysts' forecasts rather than historically based growth figures such as the ten-year historical growth in dividends per share or the five-year growth in book value per share. The Cragg and Malkiel study is based on data for the 1960s, however, a decade that was considerably more stable than the recent past.

As the issue of which growth rate to use in implementing the DCF model is so important to applications of the model, we decided to investigate

$$P_s = \frac{D(1+g)}{k-g} \qquad (1)$$

where:

P_s = current price per share of the firm's stock;

D = current annual dividend per share;

g = expected constant dividend growth rate; and

k = required return on the firm's stock.

Dividing both sides of Equation (1) by the firm's current earnings, E, we obtain:

$$\frac{P_s}{E} = \frac{D}{E} \cdot \frac{(1+g)}{k-g} \qquad (2)$$

Thus, the firm's price/earnings (P/E) ratio is a non-

[redacted] k in Equation (3) depends on the [redacted] We have defined "earnings" as the consensus

values of the risk variables B, Cov, Rsq, and Sa, where B is the firm's Value Line beta; Cov is the firm's pretax interest coverage ratio; Rsq is a measure of the stability the firm's five-year historical EPS; and Sa is the ndard deviation of the consensus analysts' five-year EPS growth forecast for the firm. Finally, as the linear form of the P/E equation is only an approximation to the true P/E equation, and B, Cov, Rsq, and Sa are only proxies for k, we will add an error term, e, that represents the degree of approximation to the true relationship.

With these assumptions, the final form of our P/E equation is as follows:

analyst estimate (as reported by IBES) of the firm's earnings for the forthcoming year.[1] This definition approximates the normalized earnings that investors most likely have in mind when they make stock purchase and sell decisions. It implicitly incorporates the analysts' adjustments for differences in accounting treatment among firms and the effects of the business cycle on each firm's results of operations. Although we thought at first that this earnings estimate might be highly correlated with the analysts' five-year earnings growth forecasts, that was not the case. Thus, we avoided a potential spurious correlation problem.

Price/Earnings Ratio. Corresponding to our definition of "earnings," the price/earnings ratio (P/E) is calcu-

per share growth compiled by IBES and reported in mid-January of each year. This number represents the consensus (i.e., mean) forecast produced by analysts from the research departments of leading Wall Street and regional brokerage firms over the preceding three months. IBES selects the contributing brokers "because of the superior quality of their research, professional reputation, and client demand" (IBES *Monthly Summary Book*).

Risk Variables. Although many risk factors could potentially affect the firm's stock price, most of these [illegible] highly correlated with one another. As shown above in Equation (4), we decided to restrict our attention to four risk measures that have intuitive appeal and are followed by many financial analysts: 1) B, the firm's beta as published by Value Line; 2) Cov, the firm's pretax interest coverage ratio (obtained from Standard & Poor's Compustat); 3) Rsq, the stability of the firm's five-year historical EPS (measured by the R^2 from a log-linear least squares regression); and 4) Sa, the standard deviation of the consensus analysts' five-year EPS growth forecast (mean forecast) as computed by IBES.

After careful analysis of the data used in our study, we felt that we could obtain more meaningful results by imposing six restrictions on the companies included in our study:

1. Because of the need to calculate ten-year historical growth rates, and because we studied three different time periods, 1981, 1982, and 1983, our sixty-five utility firms.[1]

RESULTS

To keep the number of calculations in our study to a reasonable level, we performed the study in two stages. In Stage 1, all forty-one historically oriented approaches for estimating future growth were correlated with each firm's P/E ratio. In Stage 2, the historical growth rate with the highest correlation to the P/E ratio was compared to the consensus analyst growth rate in the multiple regression model described by Equation (4) above. We performed our regressions for each of three recent time periods, because we felt the results of our study might vary over time.

First-Stage Correlation Study

Table 1 gives the results of our first-stage correlation study for each group of companies in each of the years 1981, 1982, and 1983. The values in this table measure the correlation between the historically oriented growth rates for the various time periods and the firm's end-of-year P/E ratio.

The four variables for which historical growth rates were calculated are shown in the left-hand column: EPS indicates historical earnings per share growth, DPS indicates historical dividend per share growth, BVPS indicates historical book value per share growth, and CFPS indicates historical cash flow per share growth. The term "plowback" refers to the

TABLE 1

Correlation Coefficients of All Historically Based Growth Estimates by Group and by Year with P/E

Historical Growth Rate Period in Years

	1	2	3	4	5	6	7	8	9	10
1981										
EPS	−0.02	0.07	0.03	0.01	0.03	0.12	0.08	0.09	0.09	0.09
DPS	0.05	0.18	0.14	0.15	0.14	0.15	0.19	0.23	0.23	0.23
BVPS	0.01	0.11	0.13	0.13	0.16	0.18	0.15	0.15	0.15	0.15
CFPS	−0.05	0.04	0.13	0.22	0.28	0.31	0.30	0.31	−0.57	−0.54
Plowback	0.19									
1982										
EPS	−0.10	−0.13	−0.06	−0.02	−0.02	−0.01	−0.03	−0.03	0.00	0.00
DPS	−0.19	−0.10	0.03	0.05	0.07	0.08	0.09	0.11	0.13	0.13
BVPS	0.07	0.08	0.11	0.11	0.09	0.10	0.11	0.11	0.09	0.09
CFPS	−0.02	−0.08	0.00	0.10	0.16	0.19	0.23	0.25	0.24	0.07
Plowback	0.04									
1983										
EPS	−0.06	−0.25	−0.25	−0.24	−0.16	−0.11	−0.05	0.00	0.02	0.02
DPS	0.03	−0.10	−0.03	0.08	0.15	0.21	0.21	0.21	0.22	0.24
BVPS	0.03	0.10	0.04	0.09	0.15	0.16	0.19	0.21	0.22	0.21
CFPS	−0.08	0.01	0.02	0.08	0.20	0.29	0.35	0.38	0.40	0.42
Plowback	−0.08									

two general conclusions regarding the pricing of equity securities.

First, we found overwhelming evidence that the consensus analysts' forecast of future growth is superior to historically oriented growth measures in predicting the firm's stock price. In every case, the R^2 ...e regression containing the consensus analysts' ...orecast is higher than the R^2 in the regression containing the historical growth measure. The regression coefficients in the equation containing the consensus analysts' forecast also are considerably more significant than they are in the alternative regression. These results are consistent with those found by Cragg and Malkiel for data covering the period 1961-1968. Our results also are consistent with the hypothesis that investors use analysts' forecasts, rather than historically oriented growth calculations, in making stock buy–and–sell decisions.

TABLE 2

Regression Results
Model I

Part A: *Historical*

$P/E = a_0 + a_1 D/E + a_2 g_a + a_3 B + a_4 Cov + a_5 Rsq - a_6 Sa$

Year	$\hat{a}_0$	$\hat{a}_1$	$\hat{a}_2$	$\hat{a}_3$	$\hat{a}_4$	$\hat{a}_5$	$\hat{a}_6$	R^2	F Ratio
1981	−6.42*	10.31*	7.67*	3.24	0.54*	1.42*	57.43	0.83	46.49
	(5.50)	(14.79)	(2.20)	(2.86)	(2.50)	(2.85)	(4.07)		
1982	−2.90*	9.32*	8.49*	2.85	0.45*	−0.42	3.63	0.86	65.53
	(2.75)	(18.52)	(4.18)	(2.83)	(2.60)	(0.05)	(0.26)		
1983	−5.96*	10.20*	19.78*	4.85	0.44*	0.33	32.49	0.82	45.26
	(3.70)	(12.20)	(4.83)	(2.95)	(1.89)	(0.50)	(1.29)		

Part B: *Analysis*

$P/E = a_0 + a_1 D/E + a_2 g_a + a_3 B + a_4 Cov + a_5 Rsq - a_6 Sa$

Year	$\hat{a}_0$	$\hat{a}_1$	$\hat{a}_2$	$\hat{a}_3$	$\hat{a}_4$	$\hat{a}_5$	$\hat{a}_6$	R^2	F Ratio
1981	−4.97*	10.62*	54.85*	−0.61	0.33*	0.63*	4.34	0.91	103.10
	(6.23)	(21.57)	(8.56)	(0.68)	(2.28)	(1.74)	(0.37)		
1982	−2.16*	9.47*	50.71*	−1.07	0.36*	−0.31	119.05*	0.90	97.62
	(2.59)	(22.46)	(9.31)	(1.14)	(2.53)	(1.09)	(1.60)		
1983	−8.47*	11.96*	79.05*	2.16	0.56*	0.20	−34.43	0.87	69.81
	(7.07)	(16.48)	(7.84)	(1.55)	(3.08)	(0.38)	(1.44)		

...s:
Coefficient is significant at the 5% level (using a one-tailed test) and has the correct sign. T-statistic in parentheses.

Second, there is some evidence that investors tend to view risk in traditional terms. The interest coverage variable is statistically significant in all but one of our samples, and the stability of the operating income variable is statistically significant in six of the twelve samples we studied. On the other hand, the beta is never statistically significant, and the standard deviation of the analysts' five-year growth forecasts is statistically significant in only two of our twelve samples. This evidence is far from conclusive, however, because, as we demonstrate later, a significant degree of cross-correlation among our four risk variables makes any general inference about risk extremely hazardous.

Possible Misspecification of Risk

The stock valuation theory says nothing about which risk variables are most important to investors. Therefore, we need to consider the possibility that the risk variables of our study are only proxies for the "true" risk variables used by investors. The inclusion of proxy variables may increase the variance of the

TABLE 3

Regression Results
Model II

Part A: *Historical*

$P/E = a_0 + a_1 D/E + a_2 g_n$

Year	$\hat{a}_0$	$\hat{a}_1$	$\hat{a}_2$	R^2	F Ratio
1981	−1.05	9.59	21.20	0.73	82.95
	(1.61)	(12.13)	(7.05)		
1982	0.54	8.92	12.18	0.83	167.97
	(1.38)	(17.73)	(6.95)		
1983	−0.75	8.92	12.18	0.77	107.82
	(1.13)	(12.38)	(7.94)		

Part B: *Analysis*

$P/E + a_0 + a_1 D/E + a_2 g_n$

Year	$\hat{a}_0$	$\hat{a}_1$	$\hat{a}_2$	R^2	F Ratio
1981	3.96	10.07	60.53	0.90	274.16
	(8.31)	(8.31)	(20.91)	(15.79)	
1982	−1.75	9.19	44.92	0.88	246.36
	(4.00)	(4.00)	(21.35)	(11.06)	
1983	−4.97	10.95	82.02	0.83	168.28
	(6.93)	(6.93)	(15.93)	(11.02)	

Notes:
* Coefficient is significant at the 5% level (using a one-tailed test)

CA-RIR-23

Ref: RT-1, Page 15, lines 22 through 25, Employee Levels.

According to the cited rebuttal testimony, "The CA contends that HECO's proposed average employee level should be reduced." Based on this statement, please respond to the following:

a. With respect to "HECO's proposed average employee level," has HECO changed its prefiled position that its year-end 2005 projected level of employees should be reflected on an annualized basis, as if all such employee positions were filled throughout the entire test year?

b. If no change in position is advocated by HECO in rebuttal testimony, please confirm that HECO has, in fact, proposed an "average" employee expense projection that actually reflects the "annualized" employee salary and wages expense projection using year-end headcounts.

c. Please provide the total number of employees at January 1, 2005 and at December 31, 2005 that were used in calculating "HECO's proposed average employee level" that is referenced in the testimony.

HECO Response:

a. No. HECO has not changed its position filed in direct testimony.

b. HECO has not changed its position filed in direct testimony. HECO proposes an "average" employee expense projection that is determined by using a 13-month average based on the forecasted total number of employees at the end of each month [illegible] HECO RT-16 [illegible]

CA-RIR-24

Ref: RT-1, page 18.
According to Mr. Alm's testimony, "the Company does not believe that the Commission should expect the Company to maintain any continuing budget austerity plans, ongoing hiring constraints or any other spending limitations in an effort to promote operations efficiency and minimize the burden of rate increases upon customers." Based on this statement, please respond to the following:

a. State every reason why a utility that has demonstrated an ability to reduce its costs of operations without compromising service quality or safety, should be allowed to include higher costs levels in determining the test year revenue requirements simply because its management claims that it desires to have higher authorized spending levels than have proven adequate historically when setting base rates.
b. Identify and describe each reason why HECO believes the Commission should not expect the Company to "promote operations efficiency and minimize the burden of rate increases upon customers."

HECO's Response

a. HECO objects to this RIR on the grounds that it is argumentative, and does not correctly state HECO's position or represent the state of the record. HECO has submitted extensive testimonies and responses to information requests that explain in exhaustive detail the reasons for the expense levels included in the 2005 test year. In addition, as explained on page 16 of HECO RT-1, a budget austerity plan cannot continue indefinitely without eventually degrading service quality and employee working conditions.

b. This question presents the referenced statement completely out of context. The Company continually strives to achieve operational and cost efficiencies, which minimize the amount of needed rate increases, and the Commission can and should expect the Company to do so, but not at the expense of operational reliability and financial integrity, and not by placing an undue burden on employees. As explained on page 16 of HECO RT-1, in the aftermath of September 11, 2001, the Company implemented a budget austerity plan to constrain costs and avoided the filing of a rate increase application. However, the Commission should not

expect the budget austerity plan to be the status quo as service quality, employee working conditions, and/or financial integrity would be negatively impacted in the long term.

CA-RIR-25

Ref: RT-1, page 18, line 3.

According to Mr. Alm's testimony, HECO, "responded to numerous specific information requests regarding its existing staffing levels, how HECO determined its optimal staffing levels, and what work would not get done with less that optimal staffing." Based on this statement, please respond to the following:

a. With regard to the many information request responses referenced at lines 4 through 7 of

managers and supervisors in the power supply area have determined, with Executive approval concurrence through the budgeting process, is needed to operate and maintain HECO's power

[redacted]

plants.

CA-RIR-26

Ref: RT-1, page 25, line 2.

According to Mr. Alm's testimony, "The CA erroneously assumes that the Company's sales will offset any rate base growth, which is simply not the case." Please provide specific page and line reference to the Consumer Advocate's direct testimony where the specific "assumption" is stated and discussed.

HECO Response:

The CA is referred to its own testimony. Mr. Alm's testimony provides the specific cites requested.

CA-RIR-27

Ref: RT-1, page 26, line 6.

According to Mr. Alm's testimony, "First, there would need to be a causal relationship such that the activity associated with the expense would cause sales to increase." Based on this statement, please respond to the following:

a. Does Mr. Alm believe that HECO will continue to add new customers and experience overall growth in kWh sales resulting in sales to increase? Explain why or why not and provide specific information relied upon to support the response.

b. Explain with specificity why HECO's customer level and kWh sales increases would be influenced by any "causal relationship" with HECO "activities associated with expenses."

c. Provide complete copies of all reports, studies, projections, workpapers and other information relied upon to support the Company's notion that HECO's sales and revenue growth is causally related to any "activity associated with the expense.

d. At line 15, Mr. Alm states, "However, it is clear that the installation of the DG units in and of itself does not cause sales to increase." Please confirm that the Consumer Advocate did not allege that the DG units had any causal relationship to ongoing HECO customers, sales and revenue growth or (in the absence of an unqualified admission) provide specific reference to the Consumer Advocate's direct testimony where such causal relationship is stated and discussed.

HECO Response:

a. As shown in HECO-RWP-203, page 18, in which HECO provided its May 2005 sales forecast ("May 2005 forecast"), HECO does forecast future sales growth. The expected sales increase in 2006 over the May 2005 forecast of sales for 2005 is approximately 2.6%. This only amounts to an approximately 1.9% increase over the higher sales estimate used for the 2005 test year. See HECO RT-2 for a comparison of the new sales forecast and the estimated test year sales.

b. For example, an increased level of advertising for a particular product could increase customer and sales levels. If such were not the case, no firm would ever use advertising to stimulate sales. The costs associated with advertising would be expensed.

c. A study is not necessary for a reasonable person to conclude that there can be a causal relationship between an expense activity and sales growth. For example, see the response to b.

d. The CA is referred to its own testimony.

CA-RIR-28

Ref: RT-1, page 22, line 19.

Mr. Alm's testimony states, "For example, the 'assumption' is made that the approved rate increase will be in effect for the full test year, even though in this case the interim increase is expected to be in effect only in the fourth quarter of 2005." Please state whether Mr. Alm believes that the Consumer Advocate has made such an "assumption" and provide specific page and line reference into the Consumer Advocate's direct testimony where such an "assumption" is believed to be stated and discussed.

HECO Response:

The referenced statement should be viewed in the context of the paragraph in which it appeared:

> Although the CA appears to argue that any annualization adjustment would "violate" the average test year concept, some major annualization adjustments are made as a matter of course that decrease the amount of the approved rate increase. For example, the "assumption" is made that the approved rate increase will be in effect for the full test year, even though in this case the interim increase is expected to be in effect only in the fourth quarter of 2005. To obtain the full increase in 2005, when it will be in effect for only one-quarter, the actual increase would have to be 4 times the authorized increase. Obviously, that would be unfair to ratepayers in the period after 2005 when the increase would continue to be in effect. Thus, the increase is "normalized", by annualizing the effect of the increase.

None of the parties has assumed that the rate increase will actually take place at the beginning of calendar year 2005. The calculation of the rate increase necessary to produce a fair rate of return, however, assumes that the rate increase is received at the beginning of the 2005 test year. For example, see CA-T-1, page 8, lines 17-19.

The rate increase is the additional revenues necessary above revenues at present rates to yield the revenue requirements (i.e., it's the difference between "revenues at present rates" and "revenues at proposed rates"). The revenue difference between is based on the annual revenues that would be received as a result of a change in rates, not the additional revenues that would be received if the increase were in effect for only part of the year. The implied assumption is that

the rate increase is received at the beginning of the year. (The annual revenues would actually be received only if the rate increase was received at the beginning of the test year.) If the assumption was that rates were increased half way through the year, then rates would have to be increased by twice as much to produce the same additional revenues in 6 months (instead of 12). All of this is stated in the testimony.

More fundamentally, since rates are set for the future, is the assumption that the relationship between revenues, expenses and rate base will remain roughly the same in the period during which the rates are expected to be in effect, so that the utility will have a reasonable opportunity to earn the return found to be fair in the future. To some extent, sales growth (resulting in revenue increases) can be expected to offset normal increases in labor expenses (due to wage and salary increases), non-labor expenses (due to inflation, in low inflation periods) and rate base (in low construction periods). (That is why HECO agreed with the CA in rate cases in the 1990's not to annualize the impact of wage and salary increases made during the test year, even though it is my understanding that the Commission commonly authorized the annualization of wages and salary increases in rate cases prior to 1990.) Sales growth should not be expected to offset expense increases for significant increases in staffing or new operational activities (such as DG at substations) that are reflected only partially in the test year O&M expenses.

CA-RIR-29

Ref: RT-1, page 20, line 4.

According to Mr. Alm's testimony, "For certain expenses, HECO is proposing to annualize the level of those expenses." Then, at line 11 of RT-1 is the statement, "Two examples in HECO's rate case are the distributed generation ("DG") units to be installed in the late third and early fourth quarters of 2005 and the filling of newly created positions, which is occurring over the course of 2005. These are "known and measurable changes...." Please respond to the following:

a. Confirm that the Consumer Advocate has not challenged the inclusion of these expenses in the test year revenue requirement on the basis that the expenses were not "known and measurable."

b. Please confirm that the Consumer Advocate has, in fact, included the Company's estimates of such costs in the test year revenue requirements, on an average, rather than annualized basis.

c. If anything but an unqualified yes is provided in response to part (a) of this information request, please explain your response and provide complete copies of all documents relied upon to support such explanation.

HECO Response:

a. The CA is referred to its own testimony. However, the C[redacted]

CA-RIR-30

Ref: RT-1, page 36, line 21.

Mr. Alm states, "Accordingly, based on the current planned investments and proposed treatment of lost margins for DSM programs, it is not unlikely that HECO's next rate case would be filed within three years from the conclusion of this proceeding." Please provide the earliest probable date on which the Company's next rate case will be filed and explain what test year would be used in such a filing.

HECO Response:

See HECO response to DOD-RIR-61.

CA-RIR-31

Ref: RT-1, pages 14-15 (Pension Asset).

The referenced testimony discusses the Company's opposition to the Consumer Advocate's proposed elimination of the pension asset from rate base. Please provide the following:

a. Has Mr. Alm previously filed testimony on the pension asset issue in any regulatory

CA-RIR-32

Ref: RT-1, page 14, lines 13-18 (Pension Asset).

In discussing why the pension asset should be included in rate base, the referenced testimony states:

> First, this ratemaking treatment would be consistent with the ratemaking treatment that has consistently been used for pension costs. Pension costs have consistently been determined under the guidance in Statement of Financial Accounting Standards No. 87 ("SFAS 87"). Recognition of the prepaid pension asset results from the consistent and proper application of SFAS 87.

Based on the above, please provide the following:

a. For clarification purposes, is the purpose of this excerpt to convey the concept that the pension asset is properly included in rate base because FAS87 has been adopted by HECO for pension accounting purposes? If not, please clarify the intent of the statement made in the cited testimony.

b. Please provide a pinpoint reference to the specific paragraph(s) of FAS87 that address the rate base inclusion of the pension asset for **regulatory ratemaking** purposes. If none, please so state.

c. Please provide a pinpoint reference to the specific paragraph(s) of any HPUC decision concluding that the pension asset should be included in rate base because the utility has accounted for pension costs pursuant to FAS87. If none, please so state.

d. Referring to the response to part (c) above, please identify each HPUC decision that resulted from the litigation of this issue.

HECO Response:

a. Yes, and because the Commission in prior rate case decisions since the issuance of SFAS 87 has determined HECO's revenue requirements based on pension costs determined under SFAS 87. To clarify the statement, the consistent application of an accounting methodology is necessary to arrive at fair treatment. For instance, it would not be appropriate to use accrual-based accounting on the balance sheet while using cash flow accounting for an income statement nor would it be appropriate to switch from year-to-year between accrual-based accounting and cash flow depending on which one provided a desired result. It is HECO's

position that consistent application of an accounting methodology is necessary to capture all, and not duplicate any, costs. For costs associated with the pension plan, it is appropriate to consistently apply the accounting treatment specified by FAS 87 to pension costs as well as to pension-related rate base items. Since the accounting methodology promulgated by FAS 87 has been used as the basis for determining pension costs, the same methodology should also be used as the basis for the pension-related rate base items.

b. Please see response to CA-RIR-90(b).

c. Decision and Order No. 18365 in Docket No. 99-0207 approved the inclusion of HELCO's prepaid pension asset into rate base according to the following:

> For the test year, HELCO's estimate of average prepaid pension cost is $1,413,000. The Consumer Advocate's year-end estimate of prepaid pension cost is $2,914,000. The difference between parties arises out of the Consumer Advocate's use of the year-end methodology.
>
> The commission finds reasonable HELCO's estimated amount of $1,413,000.

HELCO's position in the rate case was that the prepaid pension cost should be included in rate base because HELCO had accounted for the associated pension costs according to FAS87. The Commission in prior rate case decisions since the issuance of SFAS 87, including Decision and Order No. 11317 (Oct. 17, 1991) in Docket No. 6531, Decision and Order No. 11699 (June 30, 1992) in Docket No. 6998, Decision and Order No. 13704 (December 28, 1994) in Docket No. 7700 and Decision and Order No. 14412 (December 11, 1996) in Docket No. 7766

CA-RIR-33

Ref: RT-1, page 14, lines 18-23 (Pension Asset).

The referenced testimony states, in part:

> Second, it reflects an investment that the Company has made in the pension plan.

Please provide a copy of any checks or wire transfers documenting pension fund "contributions" that were then explicitly recorded in the pension asset account under FAS87. If none, please so state.

HECO Response:

Attached on page 2 is a summary of the contributions made to the pension plan for the past 10 years (1995-2004), which accounts for all years since HECO's last rate case.

Pages 3 to 10 are the January through August 1995 check request vouchers for HECO's pension contributions to First Hawaiian Bank, the trustee for the pension plan at that time. The actual cancelled checks have been destroyed per the company's record retention policy. Effective September 1, 1995, The Bank of New York was appointed trustee and custodian for the pension plan, replacing First Hawaiian Bank. Therefore, from September 1995 to the present, HECO's pension fund contributions are made by the transfer of funds from HECO's bank account to HEI's bank account, and then the consolidated funds are wired to the Bank of New York.

Attached on pages 11 to 50 are the September 1995 through December 2004 documents showing the authorization of the company's pension fund contributions and the confirmation from Bank of Hawaii confirming the transfer of funds from HECO's bank account to HEI's bank account for the pension contributions. Note that from January 1999 through December 2002, HECO did not make any contributions to the pension fund.

PENSION - Contributions to Trust

	Date		Amount	
1995	1/31/1995	$	760,917	First Hawaiian Bank, Trustee
	2/28/1995		760,917	
	3/31/1995		760,917	
	4/28/1995		760,917	
	5/31/1995		760,917	
	6/30/1995		760,917	
	7/31/1995		760,917	
	8/31/1995		760,917	
	9/14/1995		2,970,788	Eff. Sept 1, 1995 Bank of New York appointed Trustee
			9,058,124	
1996	1/31/1996	$	501,412	
	2/29/1996		501,412	
	3/29/1996		501,412	
	4/30/1996		501,412	
	5/31/1996		501,412	
	6/28/1996		501,412	
	7/31/1996		501,412	
	8/30/1996		501,412	
	9/13/1996		2,959,988	
			6,971,284	
1997	3/31/1997	$	2,026,540	
	6/30/1997		2,026,540	
	9/12/1997		1,823,275	
			5,876,355	
1998	3/31/1998	$	1,103,017	
	6/30/1998		1,103,017	
			2,206,034	
1999-2002	No Pension Contributions were made in these years.			
2003	6/30/2003	$	2,914,000	
	9/30/2003		1,490,248	
	12/30/2003		8,990,000	
			13,394,248	
2004	9/15/2004	$	9,686,494	
	12/29/2004		5,500,000	
			15,186,494	

E326

HAWAIIAN ELECTRIC COMPANY, INC.

PAID JAN 31 1995 203418

CHECK REQUEST VOUCHER

Date: January 18, 1995 (Check Date: January 31, 199 $760,917.00

Purpose of Expenditure: Pension contribution for January 1995.

ACCT	ACTIVITY WORK ORDER	SUB-ACT	COST TYPE	AMOUNT
F,B	2,4,2,0,3	-,-,-	6,0,0	760,917.00

Make check to: FIRST HAWAIIAN BANK, TRUSTEE

Please send check to Julie Haraga-MM by January 25th.

Approved By:

HAWAIIAN ELECTRIC COMPANY, INC.

F326

PAID FEB 1 8 1995 20497

CHECK REQUEST VOUCHER

Date: February 14, 1995 (Check Date: February 28, 1995) $760,917.00

Purpose of Expenditure: Pesnion contribution for February, 1995.

RA	ACTIVITY WORK ORDER	SUB-ACT	COST TYPE	AMOUNT
F B	2 4 2 0 3	- - -	6 0 0	760,917.00

Make check to: FIRST HAWAIIAN BANK, TRUSTEE

Please send check to Julie Haraga--MM by February 22nd

Approved By: [signature]

HE 49 (REV. 1/88)

HAWAIIAN ELECTRIC COMPANY, INC.

CHECK REQUEST VOUCHER

Date: March 21, 1995 (Check Date: March 31, 1995) $760,917.00

Purpose of Expenditure: Pension contribution for March, 1995.

20579

BA	ACTIVITY / WORK ORDER	SUB-ACT	COST TYPE	AMOUNT
OF B	2 4 2 0 3	- - -	6 0 0	760,917 00

Make check to: FIRST HAWAIIAN BANK, TRUSTEE

Approved By: [signature]

Please send check to Julie Haraga-MM by March 27th.

Pension and OPEB Contribution
APRIL 1995

	RA	ACTIVITY	SUB-ACT	COST TYPE	AMOUNT
PENSION CONTRIBUTION	FB	24203	- - -	600	760,917.00
RABBI TRUST	FB	25390	RTR	501	25,000.00
IRREVOC TRUST	FB	25390	NTX	501	25,000.00
BU VEBA	FB	25390	VEB	501	633,840.00

Pension and OPEB Contribution
MAY 1995

	RA	ACTIVITY	SUB-ACT	COST TYPE	AMOUNT
PENSION CONTRIBUTION	FB	24203	---	600	760,917.00
RABBI TRUST	FB	25390	RTR	501	25,000.00
IRREVOC TRUST	FB	25390	NTX	501	25,000.00
BU VEBA	FB	25390	VEB	501	633,840.00
NBU VEBA	FB	25390	VEM	501	250,900.00
401(H)	FB	25390	Z4H	501	599,060.00
TOTAL					2,294,717.00

F326

HAWAIIAN ELECTRIC COMPANY, INC.

CHECK REQUEST VOUCHER

MAY 31 1995
24371d

Date: May 18, 1995 (Check Date: May 31, 1995) $ 2,294,717.00

Purpose of Expenditure: Pension & OPEB Contribution for May 1995

RA	ACTIVITY / WORK ORDER	SUB-ACT	COST TYPE	AMOUNT
	SEE ATTACHED			

Make check to: FIRST HAWAIIAN BANK, TRUSTEE

Please send check to Julie Haraga-MM by May 24th.

Approved By: Jan M Diamond

Pension and OPEB Contribution
JUNE 1995

	RA	ACTIVITY	SUB-ACT	COST TYPE	AMOUNT
PENSION CONTRIBUTION	FB	24203	---	600	760,917.00
RABBI TRUST	FB	25390	RTR	501	25,000.00
IRREVOC TRUST	FB	25390	NTX	501	25,000.00
BU VEBA	FB	25390	VEB	501	633,840.00
NBU VEBA	FB	25390	VEM	501	250,900.00
401(H)	FB	25390	Z4H	501	599,060.00
TOTAL					2,294,717.00

HAWAIIAN ELECTRIC COMPANY, INC.

FB26

PAID JUN 30 1995

CHECK REQUEST VOUCHER

Date: June 20, 1995 (Check Date: June 30, 1995) 2,294,717.00

Purpose of Expenditure: Pension & OPEB Contribution for June, 1995

RA	ACTIVITY / WORK ORDER	SUB-ACT	COST TYPE	AMOUNT
	SEE ATTACHED			

Approved By: Jan M Damgard

Make check to: FIRST HAWAIIAN BANK, TRUSTEE

Please send check to Julie Harage-MM by June 26th.

Pension and OPEB Contribution
JULY 1995

	RA	ACTIVITY	SUB-ACT	COST TYPE	AMOUNT
PENSION CONTRIBUTION	FB	24203	---	600	760,917.00
RABBI TRUST	FB	25390	RTR	501	25,000.00
IRREVOC TRUST	FB	25390	NTX	501	25,000.00
BU VEBA	FB	25390	VEB	501	633,840.00
NBU VEBA	FB	25390	VEM	501	250,900.00
401(H)	FB	25390	Z4H	501	599,060.00
TOTAL					2,294,717.00

PAID
JUL 31 1995
02023/9

F326.

HAWAIIAN ELECTRIC COMPANY, INC.

CHECK REQUEST VOUCHER

Date: July 19, 1995 (Check Date: July 31, 1995) $ 2,294,717.00

Purpose of Expenditure: Pension & OPEB contribution for July, 1995

Mail check to: FIRST HAWAIIAN BANK, TRUSTEE

RA	ACTIVITY / WORK ORDER	SUB-ACT	COST TYPE	AMOUNT
	SEE ATTACHED			

Approved By:

Please send check to Julie Haraga-MM by July 25th.

Pension and OPEB Contribution
AUGUST 1995

	RA	ACTIVITY	SUB-ACT	COST TYPE	AMOUNT
PENSION CONTRIBUTION	FB	24203	---	600	760,917.00
RABBI TRUST	FB	25390	RTR	501	25,000.00
IRREVOC TRUST	FB	25390	NTX	501	25,000.00
BU VEBA	FB	25390	VEB	501	633,840.00
NBU VEBA	FB	25390	VEM	501	250,900.00
401(H)	FB	25390	ZAH	501	599,060.00
TOTAL					2,294,717.00

HAWAIIAN ELECTRIC COMPANY, INC. F326

CHECK REQUEST VOUCHER

Date: August 21, 1995 (Check Date: August 31, 1995)

$ 2,294,717.00

Purpose of Expenditure: Pension & OPEB contribution for August, 1995.

AUG 31 1995
2238

AA	ACTIVITY WORK ORDER	SUB-ACT	COST TYPE	AMOUNT
	SEE ATTACHED			

Make check for: FIRST HAWAIIAN BANK, TRUSTEE

Approved By:

Please send check to Julie Haraga-HH by August 25th.

AUTHORIZATION
INTERCOMPANY BORROWING & INVESTMENT AND FUNDS TRANSFER

To: HECO Cash Management, Fax No. (808) 543-7396
Attention: Miles Suzuki or Melanie Miyashiro

The undersigned authorized officer(s) of:

✓ HECO	___ HELCO	___ MECO	___ HTB	___ MPC	
___ HEI	___ LVI	___ HEIDI	___ HEIIC	___ PECS	___ HPC

Signature requirements:
HECO & HEI: Two signatures required for amounts over $100,000
All other Companies: Two signatures required for amounts over $10,000

(TO BORROW)

___ hereby request a loan of $_____ on _____ from ___ HEI ___ HECO ___ Other _____.

Funds should be:

___ transferred to our main bank account at ___ BOH ___ FHB ___ ASB ___ Other_____

Date: _____ By _____

By _____

(TO PAY DOWN, DRAW DOWN, OR INVEST)

___ hereby request ___ a paydown ___ an interest payment of $_____ on _____ on our outstanding loan fr
___ HEI ___ HECO ___ Other_____.

___ hereby request a drawdown of $_____ on _____ on our outstanding investment with ___ HEI ___ HEC
___ Other_____.

___ hereby request an investment of $_____ on _____ with ___ HEI ___ HECO ___ Other _____.

Funds should be:

___ transferred from our main bank account at ___ BOH ___ FHB ___ ASB ___ Other _____
___ transferred to our main bank account at ___ BOH ___ FHB ___ ASB ___ Other _____

Date: _____ By _____

By _____

(TO TRANSFER FUNDS)

✓ hereby request a transfer of $ 2,970,788.00 on 9/14/95 to ✓ HEI ___ HECO ___ Other _____

For:
___ Intercompany ___ state ___ federal tax settlement
___ Intercompany dividend settlement
✓ September pension contribution

Funds should be:

✓ transferred from our main bank account at ✓ BOH ___ FHB ___ ASB ___ Other _____

Date: 9/11/95 By [signature]

ENTERED By [signature]

HAWAIIAN ELECTRIC INDUSTRIES
GEN ACCT ATTN L SHIBATA
COST ACCTG DEPT POB 2750
HONOLULU HI (USA) 96840

FROM: BANK OF HAWAII HONOLULU
OUR REF: BH 950914-000512-504
TEST 000

ORIGINAL ADVICE
WE CREDITED YOUR ACCOUNT WITH US:

ACCOUNT: DA

AMOUNT: USD 2,970,788.00 USD

VALUE DATE: SEP 14, 95

RELATED REFERENCE: 950914-60

ORDERING BANK: HAWAIIAN ELECTRIC CO INC
ATTN: TREASURY ADMINISTRATION
PO BOX 2750
HONOLULU HI (USA) 96840

FOR PAYMENT TO: HAWAIIAN ELECTRIC INDUSTRIES
GEN ACCT ATTN L SHIBATA
COST ACCTG DEPT POB 2750
HONOLULU HI (USA) 96840
DETAILS: BANK LINK TRANSFER

SIGNATURE
HONOLULU FEDWIRE DEPT

REPLY TO: 633121 BANKOH

AUTHORIZATION
INTERCOMPANY BORROWING & INVESTMENT AND FUNDS TRANSFER

To: HECO Cash Management, Fax No. (808) 543-7396
Attention: Miles Suzuki or Melanie Miyashiro

The undersigned authorized officer(s) of:

✓ HECO	___ HELCO	___ MECO	___ HTB	___ YB	___ MPC
___ HEI	___ LVI	___ HEIDI	___ HEIIC	___ PECS	___ HPC

Signature requirements:
HECO & HEI: Two signatures required for amounts over $100,000
All other Companies: Two signatures required for amounts over $10,000

(TO BORROW)

___ hereby request a loan of $_____ on _____ from ___ HEI ___ HECO ___ Other _____.

Funds should be:

___ transferred to our main bank account at ___ BOH ___ FHB ___ ASB ___ Other_____

Date: _____ By _____

By _____

(TO PAY DOWN, DRAW DOWN, OR INVEST)

___ hereby request ___ a paydown ___ an interest payment of $_____ on _____ on our outstanding loan ___ HEI ___ HECO ___ Other_____.

___ hereby request a drawdown of $_____ on _____ on our outstanding investment with ___ HEI ___ HI ___ Other_____.

___ hereby request an investment of $_____ on _____ with ___ HEI ___ HECO ___ Other _____.

Funds should be:

___ transferred from our main bank account at ___ BOH ___ FHB ___ ASB ___ Other _____
___ transferred to our main bank account at ___ BOH ___ FHB ___ ASB ___ Other _____

Date: _____ By _____

By _____

(TO TRANSFER FUNDS)

✓ hereby request a transfer of $ 22,916.00 (Invst Trust) on 1/31/96 to ✓ HEI ___ HECO ___ Other _____
• $501,412.00 (Pension) on 1/31/96
• $903,989.00 (Bal VEBA) on 1/31/96
• $319,083.00 (401(h)) on 1/31/96

For:
___ Intercompany ___ state ___ federal tax settlement
___ Intercompany dividend settlement
✓ Pension & OPEB Contributions

Funds should be:

✓ transferred from our main bank account at ✓ BOH ___ FHB ___ ASB ___ Other _____

Date: 1/26/96 By _____

By _____

HAWAIIAN ELECTRIC INDUSTRIES
GEN ACCT ATTN L SHIBATA
COST ACCTG DEPT POB 2750
HONOLULU HI (USA) 96840

FROM: BANK OF HAWAII HONOLULU
OUR REF: BH 960131-000639-504
TEST 000

ORIGINAL ADVICE
WE CREDITED YOUR ACCOUNT WITH US:

ACCOUNT: DA

AMOUNT: USD 501,412.00 USD

VALUE DATE: JAN 31, 96

RELATED REFERENCE: 22

ORDERING BANK: HAWAIIAN ELECTRIC CO INC
ATTN: TREASURY ADMINISTRATION
PO BOX 2750
HONOLULU HI (USA) 96840

FOR PAYMENT TO: HAWAIIAN ELECTRIC INDUSTRIES
GEN ACCT ATTN L SHIBATA
COST ACCTG DEPT POB 2750
HONOLULU HI (USA) 96840
DETAILS: BANK LINK TRANSFER

SIGNATURE
HONOLULU FEDWIRE DEPT

REPLY TO: 633121 BANKOH

AUTHORIZATION
INTERCOMPANY BORROWING & INVESTMENT AND FUNDS TRANSFER

To: HECO Cash Management, Fax No. (808) 543-7396
Attention: Miles Suzuki or Melanie Miyashiro

The undersigned authorized officer(s) of:

✓ HECO	___ HELCO	___ MECO	___ HTB	___ YB	___ MPC
___ HEI	___ LVI	___ HEIDI	___ HEIIC	___ PECS	___ HPC

Signature requirements:
HECO & HEI: Two signatures required for amounts over $100,000
All other Companies: Two signatures required for amounts over $10,000

(TO BORROW)

___ hereby request a loan of $_____ on _____ from ___ HEI ___ HECO ___ Other _____.

Funds should be:

___ transferred to our main bank account at ___ BOH ___ FHB ___ ASB ___ Other_____

Date: _____ By _____

By _____

(TO PAY DOWN, DRAW DOWN, OR INVEST)

___ hereby request ___ a paydown ___ an interest payment of $_____ on _____ on our outstanding loan ___ HEI ___ HECO ___ Other_____.

___ hereby request a drawdown of $_____ on _____ on our outstanding investment with ___ HEI ___ H ___ Other_____.

___ hereby request an investment of $_____ on _____ with ___ HEI ___ HECO ___ Other _____.

Funds should be:

___ transferred from our main bank account at ___ BOH ___ FHB ___ ASB ___ Other _____
___ transferred to our main bank account at ___ BOH ___ FHB ___ ASB ___ Other _____

Date: _____ By _____

By _____

(TO TRANSFER FUNDS)

$501,412.00 (pension)
✓ hereby request a transfer of $ 22,916.00 (Elec. Disc) on 2/29/96 to ✓ HEI ___ HECO ___ Other _____
$959,986.00 (Bu VEBA)
$313,083.00 (401 h)

For:
___ intercompany ___ state ___ federal tax settlement
___ intercompany dividend settlement
✓ Pension + OPEB Contributions - settle w/HEI.

Funds should be:

✓ transferred from our main bank account at ✓ BOH ___ FHB ___ ASB ___ Other _____

Date: 2/15/96 By [signature]

By [signature]

HAWAIIAN ELECTRIC INDUSTRIES
GEN ACCT ATTN L SHIBATA
COST ACCTG DEPT POB 2750
HONOLULU HI (USA) 96840

FROM: BANK OF HAWAII HONOLULU
OUR REF: BH 960229-000680-504
TEST 000

ORIGINAL ADVICE
WE CREDITED YOUR ACCOUNT WITH US:

ACCOUNT: DA

AMOUNT: USD 501,412.00 USD

VALUE DATE: FEB 29, 96

RELATED REFERENCE: 0229-24

ORDERING BANK: HAWAIIAN ELECTRIC CO INC
ATTN: TREASURY ADMINISTRATION
PO BOX 2750
HONOLULU HI (USA) 96840

FOR PAYMENT TO: HAWAIIAN ELECTRIC INDUSTRIES
GEN ACCT ATTN L SHIBATA
COST ACCTG DEPT POB 2750
HONOLULU HI (USA) 96840
DETAILS: BANK LINK TRANSFER

SIGNATURE
HONOLULU FEDWIRE DEPT

REPLY TO: 633121 BANKOH

AUTHORIZATION
INTERCOMPANY BORROWING & INVESTMENT AND FUNDS TRANSFER

To: HECO Cash Management, Fax No. (808) 543-7396
Attention: Miles Suzuki or Melanie Miyashiro

The undersigned authorized officer(s) of:

✓ HECO	___ HELCO	___ MECO	___ HTB	___ YB	___ MPC
___ HEI	___ LVI	___ HEIDI	___ HEIIC	___ PECS	___ HPC

Signature requirements:
HECO & HEI: Two signatures required for amounts over $100,000
All other Companies: Two signatures required for amounts over $10,000

(TO BORROW)

___ hereby request a loan of $_____ on _____ from ___ HEI ___ HECO ___ Other _____.

Funds should be:

___ transferred to our main bank account at ___ BOH ___ FHB ___ ASB ___ Other_____

Date: _____ By _____

By _____

(TO PAY DOWN, DRAW DOWN, OR INVEST)

___ hereby request ___ a paydown ___ an interest payment of $_____ on _____ on our outstanding loan ___ HEI ___ HECO ___ Other_____.

___ hereby request a drawdown of $_____ on _____ on our outstanding investment with ___ HEI ___ ___ Other_____.

___ hereby request an investment of $_____ on _____ with ___ HEI ___ HECO ___ Other _____.

Funds should be:

___ transferred from our main bank account at ___ BOH ___ FHB ___ ASB ___ Other _____
___ transferred to our main bank account at ___ BOH ___ FHB ___ ASB ___ Other _____

Date: _____ By _____

By _____

(TO TRANSFER FUNDS)

✓ hereby request a transfer of $501,412.00 on 3/20/96 to ✓ HEI ___ HECO ___ Other _____

For:
___ Intercompany ___ state ___ federal tax settlement
___ intercompany dividend settlement
✓ Pension Contribution

Funds should be:

✓ transferred from our main bank account at ✓ BOH ___ FHB ___ ASB ___ Other _____

Date: 3/20/96 By _____

By _____

HAWAIIAN ELECTRIC INDUSTRIES
GEN ACCT ATTN L SHIBATA
COST ACCTG DEPT POB 2750
HONOLULU HI (USA) 96840

FROM: BANK OF HAWAII HONOLULU
OUR REF: BH 960329-000800-504
TEST 000

ORIGINAL ADVICE
WE CREDITED YOUR ACCOUNT WITH US:

ACCOUNT: DA

AMOUNT: USD 501,412.00 USD

VALUE DATE: MAR 29, 96

RELATED REFERENCE: 25

ORDERING BANK: HAWAIIAN ELECTRIC CO INC
ATTN: TREASURY ADMINISTRATION
PO BOX 2750
HONOLULU HI (USA) 96840

FOR PAYMENT TO: HAWAIIAN ELECTRIC INDUSTRIES
GEN ACCT ATTN L SHIBATA
COST ACCTG DEPT POB 2750
HONOLULU HI (USA) 96840
DETAILS: BANK LINK TRANSFER

SIGNATURE
HONOLULU FEDWIRE DEPT

REPLY TO: 633121 BANKOH

AUTHORIZATION
INTERCOMPANY BORROWING & INVESTMENT AND FUNDS TRANSFER

To: HECO Cash Management, Fax No. (808) 543-7396
Attention: Miles Suzuki or Melanie Miyashiro

The undersigned authorized officer(s) of:

✓ HECO ___ HELCO ___ MECO ___ HTB ___ YB ___ MPC
___ HEI ___ LVI ___ HEIDI ___ HEIIC ___ HPC

Signature requirements:
HECO & HEI: Two signatures required for amounts over $100,000
All other Companies: Two signatures required for amounts over $10,000

(TO BORROW)

___ hereby request a loan of $_____ on _____ from ___ HEI ___ HECO ___ Other _____.

Funds should be:

___ transferred to our main bank account at ___ BOH ___ FHB ___ ASB ___ Other_____

Date: _____ By _____

By _____

(TO PAY DOWN, DRAW DOWN, OR INVEST)

___ hereby request ___ a paydown ___ an interest payment of $_____ on _____ on our outstanding loan ___ HEI ___ HECO ___ Other_____.

___ hereby request a drawdown of $_____ on _____ on our outstanding investment with ___ HEI ___ H ___ Other_____.

___ hereby request an investment of $_____ on _____ with ___ HEI ___ HECO ___ Other _____.

Funds should be:

___ transferred from our main bank account at ___ BOH ___ FHB ___ ASB ___ Other _____
___ transferred to our main bank account at ___ BOH ___ FHB ___ ASB ___ Other _____

Date: _____ By _____

By _____

(TO TRANSFER FUNDS)

✓ hereby request a transfer of $ 501,412.00 on 4/30/96 to ✓ HEI ___ HECO ___ Other _____

For:
___ intercompany ___ state ___ federal tax settlement
___ intercompany dividend settlement
✓ Pension contribution

Funds should be:

✓ transferred from our main bank account at ✓ BOH ___ FHB ___ ASB ___ Other _____

Date: 4/23/96 ENTERED By _____

By _____

HAWAIIAN ELECTRIC INDUSTRIES
GEN ACCT ATTN L SHIBATA
COST ACCTG DEPT POB 2750
HONOLULU HI (USA) 96840

FROM: BANK OF HAWAII HONOLULU
OUR REF: BH 960430-000781-504
TEST 000

ORIGINAL ADVICE
WE CREDITED YOUR ACCOUNT WITH US:

ACCOUNT: DA

AMOUNT: USD 501,412.00 USD

VALUE DATE: APR 30, 96

RELATED REFERENCE: 1210038

ORDERING BANK: HAWAIIAN ELECTRIC CO INC
ATTN: TREASURY ADMINISTRATION
PO BOX 2750
HONOLULU HI (USA) 96840

FOR PAYMENT TO: HAWAIIAN ELECTRIC INDUSTRIES
GEN ACCT ATTN L SHIBATA
COST ACCTG DEPT POB 2750
HONOLULU HI (USA) 96840
DETAILS: BANK LINK TRANSFER

SIGNATURE
HONOLULU FEDWIRE DEPT

REPLY TO: 633121 BANKOH

AUTHORIZATION
INTERCOMPANY BORROWING & INVESTMENT AND FUNDS TRANSFER

To: HECO Cash Management, Fax No. (808) 543-7396
Attention: Miles Suzuki or Melanie Miyashiro

The undersigned authorized officer(s) of:

✓ HECO ___ HELCO ___ MECO ___ HTB ___ YB ___ MPC
___ HEI ___ LVI ___ HEIDI ___ HEIIC ___ HPC

Signature requirements:
HECO & HEI: Two signatures required for amounts over $100,000
All other Companies: Two signatures required for amounts over $10,000

(TO BORROW)

___ hereby request a loan of $_____ on _____ from ___ HEI ___ HECO ___ Other _____.

Funds should be:

___ transferred to our main bank account at ___ BOH ___ FHB ___ ASB ___ Other _____

Date: _____ By _____

By _____

(TO PAY DOWN, DRAW DOWN, OR INVEST)

___ hereby request ___ a paydown ___ an interest payment of $_____ on _____ on our outstanding loan ___ HEI ___ HECO ___ Other_____.

___ hereby request a drawdown of $_____ on _____ on our outstanding investment with ___ HEI ___ H ___ Other_____.

___ hereby request an investment of $_____ on _____ with ___ HEI ___ HECO ___ Other _____.

Funds should be:

___ transferred from our main bank account at ___ BOH ___ FHB ___ ASB ___ Other _____
___ transferred to our main bank account at ___ BOH ___ FHB ___ ASB ___ Other _____

Date: _____ By _____

By _____

(TO TRANSFER FUNDS)

$ 501,412.00 (pension)
✓ hereby request a transfer of $ 22,916.00 (Inv Tr) on 5/31/96 to ✓ HEI ___ HECO ___ Other _____
$ 313,083.00 (401(h))
$ 959,986.00 (BUVEBA)

For:
___ intercompany ___ state ___ federal tax settlement
___ intercompany dividend settlement
✓ Pension + OPEB contributions

Funds should be:

✓ transferred from our main bank account at ✓ BOH ___ FHB ___ ASB ___ Other _____

Date: 5/28/96

ENTERED

By [signature]

By [signature]

HAWAIIAN ELECTRIC INDUSTRIES
GEN ACCT ATTN L SHIBATA
COST ACCTG DEPT POB 2750
HONOLULU HI (USA) 96840

FROM: BANK OF HAWAII HONOLULU
OUR REF: BH 960531-000797-504
TEST 000

ORIGINAL ADVICE
WE CREDITED YOUR ACCOUNT WITH US:

ACCOUNT: DA

AMOUNT: USD 501,412.00 USD

VALUE DATE: MAY 31, 96

RELATED REFERENCE: 1520036

ORDERING BANK: HAWAIIAN ELECTRIC CO INC
ATTN: TREASURY ADMINISTRATION
PO BOX 2750
HONOLULU HI (USA) 96840

FOR PAYMENT TO: HAWAIIAN ELECTRIC INDUSTRIES
GEN ACCT ATTN L SHIBATA
COST ACCTG DEPT POB 2750
HONOLULU HI (USA) 96840
DETAILS: BANK LINK TRANSFER

SIGNATURE
HONOLULU FEDWIRE DEPT

REPLY TO: 633121 BANKOH

AUTHORIZATION
INTERCOMPANY BORROWING & INVESTMENT AND FUNDS TRANSFER

To: HECO Cash Management, Fax No. (808) 543-7396
Attention: Miles Suzuki or Melanie Miyashiro

The undersigned authorized officer(s) of:

✓ HECO ___ HELCO ___ MECO ___ HTB ___ YB ___ MPC
___ HEI ___ LVI ___ HEIDI ___ HEIIC ___ HPC

Signature requirements:
HECO & HEI: Two signatures required for amounts over $100,000
All other Companies: Two signatures required for amounts over $10,000

(TO BORROW)

___ hereby request a loan of $_____ on _____ from ___ HEI ___ HECO ___ Other _____.

Funds should be:

___ transferred to our main bank account at ___ BOH ___ FHB ___ ASB ___ Other_____

Date: _____ By _____

By _____

(TO PAY DOWN, DRAW DOWN, OR INVEST)

___ hereby request ___ a paydown ___ an interest payment of $_____ on _____ on our outstanding loa
___ HEI ___ HECO ___ Other_____.

___ hereby request a drawdown of $_____ on _____ on our outstanding investment with ___ HEI ___
___ Other_____.

___ hereby request an investment of $_____ on _____ with ___ HEI ___ HECO ___ Other _____.

Funds should be:

___ transferred from our main bank account at ___ BOH ___ FHB ___ ASB ___ Other _____
___ transferred to our main bank account at ___ BOH ___ FHB ___ ASB ___ Other _____

Date: _____ By _____

By _____

(TO TRANSFER FUNDS)

✓ hereby request a transfer of $ 22,916.00 (inv tr.) on 6/28/96 to ✓ HEI ___ HECO ___ Other _____

For: $501,412.00 (pension) $959,986.00 (BU VEBA) $313,083.00 ~~(401(h))~~ (BU VEBA) } $1,273,069.00
___ Intercompany ___ state ___ federal tax settlement
✓ Intercompany dividend settlement
✓ Pension + OPEB Contributions to HEI

Funds should be:

✓ transferred from our main bank account at ✓ BOH ___ FHB ___ ASB ___ Other _____

Date: 6/18/96 By _____

By _____

HAWAIIAN ELECTRIC INDUSTRIES
GEN ACCT ATTN L SHIBATA
COST ACCTG DEPT POB 2750
HONOLULU HI (USA) 96840

FROM: BANK OF HAWAII HONOLULU
OUR REF: BH 960628-000993-504
TEST 000

ORIGINAL ADVICE
WE CREDITED YOUR ACCOUNT WITH US:

ACCOUNT: DA

AMOUNT: USD 501,412.00 USD

VALUE DATE: JUN 28, 96

RELATED REFERENCE: 1800033

ORDERING BANK: HAWAIIAN ELECTRIC CO INC
ATTN: TREASURY ADMINISTRATION
PO BOX 2750
HONOLULU HI (USA) 96840

FOR PAYMENT TO: HAWAIIAN ELECTRIC INDUSTRIES
GEN ACCT ATTN L SHIBATA
COST ACCTG DEPT POB 2750
HONOLULU HI (USA) 96840

DETAILS: BANK LINK TRANSFER

SIGNATURE
HONOLULU FEDWIRE DEPT

REPLY TO: 633121 BANKOH

AUTHORIZATION
INTERCOMPANY BORROWING & INVESTMENT AND FUNDS TRANSFER

To: HECO Cash Management, Fax No. (808) 543-7396
Attention: Miles Suzuki or Melanie Miyashiro

The undersigned authorized officer(s) of:

✓ HECO ___ HELCO ___ MECO ___ HTB ___ YB ___ MPC
___ HEI ___ LVI ___ HEIDI ___ HEIIC ___ HPC

Signature requirements:
HECO & HEI: Two signatures required for amounts over $100,000
All other Companies: Two signatures required for amounts over $10,000

(TO BORROW)

___ hereby request a loan of $_____ on _____ from ___ HEI ___ HECO ___ Other _____.

Funds should be:

___ transferred to our main bank account at ___ BOH ___ FHB ___ ASB ___ Other _____

Date: _____ By _____

By _____

(TO PAY DOWN, DRAW DOWN, OR INVEST)

___ hereby request ___ a paydown ___ an interest payment of $_____ on _____ on our outstanding loan ___ HEI ___ HECO ___ Other_____.

___ hereby request a drawdown of $_____ on _____ on our outstanding investment with ___ HEI ___ H ___ Other_____.

___ hereby request an investment of $_____ on _____ with ___ HEI ___ HECO ___ Other _____.

Funds should be:

___ transferred from our main bank account at ___ BOH ___ FHB ___ ASB ___ Other _____
___ transferred to our main bank account at ___ BOH ___ FHB ___ ASB ___ Other _____

Date: _____ By _____

By _____

(TO TRANSFER FUNDS)

$ 501,412.00 (Pension)
✓ hereby request a transfer of $ 22,916.00 (Irrev) on 7/31/96 to ✓ HEI ___ HECO ___ Other _____
$ 1,273,069.00 (Bu VEBA)

For:
___ intercompany ___ state ___ federal tax settlement
___ intercompany dividend settlement
✓ Pension & OPEB Contributions

Funds should be:

✓ transferred from our main bank account at ✓ BOH ___ FHB ___ ASB ___ Other _____

Date: 7/23/96 By [signature]

By [signature]

HAWAIIAN ELECTRIC INDUSTRIES
GEN ACCT ATTN L SHIBATA
COST ACCTG DEPT POB 2750
HONOLULU HI (USA) 96840

FROM: BANK OF HAWAII HONOLULU
OUR REF: BH 960731-000875-504
TEST 000

ORIGINAL ADVICE
WE CREDITED YOUR ACCOUNT WITH US:

ACCOUNT: DA

AMOUNT: USD 501,412.00 USD

VALUE DATE: JUL 31, 96

RELATED REFERENCE: 2130036

ORDERING BANK: HAWAIIAN ELECTRIC CO INC
ATTN: TREASURY ADMINISTRATION
PO BOX 2750
HONOLULU HI (USA) 96840

FOR PAYMENT TO: HAWAIIAN ELECTRIC INDUSTRIES
GEN ACCT ATTN L SHIBATA
COST ACCTG DEPT POB 2750
HONOLULU HI (USA) 96840
DETAILS: BANK LINK TRANSFER

SIGNATURE
HONOLULU FEDWIRE DEPT

REPLY TO: 633121 BANKOH

AUTHORIZATION
INTERCOMPANY BORROWING & INVESTMENT AND FUNDS TRANSFER

To: HECO Cash Management, Fax No. (808) 543-7396
Attention: Miles Suzuki or Melanie Miyashiro

The undersigned authorized officer(s) of:

✓ HECO	___ HELCO	___ MECO	___ HTB	___ YB	___ MPC
___ HEI	___ LVI	___ HEIDI	___ HEIIC	___ HPC	

Signature requirements:
HECO & HEI: Two signatures required for amounts over $100,000
All other Companies: Two signatures required for amounts over $10,000

(TO BORROW)

___ hereby request a loan of $_____ on _____ from ___ HEI ___ HECO ___ Other _____.

Funds should be:

___ transferred to our main bank account at ___ BOH ___ FHB ___ ASB ___ Other_____

Date: _____ By _____

By _____

(TO PAY DOWN, DRAW DOWN, OR INVEST)

hereby request a paydown an interest payment of $_____ on on our outstanding loan

___ hereby request a drawdown of $_____ on _____ on our outstanding investment with ___ HEI ___ HI ___ Other_____.

___ hereby request an investment of $_____ on _____ with ___ HEI ___ HECO ___ Other _____.

Funds should be:

___ transferred from our main bank account at ___ BOH ___ FHB ___ ASB ___ Other _____
___ transferred to our main bank account at ___ BOH ___ FHB ___ ASB ___ Other _____

HAWAIIAN ELECTRIC INDUSTRIES
GEN ACCT ATTN L SHIBATA
COST ACCTG DEPT POB 2750
HONOLULU HI (USA) 96840

FROM: BANK OF HAWAII HONOLULU
OUR REF: BH 960830-001015-504
TEST 000

ORIGINAL ADVICE
WE CREDITED YOUR ACCOUNT WITH US:

ACCOUNT: DA

AMOUNT: USD 501,412.00 USD

VALUE DATE: AUG 30, 96

RELATED REFERENCE: 2430047

ORDERING BANK: HAWAIIAN ELECTRIC CO INC

ATTN: TREASURY ADMINISTRATION
PO BOX 2750
HONOLULU HI (USA) 96840

FOR PAYMENT TO: HAWAIIAN ELECTRIC INDUSTRIES
GEN ACCT ATTN L SHIBATA
COST ACCTG DEPT POB 2750
HONOLULU HI (USA) 96840
DETAILS: BANK LINK TRANSFER

SIGNATURE
HONOLULU FEDWIRE DEPT

REPLY TO: 633121 BANKOH

AUTHORIZATION
INTERCOMPANY BORROWING & INVESTMENT AND FUNDS TRANSFER

To: HECO Cash Management, Fax No. (808) 543-7396
Attention: Miles Suzuki or Melanie Miyashiro

The undersigned authorized officer(s) of:

✓ HECO ___ HELCO ___ MECO ___ HTB ___ YB ___ MPC
___ HEI ___ LVI ___ HEIDI ___ HEIIC ___ HPC

Signature requirements:
HECO & HEI: Two signatures required for amounts over $100,000
All other Companies: Two signatures required for amounts over $10,000

(TO BORROW)

___ hereby request a loan of $_____ on _____ from ___ HEI ___ HECO ___ Other _____.

Funds should be:

___ transferred to our main bank account at ___ BOH ___ FHB ___ ASB ___ Other_____

Date: _____ By _____

By _____

(TO PAY DOWN, DRAW DOWN, OR INVEST)

___ hereby request ___ a paydown ___ an interest payment of $_____ on _____ on our outstanding loan
___ HEI ___ HECO ___ Other_____.

___ hereby request a drawdown of $_____ on _____ on our outstanding investment with ___ HEI ___ HI
___ Other_____.

___ hereby request an investment of $_____ on _____ with ___ HEI ___ HECO ___ Other _____.

Funds should be:

___ transferred from our main bank account at ___ BOH ___ FHB ___ ASB ___ Other _____
___ transferred to our main bank account at ___ BOH ___ FHB ___ ASB ___ Other _____

Date: By _____

(TO TRANSFER FUNDS)

✓ hereby request a transfer of $2,959,988.00 on 9/13/96 to ✓ HEI ___ HECO ___ Other _____

For:
___ intercompany ___ state ___ federal tax settlement
___ intercompany dividend settlement
✓ Pension Contribution

Funds should be:

✓ transferred from our main bank account at ✓ BOH ___ FHB ___ ASB ___ Other _____

Date: 9/6/96 ENTERED By _____

HAWAIIAN ELECTRIC INDUSTRIES
GEN ACCT ATTN L SHIBATA
COST ACCTG DEPT POB 2750
HONOLULU HI (USA) 96840

FROM: BANK OF HAWAII HONOLULU
OUR REF: BH 960913-000781-504
TEST 000

ORIGINAL ADVICE
WE CREDITED YOUR ACCOUNT WITH US:

ACCOUNT: DA

AMOUNT: USD 2,959,988.00 USD

VALUE DATE: SEP 13, 96

RELATED REFERENCE: 2570029

ORDERING BANK: HAWAIIAN ELECTRIC CO INC
ATTN: TREASURY ADMINISTRATION
PO BOX 2750
HONOLULU HI (USA) 96840

FOR PAYMENT TO: HAWAIIAN ELECTRIC INDUSTRIES
GEN ACCT ATTN L SHIBATA
COST ACCTG DEPT POB 2750
HONOLULU HI (USA) 96840
DETAILS: BANK LINK TRANSFER

SIGNATURE
HONOLULU FEDWIRE DEPT

REPLY TO: 633121 BANKOH

AUTHORIZATION
INTERCOMPANY BORROWING & INVESTMENT AND FUNDS TRANSFER

To: HECO Cash Management, Fax No. (808) 543-7396
Attention: Miles Suzuki or Melanie Miyashiro

The undersigned authorized officer(s) of:

✓ HECO ___ HELCO ___ MECO ___ HTB ___ YB ___ MPC
___ HEI ___ LVI ___ HEIDI ___ HEIIC ___ HPC

Signature requirements:
HECO & HEI: Two signatures required for amounts over $100,000
All other Companies: Two signatures required for amounts over $10,000

(TO BORROW)

___ hereby request a loan of $_____ on _____ from ___ HEI ___ HECO ___ Other _____.

Funds should be:

___ transferred to our main bank account at ___ BOH ___ FHB ___ ASB ___ Other_____
___ _____

Date: _____ By _____

By _____

(TO PAY DOWN, DRAW DOWN, OR INVEST)

___ hereby request ___ a paydown ___ an interest payment of $_____ on _____ on our outstanding loan ___ HEI ___ HECO ___ Other_____.

___ hereby request a drawdown of $_____ on _____ on our outstanding investment with ___ HEI ___ H ___ Other_____.

___ hereby request an investment of $_____ on _____ with ___ HEI ___ HECO ___ Other _____.

Funds should be:

___ transferred from our main bank account at ___ BOH ___ FHB ___ ASB ___ Other _____
___ transferred to our main bank account at ___ BOH ___ FHB ___ ASB ___ Other _____
___ _____

Date: _____ By _____

By _____

(TO TRANSFER FUNDS)

✓ hereby request a transfer of $ $2,026,540.00 (pension) 83,250.00 (insiv) 3,691,671.00 (BU VEBA) on 3/31/97 to ✓ HEI ___ HECO ___ Other _____

For:
___ intercompany ___ state ___ federal tax settlement
___ intercompany dividend settlement
✓ Pension/OPEB Contributions

Funds should be:

✓ transferred from our main bank account at ✓ BOH ___ FHB ___ ASB ___ Other _____

Date: 3/25/97 By _____

By _____

HAWAIIAN ELECTRIC INDUSTRIES
GEN ACCT ATTN L SHIBATA
COST ACCTG DEPT POB 2750
HONOLULU HI (USA) 96840

FROM: BANK OF HAWAII HONOLULU
OUR REF: BH 970331-001206-504
TEST 000

ORIGINAL ADVICE
WE CREDITED YOUR ACCOUNT WITH US:

ACCOUNT: DA

AMOUNT: USD 2,026,540.00 USD

VALUE DATE: MAR 31, 97

RELATED REFERENCE: 0900082

ORDERING BANK: HAWAIIAN ELECTRIC CO INC
ATTN: TREASURY ADMINISTRATION
PO BOX 2750
HONOLULU HI (USA) 96840

FOR PAYMENT TO: HAWAIIAN ELECTRIC INDUSTRIES
GEN ACCT ATTN L SHIBATA
COST ACCTG DEPT POB 2750
HONOLULU HI (USA) 96840
DETAILS: BANK LINK TRANSFER

SIGNATURE
HONOLULU FEDWIRE DEPT

REPLY TO: 633121 BANKOH

AUTHORIZATION
INTERCOMPANY BORROWING & INVESTMENT AND FUNDS TRANSFER

To: HECO Cash Management, Fax No. (808) 543-7396
Attention: Miles Suzuki or Melanie Miyashiro

The undersigned authorized officer(s) of:

✓ HECO	___ HELCO	___ MECO	___ HTB	___ YB	___ MPC
___ HEI	___ HEIDI	___ HEIIC	___ HPC	___ PECS	

Signature requirements:
HECO, HEI, and HPC: Two signatures required for amounts over $100,000
All other Companies: Two signatures required for amounts over $10,000

(TO BORROW)

___ **hereby request a loan of $_____ on _____ from ___ HEI ___ HECO ___ Other _____.**

Funds should be:

___ **transferred to our main bank account at ___ BOH ___ FHB ___ ASB ___ Other_____**

Date: _____ **By** _____

By _____

(TO PAY DOWN, DRAW DOWN, OR INVEST)

___ **hereby request ___ a paydown ___ an interest payment of $_____ on _____ on our outstanding loan ___ HEI ___ HECO ___ Other_____.**

___ **hereby request a drawdown of $_____ on _____ on our outstanding investment with ___ HEI ___ H ___ Other_____.**

___ **hereby request an investment of $_____ on _____ with ___ HEI ___ HECO ___ Other _____.**

Funds should be:

___ **transferred from our main bank account at ___ BOH ___ FHB ___ ASB ___ Other _____**
___ **transferred to our main bank account at ___ BOH ___ FHB ___ ASB ___ Other _____**

Date: _____ **By** _____

By _____

(TO TRANSFER FUNDS) $ 2,026,540.00 (pension) /

✓ **hereby request a transfer of $** 83,250.00 (dec div) **on** 6/30/97 **to** ✓ **HEI ___ HECO ___ Other _____**

For: $ 3,691,671.00 (current) /

___ **intercompany ___ state ___ federal tax settlement**
___ **intercompany dividend settlement**
✓ Pension & OPEB Contributions

Funds should be:

✓ **transferred from our main bank account at** ✓ **BOH ___ FHB ___ ASB ___ Other _____**

Date: 6/20/97 **By** _____

ENTERED

By _____

HAWAIIAN ELECTRIC INDUSTRIES
GEN ACCT ATTN L SHIBATA
COST ACCTG DEPT POB 2750
HONOLULU HI (USA) 96840

FROM: BANK OF HAWAII HONOLULU
OUR REF: BH 970630-001261-504
TEST 000

ORIGINAL ADVICE
WE CREDITED YOUR ACCOUNT WITH US:

ACCOUNT: DA

AMOUNT: USD 2,026,540.00 USD

VALUE DATE: JUN 30, 97

RELATED REFERENCE: 1810067

ORDERING BANK: HAWAIIAN ELECTRIC CO INC
ATTN: TREASURY ADMINISTRATION
PO BOX 2750
HONOLULU HI (USA) 96840

FOR PAYMENT TO: HAWAIIAN ELECTRIC INDUSTRIES
GEN ACCT ATTN L SHIBATA
COST ACCTG DEPT POB 2750
HONOLULU HI (USA) 96840
DETAILS: BANK LINK TRANSFER

SIGNATURE
HONOLULU FEDWIRE DEPT

REPLY TO: 633121 BANKOH

AUTHORIZATION
INTERCOMPANY BORROWING & INVESTMENT AND FUNDS TRANSFER

To: HECO Cash Management, Fax No. (808) 543-7396
Attention: Miles Suzuki or Melanie Miyashiro

The undersigned authorized officer(s) of:

✓ HECO ___ HELCO ___ MECO ___ HTB ___ YB ___ MPC
___ HEI ___ HEIDI ___ HEIIC ___ HPC ___ PECS

Signature requirements:
HECO, HEI, and HPC: Two signatures required for amounts over $100,000
All other Companies: Two signatures required for amounts over $10,000

(TO BORROW)

___ hereby request a loan of $_____ on _____ from ___ HEI ___ HECO ___ Other _____.

Funds should be:

___ transferred to our main bank account at ___ BOH ___ FHB ___ ASB ___ Other_____

Date: _____ By _____

By _____

(TO PAY DOWN, DRAW DOWN, OR INVEST)

___ hereby request ___ a paydown ___ an interest payment of $_____ on _____ on our outstanding loan f
___ HEI ___ HECO ___ Other_____.

___ hereby request a drawdown of $_____ on _____ on our outstanding investment with ___ HEI ___ HE
___ Other_____.

___ hereby request an investment of $_____ on _____ with ___ HEI ___ HECO ___ Other _____.

Funds should be:

___ transferred from our main bank account at ___ BOH ___ FHB ___ ASB ___ Other _____
___ transferred to our main bank account at ___ BOH ___ FHB ___ ASB ___ Other _____

Date: _____ By _____

By _____

(TO TRANSFER FUNDS)

✓ hereby request a transfer of $ 3,695,472.00 (pension) $1,823,275.00 on 9/2/97 to ✓ HEI ___ HECO ___ Other _____

For:
___ intercompany ___ state ___ federal tax settlement
___ intercompany dividend settlement
✓ Pension & OPEB Contributions.

Funds should be:

✓ transferred from our main bank account at ✓ BOH ___ FHB ___ ASB ___ Other _____

Date: 9/2/97

ENTERED

By _____

By _____

HAWAIIAN ELECTRIC INDUSTRIES
GEN ACCT ATTN L SHIBATA
COST ACCTG DEPT POB 2750
HONOLULU HI (USA) 96840

FROM: BANK OF HAWAII HONOLULU
OUR REF: BH 970912-000920-504
TEST 000

ORIGINAL ADVICE
WE CREDITED YOUR ACCOUNT WITH US:

ACCOUNT: DA

AMOUNT: USD 1,823,275.00 USD

VALUE DATE: SEP 12 97

RELATED REFERENCE: 2550033

ORDERING BANK: HAWAIIAN ELECTRIC CO INC
ATTN: TREASURY ADMINISTRATION
PO BOX 2750
HONOLULU HI (USA) 96840

FOR PAYMENT TO: HAWAIIAN ELECTRIC INDUSTRIES
GEN ACCT ATTN L SHIBATA
COST ACCTG DEPT POB 2750
HONOLULU HI (USA) 96840
DETAILS: BANK LINK TRANSFER

SIGNATURE
HONOLULU FEDWIRE DEPT

REPLY TO: 633121 BANKOH

AUTHORIZATION
INTERCOMPAN BORROWING & INVESTMENT AND JNDS TRANSFER

To: HECO Cash Management, Fax No. (808) 543-7396
Attention: Miles Suzuki or Melanie Miyashiro

The undersigned authorized officer(s) of:

✓ HECO	___ HELCO	___ MECO	___ HTB	___ YB	___ MPC	___ HYCAP
___ HEI	___ HEIDI	___ HEIIC	___ HPC	___ PECS	___ HPC Guam	___ HPF

Signature requirements:
HECO, HEI, and HPC, HPC Guam, HYCAP, & HPF: Two signatures for amounts over $100,000
All other Companies: Two signatures required for amounts over $10,000

(TO BORROW)

___ hereby request a loan of $_____ on _____ from ___ HEI ___ HECO ___ Other _____.

Funds should be:

___ transferred to our main bank account at ___ BOH ___ FHB ___ ASB ___ Other_____

Date: _____ **By _____**

By _____

(TO PAY DOWN, DRAW DOWN, OR INVEST)

___ hereby request ___ a paydown ___ an interest payment of $_____ on _____ on our outstanding loan fr ___ HEI ___ HECO ___ Other_____.

___ hereby request a drawdown of $_____ on _____ on our outstanding investment with ___ HEI ___ HEC ___ Other_____.

___ hereby request an investment of $_____ on _____ with ___ HEI ___ HECO ___ Other _____.

Funds should be:

___ transferred from our main bank account at ___ BOH ___ FHB ___ ASB ___ Other _____
___ transferred to our main bank account at ___ BOH ___ FHB ___ ASB ___ Other _____

Date: _____ **By _____**

By _____

(TO TRANSFER FUNDS)

✓ hereby request a transfer of $1,103,017.00 ✓ on 3/31/98 to ✓HEI ___ HECO ___ Other _____

For:
___ intercompany ___ state ___ federal tax settlement
___ intercompany dividend settlement
✓ Pension Contribution

Funds should be:

✓ transferred from our main bank account at ✓BOH ___ FHB ___ ASB ___ Other _____

Date: 3/31/98 **By _____**

ENTERED

By _____

MAR 31'98 14:29EST FROM: 160558 BOH UT MSG#: QDG533 BOH6890 PAGE 0

FROM: BANK OF HAWAII HONOLULU
HONOLULU HI
OUR REF: BH 980331-001075-504(FED)
TEST 000

HAWAIIAN ELECTRIC INDUSTRIES
GEN ACCT ATTN L SHIBATA
COST ACCTG DEPT POB 2750
HONOLULU HI (USA) 96840

ORIGINAL ADVICE
WE CREDITED YOUR ACCOUNT WITH US:

ACCOUNT: DA

AMOUNT: USD 1,103,017.00 USD

VALUE DATE: MAR 31, 98

RELATED REFERENCE: 0900040

ORDERING BANK: HAWAIIAN ELECTRIC CO INC
ATTN: TREASURY ADMINISTRATION
PO BOX 2750
HONOLULU HI (USA) 96840

FOR PAYMENT TO: HAWAIIAN ELECTRIC INDUSTRIES
GEN ACCT ATTN L SHIBATA
COST ACCTG DEPT POB 2750
HONOLULU HI (USA) 96840

DETAILS: BANK LINK TRANSFER

SIGNATURE
HONOLULU FEDWIRE DEPT

REPLY TO: 160558 BOH UT

AUTHORIZATION
INTERCOMPA. . BORROWING & INVESTMENT ANI UNDS TRANSFER

To: HECO Cash Management, Fax No. (808) 543-7396
Attention: Miles Suzuki or Melanie Miyashiro

The undersigned authorized officer(s) of:

✓ HECO	___ HELCO	___ MECO	___ HTB	___ YB	___ MPC	___ HYCAP
___ HEI	___ HEIDI	___ HEIIC	___ HPC	___ PECS	___ HPC Guam	___ HPF

Signature requirements:
HECO, HEI, and HPC, HPC Guam, HYCAP, & HPF: Two signatures for amounts over $100,000
All other Companies: Two signatures required for amounts over $10,000

(TO BORROW)

___ hereby request a loan of $_____ on _____ from ___ HEI ___ HECO ___ Other _____.

Funds should be:

___ transferred to our main bank account at ___ BOH ___ FHB ___ ASB ___ Other_____

Date: _____ By _____

By _____

(TO PAY DOWN, DRAW DOWN, OR INVEST)

___ hereby request ___ a paydown ___ an interest payment of $_____ on _____ on our outstanding loan fr ___ HEI ___ HECO ___ Other_____.

___ hereby request a drawdown of $_____ on _____ on our outstanding investment with ___ HEI ___ HEI ___ Other_____.

___ hereby request an investment of $_____ on _____ with ___ HEI ___ HECO ___ Other _____.

Funds should be:

___ transferred from our main bank account at ___ BOH ___ FHB ___ ASB ___ Other _____
___ transferred to our main bank account at ___ BOH ___ FHB ___ ASB ___ Other _____

Date: _____ By _____

By _____

(TO TRANSFER FUNDS)

✓ hereby request a transfer of $1,103,017.00 on 6/30/98 to ✓ HEI ___ HECO ___ Other _____

For:
___ intercompany ___ state ___ federal tax settlement
___ intercompany dividend settlement
✓ Pension contribution

Funds should be:

✓ transferred from our main bank account at ✓ BOH ___ FHB ___ ASB ___ Other _____

Date: 6/23/98 By _____

By _____

ENTERED 6/26

JUN 30 98 16:27EST FROM: (808) 160558 BOH UT MSG#: QDJB5F BOH4903 PAGE 02

FROM: BANK OF HAWAII HONOLULU
HONOLULU HI
OUR REF: BH 980630-001430-504(FED)
TEST 000

HAWAIIAN ELECTRIC INDUSTRIES
GEN ACCT ATTN L SHIBATA
COST ACCTG DEPT POB 2750
HONOLULU HI (USA) 96840

ORIGINAL ADVICE
WE CREDITED YOUR ACCOUNT WITH US:

ACCOUNT: DA

AMOUNT: USD 1,103,017.00 USD

VALUE DATE: JUN 30, 98

RELATED REFERENCE: 1810116

ORDERING BANK: HAWAIIAN ELECTRIC CO INC
ATTN: TREASURY ADMINISTRATION
PO BOX 2750
HONOLULU HI (USA) 96840

FOR PAYMENT TO: HAWAIIAN ELECTRIC INDUSTRIES
GEN ACCT ATTN L SHIBATA
COST ACCTG DEPT POB 2750
HONOLULU HI (USA) 96840

DETAILS: BANK LINK TRANSFER

SIGNATURE
HONOLULU FEDWIRE DEPT

REPLY TO: 160558 BOH UT

AUTHORIZATION{PRIVATE }
INTERCOMPANY BORROWING & INVESTMENT AND FUNDS TRANSFER

To: HECO Cash Management, Fax No. (808) 543-7396
Attention: Elizabeth Lee or Melanie Sawai

The undersigned authorized officer(s) of:

√ HECO ___ HELCO ___ MECO ___ TOOTS ___ MPC ___ PECS ___ PVT
___ HEI ___ HEIDC ___ HEIDI ___ HEIII ___ HPC ___ OTHER_____

Signature Requirements:
HECO, HEI, HEILI, HEIPI, HEIDC, HPC, PVT, Hycap, and HEI Pref: Two signatures * for amounts over $100,000
HELCO, MECO, HEIII, HEICF, HEIDI, TOOTS, MPC, and PECS: Two signatures * for amounts over $10,000
* For authorized officers, see respective Board Resolution re Establishment of Bank Accounts & Signature Requirements

(TO BORROW)

___ hereby request a loan of $_____ on _____ from ___ HEI ___ HECO ___ Other _____

Funds should be:
___ transferred to our main bank account at ___ BOH ___ FHB ___ ASB ___ Other_____

Date: _____ By_____

By_____

(TO PAY DOWN, DRAW DOWN, OR INVEST)

___ hereby request ___ a paydown ___ an interest payment of $_____ on _____ on our outstanding loan from ___ HEI ___ HECO ___ Other_____.

___ hereby request a drawdown of $_____ on _____ on our outstanding investment with ___ HEI ___ HECO ___ Other_____.

___ hereby request an investment of $_____ on _____ with ___ HEI ___ HECO ___ Other _____

Funds should be:
transferred from our main bank account at BOH ___ FHB ___ ASB ___ Other

HAWAIIAN ELECTRIC INDUSTRIES
ATTN: ELIZABETH LEE .
COST ACCTG DEPT POB 2750
HONOLULU HI (USA) 96840

FROM: BANK OF HAWAII HONOLULU
OUR REF: BH 030630-001636-504
TEST 000

ORIGINAL ADVICE
WE CREDITED YOUR ACCOUNT WITH US:

ACCOUNT: DA

AMOUNT: USD 2,914,000.00 USD

VALUE DATE: JUN 30, 03

RELATED REFERENCE: DO 025575

ORDERING BANK: HAWAIIAN ELECTRIC CO INC
ATTN: ELIZABETH LEE
PO BOX 2750 .
HONOLULU HI (USA) 96840

FOR PAYMENT TO: HAWAIIAN ELECTRIC INDUSTRIES
ATTN: ELIZABETH LEE .
COST ACCTG DEPT POB 2750
HONOLULU HI (USA) 96840

DETAILS: BANK LINK TRANSFER

SIGNATURE
HONOLULU FEDWIRE DEPT

REPLY TO: 633121 BANKOH

AUTHORIZATION(PRIVATE)

[redacted]

To: HECO Cash Management, Fax No. (808) 543-7396
Attention: Elizabeth Lee or Melanie Sawai

The undersigned authorized officer(s) of:

✓ HECO ___ HELCO ___ MECO ___ TOOTS ___ MPC ___ PECS ___ PVT
___ HEI ___ HEIDC ___ HEIDI ___ HEIII ___ HPC ___ OTHER_____

Signature Requirements: [redacted]

HECO, HEI, HEILI, HEIPI, HEIDC, HPC, PVT, Hycap, and HEI Pref: Two signatures * for amounts over $100,000
HELCO, MECO, HEIII, HEICF, HEIDI, TOOTS, MPC, and PECS: Two signatures * for amounts over $10,000
*** For authorized officers, see respective Board Resolution re Establishment of Bank Accounts & Signature Requirements**

(TO BORROW)

07/30/2003 10:00 [illegible]

HAWAIIAN ELECTRIC INDUSTRIES
ATTN: ELIZABETH LEE
COST ACCTG DEPT POB 2750
HONOLULU HI (USA) 96840

FROM: BANK OF HAWAII HONOLULU
OUR REF: BH 030930-001479-504
TEST 000

ORIGINAL ADVICE
WE CREDITED YOUR ACCOUNT WITH US:

ACCOUNT: DA

AMOUNT: USD 1,490,248.00 USD

VALUE DATE: SEP 30, 03

RELATED REFERENCE: DO 029335

ORDERING BANK: HAWAIIAN ELECTRIC CO INC
ATTN: ELIZABETH LEE
PO BOX 2750
HONOLULU HI (USA) 96840

FOR PAYMENT TO: HAWAIIAN ELECTRIC INDUSTRIES
ATTN: ELIZABETH LEE
COST ACCTG DEPT POB 2750
HONOLULU HI (USA) 96840

DETAILS: BANK LINK TRANSFER

SIGNATURE
HONOLULU FEDWIRE DEPT

REPLY TO: 633121 BANKOH

AUTHORIZATION
INTERCOMPANY BORROWING & INVESTMENT AND FUNDS TRANSFER

To: HECO Cash Management, Fax No. (808) 543-7396
Attention: Elizabeth Lee or Melanie Sawai

The undersigned authorized officer(s) of:

✓ HECO ___ HELCO ___ MECO ___ TOOTS ___ MPC ___ PECS ___ PVT
___ HEI ___ HEIDC ___ HEIDI ___ HEIII ___ HPC ___ OTHER_____

Signature Requirements:
HECO, HEI, HEILI, HEIPI, HEIDC, HPC, PVT, Hycap, and HEI Pref: Two signatures * for amounts over $100,000
HELCO, MECO, HEIII, HEICF, HEIDI, TOOTS, MPC, and PECS: Two signatures * for amounts over $10,000
* For authorized officers, see respective Board Resolution re Establishment of Bank Accounts & Signature Requirements

---

(TO BORROW)

___ hereby request a loan of $_____ on _____ from ___ HEI ___ HECO ___ Other _____

Funds should be:
___ transferred to our main bank account at ___ BOH ___ FHB ___ ASB ___ Other_____

Date: _____ By_____

By_____

(TO PAY DOWN, DRAW DOWN, OR INVEST)

___ hereby request ___ a paydown ___ an interest payment of $_____ on _____ on our outstanding loan from ___ HEI ___ HECO ___ Other_____.

___ hereby request a drawdown of $_____ on _____ on our outstanding investment with ___ HEI ___ HECO ___ Other_____.

___ hereby request an investment of $_____ on _____ with ___ HEI ___ HECO ___ Other _____

Funds should be:
___ transferred from our main bank account at ___ BOH ___ FHB ___ ASB ___ Other_____
___ transferred to our main bank account at ___ BOH ___ FHB ___ ASB ___ Other _____

Date: _____ By_____

By_____

(TO TRANSFER FUNDS)

✓ hereby request a transfer of $1,009,308.00 (DH VEBA) / $8,990,000.00 (pension) / $869,509.00 (NBH VEBA) on 12/30/03 to ✓ HEI ___ HECO ___ Other _____

For:
___ intercompany ___ state ___ federal tax settlement ___ Intercompany OCARS settlement
___ intercompany dividend settlement ___ intercompany HEIRS settlement
___ Other_____

Funds should be:
✓ transferred from our main bank account at ✓ BOH ___ FHB ___ ASB ___ Other _____

Date: 12/29/03 By [signature]

By [signature]

ENTERED

1/14/2002 Authorization.doc

HAWAIIAN ELECTRIC INDUSTRIES
ATTN: ELIZABETH LEE .
COST ACCTG DEPT POB 2750
HONOLULU HI (USA) 96840

FROM: BANK OF HAWAII HONOLULU
OUR REF: BH 031230-001206-504
TEST 000

ORIGINAL ADVICE
WE CREDITED YOUR ACCOUNT WITH US:

ACCOUNT: DA

AMOUNT: USD 8,990,000.00 USD

VALUE DATE: DEC 30, 03

RELATED REFERENCE: DO 032905

ORDERING BANK: HAWAIIAN ELECTRIC CO INC
ATTN: ELIZABETH LEE
PO BOX 2750 .
HONOLULU HI (USA) 96840

FOR PAYMENT TO: HAWAIIAN ELECTRIC INDUSTRIES
ATTN: ELIZABETH LEE .
COST ACCTG DEPT POB 2750
HONOLULU HI (USA) 96840

DETAILS: BANK LINK TRANSFER

SIGNATURE
HONOLULU FEDWIRE DEPT

REPLY TO: 633121 BANKOH

AUTHORIZATION
INTERCOMPANY BORROWING & INVESTMENT AND FUNDS TRANSFER

To: HECO Cash Management, Fax No. (808) 543-7396
Attention: Nora Toshi or Melanie Sawai

The undersigned authorized officer(s) of:

✓ HECO ___ HELCO ___ MECO ___ TOOTS ___ MPC ___ PECS
___ HEI ___ HEIDI ___ HEIII ___ HEIPI ___ HPC ___ OTHER_____

Signature Requirements:
HECO, HEI, HEIPI, HPC, Hycap Mgmt, and HEI Preferred: Two signatures * for amounts over $100,000
HELCO, MECO, HEIII, HEICF, HEIDI, TOOTS, MPC, and PECS: Two signatures * for amounts over $10,000
* For authorized officers, see respective Board Resolution re Establishment of Bank Accounts & Signature Requirements

---

(TO BORROW)

___ hereby request a loan of $_____ on _____ from ___ HEI ___ HECO ___ Other _____

Funds should be:
___ transferred to our main bank account at ___ BOH ___ FHB ___ ASB ___ Other_____

Date: _____ By_____

By_____

(TO PAY DOWN, DRAW DOWN, OR INVEST)

___ hereby request ___ a paydown ___ an interest payment of $_____ on _____ on our outstanding loan from ___ HEI ___ HECO ___ Other_____.

___ hereby request a drawdown of $_____ on _____ on our outstanding investment with ___ HEI ___ HECO ___ Other_____.

___ hereby request an investment of $_____ on _____ with ___ HEI ___ HECO ___ Other _____

Funds should be:
___ transferred from our main bank account at ___ BOH ___ FHB ___ ASB ___ Other_____
___ transferred to our main bank account at ___ BOH ___ FHB ___ ASB ___ Other _____

Date: _____ By_____

By_____

(TO TRANSFER FUNDS)

✓ hereby request a transfer of $ 9,696,494.00 on 9/15/04 to ✓ HEI ___ HECO ___ Other _____

For:
___ Intercompany ___ state ___ federal tax settlement ___ Intercompany OCARS settlement
___ Intercompany dividend settlement ___ HEIRS settlement
✓ Other Pension contribution

Funds should be:
✓ transferred from our main bank account at ✓ BOH ___ FHB ___ ASB ___ Other _____

Date: 9/10/04 By [signature]

ENTERED 9/10 MH By [signature]

MSR: At 09/15/2004 10:54:00 AM Page 1

Bank of Hawaii

HAWAIIAN ELECTRIC INDUSTRIES
FINANCIAL VP, TREASURER & CFO (KS4-ZA)
PO BOX 730
HONOLULU HI 96808-0730

Book Transfer Advice

Date:	09/15/2004
Amount:	$9,686,494.00 NHT
From Account Number:	*****00853
To Account Number:	*****40251
Reference Number:	20042590105200
Additional Information:	

A book transfer has been processed between the above accounts.

AUTHORIZATION
INTERCOMPANY BORROWING & INVESTMENT AND FUNDS TRANSFER

To: HECO Cash Management, Fax No. (808) 543-7396
Attention: Nora Toshi or Melanie Sawai

The undersigned authorized officer(s) of:

✓ HECO ___ HELCO ___ MECO ___ TOOTS ___ PECS
___ HEI ___ HEIDI ___ HEIII ___ HEIPI ___ HPC ___ OTHER_____

Signature Requirements:
HECO, HEI, HEIPI, HPC, and Hycap Mgmt: Two signatures * for amounts over $100,000
HELCO, MECO, HEIII, HEICF, HEIDI, TOOTS, and PECS: Two signatures * for amounts over $10,000
*** For authorized officers, see respective Board Resolution re Establishment of Bank Accounts & Signature Requirements**

(TO BORROW)

___ hereby request a loan of $_____ on _____ from ___ HEI ___ HECO ___ Other _____

Funds should be:
___ transferred to our main bank account at ___ BOH ___ FHB ___ ASB ___ Other_____

Date: _____ **By_____**

By_____

(TO PAY DOWN, DRAW DOWN, OR INVEST)

___ hereby request ___ a paydown ___ an interest payment of $_____ on _____ on our outstanding loan from ___ HEI ___ HECO ___ Other_____.

___ hereby request a drawdown of $_____ on _____ on our outstanding investment with ___ HEI ___ HECO ___ Other_____.

___ hereby request an investment of $_____ on _____ with ___ HEI ___ HECO ___ Other _____

Funds should be:
___ transferred from our main bank account at ___ BOH ___ FHB ___ ASB ___ Other_____
___ transferred to our main bank account at ___ BOH ___ FHB ___ ASB ___ Other _____

Date: _____ **By_____**

By_____

(TO TRANSFER FUNDS)

✓ hereby reguest a transfer of $ 5500.000 **on** 12/29/04 **to ✓ HEI HECO Other**

XSR: AS 12/29/2004 10:57:03 AM Page 1

Bank of Hawaii

Administrator
FINANCIAL VP, TREASURER & CFO (KS4-ZA)
PO BOX 730
HONOLULU HI 96808-0730

Book Transfer Advice

Date:	12/29/2004
Amount:	$5,500,000.00
Originating Customer:	HAWAIIAN ELECTRIC CO INC
Originating Bank:	
Beneficiary Customer:	HAWAIIAN ELECTRIC INDUSTRIES
Credited to Account Number:	
Reference Number:	20043640144400
Reference for Beneficiary:	
Originator to Beneficiary Details:	07

An internal Bank of Hawaii transfer has been processed between the above customers.

CA-RIR-34

Ref: RT-1, page 14, beginning at line 23 (Pension Asset).

The referenced testimony states, in part:

> Third, the prepaid pension asset accrues definite benefits to the ratepayer. Generation of the prepaid pension asset has resulted in a lower NPPC, enabled the Company to avoid negative tax consequences and has a positive impact on the Company's credit quality.

Based on the above, please provide the following:

a. In the context of the cited testimony, is Mr. Alm referring to the pension plan assets being held by the pension trust or to the prepaid pension asset recorded on HECO's balance sheet pursuant to FAS87? Please explain.

b. Under the accounting requirements of FAS87, does Mr. Alm believe that the prepaid pension asset recorded on HECO's balance sheet results in lower NPPC or that a NPPC below amounts contributed to the pension fund results in the recording of a prepaid pension asset? If the former, please provide a pinpoint reference to the specific paragraphs of FAS87 relied upon in reaching that conclusion.

c. Please explain how the specific prepaid pension asset recorded on HECO's balance sheet pursuant to FAS87 has allowed HECO to avoid negative tax consequences. Also, please provide a copy of any supporting documentation relied upon in formulating the response.

d. Please explain how the specific prepaid pension asset recorded on HECO's balance sheet pursuant to FAS87 has had a positive impact on the Company's credit quality. Also, please provide a copy of any supporting documentation.

HECO Response:

a. As stated in the referenced testimony, the Company is referring to the prepaid pension asset. However, please note that the prepaid pension asset balance is the net of: the projected benefit obligation, the fair value of plan assets, unrecognized loss, and unrecognized prior service costs. The pension trust (the fair value of the plan assets) is a component of the prepaid pension asset.

b. As discussed response to (a) above and by Ms. Sekimura in RT-16, the prepaid pension asset is the net of several items. Fund contributions result in higher fair value of plan assets

which we expect will result in higher pension trust returns which lower NPPC. Funding the pension fund increases the prepaid pension asset recorded on HECO's balance sheet and also will normally result in lowering NPPC. In addition, cumulative NPPC below cumulative amounts contributed to the pension fund result in the prepaid pension asset.

c. Negative tax consequences could result from either not funding the minimum requirements or from taking disbursements from the pension fund. See HECO-RT-16, page 41, lines 1 to 17.

d. Funding of the pension fund reduces the underfunded status of the pension fund which improves credit quality. See HECO-RT-16, page 42, line 23 to page 45, line 2.

CA-RIR-35

Ref: RT-1, page 14, lines 23-24 (Pension Asset).

The referenced testimony states, in part:

> Third, the prepaid pension asset accrues definite benefits to the ratepayer.

Based on the above, please provide the following:

a. Please define the word "accrues" as used in this context.

b. Please define the word "benefits" as used in this context.

c. Please quantify the "benefits" that have arisen or been created since the last rate case.

d. Please identify and describe the specific mechanism(s) (e.g., refunds, cost tracker, earnings sharing plan, rate reductions, etc.) through which HECO has conveyed these "benefits" to ratepayers during the years since the Company's last rate case.

HECO Response:

a. "Accrues" means "adds" or "brings about."

b. "Benefits" means something that promotes well-being or provides an advantage.

c. The benefits are briefly summarized in the next sentence (HECO RT-1, page 14 line 24 to page 15, line 2). The benefits are further explained in HECO RT-16 particularly pages 44, 50, and 53.

d. See response to (c).

CA-RIR-36

Ref: RT-1, page 15, lines 4-8 (Pension Asset).

The referenced testimony states, in part:

> The CA and the DOD recommend the complete removal of the prepaid pension asset from rate base. However, their arguments are flawed and constitute retroactive ratemaking. By disallowing the prepaid pension asset from rate base, they seek to make up for what they perceive to be an over recovery of NPPC in the ten years between this and the Company's last rate case.

Based on the above, please provide the following:

a. Please define the term "retroactive ratemaking" as used and applied by Mr. Alm in this context.

b. Have any analyses been prepared by, or for, HECO on which Mr. Alm relied in support of his testimony that the removal of the pension asset from rate base will "make up" for a perceived over-recovery of NPPC since the Company's last rate case?

1. If so, please provide a copy of the detailed analyses, in both hard copy and spreadsheet file format, demonstrating how this alleged "make up" process would return past over

to refund revenues collected pursuant to then lawfully established rates, for such past use. Retroactive ratemaking also occurs when past deficits are made up by excessive charges in the future, or past profits are reduced by disallowances to future costs for ratemaking purposes.

Mr. Carver's argument appears to be that the ratepayers did not benefit from the negative NPPC in the past, and the Company "overrecovered" pension costs in the past, so rate base should be reduced (by the amount of the net pension asset) for purposes of setting future rates. (As is addressed in HECO RT-16, the two premises are incorrect.) The use of alleged overrecoveries in the past to reduce costs used to set future rates falls within the second category of retroactive ratemaking.

b. An analysis was not necessary as the CA's testimony suggests that the prepaid pension asset be disallowed from rate base in order to make up for what it perceived to be an over recovery of NPPC in the ten years between this and the Company's last rate case.

c. See CA-T-1, pages 16-26.

d. See the response to c.

CA-RIR-37

Ref: RT-1, page 15, lines 8-10 (Pension Asset).

The referenced testimony states, in part:

> Neither the CA nor the DOD question the validity or value of the asset, they simply take the position that ratepayers have funded the investment.

Based on the above, please provide the following:

a. Please define the phrase "funded the investment" as used by Mr. Alm in this context.

b. Please provide a pinpoint reference into Mr. Carver's direct testimony (CA-T-2) wherein he takes the position that ratepayers have funded the investment in the pension asset HECO has recorded on its balance sheet. If none, please so state.

HECO Response:

a. The phrase "funded the investment" means "provided funds for the investment.

b. Mr. Carver argues that the benefit of the negative NPPC was not flowed through to ratepayers. By implication, he appears to be arguing that ratepayers, not investors, somehow funded the net pension asset. If Mr. Carver agrees that investors funded the net pension asset (which is one of the points underlying the Company's position), then the Company does not understand the basis for the CA's position that the net pension asset should be removed from rate base.

CA-RIR-38

Ref: RT-1, page 15, lines 10-12 (Pension Asset).

The referenced testimony states, in part:

> Because this disallowance would reduce revenue requirement and ultimately decrease the Company's rates, it would in effect pay money back to ratepayers for this alleged over-recovery.

Based on the above, please provide the following:

a. Please confirm that the Company's existing rates (i.e., the rates resulting from the last rate case, Docket No. 7766) are based on an overall revenue requirement that did not include any (i.e., "zero") amount for the pension asset in rate base. If this cannot be confirmed, please explain.

b. Please confirm that HECO has proposed to include a pension asset in rate base of approximately $78.8 million, gross of accumulated deferred income tax reserves. (See HECO's response to CA-IR-337 and HECO-R-1901.) If this cannot be confirmed, please explain.

c. Referring to part (b) above, please confirm that HECO's proposed inclusion of the pension asset in rate base increases the overall revenue requirement, as compared to a rate base valuation that does not include the pension asset in rate base. If this cannot be confirmed, please explain.

d. Please confirm that CA Adjustment B-10 removes from rate base the $78.8 million pension asset HECO proposes to include in rate base, net of related accumulated deferred income tax reserves. If this cannot be confirmed, please explain.

HECO Response:

a. In Docket No. 7766, the Company did not propose to include an amount for prepaid pension asset in its rate base as none existed at the time the Company prepared its case for that proceeding.

b. Yes. The referenced IR response and exhibit speak for themselves.

c. Including the net pension asset in rate base results in higher revenue requirements than if the net pension asset is arbitrarily excluded from rate base. See also HECO-R-2301.

d. The CA should refer to its own witness to explain the effect of CA Adjustment B-10.

CA-RIR-39

Ref: RT-1, page 15, line 13 (Pension Asset).

The referenced testimony states:

> This is clearly retroactive ratemaking and should be rejected by the Commission.

Please provide a copy of all information, documentation and analyses relied upon by Mr. Alm to conclude that the Consumer Advocate's proposed exclusion of the pension asset HECO proposes to include in rate base constitutes prohibited "retroactive ratemaking."

HECO Response:

See response to CA-RIR-36.

CA-RIR-40

Ref: RT-1, pages 15-20 (Employee Count).

In discussing the Consumer Advocate's proposed use of average 2005 forecast employee counts; the following statement appears at page 18, lines 18-25 of Mr. Alm's rebuttal testimony:

> As such, the Company does not believe that the Commission should expect the Company to maintain any continuing budget austerity plans, ongoing hiring constraints or any other spending limitations in an effort to promote operational efficiency and minimize the burden of rate increases upon customers. The Company, however, may institute budget austerity plans, hiring constraints, and other spending limits in times of economic uncertainty, while not compromising reliability and safety, and in an effort to maintain financial integrity.

Based on the above, please provide the following:

a. Please provide a pinpoint reference into Mr. Carver's direct testimony (CA-T-2) wherein he claims or asserts that the Commission should expect the Company to maintain or remain on a continuing austerity program, impose ongoing hiring constrains or maintain spending limitations to promote operational efficiency. If none, please so state.

b. Does HECO currently have any specific plans or has management discussed internally the possibility of instituting "budget austerity plans, hiring constraints, and other spending limits" in 2005, 2006 or 2007? If so, please describe those plans and explain the context of any discussions thereon.

HECO Response:

a. The quoted passage above appeared in the following question and answer.

Q. The CA contends that the Company's assumptions are not realistic, "[p]articularly true when a company is in the process of transitioning from a self imposed austerity program that constrained the hiring of employees to a more robust staffing environment." CA-T-2, page 78, lines 12-14. What is the Company's response?

A. As the Company is mindful of producing and delivering a reliable supply of electricity when and where our customers need it, in a safe manner, and at reasonable prices, the Company continually strives to achieve improvements in efficiency and productivity

and reflects them in our budgeted work force requirements and non-labor costs. As such, the Company does not believe that the Commission should expect the Company to maintain any continuing budget austerity plans, ongoing hiring constraints or any other spending limitations in an effort to promote operational efficiency and minimize the burden of rate increases upon customers. The Company, however, may institute budget austerity plans, hiring constraints, and other spending limits in times of economic uncertainty, while not compromising reliability and safety, and in an effort to maintain financial integrity. HECO's response to CA-IR-269.

There is no reference in Mr. Carver's direct testimony (CA-T-2) wherein he claims or asserts that the Commission should expect the Company to maintain or remain on a continuing austerity program, impose ongoing hiring constrains or maintain spending limitations to promote operational efficiency. In CA-IR-269d, the CA did ask the following question, "Explain whether HECO believes that the Commission should expect to maintain any continuing budget austerity plans, ongoing hiring constraints or any other spending limitations in an effort to promote operational efficiency and minimize the burden of rate increases upon customers."

b. As stated in testimony and responses to IRs, the Company has and may institute budget austerity plans, hiring constraints, and other spending limitations in times of economic uncertainty, while not compromising reliability and safety, and in an effort to maintain financial integrity.

As stated in the responses to CA-IR-14, management was concerned that 2005 revenues would not be able to support the level of spending in the budget because rate relief was expected to begin no earlier than in the fourth quarter of 2005. An adjustment was made to

reflect an assumed reduction in spending in the short run, keeping in mind that it is in the interest of its customers for management to keep earnings from falling too far.

Whether the Company institutes any similar type of adjustments for 2006 or 2007 will depend on a number of factors, including, but not limited to, the amount of rate relief granted in this proceeding, the impact and results of the Energy Efficiency Docket proceeding and the mechanism used to recover DSM program related costs, the completion of significant capital expenditures and computer software development projects, increase in operations and maintenance expenses beyond the normalized amounts included in rates as a result of this rate case, and changes in kilowatthour sales and the cost of capital for the Company.

CA-RIR-41

Ref: RT-1, pages 15-20 (Employee Count).

In discussing the Consumer Advocate's proposed use of average 2005 forecast employee counts; the [redacted]

> The CA bases its approach on the use of an 'average' test year. However, for purposes of this rate case, there are at least three fundamental problems with the CA's approach, as Ms. Sekimura addresses in HECO RT-16.

Based on the above, please provide the following:

a. Please define the "average" test year concept, as understood by Mr. Alm.

b. In the context of an "average" forecast test year, does Mr. Alm believe that it is acceptable in determining overall revenue requirement to base certain elements of overall revenue

months ending December 31", so the average amounts generally are the "course-of the year" amounts, that is the amounts that are incurred during the 12 months of the test year.

b. The test year is a measure of the operations and investment for a specified twelve-month period. The test year provides the data foundation upon which the rate case is built. It is the starting point for developing investment and operating results that are presumed to be representative of future conditions so that future rate needs may be reasonably estimated. Revenues, expenses, or costs may then need to be adjusted to reflect the conditions during the period in which the rates established as a result of the proceeding would be in effect.

Since rates are set for the future, the fundamental test period assumption is that the relationship between revenues, expenses and rate base will remain roughly the same in the period during which the rates are expected to be in effect, so that the utility will have a reasonable opportunity to earn the return found to be fair in the future. If an average test year is used, adjustments are made to the test year estimates so that the results of operations reflect known changes and better reflect future "normalized" operating conditions when the rates will actually be in effect. The scope of the normalization adjustments that may be appropriate depend on the specific circumstances in a case. (For example, in a period of high rate base additions coupled with high inflation, the Commisssion authorized the use of a year end rate base with average revenues and expenses, resulting in a deliberate mismatch to offset the effects of attrition. In HECO's 1990 test year rate case, the Commission authorized the inclusion of a full year of Kalaeloa costs, even though the operation of the facility was delayed to May 1991.) In this case, HECO has identified the adjustments that are appropriate, and has explained the basis for each adjustment.

To some extent, sales growth (resulting in revenue increases) can be expected to offset normal increases in labor expenses (due to wage and salary increases), non-labor expenses (due to inflation, in low inflation periods) and rate base (in low construction periods). (That is why HECO agreed with the CA in rate cases in the 1990's not to annualize the impact of wage and salary increases made during the test year, even though it is my understanding that the Commission commonly authorized the annualization of wages and salary increases in rate cases prior to 1990.) Sales growth should not be expected to offset expense increases for significant increases in staffing or new operational activities (such as DG at substations) that are reflected only partially in the test year O&M expenses.

Thus, in some cases (such as this rate case), it is appropriate to base certain expenses on the annualized costs, particularly in the case of a significant new cost that begins during the test

year, and will be in effect for the full year during the period when rates are in effect.

c. In general there should be consistency in the approach to quantifying the various elements of the rate making formula, however, the overall objective of the rate making process should also

CA-RIR-42

Ref: RT-1, pages 15-20 (Employee Count).

In discussing the Consumer Advocate's proposed use of average 2005 forecast employee counts, the following statement appears at page 19, line 4, of Mr. Alm's rebuttal testimony:

> First, much of the staffing increase is for new positions, and is not just to fill previously authorized but unfilled positions. For example, in Production, HECO needs to add 20 employees to establish night maintenance crews. The CA has included the annual costs for only one-half the new positions (by including one-half the full year's cost for all of the positions). Allowing the costs for only 10 new employees (by including only one-half the annual cost for 20 new employees) is not going to provide funding for 20 new employees. Sales growth from 2005 to 2006 is not going to pay for the other one-half of this new cost.
>
> Based on the above, please provide the following:

a. Please confirm that the above quote draws a distinction between a new position that has not yet been filled with a previously authorized position that is unfilled. If this cannot be confirmed, please explain.

b. Please explain why an unfilled new position should be treated differently for ratemaking purposes than an unfilled position that had been previously authorized.

HECO Response:

a. The quoted language is distinguishing between vacancies that result from increases in HECO's permanent organizational staffing (i.e., new staffing positions) and an existing position in the organizational structure that is vacant. the significance of this distinction for ratemaking purposes is discussed in the remainder of the language cited above, and in HECO RT-16.

b. See HECO RT-16 and the remainder of the cited testimony. As is indicated in HECO RT-16 (pages 16-17), vacancies arising out of new staffing positions created to enable HECO to perform new or substantially increased work that will carry over into future years should not be treated in the same manner as "structural vacancies" due to retirements and/or

terminations that periodically occur. A number of increases in HECO's permanent organizational staffing were included in test year expenses for 12 months as a normalized expenditure because the positions are in addition to the organizational structure as opposed to an existing position in the organizational structure that is vacated. For example, in the Production Department, 20 of the additions to the organizational structure were due to increasing the maintenance staffing level to establish night maintenance crews. These type of positions created additional vacancies that are not the same as vacancies created due to normal turnover caused by voluntary (e.g., retirements, transfers, resignations, military deployment) and involuntary (e.g., terminations) separation from the position or HECO. The CA's proposed labor expense adjustment provides the annual costs for only one-half the new positions (by including one-half the full year's cost for all of the positions). Allowing the costs for only 10 new employees (by including only one-half the annual costs for 20 new employees) is not going to provide funding for 20 new employees. If the difference between vacancies created by the new staffing positions (which could take longer to fill and should not be on a recurring basis, unlike the "structural vacancies") and the "structural vacancies" is not taken into consideration, then the vacancy level with respect to positions included in the test year estimates is misleading.

The rebuttal testimonies also note that the level of vacancies and staffing expenses should not be viewed in isolation. For example, as discussed in HECO's rebuttal testimonies, (1) in some areas (e.g., the Production area), expenses are expected to exceed

and are being filled (i.e., the additional unforecasted positions), and (3) HECO is incurring additional, unforecasted overtime in some areas as a result of some of the vacancies.

CA-RIR-43

Ref: RT-1, page 35, line 9-12 (Test Year Results & Rate Changes).

The referenced testimony states, in part:

Under the test year concept, the amount of the rate increase approved by the Commission in a general rate case, which uses an average rate base, generally is the increase in revenues necessary at the beginning of the test year. Unless a rate increase is effective at the beginning of a test year, the utility will not have an opportunity to earn the fair rate of return on rate base determined to be fair and reasonable by the Commission, based on the estimated results of operations for the normalized test year.

Based on the above, please provide the following:

a. Please provide the basis for Mr. Alm's contention that use of an average rate base implies, or presupposes that any change in rates will occur at the beginning of the test year.

b. Referring to part (a) above, please provide a citation to, and copy of any authoritative support or specific documents (e.g., regulatory orders, publications, etc.) which support the contention that use of an average rate base implies or presupposes that any change in rates will occur at the beginning of the test year.

HECO Response:

a. The testimony states as follows: "Under the test year concept, the amount of the rate increase approved by the Commission in a general rate case, which uses an average rate base, generally is the increase in revenues necessary at the beginning of the test year. Unless a rate increase is effective at the beginning of a test year, the utility will not have an opportunity to earn the fair rate of return on rate base determined to be fair and reasonable by the Commission, based on the estimated results of operations for the normalized test year. If the rate increase is received later in the test year, the amount of the rate relief actually received in the test year will be proportionately lower than that determined to be necessary. For example, if rate relief is delayed in this docket (Docket No. 04 0113) until three-fourths of the year is over, HECO would only receive a portion of the needed rate

relief in the test year."

The rate increase is the additional revenues necessary above revenues at present rates to yield the revenue requirements (i.e., it's the difference between "revenues at present rates" and "revenues at proposed rates"). The revenue difference between is based on the annual revenues that would be received as a result of a change in rates, not the additional revenues that would be received if the increase were in effect for only part of the year. The implied assumption is that the rate increase is received at the beginning of the year. (The annual revenues would actually be received only if the rate increase was received at the beginning of the test year.) If the assumption was that rates were increased half way through the year, then rates would have to be increased by twice as much to produce the same additional revenues in 6 months (instead of 12).

None of the parties has assumed that the rate increase will actually take place at the beginning of calendar year 2005. The calculation of the rate increase necessary to produce a fair rate of return, however, assumes that the rate increase is received at the beginning of the 2005 test year.

b. See response to subpart a. As stated above, none of the parties has assumed that the rate increase will actually take place at the beginning of calendar year 2005. The calculation of the rate increase necessary to produce a fair rate of return, however, assumes that the rate increase is received at the beginning of the 2005 test year.

CA-RIR-44

Ref: RT-1, pages 37-38 (Potential Reserve Mechanism).

Beginning at page 38, line 11, the referenced testimony states, in part:

> The Consumer Advocate's recommendations are akin to single-issue ratemaking, which the Consumer Advocate has opposed in the past. For this reason, HECO must respectfully object to the CA's recommendations at this time. However, the Company would be willing to consider these recommendations in the context of an overall policy allowing the use of adjustment mechanisms for specific issues – provided the adjustment mechanism policy works both ways.

Based on the above please provide the following:

a. Please define the phrase "single-issue ratemaking" as used by Mr. Alm in this context.

b. Please identify and describe any forms of deferral accounting or cost recovery mechanisms the Commission has previously authorized for HECO that would conform to Mr. Alm's definition of "single-issue ratemaking," as provided in response to part (a) above.

HECO Response:

a. The term single-issue ratemaking refers to considering an individual item to determine cost recovery or refund to ratepayers outside of the general rate increase process (where all revenues, costs, expenses, rate base and returns would be considered in determining a utility's rates).

b. Deferral accounting and cost recovery of specific items have been rare for this Commission

[redacted]

development of an IRP at that time was difficult to estimate since developing an IRP was a new endeavor for the company and the review process would be new for the Consumer Advocate and other parties. However, in Docket No. 99-0207 (HELCO's 2000 test year rate case), the Consumer Advocate argued (contrary to its position in this case) that HELCO's IRP planning costs should be recovered in base rates. The Commission concluded that this was appropriate, and HELCO's IRP planning costs incurred subsequent to the rate case decision have not been recovered through the IRP Clause.

seeks special treatment for a single expense item") and the Commission denied the request of the Gas Company and Kauai Electric to defer Y2K compliance costs until their next rate cases.

There have been instances when a utility has been allowed to defer and amortize certain costs, and utility's are generally required to defer and amortize the gains on sale of property. In a few instances, deferral and amortization has been timed to begin with the next rate case. In addition, the Legislature provided for interim (between rate cases) surcharge recovery mechanisms when it increased the public utility fee to pay for the CA's consultants, and when it provided for a firm capacity surcharge in H.R.S. § 269-27.2 to recover firm capacity payments to nonfossil fuel producers that are initiated between rate cases. The CA should be aware of more instances then HECO, as the CA is a party to all utility proceedings.

CA-RIR-45

Ref: RT-3, page 2, line 21 through page 3, line 3.

At the referenced testimony, Mr. Young identifies eight causes of changes made to HECO's proposed test year revenues. For each of the eight reasons, please provide a separate breakdown of the revenue dollar impacts and gross margin impacts (revenue less associated changes in fuel/energy costs) associated with the cause.

HECO Response:

The following are the revenue dollar impacts, in $000s:

1.	Revised estimate of test year 2005 sales	$1,299.4
2.	Revised estimate of Schedule PP power factor	716.3
3.	Revised estimate of the energy cost adj. factor	222,509.1
4.	Revised estimate of Rider M and Rider I adj.	22.3
5.	Eliminate adj. for Rider EDR	7.2
6.	Eliminate adj. for Schedule CHP	-134.3
7.	Revised estimate of Rate Adj. % factor	1.1
8.	Revised estimates of adj. for min. bills, Employee discount, Apt. House billing discount	-186.4
	Total change in electric sales revenue at present rates	$224,234.7

Only the first item, the revised estimate of test year 2005 sales would have an associated change in fuel/energy costs. Please refer to HECO RT-4 for an estimate of the change in fuel expense associated with the revised estimate of test year 2005 sales.

CA-RIR-46

Ref: RT-3, page 2, line 21 through page 3, line 3.

At the referenced testimony, Mr. Young describes differences between the Consumer Advocate's and the Company's revenue estimate at present rates. Please provide the Company's best estimate of the revenue dollar impact and gross margin impacts (revenue less associated changes in fuel/energy costs) of each such difference and provide all supporting calculations of same.

HECO Response:

The differences between the Consumer Advocate's and the Company's revenue estimate at present rates are listed at HECO RT-3, page 8, beginning at line 15, and are summarized in HECO-R-309:

In $000s	CA	Company	Difference
1. Impact of Sales Adjustment Including min bills and discounts, rate adj. %, and PF% adj. (See CA Sch. C-1, C-3; CA-RIR-45)	$2,377	$1,831	$546
2. Adj. Energy Cost Adj. Factor (See CA Sch. C-4, CA-RIR-45)	$251,628	$222,509	$29,119
3. Rider Adjustments, M, I, EDR (See CA Sch. C-2, CA-RIR-45)	$135	$30	$105
4. Amortization of Gain on Sale (See CA Sch. C-5, HECO-R-308)	$30	$35	-$5
5. Change in Late Payment Charge (HECO-R-308)	$0	$224	-$224
Total Difference (not exact due to rounding)			$29,541

Only the first item, the revised estimate of test year 2005 sales would have an associated change in fuel/energy costs. Please refer to HECO RT-4 for an estimate of the change in fuel expense associated with the revised estimate of test year 2005 sales.

CA-RIR-47

Ref: HECO-RWP-302, pages 1-166.

Please identify and explain each change in input data and each changed calculation algorithm that is contained in these computations to support HECO's asserted Rebuttal revenue at present rates and revenue at proposed rates, relative to the corresponding calculations in HECO WP-304 supporting the Company's initial filing. In addition, provide the electronic spreadsheet files for HECO-RWP-302 with all cell formulae and links intact.

HECO Response:

The following descriptions will reference the rebuttal workpaper page (direct testimony workpaper page) and describe the change in input data; there are no changes to the calculation logic:

1. HECO-RWP-302, page 1 (HECO-WP-304, page 1) change in the forecast of Schedule R and Schedule E MWH sales;
2. HECO-RWP-302, page 2 (HECO-WP-304, page 2) change in the number of Schedule R 1 phase and 3 phase bills and MWH subject to the minimum bill due to change in the energy cost adjustment factor from 2.586 ¢/kWh to 5.414 ¢/kWh, and change in proposed Schedule R rates;
3. HECO-RWP-302, page 5 (HECO-WP-304, page 5) change in estimate of employee discount due to change in Schedule E forecast sales and change in energy cost adjustment factor from 2.586 ¢/kWh to 5.414 ¢/kWh;
4. HECO-RWP-302, page 6 (HECO-WP-304, page 6) change in number of bills and mWh subject to apartment house collection provision due to change in forecast sales and change in energy cost adjustment factor from 2.586 ¢/kWh to 5.414 ¢/kWh, and change in proposed Schedule R rates;
5. HECO-RWP-302, page 8 (HECO-WP-304, page 8) change in Schedule TOU-R revenue adjustment due to change in proposed Schedule R and Schedule TOU-R rates;

6. HECO-RWP-302, page 9 (HECO-WP-304, page 9) change in forecast Schedule G MWH sales;
7. HECO-RWP-302, page 12 (HECO-WP-304, page 12) change in the number of Schedule G 1 phase and 3 phase bills and MWH subject to the minimum bill due to change in the energy cost adjustment factor from 2.586 ¢/kWh to 5.414 ¢/kWh, and change in proposed Schedule G rates;
8. HECO-RWP-302, page 15 (HECO-WP-304, page 15) change in Schedule TOU-C revenue adjustment due to change in proposed Schedule G and Schedule TOU-C rates;
9. HECO-RWP-302, page 16 (HECO-WP-304, page 16) change in forecast Schedule J MWH sales;
10. HECO-RWP-302, page 21(HECO-WP-304, page 21) change in Schedule J TP Voltage Adjustment at proposed rates due to change in proposed Schedule J rates;
11. HECO-RWP-302, page 26 (HECO-WP-304, page 26) change in Schedule J TS Voltage Adjustment at proposed rates due to change in proposed Schedule J rates;
12. HECO-RWP-302, page 33 (HECO-WP-304, page 33) change in Schedule J DP Voltage Adjustment at proposed rates due to change in proposed Schedule J rates;
13. HECO-RWP-302, page 40 (HECO-WP-304, page 40) change in Schedule J DS Voltage Adjustment at proposed rates due to change in proposed Schedule J rates;
14. HECO-RWP-302, page 45 (HECO-WP-304, page 45) change in Schedule J Network Service Adjustment at proposed rates due to change in proposed Schedule J rates;
15. HECO-RWP-302, page 53 (HECO-WP-304, page 53) change in Schedule J demand and energy charges subject to power factor adjustment at proposed rates due to change in proposed Schedule J rates;

16. HECO-RWP-302, pages 55,66-71,73-80,106-109, (HECO-WP-304, pages 55,66-68,95-100) changes in the estimates of adjustments for Rider customers;
17. HECO-RWP-302, page 110 (HECO-WP-304, page 101) change in Schedule TOU-C revenue adjustment due to change in proposed Schedule J and Schedule TOU-C rates;
18. HECO-RWP-302, page 114 (HECO-WP-304, page 105) change in forecast Schedule P mWh sales;
19. HECO-RWP-302, page 116 (HECO-WP-304, page 107) change in Schedule PS5 % kW Demand billed in each block due to change in forecast average kW per bill;
20. HECO-RWP-302, page 117 (HECO-WP-304, page 108) change in Schedule PS5 network adjustment due to change in proposed Schedule PS rates;
21. HECO-RWP-302, page 118 (HECO-WP-304, page 109) change in Schedule PS % kW Demand billed in each block due to change in forecast average kW per bill;
22. HECO-RWP-302, page 119 (HECO-WP-304, page 110) change in Schedule PS demand and energy charges subject to power factor adjustment at proposed rates due to change in Schedule PS proposed rates;
23. HECO-RWP-302, pages 120, 125-129, (HECO-WP-304, pages 111, 116, 118-120) changes in the estimates of adjustments for Rider customers;
24. HECO-RWP-302, page 131 (HECO-WP-304, page 121) change in forecast Schedule P mWh sales;
25. HECO-RWP-302, page 133 (HECO-WP-304, page 123) change in Schedule PP % kW Demand billed in each block due to change in forecast average kW per bill;
26. HECO-RWP-302, page 134 (HECO-WP-304, page 124) change in Schedule PP demand and energy charges subject to power factor adjustment at proposed rates due to change in

Schedule PP proposed rates, and change in power factor adjustment at present and at proposed rates due to fixing Schedule PP power factor at 95%;

27. HECO-RWP-302, page 135 (HECO-WP-304, page 125) change in calculation of secondary metering adjustment at proposed rates due to change in Schedule PP proposed rates;
28. HECO-RWP-302, pages 136, 147-153 (HECO-WP-304, pages 126, 137-138,141-143) changes in the estimates of adjustments for Rider customers;
29. HECO-RWP-302, page 156 (HECO-WP-304, page 144) change in forecast Schedule P mWh sales;
30. HECO-RWP-302, page 160 (HECO-WP-304, page 148) change in Schedule PT % kW Demand billed in each block due to change in forecast average kW per bill;
31. HECO-RWP-302, page 161 (HECO-WP-304, page 149) change in Schedule PT demand and energy charges subject to power factor adjustment at proposed rates due to change in Schedule PT proposed rates;
32. HECO-RWP-302, page 164 (HECO-WP-304, page 152) change in mWh sales and bills subject to minimum bill due to change in the energy cost adjustment factor from 2.586 ¢/kWh to 5.414 ¢/kWh, and change in proposed Schedule F rates; and
33. HECO-RWP-302, page 166 (HECO-WP-304, page 154) change in revenues subject to secondary metering adjustment due to change in proposed Schedule F rates.

The electronic spreadsheet file for HECO-RWP-302 has been provided.

CA-RIR-48

Ref: RT- 4, Page 16, Line 1 – 25.

Please indicate the EFORS that were used in the HECO August 5, 2005 Rebuttal Testimony filing. Please refer to HECO's response to CA-IR-461 when responding to this question.

HECO Response:

Please refer to the table, titled "HECO Generating Unit EFOR" on page 2 of HECO's response to CA-IR-461. The EFORs for each HECO unit are provided under three columns. The first column is titled "2004 Recorded EFOR." The second (i.e., middle) column is titled "5-Year (2000-2004) Average EFOR." The third (i.e., right-most) column is titled "EFOR Forecast 2005-2009." The EFORs in the third column titled "EFOR Forecast 2005-2009" were used in HECO's August 5, 2005 rebuttal testimony.

CA-RIR-49

Ref: RT- 4, Page 19, Line 10.

[redacted]

should be HECO-R-WP-411; however that workpaper cannot be located in HECO's rebuttal testimony filing.

CA-RIR-50

Ref: RT-6, page 10, line 24.

According to Mr. Fujinaka, "Sales growth from 2005 to 2006 is not going to pay for the other one-half of this new cost." Based on this statement, please respond to the following:

a. Please confirm that Mr. Fujinaka believes that HECO will continue to experience ongoing growth in the number of customers served by the Company, the kWh and sales revenue from the last half of 2005 into 2006 and beyond.

b. In Mr. Fujinaka's opinion, how much additional revenue does HECO expect to receive in 2006, relative to the 2005 levels, as a result of the referenced sales growth.

c. In Mr. Fujinaka's opinion, how much additional revenue does HECO expects to receive in 2006, relative to the 2005 levels, as a result of the referenced sales growth.

d. After paying for fuel and variable purchased power costs incurred to serve load and sales growth in 2006, provide the calculations indicating how much additional revenue is expected by HECO to be available to help offset growth in HECO's overall expenses, including any "new" production O&M expenses.

HECO Response:

a. HECO Witness T-6, Mr. Aaron Fujinaka, confirms that, at this time, he believes HECO will continue to experience ongoing growth in the number of customers served by the Company, the kWh and sales revenue from the last half of 2005 into 2006. For 2006 and beyond, Mr. Fujinaka cannot confirm that he believes HECO will experience ongoing growth. Questions related to sales and revenues should be directed to HECO's Electricity Sales and Customer Forecast witness (HECO T-2) and Electric Revenues and Other Operating Revenues witness (HECO T-3).

b. See response to a.

c. See response to a.

d. Witness HECO T-6 has not performed calculations to determine the amount of revenue expected by HECO to be available in 2006 to help offset growth in HECO's overall expense

and any "new" Production O&M expense. However, in very simplistic terms, sales, and therefore revenues, would have to at least match the increase in expenses to allow HECO to receive what would be finally determined by the PUC to be a fair rate of return. HECO's assumptions for budgeting in 2005 TY were stated by Mr. Robert Alm in HECO T-1, page 25, beginning at line 17. These assumptions include bargaining unit wage increases of between 3% and 1.5% occurred or will occur in the period 11/1/03 to 11/1/05. A merit salary increase of 3.5% was expected on May 1, 2005 and 0.25% on September 1, 2005. A base nonlabor inflation factor of 2.0% was assumed where specific information was not available. Electricity sales, and therefore revenues, would have to increase at least enough to match the assumed increased labor and nonlabor expense. To cover any other known or unexpected additional expenses to HECO, sales and revenues will have to increase even more. A review of HECO-R-205 shows that sales increased from 6,997.9 GWh in 1999 to 7,732.8 GWh in 2004, an average increase of just over 2% per year. Ms. Hazama states, in HECO RT-2, page 9, that while HECO's rebuttal test year estimate for electricity sales is 7,856.0 GWh, year to date actual sales through June 2005 are lower. See also response to DOD-RIR-61. Again, in very simplistic terms, sales and revenues would have to increase more than any expected or unexpected increases in expenses to allow HECO to earn the rate of return found to be fair in this docket.

CA-RIR-51

Ref: RT-6, page 17, line 7.

According to Mr. Fujinaka's Rebuttal, "HECO agrees with the CA's option to allow $121,000 for 2005 ESA development, but seeks flexibility in the use of the remaining funds in other research and development ("R&D") projects. HECO's expenditures for R&D activities could increase in the future so the test year level of expenses might actually understate the on going level of expenses for this type of activity." Based on these statements, please provide the following information:

a. Confirm that the new R&D projects described at pages 18 through 24 of RT-6 were not included in the Company's Direct Testimony rate case forecast and were not the subject of any Consumer Advocate information requests previously answered by HECO.

b. Provide a schedule showing the actual expenditures made to date by HECO for each of the new LPG reforming unit, NaS battery, emerging PV and communications technology projects listed at page 18, lines 6-11.

c. Provide complete copies of all contracts, agreements, requests for proposals, proposals and other documents indicative of the known and measurable status of each of the new R&D projects described at pages 18 through 24 of RT 6.

HECO Response:

a. The new R&D projects described at pages 18 through 24 of RT-6 were not specifically mentioned in the Company's Direct Testimony and were not the subject of any Consumer Advocate pre-rebuttal testimony information requests previously answered by HECO. The cost of these new R&D projects is discussed in HECO's response to CA-RIR-70. The estimated R&D costs have not increased, however, have slightly decreased from the amount included in direct testimony (from $500,000 to $480,000). In 2005, HECO plans to use remaining funds from ESA development towards the new R&D projects.

b. No expenditures have been made to date for the new LPG reforming unit, NaS battery, emerging PV, and communications technology projects. Efforts are ongoing to develop

these projects.

c. Status and documentation to support such status for the new R&D projects are provided below:

- Testing and characterization of liquefied petroleum gas ("LPG") reforming unit

  A draft Consultant Services Master Agreement ("CSMA") to be executed with the University of Hawaii has been issued to the University of Hawaii for review. A Work Authorization ("WA") document for the LPG reformer project (to be executed under the CSMA) also is under review. These draft documents (in their present draft forms) are provided on pages 3-28. University of Hawaii researchers have been in contact with LPG reformer manufacturer for delivery of this unit to Hawaii.

- Stationary sodium-sulfur ("NaS") battery energy storage

  As stated in CA-RIR-70, HECO plans to defer this project to 2006.

- Performance assessment of emerging photovoltaic ("PV") technology

  Current activities include preliminary discussions with PV equipment vendors for price estimates and delivery schedules and local PV manufacturer representative and integrator for packaging of the PV systems, ordering the PV modules and inverter from local PV representative, site screening and selection with HECO Facilities personnel for installation on HECO Ward facilities, and formulation of data monitoring strategies. A draft services agreement will be developed for this project.

- Research and development of a new communication technology

  An executed Work Authorization document and supporting material for a grid communications RD&D project are provided on pages 29-55.

Due to the voluminous nature of the information, one copy (pages 3-55) will be provided to the Consumer Advocate, Department of Defense and the Public Utilities Commission under separate transmittal.

CA-RIR-52

Ref: RT-7, page 7, line 12 and line 14.

According to Mr. Seu, "Non-fuel O&M expenses for the nine units total $1,466,000 on an annualized basis." Furthermore, "As mentioned earlier, HECO proposes to normalize the impact on O&M expenses by including the annual O&M expenses for the nine units in the 2005 test year revenue requirements." Please explain Mr. Seu's understanding of the difference between "normalizing" versus "annualizing" expenses for ratemaking purposes and describe each known distinction in these two concepts.

HECO Response:

Annualization means to make an adjustment to reflect what the normal ongoing level of expenses would be in the test year had the associated activity been performed for the entire year. Normalization is an adjustment to convert unusually high or low expenses into more normal levels. As stated in HECO RT-1, page 23, line 15: "Annualization, when properly applied, is a form of normalization. Both seek to adjust expenses or revenue amounts to normal, ongoing levels." Please see HECO RT-1, pages 20-26, for a full description of annualization and normalization.

To clarify, HECO is proposing to annualize the non-fuel DG O&M expenses in order to reflect the normal ongoing level of expenses that will be incurred. The point of the testimony in RT-7 is that the normal, ongoing level of non-fuel O&M expense to be incurred by HECO for its DG installations is $1,466,000 per year, not the $394,000 that the Consumer Advocate proposes.

CA-RIR-53

Ref: RT-7, page 10, line 24.

According to Mr. Seu, "The gap between the Consumer Advocate's recommended O&M number and the actual costs that will be incurred by HECO is simply too large to rely on a hope that revenues will grow and that utility costs in other areas will not increase." Please explain and provide complete copies of all analyses, reports, projections, workpapers and other information prepared or relied upon in making this statement.

HECO Response:

The basis for this statement is the fact that the CA's recommended amount of cost recovery for the HECO DG projects amounts to only 27% of the expenses that will be incurred by HECO.

CA-RIR-54

Ref: RT-7, page 11, line 5.

According to Mr. Seu, "Revenues from the energy generated by the DG units will in no way pay for the expenses that will be incurred to have the units available to serve HECO's customers." Based on this statement, please provide the following information:

a. State whether Mr. Seu believes that the Consumer Advocate asserted anywhere in its direct testimony the premise that "Revenues from the energy generated by the DG units will...pay for the expenses that will be incurred to have the units available to serve HECO's customers."

b. If your response to part (a) is affirmative, provide specific citation to each place in the Consumer Advocate's direct testimony where such an assertion is made and discussed.

HECO Response:

a. The Consumer Advocate did not make this assertion. Rather it asserted, with no specific analysis, that new revenues from continuing load growth would offset the full annual costs of HECO's DG (See, CA-T-1, page 32, lines 13-18), and thus the Consumer Advocate recommends allowing recovery of only 27% of the actual costs that HECO would incur for the DG.

b. See response to subpart a.

CA-RIR-55

Ref: RT- 7, Page 11, Lines 8 through 11.

a. Will DG units decrease energy losses and/or avoid delivery systems (distribution and/or transmission) capital expenditures?

b. If no, please explain why not.

c. If there is a decrease in losses and/or capital expenditures, please quantify the decreases in dollars and explain how the amount was quantified.

HECO Response:

a. HECO's 2005 DG installations will have an insignificant effect on transmission and distribution ("T&D") energy losses and will not avoid T&D capital expenditures. The 2005 DG installations are to serve as limited-duty peaking units to supplement HECO's system reserve capacity and help with grid stabilization. There would be insignificant reduction in line losses due to the limited dispatch of the DG units. Furthermore, the DG sites – Ewa Nui Substation, Helemano Substation, and Iwilei Tank Farm – were selected on the basis of having available space, site access, appropriate zoning, and being able to obtain required noncovered source air permits and land use permits. No overload conditions exist at the sites, and currently there is no identified need for additional T&D infrastructure in the surrounding areas.

The energy loss reduction and avoided T&D benefits of DG are more typically associated with permanent, long-term customer-sited DG. The HECO DG installations, however, are grid-sited, limited duty units, with no avoided T&D benefit.

b. Please see the response to subpart a.

c. Please see the response to subpart a.

CA-RIR-56

Ref: RT- 7, Page 13, Lines 9 through 18.

When more DG units will be installed in the future, please indicate the avoided capital expenditures and operation and maintenance expenses that would be decreased including the fuel caused by decreased delivery system energy losses.

HECO Response:

As described in response to CA-RIR-55, HECO's 2005 DG unit installations will not avoid T&D capital expenditures and will have an insignificant impact on T&D energy losses. The same would be expected for future DG units that are installed at HECO sites with similar purpose and configuration as the 2005 installations. It is possible that customer-sited DG opportunities may arise in the future which provide avoided T&D capital and/or O&M reduction benefits, however, no analysis has been conducted of such benefits.

CA-RIR-57

Ref: RT-8, page 4, line 25 (Software Costs – T&D).

The referenced testimony states, in part:

As noted earlier in this rebuttal testimony, HECO agrees with removing $25,000 of these costs per HECO-R-1302, as shown in HECO-R-803. Please refer to Ms. Yamauchi's testimony at HECO-RT-13 for discussion of the Ellipse maintenance buy-down cost.

HECO-R-1302 addresses employee counts, not software costs, and HECO-R-803 merely shows the $25,000 reduction as an input into the supporting spreadsheet file. In addition, the source for HECO's T&D rebuttal position on software (see HECO-R-803, Column A) is to HECO's direct testimony (HECO-1604, page 17). Please provide the following:

a. It is unclear how the $25,000 reduction in software costs, that HECO agrees with removing, was quantified. Please provide additional supporting calculations of this amount.

b. Did HECO intend to refer to HECO-1604, page 17, as support for the $25,000 amount on HECO-R-803?

   1. If so, please clarify how HECO-1604 supports the referenced amount removed by the Company in rebuttal.

   2. If not, please explain.

c. Does the $25,000 reduction relate to Ellipse buy down costs or upgrade amortization? Please explain.

HECO's Response

a. Please refer to HECO-R-1303 for additional supporting calculations of the $25,000 reduction for Ellipse software maintenance fees. The amount consists of costs listed in column (c) for the following NARUC accounts: 562, 563, 566, 570, 571, 582, 583, 584, 592, 593, 594 and 598.

b. Yes, HECO intended to refer to HECO-1604, page 17 as support for the $25,000 amount. The amounts listed in HECO-1604, page 17 showed the breakdown of the original amount that HECO included for Ellipse software maintenance fees, which provides the basis for the

adjustment that was subsequently calculated.

c. The $25,000 reduction relates to the maintenance buy-down fee amortization. Please refer to HECO-RT-13, pages 14 and 15 of 30 for additional details.

CA-RIR-58

Ref: RT-8 , page 5, line 20 (Employee Count).

The referenced testimony states:

HECO's position is that all positions forecasted in the 2005 test year should be considered as filled for the entire test year. The CA's approach to take one-half of the costs for these "open" positions does not account for these positions being filled in future years when rate recovery for these positions will be required.

Based on the above, please provide the following:

a. The quoted testimony contends, in part, that the Consumer Advocate's approach "does not

- Load Dispatcher – Filled 4/05
- Systems Engineer – Filled 4/05
- Substation Electrician – Filled 5/05
- Systems Analyst – Interview completed, completing final background check, to be filled during August 2005.
- Load Dispatcher – Trouble Dispatcher is currently training to be promoted to Load Dispatcher, anticipated to be completed and promoted in October 2005.
- Trouble Dispatcher – Filled 8/05

In addition, please see the response to subpart c below and HECO RT-16, pages 14 and 18.

b. All positions at issue were included in HECO's 2005 test year forecast as being filled during each month of 2005. There was an assumption in the operating forecast that additional staffing included in the operating forecast would be filled as the year progressed. See response to CA-IR-14 and HECO RT-1, page 32. HECO RT-8 also identifies a significant number of new positions which were not included in the test year estimate, but which have now been filled or are in the process of being filled, including 7 positions for System Operation, 4 positions for EDP Engineering and 2 positions for Support Services.

c. It is HECO's position that the test year includes an annual level of labor and related benefit costs for all positions forecasted in 2005. HECO recognizes, as noted above, that all these

that HECO will equal and possibly exceed the 2005 test year estimate." HECO RT-8, page 17, lines 21 – 25 and page 18, line 1. Please see also HECO RT-16, pages 10 through 18.

CA-RIR-59

Ref: RT-8, pages 17-18 (T&D Expense).

Beginning at page 17, line 24, Mr. Yoshida compares the level of actual T&D expense through 6/30/05 with HECO's 2005 test year estimate. Please provide the following:

a. In a format comparable to HECO-809, please provide actual 2005 T&D expense by month.

b. In a format comparable to HECO-809, please provide actual 2004 T&D expense by month.

c. In a format comparable to HECO-809, please provide HECO's 2005 T&D expense forecast by month.

HECO's Response

a. Please refer to CA-RIR-59, pages 2 – 4 for actual 2005 T&D expenses by month.

b. Please refer to CA-RIR-59, pages 5 – 8 for actual 2004 T&D expenses by month.

c. Please refer to CA-RIR-59, pages 9 – 13 for 2005 T&D expense forecast by month.

Hawaiian Electric Company, Inc.
2005 TEST YEAR

TRANSMISSION AND DISTRIBUTION
OPERATION AND MAINTENANCE EXPENSE
($ Thousands)

			(A)	(B)	(C)
				2005 ACTUAL	
			TOTAL	JAN	FEB
	Transmission Operations				
1	Labor	$	1,081	163	147
2	Non-Labor	$	1,185	134	154
3	TOTAL	$	2,266	297	301
	Transmission Maintenance				
4	Labor	$	932	141	111
5	Non-Labor	$	1,248	111	146
6	TOTAL	$	2,180	252	257
7=3+6	TOTAL TRANS O&M	$	4,446	549	558
	Distribution Operations				
8	Labor	$	2,910	442	361
9	Non-Labor	$	2,487	388	278
10	TOTAL	$	5,397	830	639
	Distribution Maintenance				
11	Labor	$	2,808	465	325
12	Non-Labor	$	4,265	469	460
13	TOTAL	$	7,073	934	785
14=10+13	TOTAL DIST O&M	$	12,470	1,764	1,424
15=7+14	GRAND TOTAL O&M	$	16,916	$ 2,313	$ 1,982

Note:
Figures may not total exactly due to rounding.

Hawaiian Electric Company, Inc.
2005 TEST YEAR

TRANSMISSION AND DISTRIBUTION
OPERATION AND MAINTENANCE EXPENSE
($ Thousands)

			(A)	(B)	(C)
				2005 ACTUAL	
			MAR	APR	MAY
	Transmission Operations				
1	Labor	$	136	166	169
2	Non-Labor	$	336	136	134
3	TOTAL	$	472	302	303
	Transmission Maintenance				
4	Labor	$	100	158	115
5	Non-Labor	$	174	152	357
6	TOTAL	$	274	310	472
7=3+6	TOTAL TRANS O&M	$	746	612	775
	Distribution Operations				
8	Labor	$	425	411	452
9	Non-Labor	$	451	329	339
10	TOTAL	$	876	740	791
	Distribution Maintenance				
11	Labor	$	380	393	414
12	Non-Labor	$	747	645	735
13	TOTAL	$	1,127	1,038	1,149
14=10+13	TOTAL DIST O&M	$	2,003	1,778	1,940
15=7+14	GRAND TOTAL O&M	$	2,749	$ 2,390	$ 2,715

Note:
Figures may not total exactly due to rounding.

Hawaiian Electric Company, Inc.
2005 TEST YEAR

TRANSMISSION AND DISTRIBUTION
OPERATION AND MAINTENANCE EXPENSE
($ Thousands)

			(A)	(B)
			2005 ACTUAL	
			JUNE	JULY
	Transmission Operations			
1	Labor	$	145	155
2	Non-Labor	$	146	145
3	TOTAL	$	291	300
	Transmission Maintenance			
4	Labor	$	155	152
5	Non-Labor	$	93	215
6	TOTAL	$	248	367
7=3+6	TOTAL TRANS O&M	$	539	667
	Distribution Operations			
8	Labor	$	422	397
9	Non-Labor	$	390	312
10	TOTAL	$	812	709
	Distribution Maintenance			
11	Labor	$	439	393
12	Non-Labor	$	712	496
13	TOTAL	$	1,151	889
14=10+13	TOTAL DIST O&M	$	1,963	1,598
15=7+14	GRAND TOTAL O&M	$	2,502	$ 2,265

Note:
Figures may not total exactly due to rounding.

Hawaiian Electric Company, Inc.
2005 TEST YEAR

TRANSMISSION AND DISTRIBUTION
OPERATION AND MAINTENANCE EXPENSE
($ Thousands)

		(A)	(B)	(C)	(D)
			2004 ACTUAL		
		TOTAL	JAN	FEB	MAR
	Transmission Operations				
1	Labor	$ 1,801	145	122	$ 117
2	Non-Labor	$ 1,732	103	115	$ 131
3	TOTAL	$ 3,533	248	237	$ 248
	Transmission Maintenance				
4	Labor	$ 1,628	116	113	$ 200
5	Non-Labor	$ 2,946	58	145	$ 227
6	TOTAL	$ 4,574	174	258	$ 427
7=3+6	TOTAL TRANS O&M	$ 8,107	422	495	$ 675
	Distribution Operations				
8	Labor	$ 4,521	372	329	$ 314
9	Non-Labor	$ 3,884	257	386	$ 314
10	TOTAL	$ 8,405	629	715	$ 628
	Distribution Maintenance				
11	Labor	$ 5,039	598	320	$ 459
12	Non-Labor	$ 7,558	345	523	$ 632
13	TOTAL	$ 12,597	943	843	$ 1,091
14=10+13	TOTAL DIST O&M	$ 21,002	1,572	1,558	$ 1,719
15=7+14	GRAND TOTAL O&M	$ 29,109	$ 1,994	$ 2,053	$ 2,394

Note:
Figures may not total exactly due to rounding.

Hawaiian Electric Company, Inc.
2005 TEST YEAR

TRANSMISSION AND DISTRIBUTION
OPERATION AND MAINTENANCE EXPENSE
($ Thousands)

		(A)	(B)	(C)	(D)
		2004 ACTUAL			
		APR	MAY	JUNE	JULY
	Transmission Operations				
1	Labor	147	163	$ 150	144
2	Non-Labor	97	156	$ 129	127
3	TOTAL	244	319	$ 279	271
	Transmission Maintenance				
4	Labor	104	143	$ 133	130
5	Non-Labor	167	123	$ 374	110
6	TOTAL	271	266	$ 507	240
7=3+6	TOTAL TRANS O&M	515	585	$ 786	511
	Distribution Operations				
8	Labor	342	363	$ 366	358
9	Non-Labor	329	(71)	$ 406	84
10	TOTAL	671	292	$ 772	442
	Distribution Maintenance				
11	Labor	265	357	$ 342	320
12	Non-Labor	454	468	$ 526	339
13	TOTAL	719	825	$ 868	659
14=10+13	TOTAL DIST O&M	1,390	1,117	$ 1,640	1,101
15=7+14	GRAND TOTAL O&M	$ 1,905	$ 1,702	$ 2,426	$ 1,612

Note:
Figures may not total exactly due to rounding.

Hawaiian Electric Company, Inc.
2005 TEST YEAR

TRANSMISSION AND DISTRIBUTION
OPERATION AND MAINTENANCE EXPENSE
($ Thousands)

		(A)	(B)	(C)	(D)
			2004 ACTUAL		
		AUG	SEPT	OCT	NOV
	Transmission Operations				
1	Labor	133	$ 153	184	181
2	Non-Labor	130	$ 162	200	146
3	TOTAL	263	$ 315	384	327
	Transmission Maintenance				
4	Labor	88	$ 121	163	198
5	Non-Labor	98	$ 195	398	417
6	TOTAL	186	$ 316	561	615
7=3+6	TOTAL TRANS O&M	449	$ 631	945	942
	Distribution Operations				
8	Labor	365	$ 352	372	544
9	Non-Labor	280	$ 197	166	590
10	TOTAL	645	$ 549	538	1,134
	Distribution Maintenance				
11	Labor	450	$ 371	429	554
12	Non-Labor	754	$ 696	787	1,172
13	TOTAL	1,204	$ 1,067	1,216	1,726
14=10+13	TOTAL DIST O&M	1,849	$ 1,616	1,754	2,860
15=7+14	GRAND TOTAL O&M	$ 2,298	$ 2,247	$ 2,699	$ 3,802

Note:
Figures may not total exactly due to rounding.

Hawaiian Electric Company, Inc.
2005 TEST YEAR

TRANSMISSION AND DISTRIBUTION
OPERATION AND MAINTENANCE EXPENSE
($ Thousands)

(A)

2004 ACTUAL
DEC

	Transmission Operations		
1	Labor	$	161
2	Non-Labor	$	238
3	TOTAL	$	399
	Transmission Maintenance		
4	Labor	$	118
5	Non-Labor	$	634
6	TOTAL	$	752
7=3+6	TOTAL TRANS O&M	$	1,151
	Distribution Operations		
8	Labor	$	443
9	Non-Labor	$	946
10	TOTAL	$	1,389
	Distribution Maintenance		
11	Labor	$	576
12	Non-Labor	$	861
13	TOTAL	$	1,437
14=10+13	TOTAL DIST O&M	$	2,826
15=7+14	GRAND TOTAL O&M	$	3,977

Note:
Figures may not total exactly due to rounding.

Hawaiian Electric Company, Inc.
2005 TEST YEAR

TRANSMISSION AND DISTRIBUTION
OPERATION AND MAINTENANCE EXPENSE
($ Thousands)

			(A)	(B)	(C)
				2005 FORECAST	
			TOTAL	JAN	FEB
	Transmission Operations				
1	Labor	$	1,854	166	161
2	Non-Labor	$	1,616	139	149
3	TOTAL	$	3,470	305	310
	Transmission Maintenance				
4	Labor	$	2,002	159	173
5	Non-Labor	$	2,620	196	203
6	TOTAL	$	4,622	355	376
7=3+6	TOTAL TRANS O&M	$	8,092	660	686
	Distribution Operations				
8	Labor	$	4,790	404	389
9	Non-Labor	$	3,886	347	317
10	TOTAL	$	8,676	751	706
	Distribution Maintenance				
11	Labor	$	4,708	384	386
12	Non-Labor	$	6,743	574	546
13	TOTAL	$	11,451	958	932
14=10+13	TOTAL DIST O&M	$	20,127	1,709	1,638
15=7+14	GRAND TOTAL O&M	$	28,219	$ 2,369	$ 2,324

Note:
Figures may not total exactly due to rounding.

Hawaiian Electric Company, Inc.
2005 TEST YEAR

TRANSMISSION AND DISTRIBUTION
OPERATION AND MAINTENANCE EXPENSE
($ Thousands)

			(A)	(B)	(C)
				2005 FORECAST	
			MAR	APR	MAY
	Transmission Operations				
1	Labor	$	188	180	147
2	Non-Labor	$	162	171	140
3	TOTAL	$	350	351	287
	Transmission Maintenance				
4	Labor	$	171	195	174
5	Non-Labor	$	222	332	204
6	TOTAL	$	393	527	378
7=3+6	TOTAL TRANS O&M	$	743	878	665
	Distribution Operations				
8	Labor	$	397	400	415
9	Non-Labor	$	318	319	329
10	TOTAL	$	715	719	744
	Distribution Maintenance				
11	Labor	$	388	416	402
12	Non-Labor	$	533	583	570
13	TOTAL	$	921	999	972
14=10+13	TOTAL DIST O&M	$	1,636	1,718	1,716
15=7+14	GRAND TOTAL O&M	$	2,379	$ 2,596	$ 2,381

Note:
Figures may not total exactly due to rounding.

Hawaiian Electric Company, Inc.
2005 TEST YEAR

TRANSMISSION AND DISTRIBUTION
OPERATION AND MAINTENANCE EXPENSE
($ Thousands)

			(A)	(B)	(C)
				2005 FORECAST	
			JUNE	JULY	AUG
	Transmission Operations				
1	Labor				
2	Non-Labor	$	139	145	146
3	TOTAL	$	115	121	125
		$	254	266	271
	Transmission Maintenance				
4	Labor				
5	Non-Labor	$	156	166	166
6	TOTAL	$	196	202	194
		$	352	368	360
7=3+6	TOTAL TRANS O&M				
		$	606	634	631
	Distribution Operations				
8	Labor				
9	Non-Labor	$	410	397	392
10	TOTAL	$	331	318	316
		$	741	715	708
	Distribution Maintenance				
11	Labor				
12	Non-Labor	$	380	420	374
13	TOTAL	$	557	606	552
		$	937	1,026	926
14=10+13	TOTAL DIST O&M				
		$	1,678	1,741	1,634
15=7+14	GRAND TOTAL O&M				
		$	2,284	$ 2,375	$ 2,265

Note:
Figures may not total exactly due to rounding.

Hawaiian Electric Company, Inc.
2005 TEST YEAR

TRANSMISSION AND DISTRIBUTION
OPERATION AND MAINTENANCE EXPENSE
($ Thousands)

			(A)	(B)	(C)
				2005 FORECAST	
			SEPT	OCT	NOV
	Transmission Operations				
1	Labor				
2	Non-Labor	$	143	146	145
3	TOTAL	$	125	123	121
		$	268	269	266
	Transmission Maintenance				
4	Labor				
5	Non-Labor	$	160	170	158
6	TOTAL	$	187	201	190
		$	347	371	348
7=3+6	TOTAL TRANS O&M				
		$	615	640	614
	Distribution Operations				
8	Labor				
9	Non-Labor	$	401	396	390
10	TOTAL	$	310	308	307
		$	711	704	697
	Distribution Maintenance				
11	Labor				
12	Non-Labor	$	358	382	390
13	TOTAL	$	494	576	567
		$	852	958	957
14=10+13	TOTAL DIST O&M				
		$	1,563	1,662	1,654
15=7+14	GRAND TOTAL O&M				
		$	2,178	$ 2,302	$ 2,268

Note:
Figures may not total exactly due to rounding.

Hawaiian Electric Company, Inc.
2005 TEST YEAR

TRANSMISSION AND DISTRIBUTION
OPERATION AND MAINTENANCE EXPENSE
($ Thousands)

(A)

2005 FORECAST
DEC

	Transmission Operations		
1	Labor	$	148
2	Non-Labor	$	124
3	TOTAL	$	272
	Transmission Maintenance		
4	Labor	$	153
5	Non-Labor	$	293
6	TOTAL	$	446
7=3+6	TOTAL TRANS O&M	$	718
	Distribution Operations		
8	Labor	$	401
9	Non-Labor	$	366
10	TOTAL	$	767
	Distribution Maintenance		
11	Labor	$	427
12	Non-Labor	$	586
13	TOTAL	$	1,013
14=10+13	TOTAL DIST O&M	$	1,780
15=7+14	GRAND TOTAL O&M	$	2,498

Note:
Figures may not total exactly due to rounding.

CA-RIR-60

Ref: RT-8 , page 18, lines 6-11 (T&D Corrective Maintenance).

The referenced testimony states that HECO has expended $722,000 more on cable failures through 6/30/05 than forecasted.

a. Please provide the amount of actual cable failure expenditures charged to T&D expense by month during 2004 and 2005.

b. Please provide the forecast of cable failure expenditures charged to T&D expense by month for the 2005 test year.

c. Referring to the responses to parts (a) and (b) above, please identify how the $722,000 amount was determined.

HECO Response:

a. Please refer to pages 2 and 3 to this response for actual cable failure expenditures charged to T&D expenses by month for calendar years 2004 through July 2005.

b. Please refer to pages 2 and 3 to this response for cable failure expenditures budgeted to T&D expense by month for calendar year 2005.

Hawaiian Electric Company, Inc.
2005 TEST YEAR

T&D CORRECTIVE MAINTENANCE EXPENSE

	(A) TOTAL	(B) JAN	(C) FEB	(D) MAR	(E) APR	(F) MAY	(G) JNE	(H) JULY
2004 ACTUAL	4,047,310	338,893	231,256	401,769	145,020	302,262	6,476	240,968
2005 FORECAST	2,349,159	155,145	193,938	169,405	224,356	223,995	5,796	227,857
2005 ACTUAL	2,198,516	355,407	276,556	328,507	303,045	259,856	2,894	312,251

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gures may not total exactly due to rounding.

Hawaiian Electric Company, Inc.
2005 TEST YEAR

T&D CORRECTIVE MAINTENANCE EXPENSE

		(A) AUG	(B) SEPT	(C) OCT	(D) NOV	(E) DEC
1	2004 ACTUAL	300,183	268,421	315,899	398,028	698,137
2	2005 FORECAST	194,673	110,289	154,118	206,967	302,619

Note:
Figures may not total exactly due to rounding.

CA-RIR-61

Ref: RT-10 , pages 2 & 5-9 (DSM Expense).

At page 2, line 14, the referenced testimony states:

The amount of DSM expense remaining in the rate case is $1,030,000, as shown on line 15 of HECO-R-1003.

Beginning at page 5, RT-10 also discusses the proposed increase in DMS related advertising and marketing costs. Please provide the following:

a. Referring to HECO-R-1003, please confirm that the $1,030,000 of DSM costs that HECO proposes to include in base rates includes $250,000 for advertising/marketing

b. In the context of Decision and Order No. 21698 referenced by RT-10 (pages 2 and 4), please confirm that Commission's Decision and Order does not explicitly allow HECO to incur additional advertising and marketing costs for the RDLC or CIDLC programs.

[redacted]

stipulations with the CA in the load management dockets.

b. Order No. 21698 (not "Decision and Order") does not address advertising/marketing costs or any other specific costs of the RDLC and CIDLC programs.

Order No. 21698 allowed HECO to "temporarily continue, in the manner currently employed," its five existing energy efficiency DSM programs, which were explicitly identified. Order No. 21698, pages 12-13. Footnote 17 on page 13 of Order No. 21698

In Docket Nos. 03-0166 and 03-0415, the CA contended that advertising/marketing costs should be recovered through base rates and not the DSM surcharge (and HECO therefore stipulated that the costs would not be passed through the surcharge). Thus, the advertising/marketing costs for the load management programs clearly should be included in revenue requirements in the rate case.

1. See part c. above.

2. See part c. above.

CA-RIR-62

Ref: RT-10 , pages 4-5 (DSM Expense).

The referenced testimony refers to Decision and Order Nos. 21415 and 21421 in which the Commission approved two stipulated agreements between the Company and the Consumer Advocate (Docket Nos. 03-0166, RDLC Program, & 03-0415, CIDLC Program). Beginning at page 5, line 10, the cited testimony states:

> In addition, the marketing and advertising costs were increased above the approved program budgets by $300,000 to account for higher expenses that the Company has found necessary to meet accelerated annual program load reduction goals through actual experience as described in CA-IR-533.

Based on the above, please provide the following:

a. HECO-R-1003 includes $350,000 of advertising/marketing costs in the HECO's revised 2005 DSM forecast. Please confirm that the $350,000 includes the $300,000 referenced in the above quote plus; $25,000 for an RDLC customer recognition program

b. Correct. However, HECO is proposing to increase the advertising and marketing expense for these two load management programs to reflect actual costs incurred year-to-date and to meet accelerated annual program load reduction goals as discussed in HECO RT-10, pages 5 through 9.

   1. D&O Nos. 21415 and 21421 approved the program budgets in the respective Settlement Agreements. (See cite in HECO's response to CA-RIR-61.)

   2. Not applicable.

c. Correct.

   1. See discussion in HECO's response to CA-RIR-61.

   2. Not applicable.

CA-RIR-63

Ref: RT-10 , pages 2-3 (DSM Expense).

Beginning at page 2, line 24, the referenced testimony provides the following explanation as to why HECO did not remove all DSM expenses from the rate case:

> D&O No. 21698 stated that 'HECO may temporarily continue, in the manner currently employed, its existing two (2) residential DSM programs . . . and three (3) C&I DSM programs . . .'. HECO currently recovers DSM program base labor costs through base rates and incremental DSM program costs through the DSM component of the IRP clause. Therefore, for the purposes of the rate case HECO has continued recover the DSM program base labor costs in the manner currently employed, which is through base rates.

Please provide the following:

a. Please confirm that the cited excerpt from Decision and Order No. 21698 allows HECO to temporarily continue the identified DSM programs. If this cannot be confirmed, please explain.

b. Please confirm that the cited language from Decision and Order No. 21698 does not explicitly refer to or otherwise allow HECO to continue "recovering" the cost of the identified DSM program costs through base rates. If this cannot be confirmed, please explain.

HECO Response:

a. Yes. D&O No. 21698 allows HECO to temporarily continue, in the manner currently employed, the identified DSM programs. D&O No. 21698 is also not intended to nullify the decisions rendered by the commission in the dockets approving the RDLC and CIDLC programs.

b. The cited language does not "explicitly refer to or otherwise allow HECO to continue "recovering" the cost of the identified DSM program costs through base rates."

Yet, it is apparent in the language of the D&O that the existing programs are to be temporarily continued in the manner currently employed. It is also apparent from the D&O that the Energy Efficiency Docket was created to examine certain aspects of the DSM

programs in more detail and that the Energy Efficiency Docket was to follow the HECO rate

[redacted]

and CIDLC Programs which, per D&O Nos. 21415 and 21421, HECO cannot recover through the IRP Clause. Instead, HECO was permitted to seek the recovery of such costs in base rates in its next rate case. Therefore, should these costs now be removed from this rate case, which would be in conflict with the existing orders of the Commission, HECO would be precluded from recovering these costs through base rate and would have no recourse for cost recovery. Instead, HECO's would need to wait for the outcome of the Energy

In addition, failure to provide a mechanism for the recovery of costs for approved DSM

programs would violate the IRP Framework. Paragraph III.F.1 of the IRP Framework provides, in relevant part, that:

> The utility is entitled to recover its integrated resource planning and implementation costs that are reasonably incurred, including the costs of planning and implementing pilot and full-scale demand-side management programs.
>
> a. The cost recovery may be had through the following mechanisms:
>
> (1) Base rate recovery — the inclusion of costs in the utility's base rate during each rate case. A balancing account may be appropriate in this instance to reconcile, with interest, the utility's recovered expenditures with its actual expenditures. It may also be appropriate to consider the utility's under-expenditure of authorized cost to limit recovery, unless program objectives are met or exceeded.
>
> (2) Adjustment clause — the recovery of costs incurred

CA-RIR-64

Ref: RT-10, pages 10-11 & HECO-R-1002 (Informational Advertising).

The referenced testimony indicates that the Company has increased its original test year forecast for informational advertising expense by $750,000. At page 11, lines 4 and 7, the following passages generally describe the educational advertising campaign:

> The campaign is not claiming that it will achieve a level of energy or demand savings; therefore, it is not a DSM program.
> Since the overall objective of an energy efficiency message is to encourage customers to conserve energy, it is logical that in the same message they also be provided actions they can take to reduce energy use.

Please provide the following:

a. Is HECO undertaking the information advertising campaign with the objective of altering customer energy usage and consumption patterns? Please explain.

b. Has HECO previously presented similar informational advertising campaigns to the Commission? If so, please identify the docket in which such presentations were made and explain why those similar campaigns were presented to the Commission for approval.

c. Referring to the response to part (b) above, did the Commission approve the Company's request? If not, why not?

d. Please provide a pinpoint reference to Commission decision and order relied upon by the Company in responding to parts (b) and (c) above.

HECO response:

[redacted]

to the marketing for specific actions customers can undertake including energy efficiency measures promoted by the DSM programs, as well as encourage responsiveness during emergency situations.

The need for such an awareness campaign is supported by the findings of focus groups conducted in 2004 to test public reaction to messages about power system emergencies, such as a generation shortage. Among the findings by Ward Research, the firm that conducted the focus group, are the following:

> *"It was also clear that the masses will need some urgency in order to motivate a change in behaviors, particularly change that may result in somewhat less comfort or convenience."*
>
> *"High users admitted that their comfort and convenience are important to them and, having adjusted to their monthly bill, they were unlikely to change. Many of the Medium/Low users thought that they were already doing everything they can to conserve, such that additional conservation would be unlikely."*
>
> *"We believe that HECO must build an ongoing, mass media foundation, such that this message of urgency has context."*

b. Yes. HECO presented plans for a Residential Customer Energy Awareness (RCEA) program in Docket No. 03-0142 to determine if such an aggressive communications program could both provide an increased awareness of customer energy conservation and efficiency as well as to help achieve energy savings and peak load reductions. (D&O No. 21756, page 4 and 5).

c. No, the Commission denied the RCEA application without prejudice in Decision and Order No. 21756, issued April 20, 2005. In general, the Commission denied the application on the grounds that the Company could not "adequately demonstrate that this proposed pilot program complies with the IRP Framework requirements.... Of particular concern is HECO's inability to determine the effectiveness of the proposed RCEA Pilot Program in

accomplishing the program's objectives of achieving 'significant energy savings and peak load reduction.' " (D&O No. 21756, page 10).

d. See references noted in responses to b. and c.

CA-RIR-65

Ref: RT-10, page 10 & HECO-R-1006 (Informational Advertising).

Mr. Hee describes HECO's plans to "procure an expanded presence in print and broadcast media (including television and radio), as shown in HECO-R-1006." Please provide the following:

a. Has HECO actually initiated this informational advertising campaign? If so, when was the campaign initiated.

b. HECO-R-1006 identifies costs associated with broadcast and print media. Referring to parts (a) above, please provide specimen ad copy associated with print media, viewable television broadcast ads (DVD or VHS format) and script for the radio ads.

HECO response:

a. HECO has begun the initial phase of this campaign by producing TV and radio spots that remind customers of the importance of conservation and some of the simple steps customers can take to help conserve at all times. The initial media components of this campaign began airing in October 2004 and focus on the first level of messaging regarding general energy conservation and efficiency awareness. As noted in HECO RT-10, page 10, the Company plans to pursue a three-layered message that also communicates the importance of reducing energy use at the peak, as well as the importance of dramatically cutting use of electricity during an emergency. See HECO's response to DOD-RIR-54.

b. Copies of radio scripts for ads produced thus far can be found in HECO's response to DOD-IR-54. A DVD of the two TV spots produced thus far ("Groove" and "Cool Tips") are included in HECO's response to the DOD RIR.

CA-RIR-66

Ref: RT-10, pages 14-16 (DSM & Open Positions).

At page 14, line 15, the referenced testimony states:

> The CA's and DOD's proposed adjustment reduces labor expenses for 4 'open' DSM positions that the CA and DOD already separated from the rate case because of the Energy Efficiency Docket. Thus, even if the basis for the CA's and DOD's proposed adjustment was reasonable (which it is not), it double counts the reduction for vacant DSM positions and overestimates the impact on Customer Service Expense.

In quantifying the impact of these four open positions, HECO RT-10 (page 16) refers to HECO-R-1011 to remove the "double count." Please provide the following:

a. Please provide a pinpoint reference to HECO's direct testimony, exhibits, workpapers and/or responses to discovery which support the labor amounts for each position set forth on HECO-R-1011. If the requested information is not contained in any information previously provided, please provide a copy of all supporting workpapers and show how such positions were initially included in HECO's original 2005 test year forecast.

b. HECO-R-1003 summarizes HECO's proposed adjustment to remove DSM costs from forecast test year expense. Please identify which line (e.g., incremental direct labor) eliminates the open position positions.

c. Referring to item (b) above, please provide a detailed breakdown of the identified forecast amount and demonstrate that the open DSM positions have, in fact, been separately removed from the test year forecast.

HECO Response:

a. The basis for HECO-R-1011 is the Company's response to DOD/HECO-IR-8-8, page 5 of 11, Account 910, for Energy Services. The estimated wages & benefits of open positions included in HECO's 2005 test year forecast as if filled throughout the 2005 test year of $454,744 for the Energy Services area in Account 910, is the sum of the Wages column in HECO-R-1011. The CA relied upon DOD/HECO-IR-8-8, page 5 of 11, to derive its adjustment C-21 (see CA-101, Schedule C-21).

b. HECO does not remove the open positions from its rate case expense because HECO is

proposing to include the 4 DSM positions in base rates. The labor costs for the 4 DSM positions (RDLC Program manager, DSM Clerk, Load Management Engineer, and CIDLC Program Manager) are included in the revised 2005 Test Year base labor expense of $660,046 in HECO-R-1003.

c. The four positions have not been removed from the rate case. See response to part b. above.

CA-RIR-67

Ref: RT-10, page 19, line 15 (DSM Costs).

The referenced testimony states:

> In HECO/CA-IR-205, the CA suggests that the Commission's order to 'temporarily continue' the five existing energy efficiency programs 'until further order by the commission' does not provide 'sufficient certainty that these programs will continue as proposed'.

Please provide the following:

a. Please define the word "temporarily," or forms thereof, as HECO believes is used in this context.

b. Will the Energy Efficiency Docket be the next opportunity for the Commission to assess

CA-RIR-68

Ref: RT-10, page 19, line 18 (DSM Costs).

The referenced testimony states:

> Further, the CA contends that cost recovery is one of the issues to be taken up by the Energy Efficiency Docket. The CA concludes that there is 'no assurance that the Commission will approve, for cost recovery, the amounts that HECO has included in the 2005 test year forecast to support base rate inclusion at the present time.'

Please provide the following:

a. Please confirm that DSM cost recovery is one of the issues to be taken up in the Energy Efficiency Docket. If this cannot be confirmed, please explain.

b. Does HECO contend that the Commission has provided assurance or otherwise guaranteed that the RDLC and CIDLC programs will not be re-considered in the Energy Efficiency Docket? If so, please provide a pinpoint reference to any such assurance provided by the Commission.

c. Does HECO contend that the Commission has provided assurance or otherwise guaranteed that the amounts the Company has proposed to include in the test year forecast for the RDLC and CIDLC Programs will not be re-evaluated in the Energy Efficiency Docket? If so, please provide a pinpoint reference to any such assurance provided by the Commission

HECO Response:

a. Yes.

b. No. On the other hand, as stated in HECO RT-10, page 18, lines 10-16, D&O No. 21698 explicitly states that "This order is not intended to nullify the decisions rendered by the commission in the dockets approving the RDLC and CIDLC programs, Docket Nos. 03-0166 and 03-0415, respectively".

The commission has great latitude to consider issues surrounding HECO's DSM programs in the Energy Efficiency Docket. However, based on the D&Os issued by the commission thus far, the language in the Settlement Agreement agreed to by the CA and HECO and approved by the commission remains in force. That language permits HECO to

"seek the recovery of these operation and maintenance costs in base rates in HECO's next rate case."

c. No. See response to part b. above.

CA-RIR-69

Ref: RT-10, page 21, line 23 (Information Advertising).

The referenced testimony states:

HECO's current proposal is a general education campaign, not a DSM program. The

campaign does not have the RCEA Program objectives of achieving significant energy savings and peak load reduction. Instead, its purpose is to establish a foundation of awareness so that customers will be able to understand why using energy wisely at all times, during the peak, and during an emergency is important.

Please provide the following

a. Please confirm that HECO does not expect its general education campaign to result in energy savings. If this cannot be confirmed, please explain.

energy saving actions including energy efficiency measures promoted by the DSM programs and responsiveness during emergency situations.

54.) This campaign has not been terminated. To the contrary, the Company wants to build upon those initial efforts by increasing the media budget to ensure the messages are reinforced and to build upon the initial general energy conservation spots with more specific messages focusing on the need to reduce energy use at peak times and during system emergencies. While the requested level of funding will not allow a campaign as aggressive as was proposed in the RCEA program, it still provides a greater opportunity for the messages to take root than what was originally budgeted for the 2005 test year.

e. The additional $750,000 was not originally budgeted for because the Company was planning to receive approval for the more extensive RCEA program. However, in light of the Commission's D&O denying the application and the ongoing need to increase customer awareness of the importance of conservation, the test year estimate was revised to include the additional resources.

CA-RIR-70

Ref: RT-10, page 24, line 12 (Research & Development).

The referenced testimony states:

> HECO agrees with the CA's option to allow $121,000 for 2005 ESA development, but seeks flexibility in the use of the remaining funds in other research and development ("R&D") projects.

Please provide the following clarification:

a. Please explain what specific "flexibility" HECO is seeking.

b. Please identify, quantify and describe the "remaining funds" being referenced in the quoted testimony.

HECO Response:

a. As discussed in HECO RT-10, page 24, lines 12 to 25 and page 25, lines 1 to 7 and HECO RT-6, page 16, line 22 to 25, page 17, lines 1 to 25 and page 18, lines 1 to 3, HECO seeks flexibility in using the remaining ESA funds for other R&D projects mentioned in RT-6 and RT-10 (see CA-RIR-51 for updated details on the projects listed below). :

- Testing and characterization of a 1 kW liquefied petroleum gas ("LPG") reforming unit designed for residential use
- Stationary sodium-sulfur ("NaS") battery energy storage
- Performance assessment of emerging photovoltaic ("PV") technology
- Research and development of a new communication technology for advanced meter and customer outage detection devices

We are revising our rebuttal testimony on the use of the remaining ESA funds. As HECO prepared for the ESA installation in 2005, the Company found that it had inadvertently left out the cost for the ESA installation (estimated at $50,000) in the rate case testimonies. Therefore, to account for the additional ESA installation costs in 2005, the test year NaS project costs will be decreased to zero to cover for the ESA installation costs. The NaS

project will be funded in 2006..

b. Please see HECO T-6 response to CA-IR-2, Attachment 3E, pages 1-5 describing the ESA activities in 2005 totaling $500,000. In 2005, HECO will use $171,000 for ESA activities.

- $121,000 for ESA demonstration design, procurement and assembly
- $50,000 for HECO share of the ESA installation

Subtotal = $171,000

Remaining funds to be used for other R&D Projects as described in HECO, RT-6, pages 18-24, and RT-10, pages 25-28.

- $99,000 for LPG reformer project (Note that amount represents a corrected amount. HECO RT-6, page 19, line 7 erroneously reported $100,000 for the project)
- $30,000 for emerging PV project (Note that amount represents a corrected amount. HECO RT-6, page 23, line 17 erroneously reported $50,000 for the project)
- $180,000 for new communication technology project

Subtotal = $309,000

Total = $480,000 (No change from the total proposed by HECO in RT-6, page 24, line 16).

CA-RIR-71

Ref: RT-13 page 28, line 23

Ms. Yamauchi states that "$4.5 million of Kahe Unit 7 Project costs are being amortized over five years through September 2006, including the $900,000 of amortization included in the Company's test year 2005 estimate for Other Production Operation expenses." Based on this statement, please provide the following information:

a. A schedule showing the gross amount to be amortized over five years and the annual amortization that has been recorded historically and is to be recorded in each year 2006, 2007 and 2008 per the earlier stipulated agreement.

b. An explanation as to how the $900,000 of test year amortization expense can be considered normal and representative of ongoing costs when the entire amount remaining to be amortized in all years after test year 2005 is only $675,000.

c. A description of how the Company would not over recover the amortization expenses in

September 5, 2001, in Docket No. 95-0047). Further, the $900,000 test year 2005 amortization expense is the amount of expense to be actually recorded on the Company's books in 2005. The test year in this docket is 2005.

c. The concept of over or under recovery of test year expenses is generally not applied to individual test year expense items. Whether the Company is over or under recovering its test year expenses is generally not determined by comparing actual expenses incurred beyond the test year against the test year estimates for individual cost items. Such a process would be unmanageable as actual costs beyond the test year are more than the test year estimates in some cases (e.g. actual depreciation expense is generally higher due to plant additions beyond the test year), and less in other cases (e.g. actual amortization of the Kahe Unit 7 Project costs). In general, the Company's monthly return on rate base that is reported to the Commission is the measure used to help determine whether there is over or under recovery of the return on rate base determined by the Commission to be fair and reasonable.

CA-RIR-72

Ref: RT-13 page 30, line 16.

According to the testimony, "As explained in the previous testimony, based on current conditions, the Company's next rate case is more likely to be filed in three, rather than four, years after the conclusion of this instant proceeding." What is the expected test year that would be used by HECO in the "next rate case" that is posited? Provide all information relied upon to make such determination.

HECO Response:

See HECO's response to DOD-RIR-61.

CA-RIR-73

Ref: RT-13, page 7 & HECO-R-1301 (A&G Expense Accounts).

At page 7 of the referenced testimony, HECO indicates that because the Consumer Advocate and DOD did not post their adjustments by NARUC account number, the Company used its best judgment in determining their test year estimates by account. The reference rebuttal exhibit compares HECO's proposed A&G expense by account (both direct & rebuttal testimony) with the recommendations of Consumer Advocate and DOD by NARUC account. HECO also provided a spreadsheet file ("HECO-R-1301.xls") in support of HECO-R-1301. However, the "CA" column (e.g., Column [E] of filed HECO-R-1301) of the spreadsheet starts with amounts from the HECO direct testimony column, by account, plus or minus unidentified amounts embedded within the cell formulae that should theoretically represent the Consumer Advocate's adjustments. The Consumer Advocate has been successful in tracing certain of these "amounts" into Exhibit CA-101, while unsuccessful with other amounts. Please provide the following:

a. Did HECO prepare a separate analysis compiling the amount of each CA adjustment by account for purposes of assembling HECO-R-1301? If so, please provide a copy of that

				Administrative & General										
CA Sch	DOD Sch	Additional ref	Description	A&G-fbr	A&G-nlbr	A&G Expenses Transferred	Outside Services - Other	Emp Ben	Reg Comm Exp	Misc Genl	Rent	Total A&G Adj	CA Sch C	DOD-114
C-14	DOD-123		Software Development	920	921	922	923020	926	928	9302	931			
			Rounding										(1,000)	
			HR Suites		(184,000)								(184,000)	
			Ellipse Upgrade		0								(131,000)	
			Ellipse Maint Buy-Down		(48,000)					(110,000)			(327,000)	
			Total Software Dev adj		(232,000)					(110,000)		(342,000)	(643,000)	(184,000)
C-15			King St. Lease								642,000	642,000	601,000	0
C-16	DOD-123	CA-IR-419	HEI charges to HECO		82,000			13,000			2,000	97,000	32,000	95,000
		CA-IR-625	New phone system		(194,000)							(194,000)		
			A&G transfer related to adjustments			17,000						17,000		
C-17	DOD-116		Remove DSM Program costs									0	(618,000)	0
C-18	DOD-123		Rate Case Expense						103,000			103,000	(9,000)	(9,000)
C-19		CA-IR-78	Eliminate Director-Forecasts	(69,022)								(69,022)		0
C-20	DOD-117		Std Labor Rates & OT pay									0	(61,000)	(264,000)
C-21	DOD-118		Average Employee Levels									0	(784,000)	(784,000)
C-22			Employee Benefits					212,000				212,000	212,000	264,000
		HECO/CA-IR-202c	Employee Benefits					104,000				104,000	104,000	
			Emp transfer related to adjustments					(20,000)				(20,000)		
C-24	DOD-123		R&D costs							(96,500)		(96,500)	(96,500)	(96,500)
C-25	DOD-123		KPMG Audit/SOX charges				381,000					381,000	381,000	381,000
			Totals	(69,022)	(344,000)	17,000	381,000	309,000	103,000	(206,500)	644,000	834,478	(881,500)	(597,500)

CA-RIR-74

Ref: RT-13, page 10 & HECO-R-1302 (Employee Counts).

Please provide the following clarifications regarding the employee position table appearing on RT-13, page 10 and generally described on HECO-R-1302:

a. Please confirm that the 20 positions listed in the table at page 10 represent employee positions that were not included in HECO's 2005 test year forecast. If this cannot be confirmed, please explain.

b. In reviewing HECO-R-1302, please confirm that some of the 20 positions were filled prior to 1/1/05 even though they were not included in HECO's 2005 test year forecast. If this cannot be confirmed, please explain.

c. Based a review of HECO-R-1302, it is unclear how many of the 20 additional listed on page 10 of RT-13 were actually filled in 2004, have already been filled in 2005 or are expected to be filled sometime in 2005. Please expand the referenced table to provide the actual hiring dates and/or the expected 2005 hiring month for each additional position.

HECO Response:

a. Yes, the 20 positions listed in the table on page 10 represent employee positions that were not included in HECO's 2005 test year forecast.

b. Yes, some of the 20 postions were filled prior to 1/1/05.

c. Hire Date of the 20 additional positions are listed below:

Organization	Position	Hire Date
Corporate Audit & Compliance	Corporate Compliance Analyst	1/24/2005
Corporate Audit & Compliance	SOX Compliance Specialist	2/7/2005
Corporate Audit & Compliance	Sox Compliance Specialist	2/15/2005

Information & Technology Services	Database Administrator	3/15/2005
Information & Technology Services	IT Infastructure Analyst	2/14/2005
Information & Technology Services	IT Infastructure Analyst	11/15/2004
Information & Technology Services	IT Business Solutions Consultant	1/24/2005
Safety, Security & Facilities	Occupational Health & Safety Specialist	6/20/2005
Safety, Security & Facilities	Project Manager	12/13/2004
Safety, Security & Facilities	Administrator	3/7/2005
Workforce Staffing & Development	Director, Client Services & Consulting	7/24/2004
Government Relations	Manager, Government Relations	12/1/2004
Education & Community Affairs	Education & Community Affairs Administrator	12/1/2004
VP-Government & Community Affairs	Community Relations Coordinator	10/25/2004
Regulatory Affairs	Regulatory Analyst II	5/31/2005
Technology	Project Aide	3/31/2005

CA-RIR-75 Ref: RT-13, page 10 & HECO-R-1302 (Employee Counts).

The chart appearing on page 80 of CA-T-2 compares HECO's actual employee counts with its forecast counts for the months of December 2004 through April 2005. As noted on the chart, the data sources were HECO's responses to CA-IR-9, CA-IR-331 and CA-IR-508. Please provide the following:

a. To the extent that HECO had hired certain of the 20 additional positions listed on RT-13, page 10, as of 12/21/04, please confirm that those [illegible]

CA-RIR-76

Ref: RT-13, page 13 line 20 (Ellipse Upgrade).

In explaining why the Ellipse upgrade cost should be included in test year forecast when the upgrade will not occur in 2005, the referenced testimony states:

> Yes, because the normalization adjustment represents a reasonable level of ongoing costs incurred by the Company. The adjustment is not an advance collection of a future, post-test year cost as claimed by the Consumer Advocate (see CA-T-2, page 42). While the next upgrade will occur beyond the 2005 test year, the upcoming upgrade is not a new, first time cost for the Company. Rather, upgrades have already occurred in the past, and the already established cost pattern is for an upgrade every few years.

Please provide the following:

a. Please define the word "incurred", as used by HECO RT-13 in this context.

b. Please define the word "ongoing", as used by HECO RT-13 in this context.

c. Please define the test year concept as understood and applied by HECO RT-13.

d. Please confirm that HECO will not incur any upgrade costs until well after the test year. If this cannot be confirmed, please explain.

e. Please confirm that none of the upgrade cost HECO seeks to include in the test year forecast was incurred during the test year. If this cannot be confirmed, please explain.

HECO Response:

a. The word "incurred" as used in the sentence referenced above means that upgrade costs occur from time to time (as opposed to a given year or specified date), and that such costs have occurred and have been recorded on the Company's books in the past, and will occur again in the future.

b. The word "ongoing" as used in the same sentence referenced above means that the Company has faced in the past, and will continue to face in the future, Ellipse upgrades and upgrade costs.

c. In a rate proceeding, the Commission sets rates designed to provide the Company with an

opportunity to earn the fair and reasonable rate of return on rate base allowed by the Commission. The rates are based, in part, on the level of expenses determined by the Commission to be reasonable and necessary for the Company to incur in order to provide safe and reliable service. To the extent that test year expenses do not include necessary and allowable costs in setting the Company's rates, the Company will not have an opportunity to actually earn the return allowed by the Commission. With respect to the Ellipse upgrade costs, the necessity of periodically upgrading the Company's core business software system, which has occurred in the past and is expected to occur again in the future, has been established. Therefore, the rates required to provide the Company an opportunity to earn a fair and reasonable return on rate base allowed by the Commission would be understated if the revenue requirements used to establish the rates did not include a normalized amount of Ellipse upgrade costs. The objective of a rate case is to determine rates that would provide the company with an opportunity to earn a fair and reasonable rate of return on its rate base. To the extent there are costs that will be incurred when the rates are in effect, it is reasonable to consider the normalized level of such expenses for the test year.

d. HECO is planning to start work on the next Ellipse upgrade beginning in the second quarter of 2006.

e. The Company expects that none of the costs for the next Ellipse upgrade will be recorded on the Company's books in 2005. As stated in response to part c. (above), the Ellipse Upgrade cost amount included in HECO's 2005 test year expenses is a normalization adjustment amount.

CA-RIR-77

Ref: RT-16, pages 7-8 & HECO-R-1606 (Employee Counts).

The table appearing on RT-16, page 7, identifies 53 additional positions that were not included in HECO's 2005 test year forecast, of which 41 positions had been filled as of 6/30/05. Please provide the following clarifications regarding this information:

a. Please expand the referenced table to provide the actual hiring dates and/or the expected 2005 hiring month for each "additional" position.

b. HECO-R-1606 indicates that 17 of the additional positions were filled prior to 1/1/05. If not included in the response to part (a) above, please identify how many of the 17 positions filled prior to 1/1/05 were in Power Supply.

c. Please confirm that those 17 "filled" positions were included in the actual non-production employee counts provided in response to CA-IR-9, CA-IR-331 and CA-IR-508 and depicted

b. See response to part a.

c. The 17 "filled" positions were included in the actual non-production employee counts provided in response to CA-IR-9, CA-IR-331 and depicted in the chart on page 80 of CA-T-2. They were not included in employee counts provided in response to CA-IR-508 since only budgeted employee counts were provided for 2004 and 2005.

d. Yes. With respect to the months of January 2005 through April 2005, the 53 "additional unforecasted positions" listed on RT-16, page 7 would not have been included in the monthly forecast of non-production employee counts provided in response to CA-IR-331 and CA-IR-508, and therefore excluded from the chart on page 80 of CA-T-2 .

e. Yes. In compiling the response to DOD/HECO-IR-8-8, if the December 2005 forecasted employee count exceeded the actual December 2004 month end employee count for a department, the department was deemed to have "open" positions. Only these departments were included in HECO's response to DOD/HECO-IR-8-8. Therefore, departments with December 2005 forecasted employee count totals less than or equal to the actual December 2004 month-end employee count totals were not included in the estimated wages and benefits provided on page 5 of HECO's response to DOD/HECO-IR-8-8.

f. Yes, it may have caused the number of "open positions" to be lower. However if a department had a positive number in the "Difference" column on page 3 or 4 of HECO's response to DOD/HECO-IR-8-8 and the positive difference was solely attributable to the "additional unforecasted position" filled at 12/31/04 for that department, there would have been no effect on the estimated wages and benefits provided on page 5 of HECO's response to DOD/HECO-IR-8-8.

For example, the Workforce Staffing and Development department showed a positive difference of one in the "Difference" column shown on page 3 of the response to DOD/HECO-IR-8-8. The positive difference represented the Director, Client Services & Consulting, one of the "additional unforecasted positions" filled at 12/31/04. This would not have caused HECO to provide lower labor and benefit costs in response to DOD/HECO-IR-8-8 since all the positions for the department were filled if the "additional unforecasted position" was not considered.

CA-RIR-78

Ref: RT-16, pages 7-8, HECO-R-1603 & HECO-R-1606 (Employee Counts).

Please provide a copy of the written job or position descriptions for each of the additional 53 positions, indicating when each position was filled, or is expected to be filled.

HECO Response:

Please refer to HECO's response to DOD-RIR-7 for the written job or position descriptions and HECO's response to DOD-RIR-3 for the hiring status of these positions.

CA-RIR-79

Ref: RT-16, pages 8-9 & HECO-R-1606 (Employee Counts).

The referenced testimony generally refers to and describes the various costs associated with the additional positions presented on HECO-R-1606. In support of HECO-R-1606 and certain other rebuttal exhibits, the Company provided a spreadsheet file ("HECO R-1602 to HECO-R-1606.xls"). However, this spreadsheet file is primarily comprised of input numbers, with the only formulae representing "sums" or "subtotals." Please provide the following:

a. When did the Company conduct the analysis on which HECO-R-1606 was based?

b. Please describe the data source for the HECO-R-1606 "tab" of the referenced spreadsheet and explain how the "input" amounts were calculated.

c. Referring to the response to part (b) above, please provide additional supporting documentation (hard copy and spreadsheet file format) supporting the amounts appearing as "inputs" into the HECO-R-1606 "tab" of the referenced spreadsheet.

d. Neither HECO-R-1606 nor the supporting spreadsheet file provide any source references or support for the calculation of estimated benefits. Please provide support for the assumed 1904 productive hours per employee and the benefit rate of $7.99 per productive hour.

e. Neither HECO-R-1606 nor the supporting spreadsheet file provide any source references or support for the allocation or apportionment of labor and benefit costs between O&M, Capital, Billable and Clearing accounts. Please explain how this distribution was determined and provide support for those amounts.

HECO Response:

a. The analysis on which HECO-R-1606 was based was conducted during the preparation of rebuttal testimony. However, allocation adjustments (O&M, Capital, Billables, and Clearing) were made subsequent to the filing of the rebuttal testimony. See response to part b.

b. Calculation of the amounts included in HECO-R-1606, as revised, is provided in HECO's response to DOD-RIR-3. The derivation of estimated wages and benefit amounts for each position was explained in HECO RT-16, page 8 and the percent allocation to O&M, Capital, Billables, and Clearing were provided by the respective departments.

c. See response to part b.

d. The 1904 productive hours per employee was based on the assumption of 2,080 total hours less 176 holiday and vacation hours. The benefit rate of $7.99 per productive hour is provided in HECO-1315.

e. See response to part b.

CA-RIR-80

Ref: RT-16, page 10, lines 13-17 (Employee Counts)

In describing the two additional unforecasted positions in the Special Projects area, the referenced testimony states, in part:

> These two positions will continue for the duration of the EMS and OMS projects, currently scheduled to be completed by mid-2007. At that point, if there are no major systems projects to oversee (interoperability will continue until the completion of the CIS project around the middle of 2008), these positions will be phased out.

Based on the above, please provide the following:

a. Please clarify and explain the parenthetical reference to "interoperability" in the context of the CIS project.

b. Please explain and describe how these positions "will be phased out."

HECO Response:

a. Interoperability is the ability for information systems to communicate with each other. The CIS project will be designed to communicate directly with OMS, Ellipse, HR Suites, Intergraph Geographic Information System (GIS), and other information systems. For example, HECO's call center representative will be able to access information from the other information systems without having to log out of CIS. The relevant information will be online and available for the call center representative to do his or her job. A discussion of how the EMS, OMS and CIS are intended to work together was discussed in Exhibit D to

CA-RIR-81

Ref: RT-16, page 13, lines 13-17 (Employee Counts).

In describing the Company's disagreement with the labor expense adjustments proposed by the Consumer Advocate and DOD, the referenced testimony states, in part:

First, the CA erroneously assumes that employee vacancies directly translate into a reduction in labor expenses, when some vacancies may be offset by unforecasted overtime (in the case of bargaining unit employees) and a significant percentage of employee costs are charged to capital projects rather than expenses.

Based on the above, please provide the following:

a. Referring to the labor costs set forth on HECO-R-1606, did the Company assume that each of the 53 additional employee positions would directly translate into increased labor expenses? If not, please explain.

b. Referring to HECO-R-1606, please provide a listing of the additional employee positions that represent "bargaining unit" employees.

c. Referring to part (b) above, did the Company recognize in quantifying HECO-R-1606 that the additional "bargaining unit" employees would reduce forecasted overtime levels and compensation?

    1. If so, please provide the amount of the overtime reduction recognized in the calculations underlying HECO-R-1606.

    2. If not, please explain why that factor was not considered in preparing HECO-R-1606.

d. Is it HECO's position that CA Adjustment C-21"erroneously" removed from O&M expense the employee costs charged to capital projects? If so, please compare CA Adjustment C-21 with the response to DOD/HECO-IR-8-8 and provide a detailed explanation and quantification of the portion the CA's adjustment that erroneously removed capital project charges from O&M expense.

HECO Response:

a. No. While the personnel filling the 53 additional unforecasted positions will increase labor expenses, the Company is not seeking to adjust labor expenses for the 53 unforecasted positions as explained in DOD-RIR-4.

b. Additional employee positions that represent "bargaining unit" employees were:

- Purchasing Clerk
- Trouble Dispatcher
- Senior Helpers/Meter Apprentices (2)
- Jr. Drafters (2)

c. No. There was no overtime forecasted for the labor class of the Purchasing Clerk or for the work to be performed by the Jr. Drafter positions. The Senior Helpers/Meter Apprentices and the Trouble Dispatcher are apprenticeship/training positions created to assure that there will be qualified individuals as retirements occur. Since these positions are training positions who would not work independently without close supervision, forecasted overtime levels and compensation would not be expected to be reduced due to hiring of these positions.

d. No.

CA-RIR-82

Ref: RT-16, page 13, lines 18-21 (Employee Counts).

In describing the Company's disagreement with the labor expense adjustments proposed by the Consumer Advocate and DOD, the referenced testimony states, in part:

> In addition, the Company has added and expects to fill additional positions beyond those included in the test year estimate, which means that the year-end employee count, and/or the employee count in future years, should exceed the test year average.

Based on the above, please provide the following:

a. Please indicate when, and identify the specific letter, discovery response, etc. through which HECO first informed the Consumer Advocate that the Company's 2005 test year employee forecast excluded the 53 additional positions now asserted in rebuttal testimony.

b. Please indicate when, and identify the specific letter, discovery response, etc. through which HECO first informed the Consumer Advocate that the Company's 12/31/04 actual employee count included 17 additional positions that had not been included in the 2005 test year forecast.

HECO Response:

a. It should be noted that HECO is **not** proposing to revise its test year labor estimates to reflect the additional unforecasted positions discussed in HECO RT-16, and addressed by other various witnesses. The first time that HECO provided a company-wide quantification of the additional unforecasted positions was in rebuttal testimony. Please see the response to subpart b. below which addresses where HECO discussed some of the additional unforecasted positions in HECO's responses to IRs.

b. Although HECO did not explicitly inform the Consumer Advocate that the 12/31/04 actual employee count included 17 additional unforecasted positions, in HECO's

departments' December 2004 employee count exceeded the December 2005 test year forecast. A footnote was included for Production indicating that there were additional hirings that were not included in the test year 2005 year end employee count. HECO also discussed some of the additional unforecasted positions in HECO's responses to IRs (e.g., CA-IR-509, CA-IR-511, CA-IR-512, CA-IR-513 and CA-IR-582).

CA-RIR-83

Ref: RT-16, pages 13 and 17 (Employee Counts).

In describing the Company's disagreement with the labor expense adjustments proposed by the Consumer Advocate and DOD, the referenced testimony at page 13 states, in part:
Moreover, the CA treats vacancies arising out of new staffing positions created to enable the Company to perform new or substantially increased work that will carry over into future years in the same manner that it treats "structural vacancies" due to retirements and/or terminations that periodically occur.

At page 17, RT-16 also discusses why the structural vacancies should be treated differently from vacancies due to filling new positions. Based on the above, please provide the following:

a. It is unclear why the Company believes that an unfilled new position should be treated or viewed differently for ratemaking purposes than an unfilled position that had been previously authorized. Please explain.

b. Regardless of whether a vacancy is associated with a new position or a previously authorized position, the testimony at RT-16, page 17, does not appear to establish the conceptual regulatory framework demonstrating why these types of vacancies should be treated differently for ratemaking purposes. After all, each position is still "vacant" at a given point in time. Please provide a copy of all authoritative documentation, regulatory decisions or other support on which Ms. Sekimura relied in formulating this position.

HECO Response:

a. Please refer to HECO's response to CA-RIR-42 b.

b. Please refer to HECO's response to CA-RIR-42 b.

CA-RIR-84

Ref: RT-16, page 14, lines 1-5 (Employee Counts).

In describing the Company's disagreement with the labor expense adjustments proposed by the Consumer Advocate and DOD, the referenced testimony states, in part:

> Also, some of the "vacant" positions relate to the Company's proposals to expand its DSM programs and to include DSM program costs in base rates. The expenses related to these programs have separately been removed from the rate case, and the CA double counts the reduction when it separately reduces labor expenses due to these vacancies".

Based on the above, please provide the following:

a. Please confirm that the reference to the vacant DSM positions is the same 4 open positions referenced by HECO RT-10 at page 14. If this cannot be confirmed, please explain.

b. Referring to HECO-R-1011, please quantify the labor and benefit costs included in the response to DOD/HECO-IR-8-8 for the 4 open DSM positions, by NARUC account.

c. Referring to part (b) above, please provide a copy of all supporting workpapers in both hard copy and spreadsheet file format (with intact cell formulae).

HECO Response:

a. Yes. Reference to the vacant DSM positions is the same 4 open positions referenced by HECO RT-10 at page 14, line 15.

b. NARUC 910: $249,576

926: $60,852

c. Supporting information for all "open" positions for Energy Services were previously provided via e-mail on June 23, 2005 to the CA and DOD in response to their request for Excel files used to prepare the DOD/HECO-IR-8-8 Attachments.

CA-RIR-85

Ref: RT-16, page 15, lines 12-20 (Employee Counts).

In discussing the Consumer Advocate's proposed use of average 2005 forecast employee counts, the referenced testimony states, in part:

> In addition, new rates are not being set at the beginning of 2005. If rates were reset at the beginning of the year, and it was assumed that full staffing was in place at the beginning of the year even though staffing increases occurred gradually over the course of the year, then the amount included for staffing in rates for 2005 (looked at in isolation) might be too high. In this case, however, rates are not expected to be reset until at least October (for the interim increase) and until next year (for the final increase). The Company will not have received any rate increase during the first 9 months of 2005, even though significant staff increases have been made.

Based on the above, please provide the following:

a. Please define the "average" test year concept, as understood by Ms. Sekimura.

b. In the context of an "average" forecast test year, does Ms. Sekimura believe that it is acceptable to base certain elements of overall revenue requirement at beginning of test year levels, others at average levels and some items at end of period levels when determining overall revenue requirement? Please explain.

c. Referring to the response to parts (a) and (b) above, does Ms. Sekimura believe that there is any need to maximize consistency in the approach to quantifying the various elements of the ratemaking formula – that is, conceptual consistency in presenting the test year forecast using beginning, average or end of period prices, quantities or amounts? If not, please explain.

d. In the context of developing a test year for purposes of establishing utility rates, please describe and explain Ms. Sekimura's understanding of the linkage, if any, between the forecast test year (e.g., calendar year 2005) and the first year the rates resulting from the rate case will be in effect (e.g., calendar 2006). In other words, does Ms. Sekimura believe that the revenues, expenses and investment resulting from a 2005 forecast test year should yield amounts equal to those expected in 2006?

HECO Response:

a. The "average' test year concept generally refers to how the rate base is determined in establishing rates for the test year. HECO is proposing an "average" rate base, which is

generally determined by the simple arithmetic average of the beginning and ending test year

amounts. Since rate base items are generally balance sheet items that are determined at a date certain, it is not difficult to determine the test year "average" amounts. Revenues and expenses are income statement items, which are determined over the a period of time such as "for the 12 months ending December 31", so the average amounts generally are the "course-of the year" amounts, that is the amounts that are incurred during the 12 months of the test year.

b. The test year is a measure of the operations and investment for a specified twelve-month period. The test year provides the data foundation upon which the rate case is built. It is the starting point for developing investment and operating results that are presumed to be representative of future conditions so that future rate needs may be reasonably estimated. Revenues, expenses, or costs may then need to be adjusted to reflect the conditions during the period in which the rates established as a result of the proceeding would be in effect. Since rates are set for the future, the fundamental test period assumption is that the relationship between revenues, expenses and rate base will remain roughly the same in the period during which the rates are expected to be in effect, so that the utility will have a reasonable opportunity to earn the return found to be fair in the future. If an average test year is used, adjustments are made to the test year estimates so that the results of operations reflect known changes and better reflect future "normalized" operating conditions when the rates will actually be in effect. The scope of the normalization adjustments that may be appropriate depend on the specific circumstances in a case. (For example, in a period of high rate base additions coupled with high inflation, the Commission authorized the use of a

offset the effects of attrition. In HECO's 1990 test year rate case, the Commission authorized the inclusion of a full year of Kalaeloa costs, even though the operation of the facility was delaved to Mav 1991.) In this case. HECO has identified the adjustments that

are appropriate, and has explained the basis for each adjustment.

To some extent, sales growth (resulting in revenue increases) can be expected to offset normal increases in labor expenses (due to wage and salary increases), non-labor expenses (due to inflation, in low inflation periods) and rate base (in low construction periods). (That is why HECO agreed with the CA in rate cases in the 1990's not to annualize the impact of wage and salary increases made during the test year, even though it is my understanding that the Commission commonly authorized the annualization of wages and salary increases in rate cases prior to 1990.) Sales growth should not be expected to offset expense increases for significant increases in staffing or new operational activities (such as DG at substations) that are reflected only partially in the test year O&M expenses. Thus, in some cases (such as this rate case), it is appropriate to base certain expenses on the annualized costs, particularly in the case of a significant new cost that begins during the test year, and will be in effect for the full year during the period when rates are in effect.

c. In general there should be consistency in the approach to quantifying the various elements of the rate making formula, however, the overall objective of the rate making process should also be considered. The objective of the rate case is to determine rates that would provide an opportunity for the company to earn a fair and reasonable return for the period the rates would be in effect. The Commission in the past has made adjustments for known conditions which may create a "mismatch" to overcome situations where plant is increasing faster than

d. As described in part c, the objective of a rate case is to determine rates that would provide the company with an opportunity to earn a fair and reasonable rate of return on its rate base. To the extent there are costs that are beginning in the test year, that will continue beyond the test year, it is reasonable to consider the full year cost of such expenses for the test year.

CA-RIR-86

Ref: RT-16, page 16, lines 22-24 (Employee Counts).

The referenced testimony states, in part:
...the Company is incurring additional, unforecasted overtime in some areas as a result of some of the vacancies.

Based on the above, please provide the following:

a. Please provide a copy of all documents and analyses (both hard copy and spreadsheet file format) supporting this statement.

b. Referring to part (a) above, please explain how the Company quantified the additional overtime incurred as a result of the additional position vacancies.

c. Please provide a quantification of the overtime pay directly related to the referenced position vacancies.

HECO Response:

a. There was no analysis which specifically attributes unforecasted overtime hours to vacancies. The statement is supported by the response to CA-IR-477. For the Construction and Maintenance Department ("C&M"), as shown on page 4 of the response, the overtime rate estimated for 2005 was 10%. Please also refer to CA-IR-245, Attachment A for the Resource Leveling Report for C&M for 2005. The 10% overtime rate was based only on a comparison of supply versus demand and does not take into account other factors. As shown, on page 4, the actual overtime incurred through 5/15/05 was 18%. (The table on page 4 of the response to CA-IR-477 shows 2005 projected overtime hours for C&M as 44,075 which is 10% of productive straight time hours; the actual figures through 5/15/05 are 26,234 hours and 18%.) One of the primary reasons for the actual overtime exceeding the forecasted, even with the increase of 16 employees, is that the increase in staffing is to account for the loss of technical knowledge and experience through retirements, as

mentioned in HECO's testimony, HECO T-8 (pages 19 and 20). As Mr. Yoshida explained, due to the projected retirements over the next three to five years, productivity levels will be somewhat lower, while training requirements will be increasing, since it takes approximately 5 years to become a journey line worker.

Merit employees generally are not paid for "overtime" thus the overtime amounts for merit employees are not quantified. The need for merit employees to work extended hours on a regular basis does contribute to the "wear and tear" on such employees, however, and should not be counted on as a "resource" that allows vacancies to remain unfilled on a long term basis.

b. As stated in part a. above, no analysis was performed which quantified the additional overtime incurred as a result of additional position vacancies.

c. The requested information is not available. It would be difficult to determine the amount of overtime pay directly related to the referenced position vacancies since overtime may be

CA-RIR-87

Ref: RT-16, page 20, lines 9-25 & HECO-R-1607 (King Street Lease).

The referenced testimony indicates, in part, that HECO and Bishop Estates renegotiated the lease and executed a modified agreement, effective July 1, 2005. Under the modified terms, the lease is now deemed to be an operating lease under FAS13. Please provide the following:

a. In support of HECO-R-1607, the Company provided a spreadsheet file ("HECO-R-1607 Deferred Rent.xls"). However, this spreadsheet file is primarily comprised of input numbers, with the only formulae representing "sums" or "subtotals." Please provide a revised version of this spreadsheet file, with intact cell formulae showing how the numbers presented in the cells were derived.

b. Please provide a copy of the analysis relied upon by the Company to conclude that the modified lease is an operating lease under FAS13, in both hard copy and spreadsheet file format (with intact cell formulae).

HECO Response:

a. Please see electronic file provided (CA-RIR-87 HECO-R-1607 Deferred Rent.xls).

b. Please see analysis attached as pages 2-5. Also, please see electronic file provided of page 5 (CA-RIR-87_2005-08-01 Attachment A Lease Classification Memo.xls).

INTEROFFICE CORRESPONDENCE

Hawaiian Electric Co., Inc.

August 1, 2005

To: Corporate Accounting Files

cc: Patsy Nanbu, Tayne Sekimura, N. Lau (KPMG)

From: Bruce Tamashiro 8/1/05

Subject: Lease Classification of the King Street Lease

The purpose of this memo is to document our analysis of whether the new lease agreement between HECO and the Estate of Bernice Pauahi Bishop ("Bishop Estate") constitutes a capital or operating lease under the provisions of Statement of Financial Accounting Standards No. 13, "Accounting for Leases" ("SFAS No. 13").

BACKGROUND

HECO leases its office building located at 233 South King Street in Honolulu ("leased property" or "King Street building") from Bishop Estate, the owner of the building and underlying land. HECO has occupied the King Street building since 1927, and presently uses the building primarily for office and business-related purposes. The previous lease agreement between

3. The lease term is equal to 75% or more of the estimated economic life of the leased

Criteria #3 – The lease term is equal to 75% or more of the estimated economic life of the leased property.

As established above, the estimated economic life of the King Street building is indefinite. Therefore, the term of the King Street lease is not equal to 75% or more of the estimated economic life of the leased property, and therefore does not meet this criterion.

Criteria #4 – The present value at the beginning of the lease term of the minimum lease payments, excluding that portion of the payments representing executory costs such as insurance, maintenance, and taxes to be paid by the lessor, including any profit thereon, equals or exceeds 90 percent of the excess of the fair value of the leased property to the lessor at the inception of the lease over any related investment tax credit retained by the lessor and expected to be realized by him.

The estimated present value of the minimum lease payments amounts to approximately $8,922,000[2], based on HECO's estimated incremental borrowing rate of 5.82%[3], while the fair value of the leased property amounts to approximately $10,306,000[4]. See Attachment A. (Note that although the lease provides an option to extend the lease for a period of three years, the monthly rent for the option period is subject to negotiation at that time. Thus there is no economic incentive at this time to consider the option period and the minimum lease payment for that period was not considered in deriving the PV of the minimum payments.) Since the present value of the minimum lease payments is approximately 86.6% of the fair value of the leased property, this criterion is not met.

LEASE CLASSIFICATION CONCLUSION

Based on the above, the King Street lease between HECO and Bishop Estate for the lease of the King Street building does not meet any of the SFAS No. 13 capital lease criteria; therefore, the lease will be classified as an operating lease for financial reporting purposes.

---

[2] The present value of the King Street lease's minimum lease payments already excludes executory costs as HECO is responsible for these costs. Also, since the fair value of the land component is less than 25% of the total fair value of the leased property, both the land and the building components are considered as a single unit for the purposes of applying criteria #4 (per SFAS No. 13, paragraph 26(b)).

[3] The Company's estimated incremental borrowing rate is based on a Goldman Sachs & Company rate quote, as of July 30, 2005, predicated on the Company's ability to issue 20-year taxable and uninsured corporate bonds.

[4] Amount represents the total fair values of 1) the land and existing building based on a Hastings, Conboy Braig & Associates Ltd 2005 appraisal and 2) the present value of estimated capital improvements scheduled for the King Street building to be paid for by Bishop Estate, based on HECO's estimated incremental borrowing rate of 5.82%.

Attachment A

King Street Building Lease
Capital Lease Criteria #4 - SFAS No. 13 Paragraph 7(d)
July 30, 2005

Est land value - (per 2005 Braig appraisal)	1,000,000	9.7%
Est bldg value - (per 2005 Braig appraisal)	2,120,000	20.6%
Est bldg capital improvements value	7,185,559	69.7%
Est total value	10,305,559	100.0%

Est incremental borrowing rate 5.82% *

* (20-yr uninsured taxable bond rate quote from Goldman Sachs. Quoted at time of analysis)

Year	Annual Lease Payments (Excludes Executory Costs)	Estimated Capital Improvements to the Building (Exhibit C)
1	775,000	1,000,000
2	775,000	4,000,000
3	775,000	-
4	775,000	2,000,000
5	820,208	-
6	852,500	-
7	852,500	-
8	852,500	-
9	852,500	-
10	902,229	-
11	937,750	2,000,000
12	937,750	-
13	937,750	-
14	937,750	-
15	992,452	-
16	1,031,525	-
17	429,802	-
		-
Total	14,437,218	9,000,000
NPV	8,922,117	7,185,559

NPV of the minimum lease pmts	8,922,117
Estimated fair value of the leased property	10,305,559
NPV of the minimum payments as a % of fair value of the property	86.6%

CA-RIR-88

Ref: RT-16, page 21, lines 16-24, & HECO-R-1607 (King Street Lease).

The referenced testimony states, in part:

> Under SFAS No. 13, for financial reporting purposes, lease payments for the fixed term of the lease must be recorded on a straight-line basis over the fixed term of the lease,

[redacted]

payments escalate over time, a straight-line lease payment amount for the fixed term was calculated. HECO proposes that the ratemaking treatment and the financial accounting treatment to be the same.

expense calculated as shown on HECO-R-1607.

c. If the Commission allows the Company to include the "straight-line lease" expense in rates the difference in amounts collected from ratepayers versus the actual lease payments made to Bishop Estate will be recognized as a deferred rent expense and is treated as a reduction to rate base as discussed in HECO RT-16 and as shown on HECO-R-1901.

CA-RIR-89

Ref: RT-16, pages 42-43 & HECO-R-1609 (Pension Asset).

Beginning at page 42, line 25, the referenced testimony states, in part:

> As I described, in the period 1999 through 2002, the activity in the prepaid pension asset was solely a function of the negative NPPC.

Based on the above, please provide the following:

a. Please confirm that the negative NPPC recorded by HECO during the period 1999 through 2002 was about $56.5 million. If this cannot be confirmed, please explain.

b. Please confirm that the HECO's pension fund contributions during the period 1999 through 2002 were "zero." If this cannot be confirmed, please explain.

c. At any time during the period 1999 through 2002, did HECO reduce electric rates in recognition of the $56.5 million negative NPPC? Please explain.

d. At any time during the period 1999 through 2002, did HECO reduce fuel and purchased power costs passed on to customers in recognition of the $56.5 million negative NPPC? Please explain.

e. At any time during the period 1999 through 2002, did HECO reduce the DSM cost recoveries in recognition of the $56.5 million negative NPPC? Please explain.

f. Please confirm that during the period 1999 through 2002 the negative NPPC recorded by HECO resulted in lower operating expenses and higher operating income than would have been recorded if NPPC had been "zero" or positive. If this cannot be confirmed, please explain.

HECO Response:

a. Yes, as shown on HECO-R-1609, page 1 of 2, the negative NPPC recorded by HECO during the period 1999 through 2002 was about $56.5 million.

b. Yes, as shown on HECO-R-1609, page 1 of 2, the pension fund contributions during the period 1999 through 2002 were zero.

c. No, during the period 1999 through 2002, HECO did not reduce electric rates in recognition of the $56.5 million negative NPPC.

d. No, during the period 1999 through 2002, HECO did not reduce fuel and purchased power costs passed on to customers in recognition of the $56.5 million negative NPPC.

e. No, during the period 1999 through 2002, HECO did not reduce the DSM cost recoveries in recognition of the $56.5 million negative NPPC.

f. Yes, during the period 1999 through 2002, the negative NPPC recorded by HECO resulted in lower operating expenses and higher operating income than would have been recorded if NPPC had been "zero" or positive. Please note, however, that approximately 25% to 30% of the NPPC was allocated to corporate overhead and was capitalized annually as plant in service. That 25% to 30% of the negative NPPC has in the past and will in the future result in lower depreciation expenses and higher operating income over the life of the capitalized plant in service than what would have been recorded if NPPC in 1999 through 2002 had been "zero" or positive.

CA-RIR-90

Ref: RT-16, pages 46-47 (Pension Asset).

Beginning at line 30 of page 46, the referenced testimony states, in part:

> ...the prepaid pension asset should be included in rate base because, under SFAS 87, it is the recognized pension funding in excess of the pension obligation.

Based on the above, please provide the following:

a. Is it the position of Ms. Sekimura that FAS87 requires regulatory agencies to include the pension asset in rate base? Please explain.

b. Please provide a pinpoint reference to the specific paragraph(s) of FAS87 that address the rate base inclusion of the pension asset for regulatory ratemaking purposes. If none, please so state.

HECO Response:

a. The Company's position is that an accounting methodology should be consistently applied for cost recognition, rate base and return on rate base. For pension, the Company's position is that SFAS 87 has consistently been used as the basis for cost determination and therefore the methodology should be consistently applied to items included as additions or reductions in rate base. Financial Accounting Standards ("Standards") do not impose requirements on regulatory agencies; rather, the Standards do impose financial reporting requirements on companies issuing financial statements in accordance with generally accepted accounting principles.

b. FAS 87 does not specifically address the rate base inclusion of the pension asset for regulatory ratemaking purposes.

CA-RIR-91

Ref: RT-16, pages 39, 41 & 47 (Pension Asset).

At page 39, line 11, the referenced testimony states:

> Under SFAS 87, a prepaid pension asset is created when fund contributions exceed the NPPC. Exhibit HECO-R-1609, page 1 summarizes the annual activity in HECO's prepaid pension asset account since the inception of SFAS 87

At page 41, line 13, the referenced testimony states:

> As a result, in the period 1999 through 2002, the increase in the prepaid pension asset was solely a function of the negative NPPC.

Beginning at page 47, line 2, the referenced testimony states, in part:

> It [*the pension asset*] reflects an investment that the Company has made in the pension plan.

Based on the above, please provide the following:

a. Assuming FAS87 had resulted in NPPC in an amount equal to HECO's contribution to the

The major components of the NPPC are net of the service costs, interest costs, actual return on plan assets, and the change in unrecognized items. The negative NPPC in the period 1999 through 2002 was comprised primarily of the actual return on plan assets and the change in unrecognized items. Under ERISA, since HECO could not withdraw the funds from the pension trust, the funds were retained by the pension trust.

CA-RIR-92

Ref: RT-16, page 47, lines 14-23 (Pension Asset).

The question appearing at RT-16, page 47, line 14, contains the following quote from the direct testimony of Consumer Advocate witness Carver:

> In general terms, the utility is considered to have recovered all costs incurred between rate cases and achieved a reasonable return on its rate base investment. [CA-T-2, page 16, lines 1-2]

Beginning at line 19 of page 47, RT-16 states:

> Mr. Carver's statement implies that utilities are guaranteed their authorized rate of return when in fact they are unable to make up for past revenue deficiencies through rates. There is no true-up mechanism that will ensure that a utility will recover all costs incurred between rate cases and achieve a reasonable, let alone "authorized", rate of return on its rate base investment.

Based on the above, please provide the following:

a. Please provide a pinpoint reference to any portion of Mr. Carver's testimony that specifically states that utilities are "guaranteed" their authorized rate of return.

b. Please confirm that any true-up mechanism guaranteeing recovery all costs incurred between rate cases and achievement of the authorized return would constitute retroactive ratemaking. If this cannot be confirmed, please explain.

HECO Response:

a. Mr. Carver implies that utilities are guaranteed their authorized rate of return at CA-T-2, page 16, lines 1-2.

b. As "true-up mechanism" is not defined, the Company is unable to respond. Further, HECO RT-16 does not propose anything called a "true-up mechanism."

CA-RIR-93

Ref: RT-16, page 48 (Pension Asset).

The referenced testimony refers to and identifies HECO's achieved returns on investment in various years since the last rate case (Docket No. 7766). Please provide the following:

a. Please provide a copy of all documents relied upon by Ms. Sekimura to quantify these returns, including a detailed breakdown of achieved earnings and rate base investment.
   1. This information should be provided in both hard copy and spreadsheet file format.
   2. Referring to part (a), the information requested in not limited to the years referenced by Ms. Sekimura, but all years since the late rate case.

b. Were the returns identified by Ms. Sekimura based on average, beginning of year, or end of year rate base?

c. Referring to part (b) above, please provide monthly values for each rate base component, regardless of the rate base valuation method used by HECO.

HECO Response:

a. See attached pages 2 to 10 for the December 31 reports to the Commission for 1995 through 1997, reflecting the Company's calculation of rate of return on rate base and on common equity, and the supporting documentation. Refer to DOD-RIR-28, pages 2 to 43, for the 1998 through the present, June 30, 2005, reports to the Commission.

b. The returns identified were based on simple average.

c. See DOD-RIR-28, page 9 and pages 11 to 76 of this response for the monthly rate base calculation from July 1999, when the qualified pension asset was first included in rate base for ratemaking, through the most recent report to the Commission for June 2005.

HAWAIIAN ELECTRIC COMPANY, INC.

RATE OF RETURN ON RATE BASE AND ON COMMON EQUITY
For the 12 months ended December 31, 1995

(In thousands)

Line		Ratemaking This Month	Ratemaking Last Year
	Earnings for most recent 12 months:		
A	Operating Income	$74,590	$60,662
B	Earnings for common stock	$49,728	$44,698
	Weighted Average:		
C	Rate Base: Amount	$758,064	$697,680
D	Rate of Return (A/C)	9.84%	8.70%
E	Common Equity: Amount	$420,207	$382,463
F	Rate of Return (B/E)	11.83%	11.69%
	Simple Average:		
G	Rate Base: Amount	$757,644	$706,272
H	Rate of Return (A/G)	9.84%	8.59%
I	Common Equity: Amount	$420,036	$388,686
J	Rate of Return (B/I)	11.84%	11.50%
	End of Period:		
K	Rate Base: Amount	$786,667	$728,620
L	Rate of Return (A/K)	9.48%	8.33%
M	Common Equity: Amount	$434,417	$405,655
N	Rate of Return (B/M)	11.45%	11.02%

ROR1995 HECO ADJUSTMENTS
1995 RATEMAKING (D&O 8570)

Month	Book Rate Base (Sch 1)	Book W/C (Sch 1)	Rate W/C (Sch A)	Adjusted Rate Base	13 Mos Weighted Avg	Simple Avg	Tot Oper Income	WTD Avg (H)/(F)	Simp Avg (H)/(G)	EOP (H)/(E)
Jan	759,142	-27,925	-313	730,904						
Feb	759,834	-28,258	-377	731,199						
Mar	757,849	-28,553	-439	728,857						
Apr	760,417	-28,856	-452	731,109						
May	762,232	-29,282	-393	732,557						
June	786,173	-29,550	-363	756,260	720,240	723,078	72,729	10.10%	10.06%	9.62%
July	796,232	-29,808	-403	766,021						
Aug	815,851	-29,961	-289	785,601						
Sept	823,413	-29,681	-421	793,311						
Oct	822,774	-29,615	-539	792,620						
Nov	821,249	-29,704	-437	791,108						
Dec	817,184	-30,306	-211	786,667	758,064	757,644	74,590	9.84%	9.84%	9.48%
	9,482,350	-351,499	-4,637	9,126,214						

1994 ADJUSTED RATE BASE

Jan	684,663
Feb	688,384
Mar	684,425
Apr	687,322
May	688,888
June	689,896
July	694,929
Aug	692,814
Sept	716,587
Oct	715,889
Nov	713,497
Dec	728,620
	8,385,914

HECO
AVERATE RATE BASE AND RATE OF RETURN
($ Thousands)
December 31, 1995

Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,100,855		PUC p.10
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(96,535)		PUC p.10
5	Retirement Work in Progress	(3,839)		PUC p.10
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,000,481		
8				
9	REGULATORY ASSETS	28,095		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	8,605		PUC p.10
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,178)		Sch 1E
13				
14	FUEL STOCK	7,855		PUC p.10
15				
16	UNAMORTIZED AM/FM PROJECT COSTS	1,842		Sch 1D
17				
18	UNAMORTIZED WMS COSTS	N/A		Sch 1D
19				
20	WORKING CASH:			
21	1/24 Fuel Oil & PP Expense	15,795		Sch 1A
22				
23	1/12 Other Operation & Maintenance Expenses	10,344		Sch 1B
24	(Excluding FO & PP)			
25				
26	1/12 Taxes Other than Income, Excl. Franchise Taxes	4,167		Sch 1C
27				
28	TOTAL WORKING CASH	30,306		
29				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	123,652		PUC p.12
33	Customer Advances for Construction	3,417		PUC p.12
34	Deferred Income Taxes (Excluding Reg Assets)	81,891		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	28,095		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	13,589		Sch 1D
37	Rental Premiums - Kamoku	510		Sch 1D
38	Customer Deposits	1,824		Sch 1D
39	Unamortized Gain on ICP Sales	7,341		Sch 1D
40	Waiau Water Wells	(2,497)		Sch 1D
41	TOTAL DEDUCTIONS	257,822		
42				
43	MONTH ENDED RATE BASE	817,184		

HAWAIIAN ELECTRIC COMPANY, INC.

RATE OF RETURN ON RATE BASE AND ON COMMON EQUITY
For the 12 months ended December 31, 1996

(In thousands)

Line		Ratemaking This Month	Ratemaking Last Year
	Earnings for most recent 12 months:		
A	Operating Income	$79,385 *	$74,590
B	Earnings for common stock	$53,450 *	$49,728
	Weighted Average:		
C	Rate Base: Amount	$810,275	$758,064
D	Rate of Return (A/C)	9.80%	9.84%
E	Common Equity: Amount	$446,933	$420,207
F	Rate of Return (B/E)	11.96%	11.83%
	Simple Average:		
G	Rate Base: Amount	$818,276	$757,644
H	Rate of Return (A/G)	9.70%	9.84%
I	Common Equity: Amount	$447,698	$420,036
J	Rate of Return (B/I)	11.93%	11.84%
	End of Period:		
K	Rate Base: Amount	$849,886	$786,667
L	Rate of Return (A/K)	9.34%	9.48%
M	Common Equity: Amount	$461,379	$434,417
N	Rate of Return (B/M)	11.58%	11.45%

* These numbers exclude the net of tax amount of shareholder incentives under DSM of $432,635.

1296PUC HECO ADJUSTMENTS
1996 RATEMAKING

Month	Book Rate Base (Sch 1)	Book W/C (Sch 1)	Rate W/C (Sch A)	Adjusted Rate Base	13 Mos. Weighted Avg	Simple Avg	Total Oper Income	WTD Avg (H)/(F)	Simple Avg (H)/(G)	EOP (H)/(E)
Jan	823,586	(30,351)	562	793,797	763,078	762,351				
Feb	826,034	(30,429)	644	796,249	768,104	763,724				
Mar	825,421	(30,444)	746	795,723	773,068	762,290				
Apr	827,858	(30,467)	892	798,283	778,408	764,696				
May	828,275	(30,439)	1,079	798,915	783,624	765,736				
June	834,200	(30,884)	1,258	804,574	789,164	780,417	78,628	9.96%	10.08%	9.77%
July	835,419	(30,899)	1,394	805,914	792,983	785,967				
Aug	836,866	(31,066)	1,419	809,219	796,306	797,410				
Sept	859,329	(31,367)	1,556	829,518	799,684	811,414				
Oct	863,513	(31,696)	1,793	833,610	802,784	813,115				
Nov	861,249	(32,012)	1,985	831,222	805,754	811,165				
Dec	880,088	(32,304)	2,102	849,886	810,275	818,276	79,385	9.80%	9.70%	9.34%
	10,103,838	(372,358)	15,428	9,746,908						

1995 ADJUSTED RATE BASE

Jan	730,904
Feb	731,199
Mar	728,857
Apr	731,109
May	732,557
Jun	756,260
Jul	766,021
Aug	785,601
Sep	793,311
Oct	792,620
Nov	791,108
Dec	786,667
	9,126,214

HECO
AVERATE RATE BASE AND RATE OF RETURN
($ Thousands)
December 31, 1996

Line No.	RATE BASE	Month End	Source
1	NET UTILITY PLANT	1,138,915	PUC p.10
2	Adjustments:		
3	Franchise & Organizational Costs		
4	Construction Work in Progress	(84,087)	PUC p.10
5	Retirement Work in Progress	(5,613)	PUC p.10
6	Other		
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,049,215	
8			
9	REGULATORY ASSETS	32,421	Sch 1D
10			
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	7,915	PUC p.10
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,170)	Sch 1E
13			
14	FUEL STOCK	20,454	PUC p.10
15			
16	UNAMORTIZED AM/FM PROJECT COSTS	1,534	Sch 1D
17			
18	UNAMORTIZED WMS COSTS	N/A	Sch 1D
19			
20	WORKING CASH:		
21	1/24 Fuel Oil & PP Expense	17,228	Sch 1A
22			
23	1/12 Other Operation & Maintenance Expenses	10,597	Sch 1B
24	(Excluding FO & PP)		
25			
26	1/12 Taxes Other than Income, Excl. Franchise Taxes	4,479	Sch 1C
27			
28	TOTAL WORKING CASH	32,304	
29			
31	DEDUCTIONS:		
32	Unamortized Contributions in Aid of Construction	127,929	PUC p.12
33	Customer Advances for Construction	2,829	PUC p.12
34	Deferred Income Taxes (Excluding Reg Assets)	76,031	Sch 1D
35	Deferred Income Taxes - Regulatory Assets	32,421	Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	15,009	Sch 1D
37	Rental Premiums - Kamoku	359	Sch 1D
38	Customer Deposits	2,085	Sch 1D
39	Unamortized Gain on Sales	4,922	Sch 1D
41	TOTAL DEDUCTIONS	261,585	
42			
43	MONTH ENDED RATE BASE	880,088	

HAWAIIAN ELECTRIC COMPANY, INC.

RATE OF RETURN ON RATE BASE AND ON COMMON EQUITY
For the 12 months ended December 31, 1997

(In thousands)

Line		Ratemaking This Month	Ratemaking Last Year
	Earnings for most recent 12 months:		
A	Operating Income *	$75,672	$79,385
B	Earnings for common stock *	$48,039	$53,450
	Weighted Average:		
C	Rate Base: Amount	$866,576	$810,275
D	Rate of Return (A/C)	8.73%	9.80%
E	Common Equity: Amount	$468,879	$446,933
F	Rate of Return (B/E)	10.25%	11.96%
	Simple Average:		
G	Rate Base: Amount	$864,771	$818,276
H	Rate of Return (A/G)	8.75%	9.70%
I	Common Equity: Amount	$468,082	$447,898
J	Rate of Return (B/I)	10.26%	11.93%
	End of Period:		
K	Rate Base: Amount	$879,655	$849,886
L	Rate of Return (A/K)	8.60%	9.34%
M	Common Equity: Amount	$474,785	$461,379
N	Rate of Return (B/M)	10.12%	11.58%

* These numbers exclude the net of tax amount of shareholder incentives under DSM of $1,404 and $433 in 1997 and 1996, respectively.

HECO ADJUSTMENTS
RATEMAKING
1997

Month	Book Rate Base (Sch 1)	Book W/C (Sch 1)	Rate W/C (Sch A)	Adjusted Rate Base	13 Mos. Weighted Avg	Simple Avg	Total Oper Income	WTD Avg (H)/(F)	Simple Avg (H)/(G)	EOP (H)/(E)
Jan	887,265	(32,572)	2,239	856,932	815,680	825,364	79,523	9.75%	9.63%	9.28%
Feb	887,742	(32,774)	2,389	857,357	820,569	826,803	79,449	9.68%	9.61%	9.27%
Mar	889,984	(33,122)	2,513	859,375	825,425	827,549	78,220	9.48%	9.45%	9.10%
Apr	889,171	(33,380)	2,686	858,477	830,252	828,380	78,246	9.42%	9.45%	9.11%
May	890,875	(33,513)	2,637	859,999	835,000	829,457	76,658	9.18%	9.24%	8.91%
June	889,764	(33,474)	2,533	858,823	839,608	831,698	76,667	9.13%	9.22%	8.93%
July	905,489	(33,491)	2,516	874,514	844,988	840,214	76,092	9.01%	9.06%	8.70%
Aug	905,921	(33,494)	2,435	874,862	850,292	842,041	74,813	8.80%	8.88%	8.55%
Sept	907,113	(33,541)	2,441	876,013	855,430	852,766	74,054	8.66%	8.68%	8.45%
Oct	911,453	(33,466)	2,369	880,356	859,340	856,983	72,423	8.43%	8.45%	8.23%
Nov	910,182	(33,189)	2,247	879,240	862,851	855,231	73,240	8.49%	8.56%	8.33%
Dec	910,263	(32,728)	2,120	879,655	866,576	864,771	75,672	8.73%	8.75%	8.60%
	10,785,222	(398,744)	29,126	10,415,604						

1996 ADJUSTED RATE BASE	
Jan	793,797
Feb	796,249
Mar	795,723
Apr	798,283
May	798,915
Jun	804,574
Jul	805,914
Aug	809,219
Sep	829,518
Oct	833,610
Nov	831,222
Dec	849,886
	9,746,910

HECO
AVERATE RATE BASE AND RATE OF RETURN
($ Thousands)
December 31, 1997

Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,168,375		PUC p.10
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work In Progress	(85,603)		PUC p.10
5	Retirement Work In Progress	(4,835)		PUC p.10
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,077,937		
8				
9	REGULATORY ASSETS	34,792		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	7,671		PUC p.10
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,220)		Sch 1E
13				
14	FUEL STOCK	18,208		PUC p.10
15				
16	UNAMORTIZED AM/FM PROJECT COSTS	1,022		Sch 1D
17				
18	UNAMORTIZED ACCESS COSTS	0		
19				
20	WORKING CASH:			
21	1/24 Fuel Oil & PP Expense	17,642		Sch 1A
22				
23	1/12 Other Operation & Maintenance Expenses	10,543		Sch 1B
24	(Excluding FO & PP)			
25				
26	1/12 Taxes Other than Income, Excl. Franchise Taxes	4,543		Sch 1C
27				
28	TOTAL WORKING CASH	32,728		
29				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	127,954		PUC p.12
33	Customer Advances for Construction	2,348		PUC p.12
34	Deferred Income Taxes (Excluding Reg Assets)	74,006		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	34,791		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	15,837		Sch 1D
37	Rental Premiums - Kamoku	208		Sch 1D
38	Customer Deposits	2,284		Sch 1D
39	Unamortized Gain on Sales	2,447		Sch 1D
41	TOTAL DEDUCTIONS	259,875		
42				
43	MONTH ENDED RATE BASE	910,263		

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	January 31, 2000			
Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,197,129		PUC p.10
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(76,333)		PUC p.10
5	Retirement Work in Progress	(7,602)		PUC p.10
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,113,194		
8				
9	REGULATORY ASSETS	40,733		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	8,028		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,081)		Sch 1E
13				
14	FUEL STOCK	20,908		PUC p.8
15	QUALIFIED PENSION LIABILITY	2,219		
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	7,531		Sch 1D
18	UNAMORTIZED ACCESS COSTS	0		
19				
20	WORKING CASH:			
21	1/24 Fuel Oil & PP Expense	16,023		Sch 1A
22				
23	1/12 Other Operation & Maintenance Expenses	10,064		Sch 1B
24	(Excluding FO & PP)			
25				
26	1/12 Taxes Other than Income, Excl. Franchise Taxes	4,335		Sch 1C
27				
28	TOTAL WORKING CASH	30,422		
29				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	132,151		PUC p.9
33	Customer Advances for Construction	1,894		PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	74,843		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	40,664		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	17,543		Sch 1D
37	Rental Premiums - Kamoku	50		Sch 1D
38	Customer Deposits	3,049		Sch 1D
39	Unamortized Gain on Sales	983		Sch 1D
41	TOTAL DEDUCTIONS	271,177		
42				
43	MONTH ENDED RATE BASE	949,777		

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	February 29, 2000			
Line				
No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,197,552		PUC p.10
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(81,698)		PUC p.10
5	Retirement Work in Progress	(8,004)		PUC p.10
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,107,850		
8				
9	REGULATORY ASSETS	40,958		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	8,033		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,107)		Sch 1E
13				
14	FUEL STOCK	19,835		PUC p.8
15	QUALIFIED PENSION LIABILITY	3,030		
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	7,372		Sch 1D
18	UNAMORTIZED ACCESS COSTS	0		
19				
20	WORKING CASH:			
21	1/24 Fuel Oil & PP Expense	16,446		Sch 1A
22				
23	1/12 Other Operation & Maintenance Expenses	10,219		Sch 1B
24	(Excluding FO & PP)			
25				
26	1/12 Taxes Other than Income, Excl. Franchise Taxes	4,414		Sch 1C
27				
28	TOTAL WORKING CASH	31,079		
29				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	131,740		PUC p.9
33	Customer Advances for Construction	1,886		PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	75,063		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	40,864		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	17,645		Sch 1D
37	Rental Premiums - Kamoku	50		Sch 1D
38	Customer Deposits	3,067		Sch 1D
39	Unamortized Gain on Sales	964		Sch 1D
41	TOTAL DEDUCTIONS	271,279		
42				
43	MONTH ENDED RATE BASE	944,771		

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	March 31, 2000			
Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,198,822		PUC p.10
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(74,673)		PUC p.10
5	Retirement Work in Progress	(8,398)		PUC p.10
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,115,751		
8				
9	REGULATORY ASSETS	41,137		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	8,228		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,141)		Sch 1E
13				
14	FUEL STOCK	18,208		PUC p.8
15	QUALIFIED PENSION LIABILITY	6,077		
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	7,225		Sch 1D

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	April 30, 2000			
Line				
No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,199,803		PUC p.10
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(78,760)		PUC p.10
5	Retirement Work in Progress	(8,706)		PUC p.10
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,112,337		
8				
9	REGULATORY ASSETS	41,430		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	8,052		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,165)		Sch 1E
13				
14	FUEL STOCK	19,640		PUC p.8
15	QUALIFIED PENSION LIABILITY	6,887		Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	7,136		Sch 1D
18	UNAMORTIZED ACCESS COSTS	0		
19				
20	WORKING CASH:			
21	1/24 Fuel Oil & PP Expense	17,217		Sch 1A
22				
23	1/12 Other Operation & Maintenance Expenses	10,109		Sch 1B
24	(Excluding FO & PP)			
25				
26	1/12 Taxes Other than Income, Excl. Franchise Taxes	4,560		Sch 1C
27				
28	TOTAL WORKING CASH	31,886		
29				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	132,088		PUC p.9
33	Customer Advances for Construction	1,949		PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	75,114		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	41,284		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	17,849		Sch 1D
37	Rental Premiums - Kamoku	48		Sch 1D
38	Customer Deposits	3,204		Sch 1D
39	Unamortized Gain on Sales	1,029		Sch 1D
41	TOTAL DEDUCTIONS	272,565		
42				
43	MONTH ENDED RATE BASE	952,638		

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	May 31, 2000			
Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,200,444	/	PUC p.10
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(81,294)	/	PUC p.10
5	Retirement Work in Progress	(9,146)	/	PUC p.10
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,110,004		
8				
9	REGULATORY ASSETS	41,671		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	7,846	/	PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,180)	/	Sch 1E
13				
14	FUEL STOCK	22,729	/	PUC p.8
15	QUALIFIED PENSION LIABILITY	9,189	/	Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	6,981	/	Sch 1D
18	UNAMORTIZED ACCESS COSTS	0		
19				
20	WORKING CASH:			
21	1/24 Fuel Oil & PP Expense	17,666	/	Sch 1A
22				
23	1/12 Other Operation & Maintenance Expenses	10,023		Sch 1B
24	(Excluding FO & PP)			
25				
26	1/12 Taxes Other than Income, Excl. Franchise Taxes	4,655		Sch 1C
27				
28	TOTAL WORKING CASH	32,344		
29				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	131,838	/	PUC p.9
33	Customer Advances for Construction	1,838	/	PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	77,910		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	41,494		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	17,951		Sch 1D
37	Rental Premiums - Kamoku	48		Sch 1D
38	Customer Deposits	3,273	/	Sch 1D
39	Unamortized Gain on Sales	1,009		Sch 1D
41	TOTAL DEDUCTIONS	275,359		
42				
43	MONTH ENDED RATE BASE	953,225		

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	June 30, 2000			
Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,201,783		PUC p.10
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(82,985)		PUC p.10
5	Retirement Work in Progress	(9,640)		PUC p.10
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,109,158		
8				
9	REGULATORY ASSETS	41,848		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	8,048		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,211)		Sch 1E
13				
14	FUEL STOCK	27,514		PUC p.8
15	QUALIFIED PENSION LIABILITY	10,745		Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	6,819		Sch 1D
18	UNAMORTIZED ACCESS COSTS	0		
19				
20	WORKING CASH:			
21	1/24 Fuel Oil & PP Expense	18,136		Sch 1A
22				
23	1/12 Other Operation & Maintenance Expenses	9,948		Sch 1B
24	(Excluding FO & PP)			
25				
26	1/12 Taxes Other than Income, Excl. Franchise Taxes	4,726		Sch 1C
27				
28	TOTAL WORKING CASH	32,810		
29				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	133,013		PUC p.9
33	Customer Advances for Construction	2,033		PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	78,775		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	41,704		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	18,054		Sch 1D
37	Rental Premiums - Kamoku	47		Sch 1D
38	Customer Deposits	3,280		Sch 1D
39	Unamortized Gain on Sales	989		Sch 1D
41	TOTAL DEDUCTIONS	277,895		
42				
43	MONTH ENDED RATE BASE	966,838		

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	July 31, 2000			
Line				
No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,201,818		PUC p.10
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(84,985)		PUC p.10
5	Retirement Work in Progress	(10,018)		PUC p.10
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,106,813		
8				
9	REGULATORY ASSETS	42,059		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	8,252		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,241)		Sch 1E
13				
14	FUEL STOCK	24,343		PUC p.8
15	QUALIFIED PENSION LIABILITY	12,301		Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	6,656		Sch 1D
18	UNAMORTIZED ACCESS COSTS	0		
19				
20	WORKING CASH:			
21	1/24 Fuel Oil & PP Expense	18,647		Sch 1A
22				
23	1/12 Other Operation & Maintenance Expenses	9,890		Sch 1B
24	(Excluding FO & PP)			
25				
26	1/12 Taxes Other than Income, Excl. Franchise Taxes	4,809		Sch 1C
27				
28	TOTAL WORKING CASH	33,346		
29				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	132,810		PUC p.9
33	Customer Advances for Construction	2,026		PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	79,454		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	41,873		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	18,156		Sch 1D
37	Rental Premiums - Kamoku	47		Sch 1D
38	Customer Deposits	3,310		Sch 1D
39	Unamortized Gain on Sales	969		Sch 1D
41	TOTAL DEDUCTIONS	278,645		
42				
43	MONTH ENDED RATE BASE	952,884		

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	August 31, 2000			
Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,203,032		PUC p.10
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(89,333)		PUC p.10
5	Retirement Work in Progress	(10,258)		PUC p.10
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,103,441		
8				
9	REGULATORY ASSETS	42,268		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	8,584		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,257)		Sch 1E
13				
14	FUEL STOCK	27,284		PUC p.8
15	QUALIFIED PENSION LIABILITY	13,987		Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	6,493		Sch 1D
18	UNAMORTIZED ACCESS COSTS	0		
19				
20	WORKING CASH:			
21	1/24 Fuel Oil & PP Expense	19,178		Sch 1A
22				
23	1/12 Other Operation & Maintenance Expenses	9,798		Sch 1B
24	(Excluding FO & PP)			
25				
26	1/12 Taxes Other than Income, Excl. Franchise Taxes	4,894		Sch 1C
27				
28	TOTAL WORKING CASH	33,870		
29				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	132,481		PUC p.9
33	Customer Advances for Construction	2,023		PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	80,082		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	42,062		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	18,258		Sch 1D
37	Rental Premiums - Kamoku	46		Sch 1D
38	Customer Deposits	3,360		Sch 1D
39	Unamortized Gain on Sales	948		Sch 1D
41	TOTAL DEDUCTIONS	279,260		
42				
43	MONTH ENDED RATE BASE	954,410		

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	September 30, 2000			
Line				
No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,204,613		PUC p.10
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(93,941)		PUC p.10
5	Retirement Work in Progress	(10,474)		PUC p.10
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,100,198		
8				
9	REGULATORY ASSETS	42,244		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	8,604		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,285)		Sch 1E
13				
14	FUEL STOCK	21,843		PUC p.8
15	QUALIFIED PENSION LIABILITY	15,673		Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	6,330		Sch 1D
18	UNAMORTIZED ACCESS COSTS	0		
19				
20	WORKING CASH:			
21	1/24 Fuel Oil & PP Expense	19,619		Sch 1A
22				
23	1/12 Other Operation & Maintenance Expenses	9,777		Sch 1B
24	(Excluding FO & PP)			
25				
26	1/12 Taxes Other than Income, Excl. Franchise Taxes	4,962		Sch 1C
27				
28	TOTAL WORKING CASH	34,358		
29				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	132,196		PUC p.9
33	Customer Advances for Construction	2,023		PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	79,189		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	42,186		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	18,360		Sch 1D
37	Rental Premiums - Kamoku	46		Sch 1D
38	Customer Deposits	3,487		Sch 1D
39	Unamortized Gain on Sales	928		Sch 1D
41	TOTAL DEDUCTIONS	278,415		
42				
43	MONTH ENDED RATE BASE	948,550		

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	October 31, 2000			
Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,207,347		PUC p.10
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(96,228)		PUC p.10
5	Retirement Work in Progress	(10,661)		PUC p.10
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,100,458		
8				
9	REGULATORY ASSETS	42,487		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	8,641		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,317)		Sch 1E
13				
14	FUEL STOCK	27,234		PUC p.8
15	QUALIFIED PENSION LIABILITY	17,359		Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	6,168		Sch 1D
18	UNAMORTIZED ACCESS COSTS	0		
19				
20	WORKING CASH:			
21	1/24 Fuel Oil & PP Expense	20,032		Sch 1A
22				
23	1/12 Other Operation & Maintenance Expenses	9,773		Sch 1B
24	(Excluding FO & PP)			
25				
26	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,037		Sch 1C
27				
28	TOTAL WORKING CASH	34,842		
29				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	131,810		PUC p.9
33	Customer Advances for Construction	2,015		PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	79,558		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	42,322		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	18,462		Sch 1D
37	Rental Premiums - Kamoku	45		Sch 1D
38	Customer Deposits	3,585		Sch 1D
39	Unamortized Gain on Sales	908		Sch 1D
41	TOTAL DEDUCTIONS	278,705		
42				
43	MONTH ENDED RATE BASE	956,167		

Line No.	RATE BASE	Month End		Source
	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	November 30, 2000			
1	NET UTILITY PLANT	1,211,427		PUC p.10
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(94,437)		PUC p.10
5	Retirement Work in Progress	(7,214)		PUC p.10
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,109,776		
8				
9	REGULATORY ASSETS	42,695		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	8,277		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,335)		Sch 1E
13				
14	FUEL STOCK	22,039		PUC p.8
15	QUALIFIED PENSION LIABILITY	19,045		Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	6,006		Sch 1D
18	UNAMORTIZED ACCESS COSTS	0		
19				
20	WORKING CASH:			
21	1/24 Fuel Oil & PP Expense	20,436		Sch 1A
22				
23	1/12 Other Operation & Maintenance Expenses	10,014		Sch 1B
24	(Excluding FO & PP)			
25				
26	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,101		Sch 1C
27				
28	TOTAL WORKING CASH	35,551		
29				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	133,807		PUC p.9
33	Customer Advances for Construction	2,023		PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	79,881		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	42,458		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	18,564		Sch 1D
37	Rental Premiums - Kamoku	45		Sch 1D
38	Customer Deposits	3,644		Sch 1D
39	Unamortized Gain on Sales	888		Sch 1D
41	TOTAL DEDUCTIONS	281,310		
42				
43	MONTH ENDED RATE BASE	959,744		

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	December 31, 2000			
Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,220,696		PUC p.10
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(82,105)		PUC p.10
5	Retirement Work in Progress	(7,407)		PUC p.10
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,131,184		
8				
9	REGULATORY ASSETS	42,169		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	7,929		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,383)		Sch 1E
13				
14	FUEL STOCK	24,177		PUC p.8
15	QUALIFIED PENSION LIABILITY	20,731		Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	5,844		Sch 1D
18	UNAMORTIZED ACCESS COSTS	0		
19				
20	WORKING CASH:			
21	1/24 Fuel Oil & PP Expense	20,794		Sch 1A
22				
23	1/12 Other Operation & Maintenance Expenses	10,450		Sch 1B
24	(Excluding FO & PP)			
25				
26	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,139		Sch 1C
27				
28	TOTAL WORKING CASH	36,383		
29				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	135,323		PUC p.9
33	Customer Advances for Construction	2,000		PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	77,931		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	42,202		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	18,419		Sch 1D
37	Rental Premiums - Kamoku	44		Sch 1D
38	Customer Deposits	3,668		Sch 1D
39	Unamortized Gain on Sales	868		Sch 1D
41	TOTAL DEDUCTIONS	280,455		
42				
43	MONTH ENDED RATE BASE	985,579		

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	January 31, 2001			
Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,219,508		PUC p.10
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(78,631)		PUC p.10
5	Retirement Work in Progress	(7,696)		PUC p.10
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,133,181		
8				
9	REGULATORY ASSETS	42,354		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	7,645		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,396)		Sch 1E
13				
14	FUEL STOCK	23,852		PUC p.8
15	QUALIFIED PENSION LIABILITY	22,504		Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	5,681		Sch 1D
18	UNAMORTIZED ACCESS COSTS	0		
19				
20	WORKING CASH:			
21	1/24 Fuel Oil & PP Expense	21,094		Sch 1A
22				
23	1/12 Other Operation & Maintenance Expenses	10,606		Sch 1B
24	(Excluding FO & PP)			
25				
26	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,201		Sch 1C
27				
28	TOTAL WORKING CASH	36,901		
29				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	135,012		PUC p.9
33	Customer Advances for Construction	2,000		PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	78,345		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	42,395		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	18,462		Sch 1D
37	Rental Premiums - Kamoku	43		Sch 1D
38	Customer Deposits	3,720		Sch 1D
39	Unamortized Gain on Sales	847		Sch 1D
41	TOTAL DEDUCTIONS	280,824		
42				
43	MONTH ENDED RATE BASE	988,898		

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	February 28, 2001			
Line				
No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,218,995		PUC p.10
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(81,157)		PUC p.10
5	Retirement Work in Progress	(7,913)		PUC p.10
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,129,925		
8				
9	REGULATORY ASSETS	42,551		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	8,565		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,405)		Sch 1E
13				
14	FUEL STOCK	23,794		PUC p.8
15	QUALIFIED PENSION LIABILITY	24,278		Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	5,519		Sch 1D
18	UNAMORTIZED ACCESS COSTS	0		
19				
20	WORKING CASH:			
21	1/24 Fuel Oil & PP Expense	21,201		Sch 1A
22				
23	1/12 Other Operation & Maintenance Expenses	10,597		Sch 1B
24	(Excluding FO & PP)			
25				
26	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,209		Sch 1C
27				
28	TOTAL WORKING CASH	37,007		
29				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	134,430		PUC p.9
33	Customer Advances for Construction	2,001		PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	78,669		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	42,588		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	18,505		Sch 1D
37	Rental Premiums - Kamoku	43		Sch 1D
38	Customer Deposits	3,775		Sch 1D
39	Unamortized Gain on Sales	827		Sch 1D
41	TOTAL DEDUCTIONS	280,838		
42				
43	MONTH ENDED RATE BASE	988,396		

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	March 31, 2001			
Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,221,240		PUC p.10
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(86,957)		PUC p.10
5	Retirement Work in Progress	(8,295)		PUC p.10
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,125,988		
8				
9	REGULATORY ASSETS	42,758		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	8,567		PUC p.8

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	April 30, 2001			
Line				
No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,220,110		PUC p.10
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(62,129)		PUC p.10
5	Retirement Work in Progress	(8,460)		PUC p.10
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,149,521		
8				
9	REGULATORY ASSETS	42,899		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	8,477		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,432)		Sch 1E
13				
14	FUEL STOCK	27,046		PUC p.8
15	QUALIFIED PENSION LIABILITY	27,403		Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	5,195		Sch 1D
18	UNAMORTIZED ACCESS COSTS	0		
19				
20	WORKING CASH:			
21	1/24 Fuel Oil & PP Expense	21,418		Sch 1A
22				
23	1/12 Other Operation & Maintenance Expenses	10,740		Sch 1B
24	(Excluding FO & PP)			
25				
26	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,230		Sch 1C
27				
28	TOTAL WORKING CASH	37,388		
29				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	133,953		PUC p.9
33	Customer Advances for Construction	1,731		PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	79,550		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	42,974		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	18,590		Sch 1D
37	Rental Premiums - Kamoku	42		Sch 1D
38	Customer Deposits	3,873		Sch 1D
39	Unamortized Gain on Sales	787		Sch 1D
41	TOTAL DEDUCTIONS	281,500		
42				
43	MONTH ENDED RATE BASE	1,013,997		

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	May 31, 2001			
Line				
No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,220,570		PUC p.10
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(57,629)	✓	PUC p.10
5	Retirement Work in Progress	(8,634)	✓	PUC p.10
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,154,307		
8				
9	REGULATORY ASSETS	43,036		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	8,533	✓	PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,479)	✓	Sch 1E
13				
14	FUEL STOCK	24,235	✓	PUC p.8
15	QUALIFIED PENSION LIABILITY	29,071		Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	5,032	✓	Sch 1D
18	UNAMORTIZED ACCESS COSTS	0		
19				
20	WORKING CASH:			
21	1/24 Fuel Oil & PP Expense	21,451	✓	Sch 1A
22				
23	1/12 Other Operation & Maintenance Expenses	10,874	✓	Sch 1B
24	(Excluding FO & PP)			
25				
26	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,216	✓	Sch 1C
27				
28	TOTAL WORKING CASH	37,541		
29				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	133,645	✓	PUC p.9
33	Customer Advances for Construction	1,748	✓	PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	79,874	✓	Sch 1D
35	Deferred Income Taxes - Regulatory Assets	43,168	✓	Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	18,633	✓	Sch 1D
37	Rental Premiums - Kamoku	41	✓	Sch 1D
38	Customer Deposits	3,907	✓	Sch 1D
39	Unamortized Gain on Sales	767	✓	Sch 1D
41	TOTAL DEDUCTIONS	281,783		
42				
43	MONTH ENDED RATE BASE	1,017,493		

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	June 30, 2001			
Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,222,378		PUC p.10
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(60,651)		PUC p.10
5	Retirement Work in Progress	(8,834)		PUC p.10
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,152,891		
8				
9	REGULATORY ASSETS	43,162		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	8,893		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,525)		Sch 1E
13				
14	FUEL STOCK	28,501		PUC p.8
15	QUALIFIED PENSION LIABILITY	30,738		Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	4,870		Sch 1D
18	UNAMORTIZED ACCESS COSTS	0		
19				
20	WORKING CASH:			
21	1/24 Fuel Oil & PP Expense	21,421		Sch 1A
22				
23	1/12 Other Operation & Maintenance Expenses	10,856		Sch 1B
24	(Excluding FO & PP)			
25				
26	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,208		Sch 1C
27				
28	TOTAL WORKING CASH	37,485		
29				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	133,429		PUC p.9
33	Customer Advances for Construction	1,777		PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	80,290		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	43,361		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	18,676		Sch 1D
37	Rental Premiums - Kamoku	41		Sch 1D
38	Customer Deposits	3,962		Sch 1D
39	Unamortized Gain on Sales	746		Sch 1D
41	TOTAL DEDUCTIONS	282,282		
42				
43	MONTH ENDED RATE BASE	1,021,733		

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	July 31, 2001			
Line				
No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,222,700		PUC p.10
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work In Progress	(63,346)		PUC p.10
5	Retirement Work In Progress	(9,086)		PUC p.10
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,150,268		
8				
9	REGULATORY ASSETS	43,296		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	8,966		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,537)		Sch 1E

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	August 31, 2001			
Line				
No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,222,244		PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(64,372)		PUC p.8
5	Retirement Work in Progress	(5,912)		PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,151,960		
8				
9	REGULATORY ASSETS	43,433		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	8,959		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,548)		Sch 1E
13				
14	FUEL STOCK	33,832		PUC p.8
15	QUALIFIED PENSION LIABILITY	34,184		Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	4,545		Sch 1D
18	E-BUSINESS	314		
19	UNAMORTIZED ACCESS COSTS	0		
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	21,507		Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	10,821		Sch 1B
25	(Excluding FO & PP)			
26				
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,213		Sch 1C
28				
29	TOTAL WORKING CASH	37,541		
30				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	133,293		PUC p.9
33	Customer Advances for Construction	1,782		PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	81,103		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	43,747		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	18,761		Sch 1D
37	Rental Premiums - Kamoku	39		Sch 1D
38	Customer Deposits	4,104		Sch 1D
39	Unamortized Gain on Sales	706		Sch 1D
40	TOTAL DEDUCTIONS	283,535		
41				
42	MONTH ENDED RATE BASE	1,028,665		

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	September 30, 2001			
Line				
No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,222,366		PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(66,243)		PUC p.8
5	Retirement Work in Progress	(5,845)		PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,150,278		
8				
9	REGULATORY ASSETS	43,576		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	8,847		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,546)		Sch 1E
13				
14	FUEL STOCK	27,585		PUC p.8
15	QUALIFIED PENSION LIABILITY	35,922		Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	4,383		Sch 1D
18	E-BUSINESS	308		
19	UNAMORTIZED ACCESS COSTS	0		
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	21,515		Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	10,649		Sch 1B
25	(Excluding FO & PP)			
26				
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,205		Sch 1C
28				
29	TOTAL WORKING CASH	37,369		
30				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	132,895		PUC p.9
33	Customer Advances for Construction	1,782		PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	80,601		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	43,623		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	18,804		Sch 1D
37	Rental Premiums - Kamoku	39		Sch 1D
38	Customer Deposits	4,137		Sch 1D
39	Unamortized Gain on Sales	686		Sch 1D
40	TOTAL DEDUCTIONS	282,567		
41				
42	MONTH ENDED RATE BASE	1,023,155		

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	October 31, 2001			
Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,222,856		PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(65,712)		PUC p.8
5	Retirement Work in Progress	(4,926)		PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,152,218		
8				
9	REGULATORY ASSETS	43,722		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	8,695		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,536)		Sch 1E
13				
14	FUEL STOCK	27,826		PUC p.8
15	QUALIFIED PENSION LIABILITY	37,680		Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	4,221		Sch 1D

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	November 30, 2001			
Line				
No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,226,766		PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(65,377)		PUC p.8
5	Retirement Work in Progress	(4,905)		PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,156,484		
8				
9	REGULATORY ASSETS	43,871		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	8,503		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,519)		Sch 1E
13				
14	FUEL STOCK	21,950		PUC p.8
15	QUALIFIED PENSION LIABILITY	39,438		Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	4,058		Sch 1D
18	E-BUSINESS	297		PA59
19	UNAMORTIZED ACCESS COSTS	0		
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	21,179		Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	10,253		Sch 1B
25	(Excluding FO & PP)			
26				
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,153		Sch 1C
28				
29	TOTAL WORKING CASH	36,585		
30				
31	DEDUCTIONS:			
32	Unamortized Contributions In Aid of Construction	135,649		PUC p.9
33	Customer Advances for Construction	1,703		PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	81,236		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	43,939		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	18,889		Sch 1D
37	Rental Premiums - Kamoku	38		Sch 1D
38	Customer Deposits	4,151		Sch 1D
39	Unamortized Gain on Sales	645		Sch 1D
40	TOTAL DEDUCTIONS	286,250		
41				
42	MONTH ENDED RATE BASE	1,022,417		

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	December 31, 2001			
Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,229,061	✓	PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(70,501)	✓	PUC p.8
5	Retirement Work in Progress	(5,007)	✓	PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,153,553		
8				
9	REGULATORY ASSETS	44,003	✓	Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	8,451	✓	PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,513)	✓	Sch 1E
13				
14	FUEL STOCK	15,840	✓	PUC p.8
15	QUALIFIED PENSION LIABILITY	41,196	✓	Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	3,896	✓	Sch 1D
18	E-BUSINESS	291		PA59
19	UNAMORTIZED ACCESS COSTS	0		
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	20,871	✓	Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	9,942	✓	Sch 1B
25	(Excluding FO & PP)			
26				
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,075	✓	Sch 1C
28				
29	TOTAL WORKING CASH	35,888		
30				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	134,898	✓	PUC p.9
33	Customer Advances for Construction	1,698	✓	PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	82,359	✓	Sch 1D
35	Deferred Income Taxes - Regulatory Assets	44,035	✓	Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	19,848	✓	Sch 1D
37	Rental Premiums - Kamoku	37	✓	Sch 1D
38	Customer Deposits	4,185	✓	Sch 1D

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	January 31, 2002			
Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,228,347		PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(65,563)		PUC p.8
5	Retirement Work in Progress	(5,056)		PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,157,728		
8				
9	REGULATORY ASSETS	44,149		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	8,340		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,465)		Sch 1E
13				
14	FUEL STOCK	14,004		PUC p.8
15	QUALIFIED PENSION LIABILITY	42,305		Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	3,734		Sch 1D
18	E-BUSINESS	285		PA59
19	UNAMORTIZED ACCESS COSTS	0		
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	20,527		Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	9,849		Sch 1B
25	(Excluding FO & PP)			
26				
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,020		Sch 1C
28				
29	TOTAL WORKING CASH	35,396		
30				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	134,730		PUC p.9
33	Customer Advances for Construction	1,706		PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	82,510		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	44,178		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	19,928		Sch 1D
37	Rental Premiums - Kamoku	37		Sch 1D
38	Customer Deposits	4,235		Sch 1D
39	Unamortized Gain on Sales	605		Sch 1D
40	TOTAL DEDUCTIONS	287,929		
41				
42	MONTH ENDED RATE BASE	1,015,547		

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	February 28, 2002			
Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,227,971		PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(65,310)		PUC p.8
5	Retirement Work in Progress	(5,375)		PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,157,286		
8				
9	REGULATORY ASSETS	44,202		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	8,528		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,434)		Sch 1E
13				
14	FUEL STOCK	15,615		PUC p.8
15	QUALIFIED PENSION LIABILITY	43,942		Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	3,571		Sch 1D
18	E-BUSINESS	279		PA59
19	UNAMORTIZED ACCESS COSTS	0		
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	20,234		Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	9,768		Sch 1B
25	(Excluding FO & PP)			
26				
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	4,981		Sch 1C
28				
29	TOTAL WORKING CASH	34,983		
30				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	134,409		PUC p.9
33	Customer Advances for Construction	1,721		PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	82,571		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	44,321		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	20,009		Sch 1D
37	Rental Premiums - Kamoku	36		Sch 1D
38	Customer Deposits	4,318		Sch 1D
39	Unamortized Gain on Sales	585		Sch 1D
40	TOTAL DEDUCTIONS	287,970		
41				
42	MONTH ENDED RATE BASE	1,018,002		

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	March 31, 2002			
Line				
No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,226,596		PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(64,164)		PUC p.8
5	Retirement Work in Progress	(5,017)		PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,157,415		
8				
9	REGULATORY ASSETS	44,328		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	8,562		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,414)		Sch 1E
13				
14	FUEL STOCK	18,272		PUC p.8
15	QUALIFIED PENSION LIABILITY	45,315		Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	3,409		Sch 1D
18	E-BUSINESS	273		PA59
19	UNAMORTIZED ACCESS COSTS	0		
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	20,026		Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	9,662		Sch 1B
25	(Excluding FO & PP)			

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	April 30, 2002			
Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,228,260		PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(66,819)		PUC p.8
5	Retirement Work in Progress	(5,132)		PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,156,309		
8				
9	REGULATORY ASSETS	44,464		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	8,478		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,393)		Sch 1E
13				
14	FUEL STOCK	15,773		PUC p.8
15	QUALIFIED PENSION LIABILITY	46,687		Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	3,247		Sch 1D
18	E-BUSINESS	267		PA59
19	UNAMORTIZED ACCESS COSTS	0		
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	19,838		Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	9,737		Sch 1B
25	(Excluding FO & PP)			
26				
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	4,919		Sch 1C
28				
29	TOTAL WORKING CASH	34,494		
30				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	134,121		PUC p.9
33	Customer Advances for Construction	1,612		PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	83,086		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	44,608		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	20,170		Sch 1D
37	Rental Premiums - Kamoku	35		Sch 1D
38	Customer Deposits	4,357		Sch 1D
39	Unamortized Gain on Sales	545		Sch 1D
40	TOTAL DEDUCTIONS	288,534		
41				
42	MONTH ENDED RATE BASE	1,018,792		

HECO
AVERATE RATE BASE AND RATE OF RETURN
($ Thousands)
May 31, 2002

Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,228,959		PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(70,254)		PUC p.8
5	Retirement Work in Progress	(5,325)		PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,153,380		
8				
9	REGULATORY ASSETS	44,621		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	8,945		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,403)		Sch 1E
13				
14	FUEL STOCK	19,679		PUC p.8
15	QUALIFIED PENSION LIABILITY	48,060		Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	3,084		Sch 1D
18	E-BUSINESS	262		PA59
19	UNAMORTIZED ACCESS COSTS	0		
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	19,731		Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	9,756		Sch 1B
25	(Excluding FO & PP)			
26				
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	4,907		Sch 1C
28				
29	TOTAL WORKING CASH	34,394		
30				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	133,974		PUC p.9
33	Customer Advances for Construction	1,619		PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	83,233		Sch 1D

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	June 30, 2002			
Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,231,753		PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(75,014)		PUC p.8
5	Retirement Work in Progress	(5,497)		PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,151,242		
8				
9	REGULATORY ASSETS	44,790		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	9,355		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,413)		Sch 1E
13				
14	FUEL STOCK	17,903		PUC p.8
15	QUALIFIED PENSION LIABILITY	49,433		Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	2,922		Sch 1D
18	E-BUSINESS	256		PA59
19	UNAMORTIZED ACCESS COSTS	0		
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	19,702		Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	9,833		Sch 1B
25	(Excluding FO & PP)			
26				
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,059		Sch 1C
28				
29	TOTAL WORKING CASH	34,594		
30				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	134,296		PUC p.9
33	Customer Advances for Construction	1,619		PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	83,158		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	44,894		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	20,331		Sch 1D
37	Rental Premiums - Kamoku	34		Sch 1D
38	Customer Deposits	4,364		Sch 1D
39	Unamortized Gain on Sales	504		Sch 1D
40	TOTAL DEDUCTIONS	289,200		
41				
42	MONTH ENDED RATE BASE	1,018,882		

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	July 31, 2002			
Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,232,170		PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(79,066)		PUC p.8
5	Retirement Work in Progress	(5,372)		PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,147,732		
8				
9	REGULATORY ASSETS	44,974		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	9,662		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,415)		Sch 1E
13				
14	FUEL STOCK	20,829		PUC p.8
15	QUALIFIED PENSION LIABILITY	50,329		Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	2,760		Sch 1D
18	E-BUSINESS	250		PA59
19	UNAMORTIZED ACCESS COSTS	0		
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	19,571		Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	9,979		Sch 1B
25	(Excluding FO & PP)			
26				
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,042		Sch 1C
28				
29	TOTAL WORKING CASH	34,592		
30				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	133,964		PUC p.9
33	Customer Advances for Construction	1,625		PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	83,292		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	45,038		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	20,411		Sch 1D
37	Rental Premiums - Kamoku	33		Sch 1D
38	Customer Deposits	4,398		Sch 1D
39	Unamortized Gain on Sales	483		Sch 1D
40	TOTAL DEDUCTIONS	289,244		
41				
42	MONTH ENDED RATE BASE	1,019,469		

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	August 31, 2002			
Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,231,943		PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(76,738)		PUC p.8
5	Retirement Work in Progress	(5,549)		PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,149,656		
8				
9	REGULATORY ASSETS	45,157		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	9,271		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,410)		Sch 1E
13				
14	FUEL STOCK	23,460		PUC p.8
15	QUALIFIED PENSION LIABILITY	51,633		Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	2,597		Sch 1D
18	E-BUSINESS	244		PA59
19	UNAMORTIZED ACCESS COSTS	0		
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	19,449		Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	10,081		Sch 1B
25	(Excluding FO & PP)			
26				
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,039		Sch 1C
28				
29	TOTAL WORKING CASH	34,569		
30				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	133,623		PUC p.9
33	Customer Advances for Construction	1,627		PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	83,875		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	45,188		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	20,492		Sch 1D
37	Rental Premiums - Kamoku	33		Sch 1D
38	Customer Deposits	4,404		Sch 1D
39	Unamortized Gain on Sales	514		Sch 1D
40	TOTAL DEDUCTIONS	289,756		
41				
42	MONTH ENDED RATE BASE	1,024,421		

HECO
AVERATE RATE BASE AND RATE OF RETURN
($ Thousands)
September 30, 2002

Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,232,603		PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(59,630)		PUC p.8
5	Retirement Work in Progress	(4,648)		PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SER			

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	October 31, 2002			
Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,232,682		PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(62,417)		PUC p.8
5	Retirement Work in Progress	(4,562)		PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,165,703		
8				
9	REGULATORY ASSETS	45,457		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	9,169		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,408)		Sch 1E
13				
14	FUEL STOCK	25,699		PUC p.8
15	QUALIFIED PENSION LIABILITY	54,243		Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	2,273		Sch 1D
18	E-BUSINESS	233		PA59
19	UNAMORTIZED ACCESS COSTS	0		
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	19,385		Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	10,356		Sch 1B
25	(Excluding FO & PP)			
26				
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,062		Sch 1C
28				
29	TOTAL WORKING CASH	34,793		
30				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	133,732		PUC p.9
33	Customer Advances for Construction	1,442		PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	87,757		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	45,488		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	20,653		Sch 1D
37	Rental Premiums - Kamoku	32		Sch 1D
38	Customer Deposits	4,473		Sch 1D
39	Unamortized Gain on Sales	471		Sch 1D
40	TOTAL DEDUCTIONS	294,048		
41				
42	MONTH ENDED RATE BASE	1,041,114		

HECO
AVERATE RATE BASE AND RATE OF RETURN
($ Thousands)
November 30, 2002

Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,234,955		PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(66,169)		PUC p.8
5	Retirement Work in Progress	(4,694)		PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,164,092		
8				
9	REGULATORY ASSETS	45,593		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	9,225		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,403)		Sch 1E
13				
14	FUEL STOCK	27,500		PUC p.8
15	QUALIFIED PENSION LIABILITY	55,547		Sch 1D

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	December 31, 2002			
Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,239,230		PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(63,246)		PUC p.8
5	Retirement Work in Progress	(5,069)		PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,170,915		
8				
9	REGULATORY ASSETS	45,728		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	9,187		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,435)		Sch 1E
13				
14	FUEL STOCK	25,701		PUC p.8
15	QUALIFIED PENSION LIABILITY	56,852		Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	1,948		Sch 1D
18	E-BUSINESS	221		PA59
19	UNAMORTIZED ACCESS COSTS	0		
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	19,795		Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	10,322		Sch 1B
25	(Excluding FO & PP)			
26				
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,147		Sch 1C
28				
29	TOTAL WORKING CASH	35,264		
30				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	138,298		PUC p.9
33	Customer Advances for Construction	1,550		PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	89,721		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	45,766		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	20,801		Sch 1D
37	Rental Premiums - Kamoku	30		Sch 1D
38	Customer Deposits	4,485		Sch 1D
39	Unamortized Gain on Sales	429		Sch 1D
40	TOTAL DEDUCTIONS	301,080		
41				
42	MONTH ENDED RATE BASE	1,042,301		

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	January 31, 2003			
Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,237,543		PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(63,870)		PUC p.8
5	Retirement Work in Progress	(5,222)		PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,168,451		
8				
9	REGULATORY ASSETS	45,876		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	9,335		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,441)		Sch 1E
13				
14	FUEL STOCK	21,104		PUC p.8
15	QUALIFIED PENSION LIABILITY	56,340		Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	- 0		Sch 1D
17	PROJECT APPRISE COSTS	1,786		Sch 1D
18	E-BUSINESS	215		PA59
19	UNAMORTIZED ACCESS COSTS	0		
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	20,131		Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	10,580		Sch 1B
25	(Excluding FO & PP)			
26				
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,201		Sch 1C
28				
29	TOTAL WORKING CASH	35,912		
30				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	137,896		PUC p.9
33	Customer Advances for Construction	1,540		PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	89,631		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	45,913		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	20,896		Sch 1D
37	Rental Premiums - Kamoku	30		Sch 1D
38	Customer Deposits	4,544		Sch 1D
39	Unamortized Gain on Sales	408		Sch 1D
40	TOTAL DEDUCTIONS	300,858		
41				
42	MONTH ENDED RATE BASE	1,035,720		

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	February 28, 2003			
Line				
No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,238,374		PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress			

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	March 31, 2003			
Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,238,474		PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(62,065)		PUC p.8
5	Retirement Work in Progress	(6,050)		PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,170,359		
8				
9	REGULATORY ASSETS	46,129		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	9,457		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,483)		Sch 1E
13				
14	FUEL STOCK	31,220		PUC p.8
15	QUALIFIED PENSION LIABILITY	55,316		Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	1,461		Sch 1D
18	E-BUSINESS	204		PA59
19	UNAMORTIZED ACCESS COSTS	0		
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	21,121		Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	11,136		Sch 1B
25	(Excluding FO & PP)			
26				
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,357		Sch 1C
28				
29	TOTAL WORKING CASH	37,614		
30				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	137,995		PUC p.9
33	Customer Advances for Construction	1,547		PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	88,970		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	46,166		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	21,086		Sch 1D
37	Rental Premiums - Kamoku	29		Sch 1D
38	Customer Deposits	4,566		Sch 1D
39	Unamortized Gain on Sales	366		Sch 1D
40	TOTAL DEDUCTIONS	300,725		
41				
42	MONTH ENDED RATE BASE	1,048,552		

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	April 30, 2003			
Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,237,817		PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(61,908)		PUC p.8
5	Retirement Work in Progress	(6,098)		PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,169,811		
8				
9	REGULATORY ASSETS	46,250		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	9,669		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,508)		Sch 1E
13				
14	FUEL STOCK	34,839		PUC p.8
15	QUALIFIED PENSION LIABILITY	54,805		Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	1,299		Sch 1D
18	E-BUSINESS	198		PA59
19	UNAMORTIZED ACCESS COSTS	0		
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	21,697		Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	11,225		Sch 1B
25	(Excluding FO & PP)			
26				
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,441		Sch 1C
28				
29	TOTAL WORKING CASH	38,363		
30				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	138,570		PUC p.9
33	Customer Advances for Construction	1,567		PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	88,711		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	46,288		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	21,180		Sch 1D
37	Rental Premiums - Kamoku	28		Sch 1D
38	Customer Deposits	4,592		Sch 1D
39	Unamortized Gain on Sales	345		Sch 1D
40	TOTAL DEDUCTIONS	301,281		
41				
42	MONTH ENDED RATE BASE	1,051,445		

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	May 31, 2003			
Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,238,783		PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(65,957)		PUC p.8
5	Retirement Work in Progress	(6,457)		PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,166,369		
8				
9	REGULATORY ASSETS	46,374		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	10,526		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,587)		Sch 1E
13				
14	FUEL STOCK	33,684		PUC p.8
15	QUALIFIED PENSION LIABILITY	54,293		Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	1,136		Sch 1D
18	E-BUSINESS	192		PA59
19	UNAMORTIZED ACCESS COSTS	0		
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	22,143		Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	11,331		Sch 1B
25	(Excluding FO & PP)			
26				
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,491		Sch 1C
28				
29	TOTAL WORKING CASH	38,965		
30				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	138,587		PUC p.9
33	Customer Advances for Construction	1,545		PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	88,518		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	46,412		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	21,275		Sch 1D
37	Rental Premiums - Kamoku	28		Sch 1D
38	Customer Deposits	4,618		Sch 1D
39	Unamortized Gain on Sales	324		Sch 1D
40	TOTAL DEDUCTIONS	301,307		
41				
42	MONTH ENDED RATE BASE	1,047,645		

HECO
AVERATE RATE BASE AND RATE OF RETURN
($ Thousands)
June 30, 2003

Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,240,978		PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(72,052)		PUC p.8
5	Retirement Work in Progress	(6,801)		PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,162,125		
8				
9	REGULATORY ASSETS	46,511		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	9,974		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,621)		Sch 1E
13				
14	FUEL STOCK	29,556		PUC p.8
15	QUALIFIED PENSION LIABILITY	56,695		Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	974		Sch 1D
18	E-BUSINESS	186		PA59
	E-BUSINESS-HARDWARE	255		PA06
19	UNAMORTIZED ACCESS COSTS	0		
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	22,424		Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	11,466		Sch 1B
25	(Excluding FO & PP)			
26				
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,382		Sch 1C
28				
29	TOTAL WORKING CASH	39,272		
30				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	138,440		PUC p.9
33	Customer Advances for Construction	1,545		PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	89,153		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	46,548		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	21,370		Sch 1D
37	Rental Premiums - Kamoku	27		Sch 1D
38	Customer Deposits	4,595		Sch 1D
39	Unamortized Gain on Sales	303		Sch 1D
40	TOTAL DEDUCTIONS	301,981		
41				
42	MONTH ENDED RATE BASE	1,040,946		

HECO
AVERATE RATE BASE AND RATE OF RETURN
($ Thousands)
July 31, 2003

Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,242,822	✓	PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(73,564)	✓	PUC p.8
5	Retirement Work in Progress	(7,110)	✓	PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,162,148		
8				
9	REGULATORY ASSETS	46,648	✓	Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	9,935	✓	PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,625)	✓	Sch 1E
13				
14	FUEL STOCK	23,626	✓	PUC p.8
15	QUALIFIED PENSION LIABILITY	56,224	✓	Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	812	✓	Sch 1D
18	E-BUSINESS	180		PA59
	E-BUSINESS-HARDWARE	241		PA06
19	UNAMORTIZED ACCESS COSTS	0		
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	22,638	✓	Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	11,570	✓	Sch 1B
25	(Excluding FO & PP)			
26				
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,424	✓	Sch 1C
28				
29	TOTAL WORKING CASH	39,632		
30				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	139,753	✓	PUC p.9
33	Customer Advances for Construction	1,546	✓	PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	88,852	✓	Sch 1D
35	Deferred Income Taxes - Regulatory Assets	46,685	✓	Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	21,465	✓	Sch 1D
37	Rental Premiums - Kamoku	26	✓	Sch 1D
38	Customer Deposits	4,577	✓	Sch 1D
39	Unamortized Gain on Sales	282	✓	Sch 1D
40	TOTAL DEDUCTIONS	303,186		
41				
42	MONTH ENDED RATE BASE	1,033,635		

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	August 31, 2003			
Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,243,354	✓	PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(74,477)	✓	PUC p.8
5	Retirement Work in Progress	(7,233)	✓	PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,161,644		
8				
9	REGULATORY ASSETS	46,795	✓	Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	10,238	✓	PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,625)	✓	Sch 1E
13				
14	FUEL STOCK	23,281	✓	PUC p.8
15	QUALIFIED PENSION LIABILITY	55,713	✓	Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	649	✓	Sch 1D
18	E-BUSINESS	175	✓	PA59
	E-BUSINESS-HARDWARE	234		PA06
19	UNAMORTIZED ACCESS COSTS	0		
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	22,826	✓	Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	11,589	✓	Sch 1B
25	(Excluding FO & PP)			
26				
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,452	✓	Sch 1C
28				
29	TOTAL WORKING CASH	39,867		
30				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	139,375	✓	PUC p.9
33	Customer Advances for Construction	1,551	✓	PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	88,563	✓	Sch 1D
35	Deferred Income Taxes - Regulatory Assets	46,833	✓	Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	21,559	✓	Sch 1D
37	Rental Premiums - Kamoku	26		Sch 1D
38	Customer Deposits	4,695	✓	Sch 1D
39	Unamortized Gain on Sales	261	✓	Sch 1D
40	TOTAL DEDUCTIONS	302,863		
41				
42	MONTH ENDED RATE BASE	1,033,108		

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	September 30, 2003			
Line				
No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,244,416	/	PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(76,797)	/	PUC p.8
5	Retirement Work in Progress	(6,744)	/	PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,160,875		
8				
9	REGULATORY ASSETS	46,947	/	Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	10,657	/	PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,640)	/	Sch 1E
13				
14	FUEL STOCK	27,546	/	PUC p.8
15	QUALIFIED PENSION LIABILITY	56,691	/	Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	510	/	Sch 1D
18	E-BUSINESS	169	/	PA59
	E-BUSINESS-HARDWARE	245		PA06
19	UNAMORTIZED ACCESS COSTS	0		
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	23,011	/	Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	11,675	/	Sch 1B
25	(Excluding FO & PP)			
26				
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,472	/	Sch 1C
28				
29	TOTAL WORKING CASH	40,158		
30				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	139,257	/	PUC p.9
33	Customer Advances for Construction	1,553	/	PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	89,974	/	Sch 1D
35	Deferred Income Taxes - Regulatory Assets	46,984	/	Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	21,654	/	Sch 1D
37	Rental Premiums - Kamoku	25	/	Sch 1D
38	Customer Deposits	4,814	/	Sch 1D
39	Unamortized Gain on Sales	240	/	Sch 1D
40	TOTAL DEDUCTIONS	304,501		
41				
42	MONTH ENDED RATE BASE	1,036,657		

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	October 31, 2003			
Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,248,279		PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(78,625)		PUC p.8
5	Retirement Work in Progress	(7,060)		PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,162,594		
8				
9	REGULATORY ASSETS	47,108		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	10,820		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,643)		Sch 1E
13				
14	FUEL STOCK	20,375		PUC p.8
15	QUALIFIED PENSION LIABILITY	56,303	/	Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	325	/	Sch 1D
18	E-BUSINESS	163	/	PA59
	E-BUSINESS-HARDWARE	242		PA06
19	UNAMORTIZED ACCESS COSTS	0		
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	23,191	/	Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	11,700	/	Sch 1B
25	(Excluding FO & PP)			
26				
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,501	/	Sch 1C
28				
29	TOTAL WORKING CASH	40,392		
30				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	139,298	/	PUC p.9
33	Customer Advances for Construction	1,550	/	PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	89,880	/	Sch 1D
35	Deferred Income Taxes - Regulatory Assets	47,146	/	Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	21,749	/	Sch 1D
37	Rental Premiums - Kamoku	25	/	Sch 1D
38	Customer Deposits	5,022	/	Sch 1D
39	Unamortized Gain on Sales	219	/	Sch 1D
40	TOTAL DEDUCTIONS	304,889		
41				
42	MONTH ENDED RATE BASE	1,030,790		

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	November 30, 2003			
Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,259,251	✓	PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(85,012)	✓	PUC p.8
5	Retirement Work in Progress	(6,950)	✓	PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,167,289		
8				
9	REGULATORY ASSETS	47,280	✓	Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	10,765	✓	PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,670)	✓	Sch 1E
13				
14	FUEL STOCK	27,862	✓	PUC p.8
15	QUALIFIED PENSION LIABILITY	55,832	✓	Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	162	✓	Sch 1D
18	E-BUSINESS	157	✓	PA59
	E-BUSINESS-HARDWARE	239	✓	PA06
19	UNAMORTIZED ACCESS COSTS	0		
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	23,219	✓	Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	11,676	✓	Sch 1B
25	(Excluding FO & PP)			
26				
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,510	✓	Sch 1C
28				
29	TOTAL WORKING CASH	40,405		
30				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	144,209	✓	PUC p.9
33	Customer Advances for Construction	1,449	✓	PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	88,400	✓	Sch 1D
35	Deferred Income Taxes - Regulatory Assets	47,318	✓	Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	21,916	✓	Sch 1D
37	Rental Premiums - Kamoku	24	✓	Sch 1D
38	Customer Deposits	5,067	✓	Sch 1D
39	Unamortized Gain on Sales	198	✓	Sch 1D
40	TOTAL DEDUCTIONS	308,581		
41				
42	MONTH ENDED RATE BASE	1,038,740		

HECO
AVERATE RATE BASE AND RATE OF RETURN
($ Thousands)
December 31, 2003

Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,270,034	✓	PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work In Progress	(93,450)	✓	PUC p.8
5	Retirement Work In Progress	(6,786)	✓	PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,169,798		
8				
9	REGULATORY ASSETS	47,451	✓	Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	10,521	✓	PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,739)	✓	Sch 1E
13				
14	FUEL STOCK	32,060	✓	PUC p.8
15	QUALIFIED PENSION LIABILITY	64,352	✓	Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	0		Sch 1D
18	E-BUSINESS	151	✓	PA59
	E-BUSINESS-HARDWARE	235	✓	PA06
19	UNAMORTIZED ACCESS COSTS	0		
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	23,269	✓	Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	11,661	✓	Sch 1B
25	(Excluding FO & PP)			
26				
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,517	✓	Sch 1C
28				
29	TOTAL WORKING CASH	40,447		
30				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	143,814	✓	PUC p.9
33	Customer Advances for Construction	1,436	✓	PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	93,492	✓	Sch 1D
35	Deferred Income Taxes - Regulatory Assets	47,489	✓	Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	21,093	✓	Sch 1D
37	Rental Premiums - Kamoku	24	✓	Sch 1D
38	Customer Deposits	5,073	✓	Sch 1D
39	Unamortized Gain on Sales	287	✓	Sch 1D
40	TOTAL DEDUCTIONS	312,708		
41				
42	MONTH ENDED RATE BASE	1,049,568		

HECO
AVERATE RATE BASE AND RATE OF RETURN
($ Thousands)
January 31, 2004

Line No.	RATE BASE	Month End	Source
1	NET UTILITY PLANT	1,272,360	PUC p.8
2	Adjustments:		
3	Franchise & Organizational Costs		
4	Construction Work In Progress	(99,987)	PUC p.8
5	Retirement Work In Progress	(7,026)	PUC p.8
6	Other		
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,165,347	
8			
9	REGULATORY ASSETS	47,655	Sch 1D
10			
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	10,580	PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,751)	Sch 1E
13			
14	FUEL STOCK	26,345	PUC p.8
15	QUALIFIED PENSION LIABILITY	64,438	Sch 1D
16			
17			
18	E-BUSINESS	145	PA59
	E-BUSINESS-HARDWARE	229	PA06
19			
20			
21	WORKING CASH:		
22	1/24 Fuel Oil & PP Expense	23,384	Sch 1A
23			
24	1/12 Other Operation & Maintenance Expenses	11,432	Sch 1B
25	(Excluding FO & PP)		
26			
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,539	Sch 1C
28			
29	TOTAL WORKING CASH	40,355	
30			
31	DEDUCTIONS:		
32	Unamortized Contributions in Aid of Construction	143,335	Sch 1D
33	Customer Advances for Construction	1,436	Sch 1D
34	Deferred Income Taxes (Excluding Reg Assets)	93,801	Sch 1D
35	Deferred Income Taxes - Regulatory Assets	47,855	Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	21,257	Sch 1D
37	Rental Premiums - Kamoku	23	Sch 1D
38	Customer Deposits	5,097	Sch 1D
39	Unamortized Gain on Sales	264	Sch 1D
40	TOTAL DEDUCTIONS	313,068	
41			
42	MONTH ENDED RATE BASE	1,039,275	

HECO
AVERATE RATE BASE AND RATE OF RETURN
($ Thousands)
February 29, 2004

Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,391,612	✓	PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(102,179)	✓	PUC p.8
5	Retirement Work in Progress	(7,288)	✓	PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,282,145		
8				
9	REGULATORY ASSETS	47,869		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	10,497	✓	PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,754)	✓	Sch 1E
13				
14	FUEL STOCK	31,164	✓	PUC p.8
15	QUALIFIED PENSION LIABILITY	64,524	✓	Sch 1D
16				
17	E-BUSINESS	140	✓	PA59
18	E-BUSINESS-HARDWARE	222		PA06
19				
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	23,563	✓	Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	11,425	✓	Sch 1B
25	(Excluding FO & PP)			
26				
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,572	✓	Sch 1C
28				
29	TOTAL WORKING CASH	40,560		
30				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	142,972	✓	Sch 1D
33	Customer Advances for Construction	1,461	✓	Sch 1D
34	Deferred Income Taxes (Excluding Reg Assets)	94,735	✓	Sch 1D
35	Deferred Income Taxes - Regulatory Assets	47,908	✓	Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	21,420	✓	Sch 1D
37	Rental Premiums - Kamoku	22		Sch 1D
38	Customer Deposits	5,125	✓	Sch 1D
39	Unamortized Gain on Sales	241	✓	Sch 1D
40	Regulatory Liability	118,110	✓	
41	TOTAL DEDUCTIONS	431,994		
42				
43	MONTH ENDED RATE BASE	1,042,373		

HECO
AVERATE RATE BASE AND RATE OF RETURN
($ Thousands)
March 31, 2004

Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,399,705	✓	PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(108,922)	✓	PUC p.8
5	Retirement Work in Progress	(7,411)	✓	PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,283,372		
8				
9	REGULATORY ASSETS	48,100	✓	Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	10,734	✓	PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,765)	✓	Sch 1E
13				
14	FUEL STOCK	33,402	✓	PUC p.8
15	QUALIFIED PENSION LIABILITY	64,610	✓	Sch 1D
16				
17	E-BUSINESS	134	✓	PA59
18	E-BUSINESS-HARDWARE	216	✓	PA06
19				
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	23,502	✓	Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	11,338	✓	Sch 1B
25	(Excluding FO & PP)			
26				
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,572	✓	Sch 1C
28				
29	TOTAL WORKING CASH	40,412		
30				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	143,050	✓	Sch 1D
33	Customer Advances for Construction	1,482	✓	Sch 1D
34	Deferred Income Taxes (Excluding Reg Assets)	94,973	✓	Sch 1D
35	Deferred Income Taxes - Regulatory Assets	48,138	✓	Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	21,584	✓	Sch 1D
37	Rental Premiums - Kamoku	22	✓	Sch 1D
38	Customer Deposits	5,165	✓	Sch 1D
39	Unamortized Gain on Sales	218	✓	Sch 1D
40	Regulatory Liability	121,422	✓	
41	TOTAL DEDUCTIONS	436,054		
42				
43	MONTH ENDED RATE BASE	1,042,161		

HECO
AVERATE RATE BASE AND RATE OF RETURN
($ Thousands)
April 30, 2004

Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,404,601	✓	PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(112,533)	✓	PUC p.8
5	Retirement Work in Progress	(7,736)	✓	PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,284,332		
8				
9	REGULATORY ASSETS	48,345	✓	Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	10,709	✓	PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,771)	✓	Sch 1E
13				
14	FUEL STOCK	37,262	✓	PUC p.8
15	QUALIFIED PENSION LIABILITY	64,696	✓	Sch 1D
16				
17	E-BUSINESS	128	✓	PA59
18	E-BUSINESS-HARDWARE	210	✓	PA06
19				
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	23,467	✓	Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	11,317	✓	Sch 1B
25	(Excluding FO & PP)			
26				
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,559	✓	Sch 1C
28				
29	TOTAL WORKING CASH	40,343		
30				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	142,721	✓	Sch 1D
33	Customer Advances for Construction	1,482	✓	Sch 1D
34	Deferred Income Taxes (Excluding Reg Assets)	95,281	✓	Sch 1D
35	Deferred Income Taxes - Regulatory Assets	48,383	✓	Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	21,747	✓	Sch 1D
37	Rental Premiums - Kamoku	21	✓	Sch 1D
38	Customer Deposits	5,163	✓	Sch 1D
39	Unamortized Gain on Sales	199	✓	Sch 1D
40	Regulatory Liability For Cost of Removal	121,422	✓	GL 4005 25400001
41	TOTAL DEDUCTIONS	436,419		
42				
43	MONTH ENDED RATE BASE	1,046,835		

HECO
AVERATE RATE BASE AND RATE OF RETURN
($ Thousands)
May 31, 2004

Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,407,757	✓	PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work In Progress	(114,821)	✓	PUC p.8
5	Retirement Work In Progress	(6,543)	✓	PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,286,393		
8				
9	REGULATORY ASSETS	48,605	✓	Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	11,030	✓	PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(831)	✓	Sch 1E
13				
14	FUEL STOCK	37,248	✓	PUC p.8
15	QUALIFIED PENSION LIABILITY	64,783	✓	Sch 1D
16				
17	E-BUSINESS	122	✓	PA59
18	E-BUSINESS-HARDWARE	219	✗	PA06
19				
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	23,535	✓	Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	11,255	✓	Sch 1B
25	(Excluding FO & PP)			
26				
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,587	✓	Sch 1C
28				
29	TOTAL WORKING CASH	40,377		
30				
31	DEDUCTIONS:		✓	
32	Unamortized Contributions in Aid of Construction	142,454	✓	Sch 1D
33	Customer Advances for Construction	1,480	✓	Sch 1D
34	Deferred Income Taxes (Excluding Reg Assets)	95,517	✓	Sch 1D
35	Deferred Income Taxes - Regulatory Assets	48,643	✓	Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	21,911	✓	Sch 1D
37	Rental Premiums - Kamoku	21	✓	Sch 1D
38	Customer Deposits	5,140	✓	Sch 1D
39	Unamortized Gain on Sales	162	✓	Sch 1D
40	Regulatory Liability for Cost of Removal	121,422	✓	
41	TOTAL DEDUCTIONS	436,770		
42				
43	MONTH ENDED RATE BASE	1,051,176		

HECO
AVERATE RATE BASE AND RATE OF RETURN
($ Thousands)
June 30, 2004

Line No.	RATE BASE	Month End	Source
1	NET UTILITY PLANT	1,415,336	PUC p.8
2	Adjustments:		
3	Franchise & Organizational Costs		
4	Construction Work in Progress	(122,462)	PUC p.8
5	Retirement Work in Progress	(6,906)	PUC p.8
6	Other		
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,285,968	
8			
9	REGULATORY ASSETS	48,876	Sch 1D
10			
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	10,579	PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(834)	Sch 1E
13			
14	FUEL STOCK	34,398	PUC p.8
15	QUALIFIED PENSION LIABILITY	65,125	Sch 1D
16			
17	E-BUSINESS	116	PA59
18	E-BUSINESS-HARDWARE	216	PA06
19			
20			
21	WORKING CASH:		
22	1/24 Fuel Oil & PP Expense	23,684	Sch 1A
23			
24	1/12 Other Operation & Maintenance Expenses	11,397	Sch 1B
25	(Excluding FO & PP)		
26			
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,611	Sch 1C
28			
29	TOTAL WORKING CASH	40,692	
30			
31	DEDUCTIONS:		

HECO
AVERATE RATE BASE AND RATE OF RETURN
($ Thousands)
July 31, 2004

Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,420,036	✓	PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work In Progress	(129,528)	✓	PUC p.8
5	Retirement Work In Progress	(7,288)	✓	PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,283,220		
8				
9	REGULATORY ASSETS	49,162	✓	Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	10,199	✓	PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(835)	✓	Sch 1E
13				
14	FUEL STOCK	31,365	✓	PUC p.8
15	QUALIFIED PENSION LIABILITY	65,254	✓	Sch 1D
16				
17	E-BUSINESS	111	✓	PA59
18	E-BUSINESS-HARDWARE	208		PA06
19				
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	23,934	✓	Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	11,266	✓	Sch 1B
25	(Excluding FO & PP)			
26				
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,641	✓	Sch 1C
28				
29	TOTAL WORKING CASH	40,841		
30				
31	DEDUCTIONS:			
32	Unamortized Contributions In Aid of Construction	142,241	✓	Sch 1D
33	Customer Advances for Construction	1,566	✓	Sch 1D
34	Deferred Income Taxes (Excluding Reg Assets)	96,565	✓	Sch 1D
35	Deferred Income Taxes - Regulatory Assets	49,170	✓	Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	22,238	✓	Sch 1D
37	Rental Premiums - Kamoku	20	✓	Sch 1D
38	Customer Deposits	5,092	✓	Sch 1D
39	Unamortized Gain on Sales	151	✓	Sch 1D
40	Regulatory Liability for Cost of Removal	124,524	✓	2.5%-a
41	TOTAL DEDUCTIONS	441,567		
42				
43	MONTH ENDED RATE BASE	1,037,958		

HECO
AVERATE RATE BASE AND RATE OF RETURN
($ Thousands)
August 31, 2004

Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,424,390	/	PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(131,730)	/	PUC p.8
5	Retirement Work in Progress	(7,461)	/	PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,285,199		
8				
9	REGULATORY ASSETS	49,473	/	Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	10,185	/	PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(842)	/	Sch 1E
13				
14	FUEL STOCK	29,234	/	PUC p.8
15	QUALIFIED PENSION LIABILITY	65,383	/	Sch 1D
16				
17	E-BUSINESS	105		PA59
18	E-BUSINESS-HARDWARE	281	/	PA06
19				
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	24,225	/	Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	11,430	/	Sch 1B
25	(Excluding FO & PP)			
26				
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,685	/	Sch 1C
28				

HECO
AVERATE RATE BASE AND RATE OF RETURN
($ Thousands)
September 30, 2004

Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,434,264	✓	PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(134,907)	✓	PUC p.8
5	Retirement Work in Progress	(8,005)	✓	PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,291,352		
8				
9	REGULATORY ASSETS	49,794	✓	Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	10,308	✓	PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(854)	✓	Sch 1E
13				
14	FUEL STOCK	43,246	✓	PUC p.8
15	QUALIFIED PENSION LIABILITY	75,198	✓	Sch 1D
16				
17	E-BUSINESS	99	✓	PA59
18	E-BUSINESS-HARDWARE	277		PA06
19				
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	24,598	✓	Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	11,489	✓	Sch 1B
25	(Excluding FO & PP)			
26				
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,755	✓	Sch 1C
28				
29	TOTAL WORKING CASH	41,842		
30				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	141,736	✓	Sch 1D
33	Customer Advances for Construction	1,579	✓	Sch 1D
34	Deferred Income Taxes (Excluding Reg Assets)	99,721	✓	Sch 1D
35	Deferred Income Taxes - Regulatory Assets	49,802	✓	Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	24,096	✓	Sch 1D
37	Rental Premiums - Kamoku	20		Sch 1D
38	Customer Deposits	5,126	✓	Sch 1D
39	Unamortized Gain on Sales	317	✓	Sch 1D
40	Regulatory Liability for Cost of Removal	127,650	✓	25400001
41	TOTAL DEDUCTIONS	450,047		

HECO
AVERATE RATE BASE AND RATE OF RETURN
($ Thousands)
October 31, 2004

Line No.	RATE BASE	Month End	Source
1	NET UTILITY PLANT	1,441,680	PUC p.8
2	Adjustments:		
3	Franchise & Organizational Costs		
4	Construction Work in Progress	(140,619)	PUC p.8
5	Retirement Work in Progress	(8,224)	PUC p.8
6	Other		
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,292,837	
8			
9	REGULATORY ASSETS	50,125	Sch 1D
10			
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	10,534	PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(869)	Sch 1E
13			
14	FUEL STOCK	36,109	PUC p.8
15	QUALIFIED PENSION LIABILITY	75,327	Sch 1D
16			
17	E-BUSINESS	93	PA59
18	E-BUSINESS-HARDWARE	273	PA06
19			
20			
21	WORKING CASH:		
22	1/24 Fuel Oil & PP Expense	25,085	Sch 1A
23			
24	1/12 Other Operation & Maintenance Expenses	11,647	Sch 1B
25	(Excluding FO & PP)		
26			
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,823	Sch 1C
28			
29	TOTAL WORKING CASH	42,555	
30			
31	DEDUCTIONS:		
32	Unamortized Contributions in Aid of Construction	141,345	Sch 1D
33	Customer Advances for Construction	1,576	Sch 1D
34	Deferred Income Taxes (Excluding Reg Assets)	101,335	Sch 1D
35	Deferred Income Taxes - Regulatory Assets	50,133	Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	24,392	Sch 1D
37	Rental Premiums - Kamoku	19	Sch 1D
38	Customer Deposits	5,037	Sch 1D
39	Unamortized Gain on Sales	310	Sch 1D
40	Regulatory Liability for Cost of Removal	127,650	25400001
41	TOTAL DEDUCTIONS	451,797	
42			
43	MONTH ENDED RATE BASE	1,055,187	

HECO
AVERATE RATE BASE AND RATE OF RETURN
($ Thousands)
November 30, 2004

Line No.	RATE BASE	Month End	Source
1	NET UTILITY PLANT	1,448,537	PUC p.8
2	Adjustments:		
3	Franchise & Organizational Costs		
4	Construction Work In Progress	(140,256)	PUC p.8
5	Retirement Work In Progress	(7,634)	PUC p.8
6	Other		
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,300,647	
8			
9	REGULATORY ASSETS	50,470	Sch 1D
10			
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	10,406	PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(875)	Sch 1E
13			
14	FUEL STOCK	35,451	PUC p.8
15	QUALIFIED PENSION LIABILITY	75,456	Sch 1D
16			
17	E-BUSINESS	87	PA59
18	E-BUSINESS-HARDWARE	269	PA06
19			
20			
21	WORKING CASH:		
22	1/24 Fuel Oil & PP Expense	25,713	Sch 1A
23			
24	1/12 Other Operation & Maintenance Expenses	12,160	Sch 1B
25	(Excluding FO & PP)		
26			
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,921	Sch 1C
28			
29	TOTAL WORKING CASH	43,794	
30			
31	DEDUCTIONS:		
32	Unamortized Contributions in Aid of Construction	144,550	Sch 1D
33	Customer Advances for Construction	1,507	Sch 1D
34	Deferred Income Taxes (Excluding Reg Assets)	101,243	Sch 1D
35	Deferred Income Taxes - Regulatory Assets	50,481	Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	24,575	Sch 1D
37	Rental Premiums - Kamoku	19	Sch 1D
38	Customer Deposits	5,032	Sch 1D
39	Unamortized Gain on Sales	424	Sch 1D
40	Regulatory Liability for Cost of Removal	127,650	25400001
41	TOTAL DEDUCTIONS	455,481	
42			
43	MONTH ENDED RATE BASE	1,060,224	

HECO
AVERATE RATE BASE AND RATE OF RETURN
($ Thousands)
December 31, 2004

Line No.	RATE BASE	Month End	Source
1	NET UTILITY PLANT	1,461,069	PUC p.8
2	Adjustments:		
3	Franchise & Organizational Costs		
4	Construction Work In Progress	(79,532)	PUC p.8
5	Retirement Work in Progress	(7,115)	PUC p.8
6	Other		
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,374,422	
8			
9	REGULATORY ASSETS	50,082	Sch 1D
10			
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	11,039	PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(892)	Sch 1E
13			
14	FUEL STOCK	39,420	PUC p.8
15	QUALIFIED PENSION LIABILITY	81,085	Sch 1D
16			
17	E-BUSINESS	81	PA59
18	E-BUSINESS-HARDWARE	265	PA06
19			
20			
21	WORKING CASH:		
22	1/24 Fuel Oil & PP Expense	26,302	Sch 1A
23			
24	1/12 Other Operation & Maintenance Expenses	12,798	Sch 1B
25	(Excluding FO & PP)		
26			
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	6,017	Sch 1C
28			
29	TOTAL WORKING CASH	45,117	
30			
31	DEDUCTIONS:		
32	Unamortized Contributions in Aid of Construction	144,322	Sch 1D
33	Customer Advances for Construction	1,519	Sch 1D
34	Deferred Income Taxes (Excluding Reg Assets)	100,834	Sch 1D
35	Deferred Income Taxes - Regulatory Assets	50,090	Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	24,759	Sch 1D
37	Rental Premiums - Kamoku	19	Sch 1D
38	Customer Deposits	5,067	Sch 1D
39	Unamortized Gain on Sales	470	Sch 1D
40	Regulatory Liability for Cost of Removal	131,915	25400001
41	TOTAL DEDUCTIONS	458,995	
42			
43	MONTH ENDED RATE BASE	1,141,624	

HECO
AVERAGE RATE BASE AND RATE OF RETURN

HECO
AVERATE RATE BASE AND RATE OF RETURN
($ Thousands)
February 28, 2005

Line No.	RATE BASE	Month End	Source
1	NET UTILITY PLANT	1,462,456	PUC p.8
2	Adjustments:		
3	Franchise & Organizational Costs		
4	Construction Work in Progress	(77,806)	PUC p.8
5	Retirement Work in Progress	(6,059)	PUC p.8
6	Other		
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,378,591	
8			
9	REGULATORY ASSETS	50,310	Sch 1D
10			
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	11,287	PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(912)	Sch 1E
13			
14	FUEL STOCK	34,751	PUC p.8
15	QUALIFIED PENSION LIABILITY	80,349	Sch 1D
16			
17	E-BUSINESS	70	PA59
18	E-BUSINESS-HARDWARE	253	PA06
19			
20			
21	WORKING CASH:		
22	1/24 Fuel Oil & PP Expense	26,592	Sch 1A
23			
24	1/12 Other Operation & Maintenance Expenses	13,093	Sch 1B
25	(Excluding FO & PP)		
26			
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	6,056	Sch 1C
28			
29	TOTAL WORKING CASH	45,741	
30			
31	DEDUCTIONS:		
32	Unamortized Contributions in Aid of Construction	143,717	Sch 1D
33	Customer Advances for Construction	1,518	Sch 1D
34	Deferred Income Taxes (Excluding Reg Assets)	98,190	Sch 1D
35	Deferred Income Taxes - Regulatory Assets	50,319	Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	25,084	Sch 1D
37	Rental Premiums - Kamoku	18	Sch 1D
38	Customer Deposits	5,101	Sch 1D
39	Unamortized Gain on Sales	1,827	Sch 1D
40	Regulatory Liability for Cost of Removal	131,915	Sch 1D
41	TOTAL DEDUCTIONS	457,689	
42			
43	MONTH ENDED RATE BASE	1,142,751	

HECO
AVERATE RATE BASE AND RATE OF RETURN
($ Thousands)
March 31, 2005

Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,469,244	/	PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(71,738)	/	PUC p.8
5	Retirement Work in Progress	(5,441)	/	PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,392,065		
8				
9	REGULATORY ASSETS	50,459	/	Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	11,543	/	PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(926)	/	Sch 1E
13				
14	FUEL STOCK	47,618	/	PUC p.8
15	QUALIFIED PENSION LIABILITY	79,981	/	Sch 1D
16				
17	E-BUSINESS	64	/	PA59
18	E-BUSINESS-HARDWARE	249	/	PA06
19				
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	26,754	/	Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	13,375	/	Sch 1B
25	(Excluding FO & PP)			
26				
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	6,073	/	Sch 1C
28				
29	TOTAL WORKING CASH	46,202		
30				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	143,271	/	Sch 1D
33	Customer Advances for Construction	1,518	/	Sch 1D
34	Deferred Income Taxes (Excluding Reg Assets)	98,337	/	Sch 1D
35	Deferred Income Taxes - Regulatory Assets	50,467	/	Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	25,246	/	Sch 1D
37	Rental Premiums - Kamoku	18	/	Sch 1D
38	Customer Deposits	5,096	/	Sch 1D
39	Unamortized Gain on Sales	1,793	/	Sch 1D
40	Regulatory Liability for Cost of Removal	135,858	/	Sch 1D
41	TOTAL DEDUCTIONS	461,604		
42				
43	MONTH ENDED RATE BASE	1,165,651		

HECO
AVERATE RATE BASE AND RATE OF RETURN
($ Thousands)
April 30, 2005

Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,471,541	/	PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(68,894)	/	PUC p.8
5	Retirement Work in Progress	(5,396)	/	PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,397,251		
8				

HECO
AVERATE RATE BASE AND RATE OF RETURN
($ Thousands)
May 31, 2005

Line No.	RATE BASE	Month End	Source
1	NET UTILITY PLANT	1,475,073	PUC p.8
2	Adjustments:		
3	Franchise & Organizational Costs		
4	Construction Work In Progress	(70,984)	PUC p.8
5	Retirement Work In Progress	(4,851)	PUC p.8
6	Other		
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,399,238	
8			
9	REGULATORY ASSETS	50,711	Sch 1D
10			
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	11,759	PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(944)	Sch 1E

HECO
AVERATE RATE BASE AND RATE OF RETURN
($ Thousands)
June 30, 2005

Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,481,411	/	PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(73,500)	/	PUC p.8
5	Retirement Work in Progress	(4,664)	/	PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,403,247		
8				
9	REGULATORY ASSETS	50,847	/	Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	12,588	/	PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(962)	/	Sch 1E
13				
14	FUEL STOCK	44,528	/	PUC p.8
15	QUALIFIED PENSION LIABILITY	78,791	/	Sch 1D
16				
17	E-BUSINESS	47	/	PA59
18	E-BUSINESS-HARDWARE	236	/	PA06
19				
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	27,965	/	Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	13,935	/	Sch 1B
25	(Excluding FO & PP)			
26				
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	6,282	/	Sch 1C
28				
29	TOTAL WORKING CASH	48,182		
30				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	143,960	/	Sch 1D
33	Customer Advances for Construction	1,518	/	Sch 1D
34	Deferred Income Taxes (Excluding Reg Assets)	97,892	/	Sch 1D
35	Deferred Income Taxes - Regulatory Assets	50,855	/	Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	25,734	/	Sch 1D
37	Rental Premiums - Kamoku	17	/	Sch 1D
38	Customer Deposits	5,154	/	Sch 1D
39	Unamortized Gain on Sales	1,696	/	Sch 1D
40	Regulatory Liability for Cost of Removal	139,992	/	Sch 1D
41	TOTAL DEDUCTIONS	466,818		
42				
43	MONTH ENDED RATE BASE	1,170,686		

CA-RIR-94

Ref: RT-16, pages 50-51 (Pension Asset).

Beginning at page 50, line 21, RT-16 states:

> More importantly, Mr. Carver's analysis is a form of retroactive ratemaking...The fact remains, however, that he seeks to make up for what he perceives to be an over recovery of NPPC in years prior to the test year by disallowing the prepaid pension asset from rate

[redacted]

> decrease the Company's rates, it would in effect pay money back to ratepayers and would thus constitute retroactive ratemaking.

Please provide the following:

c. See CA-T-2, pages 19-25.

d. See CA-T-2, pages 19-25.

CA-RIR-95

Ref: RT-16, page 53, lines 3-12 (Pension Asset).

The referenced testimony states:

> Third, as I discussed earlier, ratepayers have benefited from the prepaid pension asset. Funding of the pension is part of what resulted in lower NPPC. This contributed to a lower revenue requirement, which negated the need to request a general rate increase in the last ten years. If the Company had had a rate case during the last ten years, and its rates had stayed the same (based on the results of operations that reflected a negative pension expense), Mr. Carver would not even be able to make his argument. The fact that rates were able to stay the same without a rate case should not change the result. In addition, the funding of the pension fund will contribute to a lower NPPC than what would otherwise be realized.

Based on the above, please provide the following:

a. Please provide a copy of all analyses, including related documents and spreadsheet files, relied upon by Ms. Sekimura to conclude that the lower NPPC negated the need to request a general rate increase in the past ten years. If none, please so state.

b. Referring to the response to part (a) above, please identify the individual responsible for preparing the analyses (by name and job title) and indicate when (month/year) each analysis was prepared.

HECO Response:

a. As shown on HECO-R-1609, page 1 of 2, column C, the NPPC declined substantially after 1994. It is self evident that revenue requirements were significantly lower as a result of the decline in the NPPC than they would have been if the NPPC had not declined. No separate analysis was needed to conclude that the declining NPPC helped mitigate the need to request a general rate increase. Many factors are considered in determining the Company's need for a rate case, including added investments in plant and rising costs. The declining NPPC offset other increasing and new costs and contributed to the overall result, which was that the Company did not request a rate increase in the last ten years.

b. Not applicable.

CA-RIR-96

Ref: RT-16, pages 55-57 (Pension Asset).

The referenced testimony identifies and describes various regulatory orders "enabling some form of recovery of the pension asset." Please provide the following:

a. Please provide a complete copy of all regulatory orders in HECO's possession that allow some form of recovery of the pension asset.

b. Of those regulatory orders cited by RT-16 at pages 55-56, were any of the allowed pension asset recoveries the result of litigated issues, resulting in a regulatory decision involving the merits of the issues presented? Please explain.

c. Has Ms. Sekimura previously filed written testimony or appeared as an expert witness on the pension asset issue?

   1. If so, please provide a listing of each regulatory proceeding by jurisdiction and docket.

   2. If so, please provide a copy of the testimony prepared or presented by Ms. Sekimura.

   3. If so, please state whether the issue was litigated or resolved through a negotiated settlement, and provide a copy of the regulatory decision related to the pension asset issue.

HECO Response:

a. Please refer to HECO's response and attachments to DOD-RIR-36.

b. See the response to a.

c. Ms. Sekimura has not previously filed written testimony or appeared as an expert witness on the prepaid pension asset issue.

   1. Not applicable.

   2. Not applicable.

   3. Not applicable.

CA-RIR-97

Ref: RT-18, page 10, lines 3 through 22.

According to Ms. Nagata's Rebuttal, the Company's PHFFU investment at Barbers Point is economically justified because of "minimized future higher costs" and the "options that may be available to the Company for its use of the Pipeline." Please provide complete copies of all economic analyses, reports, studies, workpapers and other documents relied upon by HECO or Ms. Nagata to conclude that this PHFFU investment is economically justified and that HECO has a definite plan for use of the facilities.

HECO Response:

As stated in RT-18, pages 9-11 and in response to the CA-IR-206, HECO does not have a defined plan for the use or commercial operation of the Kalaeloa Barbers Point Harbor Pipeline ("Pipeline"). However, constructing the Pipeline back then (installed in 1991) is more economical than constructing it after the State of Hawaii placed the 15-inch thick concrete slab in the laydown area adjacent to the piers since the Company would be faced with higher costs to install future Pipelines after the concrete slabs were poured due to inflation and the costs to demolish and replace the concrete slabs once the future Pipeline is installed. In addition, installing the Pipeline in 1991 provided for a more feasible option for the future as it will be easier to interconnect to the Pipeline than to reacquire permission from the State to access the harbor and build new pipelines now that the State has completed its work in the Barbers Point Harbor area.

Having the Pipeline installed provides for a possible gateway for imported fuel to HECO's Barbers Point Tank Farm ("BPTF") location. This option has become more attractive given the BPTF dedicated intra-system fuel transfer infrastructure which interconnects the Kahe and Waiau generating stations and Iwilei Tank Farm into a stand-alone fuel distribution system. This is enhanced with the BPTF being the site for HECO's next generating unit. HECO will then

have the ability to increase the number of fuel grades or types which it can receive, store, and consume within the BPTF. In addition, the existence of the Pipeline is used in negotiations for fuel contracts with Oahu-based refineries to provide credence to the option of importing fuel oil.

CA-RIR-98

Ref: RT-18, page 3, line 18.

According to Ms. Nagata's Rebuttal, "HECO's rebuttal plant addition estimate has been updated to reflect a correction for the New Kuahua Substation project...Attachment 6 to the June 15, 2005 Transmittal did not accurately reflect the expenditures for 2005, 2006, and 2007, resulting in an understatement of 2005 expenditures of $5,635,891." Please provide a detailed explanation of the development of the Attachment 6 amounts and reconcile all annual expenditure amounts associated with the "correction" that was discovered.

HECO Response:

Project estimates, including plant addition date estimates, as of April 1, 2005, were exported from the Company's budgeting tool to Excel and distributed to the appropriate personnel for review. Upon completion of the review of estimated expenditures and plant addition dates, the costs for projects with 2005 plant additions were used to create Attachment 6. In the course of creating Attachment 6, the expenditures for the New Kuahua Substation project were incorrectly placed in the columns for years 2005, 2006 and 2007. The error was discovered when later updated plant addition estimates were compared to Attachment 6. See page 2 for a reconciliation of annual expenditure amounts associated with the "correction" and for changes in estimate.

Reference	Project #	Project Title	Project to Date Recorded 12/31/04	2005	2006	2007	Total
6/15/05 Attachment 6, page 3	P0000277	New Kuahua Substation	1,094,327	221,219	3,695,111	26,301	5,036,958
		Error		3,473,892	-3,668,810	-26,301	
		Change in estimate		623,344			
Rebuttal - HECO-RWP-1801, page 2	P0000277	New Kuahua Substation	1,094,327	4,318,455	26,301	0	5,439,083
6/15/05 Attachment 6, page 3	P0000278	Makalapa Substation Prot	165,607	49,164	213,221	3,229	431,221
		Error		164,057	-209,992	-3,229	
		Change in estimate		44,442			
Rebuttal - HECO-RWP-1801, page 2	P0000278	Makalapa Substation Prot	165,607	257,663	3,229	0	426,499
6/15/05 Attachment 6, page 4	P0000279	Puuloa Substation Prot	35,233	47,650	79,429	1	162,313
		Error		31,779	-79,428	-1	
		Change in estimate		25,665			
Rebuttal - HECO-RWP-1801, page 3	P0000279	Puuloa Substation Prot	35,233	105,094	1	0	140,328
6/15/05 Attachment 6, page 4	P0000280	Makalapa-Kuahua FO Line	183,860	18,154	589,723	0	791,737
		Error		571,569	-589,723		
		Change in estimate		-109,890			
Rebuttal - HECO-RWP-1801, page 3	P0000280	Makalapa-Kuahua FO Line	183,860	479,833	0	0	663,693
6/15/05 Attachment 6, page 4	P0000281	Makalapa-Puuloa FO Line	23,217	1,951	566,965	1	592,134
		Error		565,014	-566,964	-1	
		Change in estimate		-165,948			
Rebuttal - HECO-RWP-1801, page 3	P0000281	Makalapa-Puuloa FO Line	23,217	401,017	1	0	424,235
6/15/05 Attachment 6, page 4	P0000282	Kuahua 46kv Ln Reconnect	12,785	10,951	475,207	318	499,261
		Error		464,256	-474,889	-318	
		Change in estimate		-52,289			
Rebuttal - HECO-RWP-1801, page 3	P0000282	Kuahua 46kv Ln Reconnect	12,785	422,918	318	0	436,021
6/15/05 Attachment 6		Total Project Cost	1,515,029	349,089	5,619,656	29,850	7,513,624
		Error	0	5,270,567 ①	-5,589,806	-29,850	
		Change in estimate	0	365,324 ①	0	0	
Rebuttal		Total Project Cost	1,515,029	5,984,980	29,850	0	7,529,859
		Total change in estimate		Σ① = 5,635,891			

CA-RIR-99

Ref: RT-22, page 4, lines 4 through 15.

According to Mr. Young's Rebuttal, HECO has modified its classification of DSM costs, so as to identify demand and energy-related allocations instead of the 100% customer-related classification included in Direct Testimony T-22.

a. Please confirm that this change was intended to better reflect cost causation.

b. Explain whether the change is the primary reason why "Unit Customer Cost" amounts for each Class at HECO-R-2208 and HECO-R-2210 are significantly lower than were contained in HECO's corresponding Direct Exhibits HECO-2208 and HECO-2210.

HECO Response:

a. Yes, this change is intended to better reflect cost causation of the DSM costs by classifying them as partly demand-related and partly energy-related.

b. The change in classification of DSM costs described above is not the primary reason why the "unit customer cost" amounts are significantly lower than as presented in direct testimony.

CA-RIR-100

Ref: RT-22, page 21, lines 2 through 6.

According to Mr. Young's Rebuttal, HECO does not "need to undertake a cost study of production O&M expenses" and "HECO recognizes that if there are variable O&M non-fuel production costs, they should be minimal."

a. Please confirm that variable O&M expenses other than fuel were estimated to exceed $34.4 million annually for the HECO system and $2.3 million for HECO generating units as shown on HECO-WP-2217, page 99 of 153.

b. Explain how such amounts are now thought to be "minimal." Provide complete copies of all reports, studies, analyses, projections and other documents associated with your response.

HECO Response:

a. The total variable O&M expenses reflected on HECO-WP-2217, page 99 are $34.4154 million. However, note that the embedded cost of service study reflects the costs of HPOWER to HECO as purchased power expenses. These purchased power expenses are classified as partly energy-related and partly demand-related.

b. The part of the variable O&M on HECO-WP-2217, page 99 that relates to production O&M expense is the $2,323,900 for the HECO generating units. Relative to other variable costs, such as fuel expense ($449,447,000 per HECO-R-401), variable O&M non-fuel production costs are minimal.

CA-RIR-101

Ref: RT-22, page 22, lines 18 through 23.
According to Mr. Young's Rebuttal, "Second, and more importantly, the CA's proposal to adjust the existing structure of customer charges, minimum charges, energy charges, and demand charges in equal percentages is inconsistent with aligning charges closer to the cost to serve. For example, the existing Schedule R single phase service customer charge of $7.00 per customer per month recovers only about 50% of the $14.12 unit customer cost..." Based on this statement,

[redacted]

a. Confirm that the "$14.12 unit customer cost" value being cited is based upon the Company's cost of service evidence and revenue requirement in Docket No. 7766.

b. Confirm that in the instant case, the $19.41 Schedule R unit customer cost at proposed rates is based upon the Company's cost of service evidence and Rebuttal revenue requirement, as summarized in HECO-R-2208.

c. Confirm that the corresponding Consumer Advocate Schedule R/E unit customer cost is only $10.89 per month, as shown at CA Exhibit 501 on the "Total Customer" line.

[redacted]

Revised_Linked.xls" in support of its Exhibit CA-500 and Exhibit CA-501. HECO wishes to enter the pages of this file into the record and attaches the pertinent ones to this response. CA-501 is based on Tab 75 "Class Rates of Return at Equal ROR", attached, which shows a sales revenue increase of $21,416,500, which is about $2.1 million less than the $23,476,000 increase proposed by the CA in Exhibit CA-101, Schedule A. In fact, the CA's proposed Schedule R/E unit customer cost should be higher than $10.89 per month, if the unit costs in CA-501 accurately reflected the CA's revenue at proposed rates.

d. It is not uncommon for an electric utility to recover some of its costs classified as demand and customer-related through the energy charge. In this case, compare the costs for Schedule PS on HECO-R-2208 with the proposed charges for Schedule PS on HECO-R-2220. The demand costs and customer cost not recovered in the demand charge and customer charge are recovered in the energy charges.

e. Assume that increasing the Schedule R customer charge on an equal percentage basis means that the percentage increase is $23,476 (CA-101, Schedule A) divided by $1,251,142 (CA-101, Schedule C) or 1.88%. That means that the CA's proposed Schedule R 1 phase customer charge should be $7.00 x 1.88% + $7.00 = $7.13. Now the Schedule R unit cost at present rates is $10.16 per month as shown in the attached Tab 60, which unitizes the values shown in CA-500. Based on the CA's position, the Schedule R customer charge recovers $7.00 ÷ $10.16 = about 69% of the customer cost at present rates. Based on the CA's proposed rates, the Schedule R customer charge recovers $7.13 ÷ $10.89 = about 65% of the customer cost at proposed rates, even less if the $10.89 is corrected to reflect the CA's revenue increase proposal. Increasing the present Schedule R customer charge on an equal percentage basis actually moves the charge farther away from indicated cost of service basis.

odule R/E sidential ervice 000s)	Schedule G Gen Service Non-Dmd ($000s)	Schedule J Gen Service Demand ($000s)	Schedule H Comm Service ($000s)	Schedule PT Large Power Trans ($000s)	Schedule PP Large Power Pri ($000s)	Schedule PS Large Power Sec ($000s)	Schedule F Street Lighting ($000s)	Total System ($000s)
$15,860.4	($4,848.9)	$2,818.0	$198.3	($938.6)	$4,677.3	$3,004.4	$845.6	$21,416.5
$602.1	$65.2	$16.1	$3.4	$0.0	$0.9	$0.5	$0.3	$688.5
$16,262.5	($4,783.7)	$2,834.1	$201.7	($938.6)	$4,678.2	$3,004.9	$845.9	$22,105.0
$20.4	($6.3)	$3.7	$0.3	($1.2)	$6.1	$3.9	$1.1	$28.0
$1,429.8	($426.8)	$251.4	$17.8	($83.4)	$415.7	$266.9	$75.1	$1,946.7
$14,812.3	($4,350.8)	$2,579.0	$183.6	($854.0)	$4,256.4	$2,734.1	$769.7	$20,130.3
$5,763.5	($1,692.8)	$1,003.5	$71.4	($332.3)	$1,656.2	$1,063.8	$299.5	$7,832.7
$7,213.7	($2,125.8)	$1,258.6	$89.5	($416.9)	$2,078.0	$1,334.6	$375.7	$9,807.4
$9,048.8	($2,657.9)	$1,575.5	$112.2	($521.7)	$2,600.2	$1,670.3	$470.2	$12,297.6
$31,901.8	$5,350.1	$20,470.7	$580.8	$859.6	$15,559.3	$7,592.8	$524.8	$82,849.9
($9,626.4)	$2,873.8	($1,693.3)	($120.1)	$561.8	($2,799.9)	($1,797.8)	($505.8)	($13,107.9)
106,790.9	$67,801.7	$260,626.8	$7,527.2	$10,875.7	$196,190.0	$96,772.3	$6,726.9	$1,055,311.5
7.84%	7.89%	7.85%	7.85%	7.90%	7.85%	7.85%	7.80%	7.85%
99.89%	100.51%	100.04%	99.98%	100.66%	100.00%	99.94%	99.36%	100.000%
39.60%	-33.19%	8.34%	23.44%	-37.77%	20.07%	28.20%	861.03%	17.43%
4.04%	-6.66%	0.88%	2.30%	-3.99%	1.66%	2.34%	12.83%	1.72%
29.90%	26.50%	3.49%	15.67%	0.00%	0.39%	0.42%	1.66%	22.17%
4.17%	-6.55%	0.89%	2.33%	-3.99%	1.55%	2.34%	12.80%	1.77%
$1,391.4	($430.8)	$250.4	$17.6	($83.4)	$415.6	$266.9	$75.1	$1,902.8
14,248.6	($4,411.8)	$2,563.9	$180.4	($854.0)	$4,255.6	$2,733.6	$769.4	$19,485.7
$5,544.1	($1,716.6)	$997.6	$70.2	($332.3)	$1,656.9	$1,063.6	$299.4	$7,581.9
$6,955.9	($2,153.7)	$1,251.7	$88.1	($416.9)	$2,077.6	$1,334.4	$375.6	$9,512.7
$8,704.5	($2,695.2)	$1,566.3	$110.2	($521.7)	$2,599.7	$1,670.0	$470.0	$11,903.8

Hawaiian Electric Company, Inc.
Docket No. 04-0113, Test-Year 2005
Unit Functionalized Class Sales Revenues At Present Rates

CA-500 At Present Rates, Unitized

	Units	Schedule R/E Residential Service	Schedule G Gen Service Non-Dmd	Schedule J Gen Service Demand	Schedule H Comm Service	Schedule PT Large Power Trans	Schedule PP Large Power Pri	Schedule PS Large Power Sec	Schedule F Street Lighting	Total System
Energy:										
Production	¢/kWh	10.03	10.115	10.008	10.042	9.719	9.728	9.965	9.714	9.93
Demand:										
Production	$/kW/Month	$5.64	$9.76	$11.54	$11.90	$16.99	$14.85	$14.74	$16.80	$9.25
Transmission	$/kW/Month	$0.99	$2.51	$2.26	$2.17	$4.59	$2.77	$2.66	$1.66	$1.74
Distribution Primary										
Substations	$/kW/Month	$0.43	$0.91	$0.89	$0.89	$0.00	$1.07	$1.05	$0.99	$0.68
Primary Lines	$/kW/Month	$0.91	$2.06	$1.93	$1.90	$0.00	$2.30	$2.26	$1.92	$1.47
Primary Demand	$/kW/Month	$1.34	$2.97	$2.82	$2.79	$0.00	$3.37	$3.31	$2.91	$2.15
Distribution Secondary										
Secondary Lines	$/kW/Month	$0.55	$1.04	$0.79	$0.86	$0.00	$0.31	$0.95	$0.12	$0.62
Line Transformer	$/kW/Month	$0.49	$1.01	$0.72	$0.77	$0.00	$0.28	$0.86	$0.09	$0.56
Secondary Demand	$/kW/Month	$1.04	$2.05	$1.51	$1.63	$0.00	$0.59	$1.81	$0.21	$1.18
Distribution Demand	$/kW/Month	$2.38	$5.02	$4.33	$4.42	$0.00	$3.96	$5.12	$3.12	$3.33
Total Demand	$/kW/Month	$9.21	$17.29	$18.13	$18.49	$21.58	$21.58	$22.52	$21.80	$14.32
Total Demand & Energy	¢/kWh	16.623	18.135	15.593	15.848	13.552	13.903	14.691	16.204	15.390
Customer:										
Primary Lines	$/Cust/Month	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.02	$0.00
Secondary Lines	$/Cust/Month	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Line Transformers	$/Cust/Month	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Services	$/Cust/Month	$3.36	$5.59	$10.92	$4.07	$191.67	$12.75	$7.37	$3.53	$3.74
Meters	$/Cust/Month	$0.69	$1.42	$11.40	$1.39	$329.17	$36.04	$8.51	$1.89	$1.03
Street Lighting	$/Cust/Month	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00	$0.00
Customer Accounts	$/Cust/Month	$4.90	$6.26	$7.81	$5.31	$6.25	$7.83	$7.41	$5.82	$5.10
Uncollectibles	$/Cust/Month	$0.27	$0.45	$2.54	$1.36	$0.00	$13.25	$31.14	$0.27	$0.37
Customer Service	$/Cust/Month	$0.94	$0.79	$23.47	$0.77	$20.83	$23.29	$23.36	$0.74	$1.47
Total Customer		$10.16	$14.51	$56.14	$12.90	$547.92	$92.96	$77.81	$12.07	$11.71
Total	¢/kWh	18.088	19.318	15.817	16.15	13.567	13.911	14.712	16.35	15.913
Unitizing Factors:										
Energy Sales	MWH	2,145,700.0	377,100.0	2,016,900.0	53,400.0	173,308.0	2,183,136.0	872,956.0	40,300.0	7,842,800.0
Sum of Customer Demands	MW (NCD)	15,346.4	1,749.6	6,214.8	167.7	307.8	4,183.2	1,832.8	121.1	29,925.2
Average Annual Customers	Number	257,648.0	25,629.0	6,580.0	1,042.0	4.0	166.0	190.0	406.0	291,765

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CA-RIR-102

Ref: RT-22, page 27, line 10.

According to Mr. Young's Rebuttal, "Any transition of Schedule H should be planned to minimize administrative costs, minimize impacts on existing Schedule H customers, and establish applicability that aligns appropriately with other company rates. HECO's Schedule H should be maintained in its current form while a transition for the rate is structured." Please state with specificity how HECO proposes to address each of the issues that are raised and provide all available details regarding the timeline for the "transition of Schedule H" that is being proposed.

HECO Response:

At this time, HECO does not have proposals to address the administrative costs of Schedule H, the impacts on existing Schedule H customers, and the applicability of Schedule H. The referenced rebuttal testimony does not contemplate a timeline for transition of Schedule H but sought to highlight issues to consider if and when Schedule H is modified. HECO recommends that Schedule H be maintained in its current form until an overall modification of the Schedule is proposed.

DOD-RIR-1

Please specifically identify each new adjustment that HECO is proposing for the first time in its rebuttal testimony, and explain why HECO could not quantify each such adjustment prior to its rebuttal testimony.

HECO Response:

The DOD is referred to HECO's rebuttal testimony and exhibits where each new adjustment is identified. For the DOD's convenience, the information below summarizes new adjustments that HECO has proposed in its rebuttal testimony.

HECO RT-2

The Company revised its test year estimates of electricity sales and customers and provided this revision to the other parties on May 5, 2005. The revisions reflected changes in assumptions as discussed on page 2 of HECO RT-2.

HECO RT-3

HECO RT-3 calculated revenues according to the new sales and customer forecast in HECO RT-

also included in HECO's rebuttal testimony. However, the value of that adjustment changed in HECO's rebuttal testimony. Although HECO quantified the adjustment prior to submitting its rebuttal testimony, HECO inadvertently omitted the updated spinning reserve adjustment value in its May 5th transmittal.

HECO RT-5

HECO made changes to its avoided costs, H-Power energy rate, LSFO price differences for KPLP and GNPIPD for AES and KPLP. The changes were based on utilization of more current data that became available to the Company. These changes were explained in HECO's rebuttal testimony and exhibits.

HECO RT-6

Production adjustments are described in DOD-RIR-53 and below:

1) Identified for Production Operations – Nonlabor in HECO RT-6, page 3, lines 10 to 14. The adjustments include:

   a. A reduction of $20,000 for EPRI R&D expenses from the $500,000 presented in direct testimony to $480,000. The reduction is due to reducing the original forecast amount of $50,000 for Performance Assessment of Emerging Photovoltaic ("PV") technology to $30,000. HECO will use existing single crystalline PV modules from another completed project for the side by side testing with the emerging PV modules instead of purchasing new single crystalline PV

to HECO's rebuttal testimony because the adjustment was made as part of developing the Company's rebuttal testimony, in response to the Consumer Advocate's testimony with respect to this issue.

2) Identified for Production Maintenance – Nonlabor in HECO RT-6, page 4, lines 17 to 22. The adjustments include:

a. An addition of $63,000 to the $1,403,000 expense estimate for Substation DG Maintenance Nonlabor which was presented in the May 5, 2005 Adjustment transmittal. The revised total for Substation DG Maintenance Nonlabor is $1,466,000 and is discussed in HECO RT-7. The adjustment is a result of an increase in the rental expense per DG unit from $145,000 to $152,000 per year for

[redacted]

each of the 9 units. This adjustment reflects final updated DG rental pricing received from Hawthorne Pacific in mid-June, 2005.

The DG capital cost was updated in RT-7 to reflect updated project cost estimates. The updated DG capital cost figure of $2,093.8 was in fact reflected earlier in HECO's plant additions information of Attachment 6, page 7, project #P0001125, provided in HECO's May 5, 2005 update to the PUC, CA, and DOD.

The non-fuel DG expense of $1,466.0 presented in RT-7 reflects final updated DG rental pricing received from Hawthorne Pacific in mid-June, 2005. DG unit rental fees will be $152,000 per unit per year, versus a previously quoted fee of $145,000 per unit per year. The $7,000 annual increase per unit multiplied by nine DG units equates to a total addition of $63,000 to the prior non-fuel DG expense figure filed in Attachment 1A of HECO's May 5, 2005 update.

HECO RT-8

A $25,000 reduction was made to Transmission and Distribution expenses relative to the Ellipse Buy-Down Fee amortization. As stated on page 15 of HECO RT-13, the Company re-evaluated the two-year amortization period and concluded that amortizing the Ellipse maintenance buy-down fee over a period up to the next software upgrade, currently planned by the vendor for September 2007, is more appropriate than the two-year amortization period. This adjustment could not be quantified prior to HECO's rebuttal testimony because the adjustment was made as part of developing the Company's rebuttal testimony, in response to the Consumer Advocate's testimony with respect to this issue. For additional details, please refer to HECO-RT-13, pages 14 and 15 of 30 and also our response at CA-RIR-57.

HECO RT-9

There were no new adjustments that HECO (RT-9 Darren Yamamoto) proposed for the first time in his rebuttal testimony. However, there were revisions to the original estimates for

Accounts Expense, please see HECO RT-9, Page 1, Lines 23-25, Page 2, Lines 1-25, and Page 3, Lines 1-13); the Customer Deposits (for further discussion of the revision to the Customer Deposits, please see HECO RT-9, Page 3, Lines 16-25 and Page 4, Lines 1-12); the Revenue Lag Days (for further discussion of the revision to the Revenue Lag Days, please see HECO RT-9, Page 4, Lines 23-25 and Page 5, Lines 1-11); and the Proposed Labor Expense Adjustment (for further discussion of the revision to the Proposed Labor Expense Adjustment, please see HECO RT-9, Page 7, Lines 24-25, and Page 8, Lines 1-25 and Page 9, Lines 1-21).

HECO RT-10

As indicated in HECO-RT-10, HECO decided that the Green Pricing Program, while important as an element of its renewable energy strategy, has a lower priority than other initiatives the Company is pursing and has been removed from been eliminated from this case.

HECO RT-13

a. Account 921 – As explained in HECO RT-13, Account 921 was reduced by $48,000 on rebuttal as a result of an adjustment to the Ellipse Buy-Down Fee amortization. As stated on page 15 of HECO RT-13, the Company re-evaluated the two-year amortization period and concluded that amortizing the Ellipse maintenance buy-down fee over a period up to the next software upgrade, currently planned by the vendor for September 2007, is more appropriate than the two-year amortization period. This adjustment could not be quantified prior to HECO's rebuttal testimony because the adjustment was made as part of developing the Company's rebuttal testimony, in response to the Consumer Advocate's testimony with respect to this issue

b. Account 928 – Most of the $103,000 adjustment to Regulatory Commission Expenses was included in response to CA-IR-258. As stated in HECO RT-13, page 19, the only difference between the Company's rebuttal testimony estimate and the amount provided in

response to CA-IR-258 related to a reduction in the Company's estimated DSM consultant's costs from $157,000 (in CA-IR-258) to $80,000. The $77,000 cost reduction resulted in a revised estimate for total rate case expenses of $595,000 (672,000 in CA-IR-258), amortized over three years at $198,000 per year ($224,000 per year in CA-IR-258). HECO reduced the DSM consultant costs in part to address the Consumer Advocate's testimony regarding excluding all the DSM consultant costs in determining the Regulatory Commission Expense estimate.

c. Account 9302 - In HECO RT-13, Account 9302 was reduced by $111,000 as a result of an adjustment to the Ellipse Buy-Down Fee amortization (see explanation for Account 921, under part a. of this response above). This adjustment was based on the Consumer Advocate's testimony with respect to this issue.

d. Account 931 – In CA-IR-260, HECO submitted a revised schedule for Rents Expense. The only difference between the amount presented in CA-IR-260 and the rents expense amount included in RT-13 is in the King Street rent. In CA-IR-260, HECO treated the King Street rent as a capital lease. Due to the complexity of the ratemaking treatment of a capital lease arrangement, and informal discussions with the Consumer Advocate's consultant which indicated some concerns regarding the capital lease treatment, HECO decided to discuss the negotiated lease with Kamehameha Schools Bishop Estate (as explained in HECO RT-16, page 20). It was not until July 2005, that HECO negotiated modifications to the initially negotiated lease and executed a modified agreement effective July 1, 2005. Based on the modified terms of the new lease, the executed lease agreement is now deemed to be an operating lease and the King Street rent amount was adjusted. The new King Street Rent amount presented in HECO's rebuttal testimony is $549,000, an increase of $43,000 from

HECO's direct testimony. See HECO's response to DOD-IR-21 for all the changes in Account 921 - Rents Expense between HECO's direct testimony and rebuttal testimony.

HECO RT-15

Employee benefit expenses and pension and post retirement costs were updated as discussed on pages 3 and 4 of HECO RT-15.

HECO RT-16

Accumulated Depreciation. As discussed in HECO RT-16, page 3, lines 7 through 11, HECO revised its accumulated depreciation estimate to updated the historical 5-year averages for actual 2004 information for retirements, cost of removal, and salvage which are used to calculate HECO's 2005 test year estimates for retirements, cost of removal, and salvage. HECO attempted to be consistent with other estimates which reflected actual 2004 information.

HECO RT-17

The Company has not proposed any new adjustments in rebuttal to our 2005 test year estimates of Taxes Other Than Income Taxes, Income Tax Expense, Unamortized net SFAS 109 Regulatory Asset, Unamortized Investment Tax Credit and Accumulated Deferred Income Taxes (ADIT).

In my rebuttal testimony, revisions to the foregoing items were explained and with respect to ADIT, certain ADIT activities have been revised for a revised plant additions estimate and for adjustments made in the course of preparing our 2004 tax return, to be filed on September 15, 2005. The revised plant additions estimate was not available until just prior to filing our rebuttal estimates. The adjustments made in the course of preparing our 2004 tax return were similarly not available until just prior to filing our rebuttal. The following ADIT activities were affected:

28310	State ITC
28319	Cap to construction
28327	Software
28328	Gain or loss on ACRS Retirements
28331	CIAC
28333	Capitalized interest
28418	IRP and DSM costs
28516	Honolulu Harbor reserve
28524	Software (e-business)
28538	Rate case—TY 2005
28540	King Street lease

The estimates of ADIT related to AFUDC in CWIP and TCI in CWIP were adjusted for the changes in the test year plant additions estimate. Although only the federal activity numbers are listed, the comparable state ADIT adjustments were similarly made to the rebuttal numbers.

In addition, in reviewing our rebuttal testimony, we noticed we should not have made an adjustment for payroll taxes for the removal of the DSM incremental labor from the test year estimates, since the DSM amount removed of $1,435,317 was a loaded amount. Payroll taxes was adjusted by $61,000 in error. This correction will be made at the next opportunity for determining revenue requirements.

HECO RT-18

a. HECO made a correction to the plant addition estimate for the New Kuahua Substation project. The discrepancy was discovered after the June 15, 2005 update was provided.

b. HECO updated the cash CIAC for the Ford Island Substation project after then June 15, 2005 update was provided.

HECO RT-19

The only new adjustment to Rate Base that HECO is proposing for the first time in its rebuttal testimony is the "Deferred Rent Expense" related to the King Street office building lease, which is shown as a deduction in the rate base calculation presented in HECO-R-1901. There is also a corresponding accumulated deferred income tax impact which is included in the accumulated deferred income tax calculation presented in HECO-RWP-1704.

As explained in HECO RT-19, page 10, the deferred rent expense was not presented in direct testimony due to the assumptions made regarding the treatment of the King Street office building lease at the time direct testimony was prepared. However, since then, the assumptions regarding the treatment of the King Street office building lease have been revised and are further discussed by Ms. Tayne Sekimura in HECO RT-16.

HECO RT-20

Based on current capital market conditions and the application of my professional judgment, it is my opinion that a just and reasonable return on the common equity capital of HECO's electric utility operations in the State of Hawaii is now 11.0%, a substantial decrease of 50 basis points from my original recommendation of 11.5%. This was explained in HECO RT-20.

[redacted]

As presented in Mr. VonGnechten's rebuttal testimony HECO RT-21, the following were adjustments proposed for the first time in rebuttal testimony:

performed prior to rebuttal testimony as the revised revenue requirement was not completed until rebuttal testimony.

b. Estimated savings to customers resulting from the use of special purpose revenue bond financing: Calculations were updated to reflect the revised capital structure particularly the issuance of the Refunding Series 2005A Special Purpose Revenue Bonds and redemption of the Series 1995A Special Purpose Revenue Bonds. Calculations were updated at the first available time which was in our rebuttal testimony.

c. King Street Building: The capital structure in this rebuttal testimony reflected imputed debt associated with the operating lease with Bishop Estate for the lease of the King Street building. The King Street building lease was not reflected in the capital structure in direct testimony. The updated capital structure provided on June 15, 2005 reflected a lease obligation associated with a proposed capital lease for the lease of the King Street Building. As a result of the capital lease obligation, HECO estimated that it would require rebalancing of its capital structure. Subsequent to filing the update of the capital structure on June 15, 2005, further negotiations with Bishop Estate resulted in an executed arrangement which was classified as an operating lease. The long-term, fixed obligation associated with the operating lease will likely result in the credit rating agencies imputing debt. The imputed debt indirectly affected the capital structure because it necessitated the rebalancing of other capital structure components. HECO estimates that it will increase common equity by $2.5 million and correspondingly decrease its short-term borrowings by $2.5 million. This rebalancing is the same as the rebalancing HECO had estimated that it would have required if HECO had entered into the proposed capital lease.

HECO RT-22

HECO RT-22 revises the allocation of the proposed revenue increase and rate design as discussed on pages 5 through 17 of HECO RT-22. The cost of service study and marginal cost study were also updated.

DOD-RIR-2

Refer to HECO RT-16, page 18, lines 17-19.

Please provide complete calculations showing the derivation of the $125,000.

HECO Response:

Calculations showing the derivation of the $125,000 were provided in HECO-R-1011.

DOD-RIR-3

Refer to HECO RT-16, page 18, lines 7-9.

Please provide complete calculations showing the derivation of the $4.5 million, and the $3.0 million.

HECO Response:

The calculations requested contain confidential information. In some instances, a position may be unique to an individual and traceable to a specific employee and his/her salary level. This information will be provided to Consumer Advocate, Department of Defense and the Public Utilities Commission under protective order.

Subsequent to the submission of rebuttal testimony, the amount charged to O&M was revised from $3.0 million to $2.8 million. This was due to notification from two departments that several positions previously allocated 100% to O&M were in error and a portion of their estimated labor and benefits should have been allocated to Capital and Billables. Changes were made for the following positions::

Filled prior to 1/1/05:

Manager, Corporate Compliance & Audit: From 100% O&M to 82% O&M and 18% Billables

Positions Filled in January 2005:

Corporate Compliance Analyst: From 100% O&M to 85% O&M and 15% Billables

Director, SOX: From 100% O&M to 74% O&M and 26% Billables

Positions Filled in February 2005:

2 SOX Compliance Specialists: From 100% O&M to 57% O&M and 43% Billables

Positions Filled in April 2005:

Sr. Technical Services Engineer: From 100% O&M to 20% O&M and 80% Capital

A revised HECO-R-1606 is provided on page 2 of this response.

HECO-R-1606 (REVISED 8-26-05)

HECO
Estimated Annual Wages & Benefits of Additional Approved Positions Not Included in TY 2005 Forecast

	# Positions	Estimated Annual Wages $ [1]	Estimated Annual Benefits [2]	Estimated Annual Wages & Benefits	Estimated Annual Wages & Benefits Charged to: O&M	Capital	Billables	Clearing
Positions Filled Prior to 1/1/05	17	1,378,416.00	258,620.32	1,637,036.32	1,184,263.39	234,806.68	52,393.15	165,573.10
Positions Filled in:								
January 2005	7	436,488.00	106,490.72	542,978.72	420,399.23	85,243.88	37,335.60	0.00
February 2005	3	191,380.80	45,638.88	237,019.68	162,753.51	6,320.52	67,945.64	0.00
March 2005	4	239,532.80	60,851.84	300,384.64	216,243.16	45,231.00	0.00	38,910.48
April 2005	5	329,929.60	76,064.80	405,994.40	15,801.31	144,063.01	196,904.06	49,226.02
May 2005	3	191,380.80	45,638.88	237,019.68	232,279.29	0.00	4,740.39	0.00
June 2005	2	110,843.20	30,425.92	141,269.12	88,345.94	49,810.05	0.00	3,113.13
Positions Filled as of June 30, 2005	41	2,877,971.20	623,731.36	3,501,702.56	2,320,085.83	565,475.15	359,318.85	256,822.73
Unfilled Positions	12	811,324.80	182,555.52	993,880.32	476,164.23	313,176.97	0.00	204,539.11
TOTAL	53	3,689,296.00	806,286.88	4,495,582.88	2,796,250.07	878,652.12	359,318.85	461,361.84

[1] Based on 2080 hours

[2] Based on 1904 productive hours @ $7.99 per productive hour

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Pages 3-5 intentionally left blank.

DOD-RIR-4

Refer to HECO RT-16.

a. Please explain fully HECO's budgeting process for "additional unforecasted positions."

b. Please explain fully why HECO is unable to forecast accurately positions that it needs to fill.

c. Please provide the source documents for all "additional unforecasted positions" discussed in HECO RT-16 and HECO's other rebuttal testimony.

d. Is there any specific mention of "additional unforecasted positions" in HECO's direct testimony in this case? If so, please identify exactly where "additional unforecasted positions" are discussed.

e. Is there any specific quantification of "additional unforecasted positions" in HECO's previous responses to CA and DOD information requests in this case? If so, please identify exactly where "additional unforecasted positions" are quantified in those responses.

f. When did HECO first become aware that it had "additional unforecasted positions"?

g. When did HECO first become aware that "additional unforecasted positions" should impact the test year labor cost amount?

h. For each month of 2004 and 2005, please identify all "additional unforecasted positions."

i. For each month of 2004 and 2005, please identify each "additional unforecasted position" that was not filled.

j. Please quantify the impact of each "additional unforecasted position" on HECO's budgets for 2004, 2005 and 2006.

HECO Response:

It should be noted that HECO is **not** proposing to revise its test year labor estimates to reflect the additional unforecasted positions discussed in HECO RT-16, and addressed by other various witnesses. However, if an adjustment is made to test year labor expenses based on differences between the test year employee count and the actual employee count for 2005, as proposed by the CA and DOD, then the expected actual 2005 employee count, which includes the additional

unforecasted positions should be considered. The Company has added and expects to fill the additional positions beyond those included in the test year estimate. which means that the year-end employee count, and/or the employee count in future years, should exceed the test year average number of employees.

a. Please refer to CA-IR-8 for an explanation of HECO's budgeting process and to CA-IR-12 for staffing guidelines for "additional unforecasted positions".

b. The TY 2005 staffing forecast was prepared based on needs at a point in time. However as time progresses, HECO adjusts its staffing accordingly to address the changing needs of the customer and community as well as changes in regulatory and workload requirements. In its rebuttal testimony, HECO is not attempting to change the test year amounts for the "additional unforecasted positions", but is instead providing support for its test year 2005 total average number of employees.

c. Documentation for the "additional unforecasted positions" was provided by the departments where these positions existed. See HECO's rebuttal testimonies and the response to part e.

d. No. There is no specific mention of "additional unforecasted positions" in HECO's direct testimony in this case. See the response to part e. for some of the IR responses that discusses the "additional unforecasted positions".

e. The existence of "additional unforecasted positions" was presented in previous responses to the CA and DOD information requests. A listing of the IRs and the respective department with the "additional unforecasted positions" is provided below:

CA-IR-509	Safety, Security & Facilities
CA-IR-511	Government & Community Affairs

CA-IR-512	Special Projects
CA-IR-513	Government Relations & Public Affairs
CA-IR-582	Planning & Engineering
DOD-IR-8-8	Production

f. The departments became aware that they had "additional unforecasted positions" when they received approval from the Staffing Committee to hire these positions.

g. HECO is not seeking to adjust the test year labor cost amounts for these "additional unforecasted positions".

h. Refer to the information provided in DOD-RIR-3 for each month (December 2004-July 2005) included in the test year average computation. Information for each month prior to December 2004 is not relevant to this rate case proceeding since the average employee count utilizes a 13-month average which includes the period from December 2004 to December 2005.

i. Information provided in DOD-RIR-3 identifies the month in which each "additional unforecasted position" was filled for the months January to June 2005 and those filled prior to January 1, 2005. The hire dates of "additional unforecasted positions" filled after June 30, 2005 are indicated in the hiring status column. Information for each month prior to December 2004 is not relevant to this rate case proceeding since the average employee count utilizes a 13-month average which includes the period from December 2004 to December 2005.

j. Please refer to CA-IR-14 for quantification of the then known changes in additional staffing at the time the 2005 budget was developed. As stated in HECO-RT-16, there were 53 "additional unforecasted positions", which updates the additional staffing

numbers provided in CA-IR-14. The estimated wages and benefits, and date hired are

DOD-RIR-5

Refer to HECO RT-16 and HECO-R-1603.

a. Please show in detail all positions in the column "Total Positions Approved for Hiring in 2005 as of 7/26/05" that have not been filled as of 7/31/05.

b. Please show in similar format to HECO-R-1603 the 8/31/05 actually filled positions.

c. Please quantify the annualized impact on labor cost associated with the difference between the 1454 actual employees on 7/27/05 from HECO-R-1604 and the 1543 "Total Positions Approved for Hiring in 2005 as of 7/26/05" on HECO-R-1603.

HECO Response:

a. Please refer to pages 2-4 for a listing of all positions in the column "Total Positions Approved for Hiring in 2005 as of 7/26/05" in HECO R-1603, that have not been filled as of 7/31/05. It is important to note that HECO is not seeking to adjust its test year 2005 total average employee count or test year expenses for the 53 "additional unforecasted positions" which are included in the "Total Positions Approved for Hiring in 2005 as of 7/26/05".

b. Information regarding the 8/31/05 actual filled positions will not be available by the filing deadline for this IR.

c. HECO objects to this RIR to the extent it asks HECO to make computations, calculations, or otherwise rework data contained in its files. The "Total Positions Approved for Hiring in 2005 as of 7/26/05" shown on HECO-R-1603 includes the "additional unforecasted positions" for which HECO is not seeking to increase its test year average employee count numbers nor labor cost estimates.

VP **Unfilled Positions as of 7/31/05 ***

Corporate Excellence

Pension Specialist
HR Assistant position

Energy Delivery

Resource Planner
Planning Administrator
Senior Helpers (2)
Truck Driver
Lead Engineer
T&D Engineer II (3)
Project Manager
Structural Engineer II
Telecommunications Engineer II
Technical Services Engineer
Senior Contract Administrator
Mechanic
Mechanic Helper
Systems Analyst (OMS)
Mapping Supervisor
Trouble Dispatcher
Chief Dispatcher
Switching Coordinator
System Coordinator
Technical Trainer
Relay Electrician

Energy Solutions

Junior Customer Planners (6)
Junior Drafter
Senior Technical Engineer
DSM C&I Direct Load Control Program Manager
DSM Load Management Engineer
Senior Resource Planning Analyst

VP	Unfilled Positions as of 7/31/05 *
Financial VP	
	Corporate Accountant
	Financial Systems Analyst
	IT Project Manager
	Sr. Development Analyst
	IT Finance & Vendor Management Analyst
	IT Infrastructure Analyst
Government and Community Affairs	
	Regulatory Analyst
Operations	
	Operations Analyst
	Director of Customer Account Services
President's Office	
	IT Auditor
	Auditor (2)
	Secretary
Power Supply	
	Electrical Engineer II
	Project Manager
	Transmission Planning Engineer
	Principal Staff Engineer
	IT Specialist
	Admin Fuels Operations
	Honolulu Clerk
	Shift Supervisor
	Kahe Senior Shift Supervisor
	Kahe Maint Supervisor
	Boiler Working Foreman
	Elec Working Foreman
	Machinist Working Foreman
	Senior Electrician
	Machinist
	Pipefitter Mechanic
	Certified Comb Welder
	Control Technician (2)

VP **Unfilled Positions as of 7/31/05 ***

Power Supply (Continued)

Planning/Project Coordinator (2)
O&M Engineer (2)
Machinist (2)
Pipefitter Mechanic (2)
Certified Comb Welder
Control Technician
Helper
Insulator
Condenser Cleaner (4)
Waiau Maint Supervisor
Boiler Working Foreman
Elec Working Foreman
Machinist Working Foreman
Senior Electrician (2)
Machinist
Pipefitter Mechanic
Certified Comb Welder
Control Technician

* Number in parenthesis indicates the number of vacancies for that position title, if greater than one.

DOD-RIR-6

Refer to HECO-R-1602.

Please identify the reduction in audit and consulting fees associated with the projected increase in internal audit from 6 to 12 positions.

HECO Response:

The Internal Audit Division of the Corporate Audit & Compliance Department provides support for HECO as well as HELCO and MECO. For 2005 Sarbanes-Oxley Act of 2002 ("SOX") compliance testing, Internal Audit added additional staff, thereby eliminating the need to use outside consultants.

Consulting fees (approximately $400,000) were incurred for the 2004 Sarbanes-Oxley (SOX) compliance testing at HELCO and MECO. When combined with Internal Audit's internal labor costs of about $87,000, the total cost for 2004 compliance testing for HELCO and MECO was approximately $487,000.

The 2005 estimate for compliance testing for the subsidiaries, using Internal Audit staff, is approximately $190,000, resulting in savings of about $297,000 from 2004 to 2005.

In addition, because our Internal Audit staff devoted 100% of their time to SOX compliance testing in 2004 and did not perform their scheduled operational and information technology audits and other reviews, additional staff was required to enable the Company to continue annual SOX compliance testing and resume the required operational and information technology audits and other reviews in accordance with the Internal Audit and the HECO Audit Committee charters. Unrelated to SOX, an analyst position was also added to accommodate the expanded responsibilities of the Corporate Audit & Compliance Department, as well as a department secretary to provide administrative assistance.

DOD-RIR-7

Please provide job descriptions for each position listed in the "Additional Approved Positions Unforecasted in TY 2005" of HECO-R-1603.

HECO Response:

Most job descriptions were previously discussed in rebuttal testimony or prior information requests. Page 2 of this response provides references as to where job descriptions for "Additional Approved Positions Unforecasted in TY 2005" for a department can be found.

HECO
Reference Table for Job Descriptions of the 53 "Additional Unforecasted Positions"

		# Positions	Reference for Job Descriptions
Corp Exc	Comp & Ben	1	HECO RT-15, page 7
Corp Exc	SSF	3	HECO-R-1302, page 2; CA-IR-509
Corp Exc	WFSD	1	HECO-R-1302, page 3
Corp Exc Total		5	
En Del	Engineering	3	HECO RT-8, pages 13-15
En Del	Supp Svcs	2	HECO RT-8, pages 16-17
En Del	Sys Op	7	HECO RT-8, pages 9-12
En Del Total		12	
EnSol	CID	5	HECO RT-10, page 17
EnSol	Engy Proj	1	HECO RT-7, pages 14-15
EnSol	Tech	1	HECO-R-1302, page 4
EnSol Total		7	
FinVP	InfoTech	5	HECO-R-1302, pages 1-2
FinVP Total		5	
Govt&Comm	Ed & Cons Aff	1	HECO-R-1302, page 3
Govt&Comm	Gov Rel	1	HECO-R-1302, page 3; CA-IR-513
Govt&Comm	Reg Affairs	1	HECO-R-1302, page 4
Govt&Comm	VP-Gov & Com	1	HECO-R-1302, page 3
Govt&Comm Total		4	
Pres	Int Audit	6	HECO-R-1302, page 1
Pres	President	2	HECO RT-16, page 9
Pres Total		8	
Pwr Sup	Plng & Eng	8	HECO RT-6, pages 38-40
Pwr Sup	Production	2	See DOD-RIR-7, page 3
Pwr Sup Total		10	
VP-Special Projects		2	HECO RT-16, page 10; CA-IR-512
Total "Additional Unforecasted Positions"		53	

Operations Power Engineer Job Description

This position provides technical and engineering expertise in improving operational procedures/processes and assigning maintenance priorities to optimize the availability, responsiveness and reliability of the station generating units.

Major job responsibilities of this position are:

- Monitors and reviews operating performance and develops and implements operating policies, procedures, including disaster plan updates and revisions and addition of new O&M and capital projects, and maintenance techniques to maximize plant available. Troubleshoots and determines root cause for generating unit reliability problems, and recommends corrective action.
- Conducts on-site forced outage investigations. Compiles and analyzes forced outage data and information and makes recommendations for future avoidance. Provides inputs to condition based/predictive/preventive operations/maintenance programs.

DOD-RIR-8

Refer to HECO RT-16, page 5, lines 10-11.

a. Please show by month of 2005 the monthly employee counts that were utilized to compute the "revised test year 2005 total average number of employees" of 1,485.

b. Please identify each figure on HECO-R-1602 which is not an actual employee count, and provide the corresponding actual employee count.

HECO Response:

a. The monthly employee counts that were utilized to compute the "revised test year 2005 total average number of employees" of 1,485 were provided in HECO-R-1602.

b. Each figure on HECO-R-1602 is a forecasted employee count. Actual employee counts for December 2004 - July 27, 2005 were provided on HECO-R-1604.

DOD-RIR-9

Refer to HECO-R-1605

a. Please quantify the impact on 2005 operating expenses of the -46 employee position difference shown on HECO-R-1605. Include supporting calculations and workpapers.

b. Please quantify the annualized labor cost associated with each figure in the Difference column on HECO-R-1605. Include supporting calculations and workpapers.

c. Please quantify the amount of labor cost that HECO is requesting in the 2005 test year for employee positions in excess of those shown in the "Employee Count as of June 30, 2005" column on HECO-R-1605. Include supporting calculations and workpapers.

HECO Response:

a. HECO objects to this RIR to the extent that it asks HECO to make computations, calculations or otherwise rework data contained in its files. The -46 employee position difference shown on HECO-R-1605 includes the "additional unforecasted positions" hired as of 6/30/05 for which HECO is not seeking to increase its test year average employee count numbers nor labor cost estimates.

b. Please refer to the response in part a.

c. Please refer to the response in part a.

DOD-RIR-10

Refer to HECO RT-16, page 6, lines 18-21.

Subsequent to the development of the Company's 2005 test year forecasted employee count, were any positions eliminated or deleted? If so, identify all eliminated and deleted positions.

HECO Response:

Two positions were eliminated subsequent to the development of the 2005 test year estimates. As provided on page 3 of HECO-RWP-807, an Administrative Assistant position in the Project Management Division of the Engineering Department was eliminated, but was subsequently replaced with an additional Transmission and Distribution Engineer position. No adjustment was made to the forecasted Engineering employee count since the Transmission and Distribution Engineer position offset the Administrative Assistant position.

In addition, as part of the Customer Solutions reorganization discussed in HECO's response to CA-IR-78, the Director-Forecasts position was eliminated. The revised Customer Solutions employee count of 56, as shown on HECO-R-1602 takes into consideration the elimination of this position.

DOD-RIR-11

Refer to HECO RT-16, page 6, lines 18-21

a. What number of positions is reflected in HECO's 2005 budget? Please show by month in similar format to HECO-R-1604 and HECO-R-1602.

b. Does HECO have a budget or forecast for 2006?

c. What number of positions is reflected in HECO's 2006 budget? Please show by month in similar format to HECO-R-1604 and HECO-R-1602.

HECO Response:

a. The number of positions reflected in HECO's 2005 budget is the same as shown in HECO's response to CA-IR-508. However adjustments to HECO's 2005 budget were made to reflect the lag in hiring. Notwithstanding the hiring lag, the 2005 budget year-end employee count is still expected to be achieved, as explained in HECO's response to CA-IR-14.

b. Please refer to HECO's response to CA-IR-454.

c. Please refer to HECO's response to CA-IR-454. As stated in the response to CA-IR-454, HECO has prepared projections of sales and capital expenditures, and a financing plan for 2006. For purposes of putting together HECO's 2006 financing plan, HECO assumed an overall level of operating expenses but did not prepare an itemized projection of operating expenses.

DOD-RIR-12

Refer to HECO RT-16, page 7, line 2.

Does the actual employee count information shown on HECO-R-1604 by month through July represent "the expected 2005 actual employee count" for January through July 2005? If not, please identify exactly what HECO means by "the expected 2005 actual employee count" for January through July 2005.

HECO Response:

No. The employee count information shown on HECO-R-1604 represents the actual employee count at month-end for December 2004 – June 2005 and at July 27, 2005. Additional positions were approved subsequent to the development of the Company's 2005 test year forecasted employee count, in addition to the four positions already discussed in HECO RT-16, page 6, lines 1-2. These additional positions have not been included in the Company's 2005 test year employee count.

The forecasted December 2005 year end employee count presented in HECO-R-1602 is 1490.

DOD-RIR-13

Refer to HECO-R-1606 and provide, in similar format, ACTUAL wages and benefits through July 31, 2005 charged to O&M, Capital, Billables and Clearing, based on actual positions as of the following dates:

a. Actual Positions Filled As of 1/1/05

Positions Filled in:

b. January 2005

c. February 2005

d. March 2005

e. April 2005

f. May 2005

g. June 2005

h. July 2005

HECO Response:

a-h. The information does not exist in the form requested. Actual wages and benefits information allocated in the manner requested are not maintained by specific position. Extracting productive wage information in the requested format for a specific position would require programming efforts to extract and summarize the information in the form requested. Also as stated in HECO's response to DOD/HECO-IR-8-8, actual benefits information is not available as it is not tracked by position. Benefits and non-productive wages are applied as on-costs, based on an on-cost rate times productive hours. The on-cost rate is derived on a Company basis and is not specific to a position. Therefore, HECO objects to the information request to the extent it requires HECO to rework data in its files or records. It should be noted that even if non-productive wages could be

computed based on the actual hourly rate of a position, providing the allocation as requested would be unduly burdensome to provide.

DOD-RIR-14

Refer to HECO-R-1606 and provide, in similar format, HECO's proposed 2005 test year wages and benefits charged to O&M, Capital, Billables and Clearing.

HECO Response:

HECO objects to this IR to the extent it asks HECO to make computations, calculations, or otherwise rework data contained in its files. However without waiving any objections, the labor and employee benefits charged to O&M, Capital, Billable and Clearing for the 2005 test year direct testimony is provided on page 2.

Bud22-Total Company Labor Dollars

Acct Grp Descr	Exp Element	_EE	FY05
Billable	Employee Benefits	422	$953,067.17
Billable	Labor Cost	150	$4,059,504.16
Billable	Non-Productive Wages	421	$455,659.15
Billable			$5,468,230.49
Capital	Employee Benefits	422	$3,583,323.32
Capital	Labor Cost	150	$15,556,673.40
Capital	Non-Productive Wages	421	$1,713,178.36
Capital			$20,853,175.08
Charges to Clearing	Employee Benefits	422	$4,919,142.26
Charges to Clearing	Labor Cost	150	$19,286,311.21
Charges to Clearing	Non-Productive Wages	421	$2,351,830.22
Charges to Clearing			$26,557,283.68
O&M	Employee Benefits	422	$14,516,567.88
O&M	Labor Cost	150	$59,071,129.76
O&M	Non-Productive Wages	421	$6,920,878.39
O&M			$80,510,576.02

DOD-RIR-15

Please summarize in one Excel sheet all changes in HECO's proposed labor cost for the 2005 test year from (1) HECO's original filing, to (2) HECO's rebuttal.

HECO Response:

See attached file for spreadsheet showing HECO's proposed labor cost for the 2005 test year from (1) HECO's original filing to (2) HECO's rebuttal.

Hawaiian Electric Company, Inc.
2005 Test Year - Labor Cost (In Thousands)
Direct vs. Rebuttal

Line No		A Direct Testimony	B Net Change	C Rebuttal Testimony
	Production Expense:			
1	Operation	13,398		13,398
2	Maintenance	12,372		12,372
3	Subtotal	25,770	-	25,770
	Transmission Expense			
4	Operation	1,854		1,854
5	Maintenance	2,002		2,002
6	Subtotal	3,856	-	3,856
	Distribution Expense			
7	Operation	4,790		4,790
8	Maintenance	4,708		4,708
9	Subtotal	9,498	-	9,498
	Customer Accounts Expense			
10	Supervision	117		117
11	Meter Reading	2,174		2,174
12	Customer Records & Collection	4,553		4,553
13	Subtotal	6,844	-	6,844
	Customer Service Expense			
14	Supervision	[illegible]		[illegible]
15	Customer Assistance	3,662	(448)	3,214
16	Informational Advertising Expense	10		10
17	Misc Customer Service Expense	13		13
18	Subtotal	3,716	(448)	3,268
	Administrative & General			
19	A&G Expense (Acct 920)	13,880	(69)	13,811
20	Property Insurance (Acct 924)	185		185
21	Injuries and Damages (Acct 925)	1,359		1,359
22	Employee Pension & Benefits (Acct 926000)	562		562
23	Employee Benefits- Flex Credits (Acct 926010)	61		61
24	Institutional/Goodwill Advert Exp (Acct 9301)	18		18
25	Misc General Expense (Acct 9302)	327		327
26	Miscellaneous General Expenses (acct 9302)	112		112
27	Subtotal	16,504	(69)	16,435
28	Labor Adjustment	-	(246)	(246)
29	Grand Total O&M Labor Expense	66,188	(763)	65,425

Source:

Lines 1-2:	Column A : HECO-615; Column C: HECO-R-602
Lines 4-5, 7-9:	Column A : HECO-809
Lines 10-13:	Column A: HECO-901, Page 2; Column C: HECO-R-901
Lines 14-18	Column A: HECO-1003; Column C: HECO-R-1001
Lines 19-26	Column A: HECO-1301
Line 28:	Column C: HECO-2301

Reconciliation:

Direct Testimony O&M labor	66,188
Rebuttal Adjustments:	
Removal of DSM	(823)
Cust Sol Reorg	375
Cust Sol - Director Forecast	(69)
BU OT adjustment	(246)
Rebuttal O&M labor	65,425

DOD-RIR-16

Refer to HECO-R-1605.

Do all of the figures in the "Employee Count as of June 30, 2005" column include actually filled and hired positions (including the so-called "additional unforecasted positions" that have actually been filled)? If not, please identify all "additional unforecasted positions" that have been filled that are not shown in the "Employee Count as of June 30, 2005" column.

HECO Response:

Yes. All of the figures in the "Employee Count as of June 30, 2005" column are actual filled and hired positions and include "additional unforecasted positions" which have been filled. As noted by the "*", the figures do not include the employees who were moved to the Energy Efficiency Docket No. 05-0069.

DOD-RIR-17

Refer to HECO-R-1604.

Do all of the figures each column include actually filled and hired positions (including the so-called "additional unforecasted positions" that have actually been filled)? If not, please identify all "additional unforecasted positions" that have been filled that are not shown in each monthly column.

HECO Response:

Yes. All of the figures in HECO-R-1604 are actual filled and hired positions and include "additional unforecasted postions" which have been filled. As noted by the "*", the figures do not include the employees who were moved to the Energy Efficiency Docket No. 05-0069.

DOD-RIR-18

Refer to HECO RT-16, page 16, lines 16-24.

Please quantify the impact of each of the following 4 items on HECO's test year 2005 labor cost request: (1) there are additional positions that were not included in the test year estimates that have been and are being filled (i.e., the additional unforecasted positions), (2) some of the vacant positions relate to expanded DSM programs, for which the expenses have been removed from the test year, (3) some of the vacancies are not "structural" vacancies, but are new positions that should be filled by the end of the test year, and (4) the Company is incurring additional, unforecasted overtime in some areas as a result of some of the vacancies.

a. Include supporting workpapers for each quantification.

HECO Response:

As explained in DOD-RIR-4, HECO is not proposing to revise its test year labor estimates to reflect the additional unforecasted positions discussed in HECO RT-16, and addressed by other various witnesses.

1. HECO quantified the impact of the additional unforecasted positions in HECO-R-1606.
2. HECO removed the incremental DSM labor costs as shown in HECO-RWP-1001.
3. Employee count information, including information as to the nature of the new positions included in the test year employee count, and the status of filling vacancies, has been provided by the various O&M witnesses in their written direct and rebuttal testimonies, and in responses to information requests such as DOD/HECO-IR-6-23.
4. The additional, unforecasted overtime as a result of some of the vacancies has not been quantified. To the extent overtime is incurred by merit employees, there would not be a dollar impact, since merit employees generally do not get paid for overtime.

DOD-RIR-19

Refer to HECO RT-16, page 16, lines 10-14.

Please provide the "prior rate cases" material that HECO is relying upon for this statement.

HECO Response:

In a number of prior rate cases HECO has shown that test year expenses should not be less than forecasted, even if there are vacancies, because labor expense savings due to vacancies will be offset by increased labor expenses for unforecasted overtime and increased non-labor expense for contracted services (and/or because the vacancies are in positions that charge to capital and not to expense). For example, please refer to Docket No. 6998 (HECO's 1992 Test Year Rate Case), HECO's written rebuttal testimony (e.g., HECO RT-3, pages 6 through 12, HECO RT-7, pages 19 through 25, and HECO RT-8, pages 44 through 53).

DOD-RIR-20

Refer to HECO RT-16, page 16, lines 8-9.

Please explain fully how there "may be" merit in the CA's and DOD's general proposition

HECO Response:

Depending on the specific circumstances faced by the Company, there may be merit to the CA's and DOD's general proposition that there will be "structural" vacancies due to retirements and/or terminations, and that the Company will incur less expenses than forecast based on the assumption that all authorized positions will not be filled. For example, in a hypothetical situation where the specific circumstances are that there are "structural" vacancies due to retirements and/or terminations, there are labor savings due to vacancies, and the labor savings due to vacancies are not offset by increased labor expenses for unforecasted overtime and increased non-labor expense for contracted service, then there may be merit to the CA's and DOD's general proposition.

However, as discussed in HECO's rebuttal testimonies, these are not the specific circumstances that HECO is facing. In fact, the number of vacancies with respect to the positions included in the test year estimate is misleading because (1) there are additional positions that were not included in the test year estimates that have been and are being filled (i.e., the additional unforecasted positions), (2) some of the vacant positions relate to expanded DSM programs, for which the expenses have been removed from the test year, (3) some of the vacancies are not "structural" vacancies, but are new positions that should be filled by the end of the test year, and (4) HECO is incurring additional, unforecasted overtime in some areas as a result of some of the vacancies.

DOD-RIR-21

Ref: HECO R-1307 – Rent Expense

Refer to HECO RT-16 concerning the new King Street operating lease. Please specifically identify and summarize in one Excel sheet all changes in building rent expense for the 2005 test year from HECO's original filing to HECO's rebuttal that HECO is proposing.

HECO Response:

See page 2 for the excel sheet listing all changes in building rent expense for the 2005 test year from HECO's original filing (HECO-1305) to HECO's rebuttal filing (HECO R-1307). The change in HECO rent expense concerning the new King Street operating lease was discussed in HECO RT-16. The changes to rent expense estimates for Central Pacific Plaza and Pauahi Tower were presented in response to CA-IR-260. Further explanation and documentation supporting the revised rent expense estimates were provided in the Company's responses to CA-IR-617 and CA-IR-618.

Hawaiian Electric Company, Inc.
Account 931 - Rent Expense

EXISTING LEASES	Net sq ft	Annual Rent TY 2005 Direct (HECO-1305)	Adjustment	Annual Rent TY 2005 Rebuttal (HECO-R-1307)
Central Pacific Plaza (CPP)				
Suite 700	7,598	202	4	206
Suite 1010	3,930	133	-16	117
Suite 1020, 1025 & 1075	3,947	0	116	116
Suite 1201 & 1212	2,500	15	0	16
Suite 1250 & 1270	1,464	0	9	9
Suite 1300	9,601	287	-24	264
Suite 1425	2,404	0	71	71
Suite 1480	1,085	36	-4	32
Suite 1515	637	22	-3	19
Suite 1520 & 1530	2,139	65	2	67
Suite 1570	2,594	88	-11	77
HEIPC Sublease		40	1	41
Total - CPP		890	145	1035
King Street (1)		506	43	549
Honolulu Club		75	3	78
Pacific Tower 8th floor		54	0	54
Waiau Viaduct		32	0	32
Pauahi Tower		0	453	453
		1557	644	2201
(1) King Street rent:				
Rent		775,000		827,212
GIT on Lease Payments		32,294		32,294
less: HEI rent		(301,368)		(310,344)
Annual rent		505,926		549,162
HEI rent:				
Total King St. lease payments		807,294		859,504
Total bldg sq ft		58,313		58,313
Monthly Base rent/sq ft		1.15		1.23
Monthly CAM		1.50		1.50
PSC tax and PUC fees		0.18		0.19
		2.83		2.91
HEI sq ft x		8,874		8,874
Monthly HEI rent		25,114		25,862
Annual HEI rent		301,368		310,344

Note: Numbers may not add exactly due to rounding.

DOD-RIR-22

Refer to HECO RT-16, page 22, line 5-7.

a. Please quantify the difference in test year rent expense. Include supporting calculations.

b. Please explain fully the basis for the conclusion that "the resulting difference in test year rent expense is not significant."

with SFAS 13 would exceed the recoveries allowed by the Commission which would be based on the actual lower lease payments. If this were the case, and all other things being as reflected in the test year, revenues would not be sufficient to earn a "fair and reasonable" return.

With sufficient assurances by the Commission as discussed in response to DOD-RIR-23, the Company would be able to record a regulatory asset. Though a regulatory asset would reduce the potential negative financial implications, it still has some potential negative impact, as discussed in RT-16, page 25, lines 7 through 19.

d. Please see Scenario C on page 3 for quantification (specifically as it relates to the King Street lease) of the negative financial implications discussed above. As shown on page 3, if the Commission were to set rates based on lease payments without sufficient assurances of recovery in the future via higher rates the Company would earn lower returns on equity in the early years of the lease term. Looking at the King Street lease only, the Company will earn a 9.7% return on equity versus the 11% being requested in this docket. The lower return in Scenario C is attributable to the reduction in earnings as well as a higher equity balance. The higher equity balance results from having to capitalize a higher rate base which isn't reduced by the deferred rent liability which is a reduction to rate base in Scenario A. (See attached page 11.)

	Scenario A "Operating Lease" for Book and Ratemaking with Deferred Rent (pages 5-6)			Scenario B Ratemaking based on Lease Payments with Reg Asset (pages 7-8)			Scenario C Ratemaking based on Lower of Lease Payments or Lease Expense (No Reg Asset) (page 9-10)		
Year	Revenue Requirement	Net Income	Book ROE	Revenue Requirement	Net Income	Book ROE	Revenue Requirement	Net Income	Book ROE
2005	1,186,000	274,000	11.0%	1,136,000	277,000	11.0%	1,132,000	244,000	9.7%
2006	1,429,000	411,000	11.0%	1,344,000	424,000	11.0%	1,330,000	354,000	9.3%
2007	1,394,000	389,000	11.0%	1,338,000	414,000	11.0%	1,309,000	338,000	9.3%
2008	1,373,000	377,000	11.0%	1,347,000	415,000	11.0%	1,303,000	332,000	9.2%
2009	1,352,000	364,000	11.0%	1,362,000	415,000	11.0%	1,303,000	330,000	9.3%
2010	1,332,000	350,000	11.0%	1,437,000	408,000	11.0%	1,370,000	362,000	10.5%
2011	1,307,000	333,000	11.0%	1,420,000	395,000	11.0%	1,348,000	347,000	10.5%
2012	1,280,000	315,000	11.0%	1,401,000	380,000	11.0%	1,325,000	331,000	10.5%
2013	1,250,000	295,000	11.0%	1,378,000	363,000	11.0%	1,299,000	313,000	10.5%
2014	1,218,000	273,000	11.0%	1,361,000	345,000	11.0%	1,278,000	297,000	10.6%
2015	1,185,000	248,000	11.0%	1,409,000	317,000	11.0%	1,265,000	283,000	11.0%
2016	1,146,000	220,000	11.0%	1,353,000	282,000	11.0%	1,218,000	251,000	11.0%
2017	1,103,000	188,000	11.0%	1,293,000	243,000	11.0%	1,166,000	216,000	11.0%
2018	1,054,000	154,000	11.0%	1,228,000	201,000	11.0%	1,109,000	177,000	11.0%
2019	1,000,000	115,000	11.0%	1,165,000	155,000	11.0%	1,046,000	135,000	11.0%
2020	944,000	71,000	11.0%	1,172,000	97,000	11.0%	974,000	84,000	11.0%
2021	848,000	50,000	11.0%	1,020,000	59,000	11.0%	857,000	54,000	11.0%
Total	20,401,000	4,427,000		22,164,000	5,190,000		20,632,000	4,448,000	

Assumptions Input

Cost of Capital Assumptions	Weight	Rate	Weighted Average	After-tax Weighted Average	Weighted Average Revenue Requirement	Rev Req
ST Debt	3.25%	3.50%	0.114%	0.069%	0.125%	3.841%
Taxable Debt	36.81%	6.25%	2.301%	1.405%	2.525%	6.859%
Hybrid	2.37%	7.55%	0.179%	0.179%	0.321%	
Preferred Stock	1.78%	5.54%	0.099%	0.099%	0.177%	
Common Stock	55.79%	11.00%	6.137%	6.137%	11.025%	19.762%
			8.829%	7.889%	14.174%	

Tax Assumptions:		
Federal	35.00%	32.89%
State	6.40%	6.02%
		38.91%

Public Service Company Ta:	5.885%	(on gross receipts)
PUC Fee	0.500%	(on gross receipts)
Franchise Tax	2.500%	(on electricity sales)
Revenue Tax Rate	8.885%	

	Total	GET	Total including GET	Land %	Building %	
Appraisal	3,470,000					
		4.0000%		0.00%	100.00%	Lease Allocation
Monthly Lease Payments		4.1667%				
Effective Date to 11/30/200	64,583.34	2,690.97	67,274.31	-	67,274.31	
12/1/2009 to 11/30/2014	71,041.67	2,960.07	74,001.74	-	74,001.74	
12/1/2014 to 11/30/2019	78,145.84	3,256.08	81,401.92	-	81,401.92	
12/1/2019 to 11/30/2024	85,960.42	3,581.68	89,542.10	-	89,542.10	
Annual Lease Payments						
Effective Date to 11/30/200	775,000	32,292	807,292	-	807,292	
12/1/2009 to 11/30/2014	852,500	35,521	888,021	-	888,021	
12/1/2014 to 11/30/2019	937,750	39,073	976,823	-	976,823	
12/1/2019 to 11/30/2024	1,031,525	42,980	1,074,505	-	1,074,505	

HEI sq. ft.	8,874
Total building sq. ft.	58,313
HEI %	15.22%

King Street Lease

Year Calendar Year	IRR	NPV	1 2005	2 2006	3 2007	4 2008	5 2009	6 2010	7 2011	8 2012
New Lease Months in Year			6	12	12	12	12	12	12	12
Month-to-Month Lease with Excise Tax			403,646							
Excise Tax on Month-to-Month			16,146							
Month-to-Month Lease			387,500							
Total Payments			403,646	807,292	807,292	807,292	814,019	888,021	888,021	888,021
Excise Tax Pmt			16,146	32,292	32,292	32,292	32,561	35,521	35,521	35,521
Lease Payment			387,500	775,000	775,000	775,000	781,458	852,500	852,500	852,500
HEI Payments - REVISED			139,719	148,207	148,207	148,207	148,251	148,732	148,732	148,732
Operating Lease Treatment - With Deferred Rent										
Cash Flow										
Lease Payment (excl. GIT)			387,500	775,000	775,000	775,000	781,458	852,500	852,500	852,500
Expense (excl. GIT)			439,712	879,424	879,424	879,424	879,424	879,424	879,424	879,424
Asset (Liability)			(52,212)	(104,424)	(104,424)	(104,424)	(97,966)	(26,924)	(26,924)	(26,924)
Accumulated Asset (Liability)			(52,212)	(156,637)	(261,061)	(365,485)	(463,451)	(490,376)	(517,300)	(544,224)
Current Tax Deduction			387,500	775,000	775,000	775,000	781,458	852,500	852,500	852,500
Book Expense			439,712	879,424	879,424	879,424	879,424	879,424	879,424	879,424
Deferred Tax Base			(52,212)	(104,424)	(104,424)	(104,424)	(97,966)	(26,924)	(26,924)	(26,924)
Deferred Tax			(20,316)	(40,631)	(40,631)	(40,631)	(38,118)	(10,476)	(10,476)	(10,476)
Accumulated Deferred Tax			(20,316)	(60,947)	(101,578)	(142,209)	(180,328)	(190,804)	(201,280)	(211,756)
Ending Rate Base			(31,897)	(95,690)	(159,483)	(223,276)	(283,123)	(299,572)	(316,020)	(332,468)
Average Rate Base			(15,948)	(63,793)	(127,586)	(191,379)	(253,200)	(291,348)	(307,796)	(324,244)
Capitalization Before Rebalancing										
Average ST Debt	3%		(518)	(2,073)	(4,147)	(6,220)	(8,229)	(9,469)	(10,003)	(10,538)
Average Taxable Debt	37%		(5,871)	(23,482)	(46,964)	(70,447)	(93,203)	(107,245)	(113,300)	(119,354)
Average Hybrid	2%		(378)	(1,512)	(3,024)	(4,536)	(6,001)	(6,905)	(7,295)	(7,685)
Average Preferred Stock	2%		(284)	(1,136)	(2,271)	(3,407)	(4,507)	(5,186)	(5,479)	(5,772)
Average Common Stock	56%		(8,898)	(35,590)	(71,180)	(106,770)	(141,260)	(162,543)	(171,719)	(180,896)
Average Capitalization			(15,948)	(63,793)	(127,586)	(191,379)	(253,200)	(291,348)	(307,796)	(324,244)
Imputed Debt (Ending Balance)	10%	DOD-RIR-25	7,000,000	6,522,062	6,399,268	6,264,195	6,109,156	5,867,572	5,601,829	5,309,512
Average Imputed Debt			3,500,000	6,761,031	6,460,665	6,331,732	6,186,676	5,988,364	5,734,701	5,455,671
Average Rebalancing		HECO RT-21	2,500,000	3,771,979	3,604,405	3,532,473	3,451,546	3,340,908	3,199,390	3,043,719
Adjusted Rebalancing			2,500,000	3,772,000	3,604,000	3,532,000	3,452,000	3,341,000	3,199,000	3,044,000
Adjusted Capitalization with Rebalancing										
Average ST Debt			(2,500,518)	(3,774,053)	(3,608,147)	(3,538,220)	(3,459,775)	(3,350,377)	(3,209,393)	(3,054,257)
Average Taxable Debt			(5,871)	(23,482)	(46,964)	(70,447)	(93,203)	(107,245)	(113,300)	(119,354)
Average Hybrid			(378)	(1,512)	(3,024)	(4,536)	(6,001)	(6,905)	(7,295)	(7,685)
Average Preferred Stock			(284)	(1,136)	(2,271)	(3,407)	(4,507)	(5,186)	(5,479)	(5,772)
Average Common Stock			2,491,102	3,736,389	3,532,820	3,425,230	3,310,286	3,178,366	3,027,670	2,862,823
Average Capitalization			(15,948)	(63,793)	(127,586)	(191,379)	(253,200)	(291,348)	(307,796)	(324,244)
Net Taxable Debt (check)			36.8%	36.8%	36.8%	36.8%	36.8%	36.8%	36.8%	36.8%
ST Interest Expense	3.5%		(87,518)	(132,092)	(126,285)	(123,838)	(121,092)	(117,263)	(112,329)	(106,899)
Taxable Debt Interest Expense	6.3%		(367)	(1,468)	(2,935)	(4,403)	(5,825)	(6,703)	(7,081)	(7,460)
Hybrid Dividends	7.6%		(29)	(114)	(228)	(342)	(453)	(521)	(551)	(580)
Preferred Dividends	5.5%		(16)	(63)	(126)	(189)	(250)	(287)	(304)	(320)
Return on Common	11.0%		274,021	411,003	388,610	376,775	364,132	349,620	333,044	314,911
Revenue Requirements based on Straight Line Expense			1,185,731	1,429,449	1,393,661	1,373,156	1,351,905	1,331,546	1,306,608	1,279,599
Revenue Taxes			105,352	127,007	123,827	122,005	120,117	118,308	116,092	113,692
Lease Expense			439,712	879,424	879,424	879,424	879,424	879,424	879,424	879,424

King Street Lease

Year	9	10	11	12	13	14	15	16	17	
Calendar Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
New Lease Months in Year	12	12	12	12	12	12	12	12	11	197
Month-to-Month Lease with Excise Tax										
Excise Tax on Month-to-Month										
Month-to-Month Lease										
Total Payments	888,021	895,421	976,823	976,823	976,823	976,823	984,963	1,074,505	984,963	15,038,767
Excise Tax Pmt	35,521	35,817	39,073	39,073	39,073	39,073	39,399	42,980	39,399	601,551
Lease Payment	852,500	859,604	937,750	937,750	937,750	937,750	945,565	1,031,525	945,565	14,437,217
HEI Payments - REVISED	148,732	148,780	149,309	149,309	149,309	149,309	149,362	149,944	137,449	2,510,289
Operating Lease Treatment - With De										
Cash Flow										
Lease Payment (excl. GIT)	852,500	859,604	937,750	937,750	937,750	937,750	945,565	1,031,525	945,565	14,437,217
Expense (excl. GIT)	879,424	879,424	879,424	879,424	879,424	879,424	879,424	879,424	806,139	14,437,217
Asset (Liability)	(26,924)	(19,820)	58,326	58,326	58,326	58,326	66,140	152,101	139,426	(0)
Accumulated Asset (Liability)	(571,149)	(590,969)	(532,643)	(474,318)	(415,992)	(357,666)	(291,526)	(139,426)	(0)	
Current Tax Deduction	852,500	859,604	937,750	937,750	937,750	937,750	945,565	1,031,525	945,565	
Book Expense	879,424	879,424	879,424	879,424	879,424	879,424	879,424	879,424	806,139	
Deferred Tax Base	(26,924)	(19,820)	58,326	58,326	58,326	58,326	66,140	152,101	139,426	
Deferred Tax	(10,476)	(7,712)	22,694	22,694	22,694	22,694	25,735	59,182	54,250	
Accumulated Deferred Tax	(222,233)	(229,945)	(207,250)	(184,556)	(161,862)	(139,167)	(113,432)	(54,250)	(0)	
Ending Rate Base	(348,916)	(361,024)	(325,393)	(289,762)	(254,130)	(218,499)	(178,094)	(85,175)	(0)	
Average Rate Base	(340,692)	(354,970)	(343,209)	(307,577)	(271,946)	(236,315)	(198,297)	(131,635)	(42,588)	
Capitalization Before Rebalancing										
Average ST Debt	(11,072)	(11,537)	(11,154)	(9,996)	(8,838)	(7,680)	(6,445)	(4,278)	(1,384)	
Average Taxable Debt	(125,409)	(130,665)	(126,335)	(113,219)	(100,103)	(86,988)	(72,993)	(48,455)	(15,677)	
Average Hybrid	(8,074)	(8,413)	(8,134)	(7,290)	(6,445)	(5,601)	(4,700)	(3,120)	(1,009)	
Average Preferred Stock	(6,064)	(6,318)	(6,109)	(5,475)	(4,841)	(4,206)	(3,530)	(2,343)	(758)	
Average Common Stock	(190,072)	(198,038)	(191,476)	(171,597)	(151,719)	(131,840)	(110,630)	(73,439)	(23,760)	
Average Capitalization	(340,692)	(354,970)	(343,209)	(307,577)	(271,946)	(236,315)	(198,297)	(131,635)	(42,588)	
Imputed Debt (Ending Balance)	4,987,963	4,627,156	4,152,121	3,629,583	3,054,792	2,422,521	1,719,208	859,604	859,604	
Average Imputed Debt	5,148,738	4,807,560	4,389,638	3,890,852	3,342,188	2,738,656	2,070,865	1,289,406	859,604	
Average Rebalancing	2,872,481	2,682,137	2,448,979	2,170,706	1,864,606	1,527,896	1,155,335	719,360	479,573	
Adjusted Rebalancing	2,872,000	2,682,000	2,449,000	2,171,000	1,865,000	1,528,000	1,155,000	719,000	480,000	
Adjusted Capitalization with Rebalancir										
Average ST Debt	(2,883,553)	(2,693,674)	(2,460,134)	(2,180,703)	(1,873,445)	(1,535,577)	(1,161,780)	(723,638)	(480,957)	
Average Taxable Debt	(125,409)	(130,665)	(126,335)	(113,219)	(100,103)	(86,988)	(72,993)	(48,455)	(15,677)	
Average Hybrid	(8,074)	(8,413)	(8,134)	(7,290)	(6,445)	(5,601)	(4,700)	(3,120)	(1,009)	
Average Preferred Stock	(6,064)	(6,318)	(6,109)	(5,475)	(4,841)	(4,206)	(3,530)	(2,343)	(758)	

King Street Lease

Year			1	2	3	4	5	6	7	8
Calendar Year	IRR	NPV	2005	2006	2007	2008	2009	2010	2011	2012
New Lease Months in Year			6	12	12	12	12	12	12	12
Month-to-Month Lease with Excise Tax			403,646							
Excise Tax on Month-to-Month			16,146							
Month-to-Month Lease			387,500							
Total Payments			403,646	807,292	807,292	807,292	814,019	888,021	888,021	888,021
Excise Tax Pmt			16,146	32,292	32,292	32,292	32,561	35,521	35,521	35,521
Lease Payment			387,500	775,000	775,000	775,000	781,458	852,500	852,500	852,500
HEI Payments - REVISED			139,719	148,207	148,207	148,207	148,251	148,732	148,732	148,732
Operating Lease Treatment with Ratemaking based on Payments										
Cash Flow										
Lease Payment (excl. GIT)			387,500	775,000	775,000	775,000	781,458	852,500	852,500	852,500
Expense (excl. GIT)			439,712	879,424	879,424	879,424	879,424	879,424	879,424	879,424
Regulatory Asset (Liability)			52,212	104,424	104,424	104,424	97,966	26,924	26,924	26,924
Accumulated Asset (Liability)			52,212	156,637	261,061	365,485	463,451	490,376	517,300	544,224
Current Tax Deduction			387,500	775,000	775,000	775,000	781,458	852,500	852,500	852,500
Book Expense			439,712	879,424	879,424	879,424	879,424	879,424	879,424	879,424
Deferred Tax Base			(52,212)	(104,424)	(104,424)	(104,424)	(97,966)	(26,924)	(26,924)	(26,924)
Deferred Tax Asset			(20,316)	(40,631)	(40,631)	(40,631)	(38,118)	(10,476)	(10,476)	(10,476)
Accumulated Deferred Tax Asset			(20,316)	(60,947)	(101,578)	(142,209)	(180,328)	(190,804)	(201,280)	(211,756)
Ending Rate Base			72,528	217,583	362,639	507,695	643,779	681,180	718,580	755,981
Average Rate Base			36,264	145,056	290,111	435,167	575,737	662,479	699,880	737,281
Capitalization Before Rebalancing										
Average ST Debt	3%		1,179	4,714	9,429	14,143	18,711	21,531	22,746	23,962
Average Taxable Debt	37%		13,349	53,395	106,790	160,185	211,929	243,859	257,626	271,393
Average Hybrid	2%		859	3,438	6,876	10,313	13,645	15,701	16,587	17,474
Average Preferred Stock	2%		645	2,582	5,164	7,746	10,248	11,792	12,458	13,124
Average Common Stock	56%		20,232	80,927	161,853	242,780	321,204	369,597	390,463	411,329
Average Capitalization			36,264	145,056	290,111	435,167	575,737	662,479	699,880	737,281
Imputed Debt (Ending Balance)	10%	DOD-RIR-25	7,000,000	6,522,062	6,399,268	6,264,195	6,109,156	5,867,572	5,601,829	5,309,512
Average Imputed Debt			3,500,000	6,761,031	6,460,665	6,331,732	6,186,676	5,988,364	5,734,701	5,455,671
Average Rebalancing		HECO RT-21	2,500,000	3,771,979	3,604,405	3,532,473	3,451,546	3,340,908	3,199,390	3,043,719
Adjusted Rebalancing			2,500,000	3,772,000	3,604,000	3,532,000	3,452,000	3,341,000	3,199,000	3,044,000
Adjusted Capitalization with Rebalancing										
Average ST Debt			(2,498,821)	(3,767,265)	(3,594,571)	(3,517,857)	(3,433,289)	(3,319,469)	(3,176,254)	(3,020,038)
Average Taxable Debt			13,349	53,395	106,790	160,185	211,929	243,859	257,626	271,393
Average Hybrid			859	3,438	6,876	10,313	13,645	15,701	16,587	17,474
Average Preferred Stock			645	2,582	5,164	7,746	10,248	11,792	12,458	13,124
Average Common Stock			2,520,232	3,852,906	3,765,853	3,774,780	3,773,204	3,710,597	3,589,463	3,455,329
Average Capitalization			36,264	145,056	290,111	435,167	575,737	662,479	699,880	737,281
Net Taxable Debt (check)			36.8%	36.8%	36.8%	36.8%	36.8%	36.8%	36.8%	36.8%
ST Interest Expense	3.5%		(87,459)	(131,854)	(125,810)	(123,125)	(120,165)	(116,181)	(111,169)	(105,701)
Taxable Debt Interest Expense	6.3%		834	3,337	6,674	10,012	13,246	15,241	16,102	16,962
Hybrid Dividends	7.6%		65	260	519	779	1,030	1,185	1,252	1,319
Preferred Dividends	5.5%		36	143	286	429	568	653	690	727
Return on Common	11.0%		277,225	423,820	414,244	415,226	415,052	408,166	394,841	380,086
Revenue Requirements based on Payments			1,135,828	1,344,444	1,338,257	1,347,353	1,361,876	1,437,189	1,419,882	1,400,506
Revenue Taxes			100,918	119,454	118,904	119,712	121,003	127,694	126,157	124,435
Lease Expense			387,500	775,000	775,000	775,000	781,458	852,500	852,500	852,500
Excise Tax Expense			32,292	32,292	32,292	32,292	32,561	35,521	35,521	35,521
Month-to-Month Expense			387,500	-	-	-	-	-	-	-
HEI Rent Payments			(139,719)	(148,207)	(148,207)	(148,207)	(148,251)	(148,732)	(148,732)	(148,732)
Lease Interest Expense			-	-	-	-	-	-	-	-
ST & LT Interest Expense			(86,624)	(128,517)	(119,136)	(113,113)	(106,920)	(100,940)	(95,067)	(88,739)

King Street Lease

Year	9	10	11	12	13	14	15	16	17	
Calendar Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
New Lease Months in Year	12	12	12	12	12	12	12	12	11	197
Month-to-Month Lease with Excise Ta										
Excise Tax on Month-to-Month										
Month-to-Month Lease										
Total Payments	888,021	895,421	976,823	976,823	976,823	976,823	984,963	1,074,505	984,963	15,038,767
Excise Tax Pmt	35,521	35,817	39,073	39,073	39,073	39,073	39,399	42,980	39,399	601,551
Lease Payment	852,500	859,604	937,750	937,750	937,750	937,750	945,565	1,031,525	945,565	14,437,217
HEI Payments - REVISED	148,732	148,780	149,309	149,309	149,309	149,309	149,362	149,944	137,449	2,510,289
Operating Lease Treatment with Ra										
Cash Flow										
Lease Payment (excl. GIT)	852,500	859,604	937,750	937,750	937,750	937,750	945,565	1,031,525	945,565	14,437,217
Expense (excl. GIT)	879,424	879,424	879,424	879,424	879,424	879,424	879,424	879,424	806,139	14,437,217
Regulatory Asset (Liability)	26,924	19,820	(58,326)	(58,326)	(58,326)	(58,326)	(66,140)	(152,101)	(139,426)	0
Accumulated Asset (Liability)	571,149	590,969	532,643	474,318	415,992	357,666	291,526	139,426	0	
Current Tax Deduction	852,500	859,604	937,750	937,750	937,750	937,750	945,565	1,031,525	945,565	
Book Expense	879,424	879,424	879,424	879,424	879,424	879,424	879,424	879,424	806,139	
Deferred Tax Base	(26,924)	(19,820)	58,326	58,326	58,326	58,326	66,140	152,101	139,426	
Deferred Tax Asset	(10,476)	(7,712)	22,694	22,694	22,694	22,694	25,735	59,182	54,250	
Accumulated Deferred Tax Asset	(222,233)	(229,945)	(207,250)	(184,556)	(161,862)	(139,167)	(113,432)	(54,250)	(0)	
Ending Rate Base	793,381	820,914	739,894	658,874	577,854	496,834	404,958	193,676	0	
Average Rate Base	774,681	807,148	780,404	699,384	618,364	537,344	450,896	299,317	96,838	
Capitalization Before Rebalancing										
Average ST Debt	25,177	26,232	25,363	22,730	20,097	17,464	14,654	9,728	3,147	
Average Taxable Debt	285,160	297,111	287,267	257,443	227,620	197,796	165,975	110,179	35,646	
Average Hybrid	18,360	19,129	18,496	16,575	14,655	12,735	10,686	7,094	2,295	
Average Preferred Stock	13,789	14,367	13,891	12,449	11,007	9,565	8,026	5,328	1,724	
Average Common Stock	432,195	450,308	435,387	390,186	344,985	299,784	251,555	166,989	54,026	
Average Capitalization	774,681	807,148	780,404	699,384	618,364	537,344	450,896	299,317	96,838	
Imputed Debt (Ending Balance)	4,987,963	4,627,156	4,152,121	3,629,583	3,054,792	2,422,521	1,719,208	859,604	859,604	
Average Imputed Debt	5,148,738	4,807,560	4,389,638	3,890,852	3,342,188	2,738,656	2,070,865	1,289,406	859,604	
Average Rebalancing	2,872,481	2,682,137	2,448,979	2,170,706	1,864,606	1,527,896	1,155,335	719,360	479,573	
Adjusted Rebalancing	2,872,000	2,682,000	2,449,000	2,171,000	1,865,000	1,528,000	1,155,000	719,000	480,000	
Adjusted Capitalization with Rebalanc										
Average ST Debt	(2,646,823)	(2,655,768)	(2,423,637)	(2,148,270)	(1,844,903)	(1,510,536)	(1,140,346)	(709,272)	(476,853)	
Average Taxable Debt	285,160	297,111	287,267	257,443	227,620	197,796	165,975	110,179	35,646	
Average Hybrid	18,360	19,129	18,496	16,575	14,655	12,735	10,686	7,094	2,295	
Average Preferred Stock	13,789	14,367	13,891	12,449	11,007	9,565	8,026	5,328	1,724	
Average Common Stock	3,304,195	3,132,308	2,884,387	2,561,186	2,209,985	1,827,784	1,406,555	885,989	534,026	
Average Capitalization	774,681	807,148	780,404	699,384	618,364	537,344	450,896	299,317	96,838	
Net Taxable Debt (check)	36.8%	36.8%	36.8%	36.8%	36.8%	36.8%	36.8%	36.8%	36.8%	
ST Interest Expense	(99,639)	(92,952)	(84,827)	(75,189)	(64,572)	(52,869)	(39,912)	(24,825)	(16,690)	(1,472,939)
Taxable Debt Interest Expense	17,823	18,569	17,954	16,090	14,226	12,362	10,373	6,886	2,228	198,920
Hybrid Dividends	1,386	1,444	1,396	1,251	1,106	961	807	536	173	
Preferred Dividends	764	796	770	690	610	530	445	295	95	8,526
Return on Common	363,461	344,554	317,283	281,730	243,098	201,056	154,721	97,459	58,743	5,190,766
Revenue Requirements based on P	1,378,424	1,360,845	1,408,718	1,352,975	1,292,774	1,227,638	1,164,877	1,171,613	1,020,304	22,163,501
Revenue Taxes	122,473	120,911	125,165	120,212	114,863	109,076	103,499	104,098	90,654	1,969,227
Lease Expense	852,500	859,604	937,750	937,750	937,750	937,750	945,565	1,031,525	945,565	14,437,217
Excise Tax Expense	35,521	35,817	39,073	39,073	39,073	39,073	39,399	42,980	39,399	617,697
Month-to-Month Expense	-	-	-	-	-	-	-	-	-	387,500
HEI Rent Payments	(148,732)	(148,780)	(149,309)	(149,309)	(149,309)	(149,309)	(149,362)	(149,944)	(137,449)	(2,510,289)
Lease Interest Expense	-	-	-	-	-	-	-	-	-	-
ST & LT Interest Expense	(81,816)	(74,382)	(66,873)	(59,099)	(50,345)	(40,507)	(29,539)	(17,938)	(14,462)	(1,274,019)
Income Before Taxes	598,478	567,675	522,913	464,349	400,743	331,555	255,315	160,892	96,597	8,536,169
Income Taxes	232,866	220,881	203,464	180,677	155,928	129,007	99,342	62,603	37,586	3,321,404
Preferred & Hybrid Dividends	2,150	2,240	2,166	1,941	1,716	1,491	1,251	831	269	23,998
Net Income	363,461	344,554	317,283	281,730	243,098	201,056	154,721	97,459	58,743	5,190,767
ROE Check	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	11.0%	

King Street Lease

Year				1	2	3	4	5	6	7	8
Calendar Year	IRR		NPV	2005	2006	2007	2008	2009	2010	2011	2012
New Lease Months in Year				6	12	12	12	12	12	12	12
Month-to-Month Lease with Excise Tax				403,646							
Excise Tax on Month-to-Month				16,146							
Month-to-Month Lease				387,500							
Total Payments				403,646	807,292	807,292	807,292	814,019	888,021	888,021	888,021
Excise Tax Pmt				16,146	32,292	32,292	32,292	32,561	35,521	35,521	35,521
Lease Payment				387,500	775,000	775,000	775,000	781,458	852,500	852,500	852,500
HEI Payments - REVISED				139,719	148,207	148,207	148,207	148,251	148,732	148,732	148,732
Operating Lease Treatment with Ratemaking based on Payments											
Cash Flow											
Lease Payment (excl. GIT)				387,500	775,000	775,000	775,000	781,458	852,500	852,500	852,500
Expense (excl. GIT)				439,712	879,424	879,424	879,424	879,424	879,424	879,424	879,424
Regulatory Asset (Liability)				-	-	-	-	-	-	-	-
Accumulated Asset (Liability)				-	-	-	-	-	-	-	-
Current Tax Deduction				387,500	775,000	775,000	775,000	781,458	852,500	852,500	852,500
Book Expense				439,712	879,424	879,424	879,424	879,424	879,424	879,424	879,424
Deferred Tax Base				(52,212)	(104,424)	(104,424)	(104,424)	(97,966)	(26,924)	(26,924)	(26,924)
Deferred Tax Asset				(20,316)	(40,631)	(40,631)	(40,631)	(38,118)	(10,476)	(10,476)	(10,476)
Accumulated Deferred Tax Asset				(20,316)	(60,947)	(101,578)	(142,209)	(180,328)	(190,804)	(201,280)	(211,756)
Ending Rate Base				20,316	60,947	101,578	142,209	180,328	190,804	201,280	211,756
Average Rate Base				10,158	40,631	81,263	121,894	161,269	185,566	196,042	206,518
Capitalization Before Rebalancing											
Average ST Debt	3%			330	1,321	2,641	3,962	5,241	6,031	6,371	6,712
Average Taxable Debt	37%			3,739	14,956	29,913	44,869	59,363	68,307	72,163	76,019
Average Hybrid	2%			241	963	1,926	2,889	3,822	4,398	4,646	4,894
Average Preferred Stock	2%			181	723	1,446	2,170	2,871	3,303	3,490	3,676
Average Common Stock	56%			5,667	22,668	45,336	68,005	89,972	103,527	109,372	115,217
Average Capitalization				10,158	40,631	81,263	121,894	161,269	185,566	196,042	206,518
Imputed Debt (Ending Balance)	10%	DOD-RIR-25		7,000,000	6,522,062	6,399,268	6,264,195	6,109,156	5,867,572	5,601,829	5,309,512
Average Imputed Debt				3,500,000	6,761,031	6,460,665	6,331,732	6,186,676	5,988,364	5,734,701	5,455,671
Average Rebalancing		HECO RT-21		2,500,000	3,771,979	3,604,405	3,532,473	3,451,546	3,340,908	3,199,390	3,043,719
Adjusted Rebalancing				2,500,000	3,772,000	3,604,000	3,532,000	3,452,000	3,341,000	3,199,000	3,044,000
Adjusted Capitalization with Rebalancing											
Average ST Debt				(2,499,670)	(3,770,659)	(3,601,359)	(3,528,038)	(3,446,759)	(3,334,969)	(3,192,629)	(3,037,288)
Average Taxable Debt				3,739	14,956	29,913	44,869	59,363	68,307	72,163	76,019
Average Hybrid				241	963	1,926	2,889	3,822	4,398	4,646	4,894
Average Preferred Stock				181	723	1,446	2,170	2,871	3,303	3,490	3,676
Average Common Stock				2,505,667	3,794,647	3,649,336	3,600,005	3,541,972	3,444,527	3,308,372	3,159,217
Average Capitalization				10,158	40,631	81,263	121,894	161,269	185,566	196,042	206,518
Net Taxable Debt (check)				36.8%	36.8%	36.8%	36.8%	36.8%	36.8%	36.8%	36.8%
ST Interest Expense	3.5%			(87,488)	(131,973)	(126,048)	(123,481)	(120,637)	(116,724)	(111,742)	(106,305)
Taxable Debt Interest Expense	6.3%			234	935	1,870	2,804	3,710	4,269	4,510	4,751
Hybrid Dividends	7.6%			18	73	145	218	289	332	351	370
Preferred Dividends	5.5%			10	40	80	120	159	183	193	204
Return on Common	11.0%			275,623	417,411	401,427	396,001	389,617	378,898	363,921	347,514
Revenue Requirements based on											
LOWER of Payments or Expense				1,132,128	1,329,643	1,308,655	1,302,951	1,303,131	1,369,593	1,348,470	1,325,278
Revenue Taxes				100,590	118,139	116,274	115,767	115,783	121,688	119,812	117,751
Lease Expense				439,712	879,424	879,424	879,424	879,424	879,424	879,424	879,424
Excise Tax Expense				32,292	32,292	32,292	32,292	32,561	35,521	35,521	35,521
Month-to-Month Expense				387,500	-	-	-	-	-	-	-
HEI Rent Payments				(139,719)	(148,207)	(148,207)	(148,207)	(148,251)	(148,732)	(148,732)	(148,732)
Lease Interest Expense				-	-	-	-	-	-	-	-
ST & LT Interest Expense				(87,255)	(131,038)	(124,178)	(120,677)	(116,926)	(112,455)	(107,232)	(101,554)
Income Before Taxes				399,008	579,033	553,050	544,352	540,540	594,146	569,677	542,867
Income Taxes				155,253	225,301	215,190	211,806	210,323	231,181	221,660	211,228
Preferred & Hybrid Dividends				28	113	226	338	448	515	544	573
Net Income				243,727	353,620	337,634	332,207	329,769	362,450	347,473	331,066
ROE Check				9.7%	9.3%	9.3%	9.2%	9.3%	10.5%	10.5%	10.5%

King Street Lease

Year	9	10	11	12	13	14	15	16	17	
Calendar Year	2013	2014	2015	2016	2017	2018	2019	2020	2021	Total
New Lease Months in Year	12	12	12	12	12	12	12	12	11	197
Month-to-Month Lease with Excise Ta										
Excise Tax on Month-to-Month										
Month-to-Month Lease										
Total Payments	888,021	895,421	976,823	976,823	976,823	976,823	984,963	1,074,505	984,963	15,038,767
Excise Tax Pmt	35,521	35,817	39,073	39,073	39,073	39,073	39,399	42,980	39,399	601,551
Lease Payment	852,500	859,604	937,750	937,750	937,750	937,750	945,565	1,031,525	945,565	14,437,217
HEI Payments - REVISED	148,732	148,780	149,309	149,309	149,309	149,309	149,362	149,944	137,449	2,510,289
Operating Lease Treatment with Ra										
Cash Flow										
Lease Payment (excl. GIT)	852,500	859,604	937,750	937,750	937,750	937,750	945,565	1,031,525	945,565	14,437,217
Expense (excl. GIT)	879,424	879,424	879,424	879,424	879,424	879,424	879,424	879,424	806,139	14,437,217
Regulatory Asset (Liability)	-	-	-	-	-	-	-	-	-	-
Accumulated Asset (Liability)	-	-	-	-	-	-	-	-	-	
Current Tax Deduction	852,500	859,604	937,750	937,750	937,750	937,750	945,565	1,031,525	945,565	
Book Expense	879,424	879,424	879,424	879,424	879,424	879,424	879,424	879,424	806,139	
Deferred Tax Base	(26,924)	(19,820)	58,326	58,326	58,326	58,326	66,140	152,101	139,426	
Deferred Tax Asset	(10,476)	(7,712)	22,694	22,694	22,694	22,694	25,735	59,182	54,250	
Accumulated Deferred Tax Asset	(222,233)	(229,945)	(207,250)	(184,556)	(161,862)	(139,167)	(113,432)	(54,250)	(0)	
Ending Rate Base	222,233	229,945	207,250	184,556	161,862	139,167	113,432	54,250	0	
Average Rate Base	216,995	226,089	218,598	195,903	173,209	150,514	126,300	83,841	27,125	
Capitalization Before Rebalancing										
Average ST Debt	7,052	7,348	7,104	6,367	5,629	4,892	4,105	2,725	882	
Average Taxable Debt	79,876	83,223	80,466	72,112	63,758	55,404	46,491	30,862	9,985	
Average Hybrid	5,143	5,358	5,181	4,643	4,105	3,567	2,993	1,987	643	
Average Preferred Stock	3,863	4,024	3,891	3,487	3,083	2,679	2,248	1,492	483	
Average Common Stock	121,061	126,135	121,956	109,294	96,633	83,972	70,463	46,775	15,133	
Average Capitalization	216,995	226,089	218,598	195,903	173,209	150,514	126,300	83,841	27,125	
Imputed Debt (Ending Balance)	4,987,963	4,627,156	4,152,121	3,629,583	3,054,792	2,422,521	1,719,208	859,604	859,604	
Average Imputed Debt	5,148,738	4,807,560	4,389,638	3,890,852	3,342,188	2,738,656	2,070,865	1,289,406	859,604	
Average Rebalancing	2,872,481	2,682,137	2,448,979	2,170,706	1,864,606	1,527,896	1,155,335	719,360	479,573	
Adjusted Rebalancing	[redacted]									

Return on Common Equity Difference between Scenario A and C

	A	C
Def Rent Liability	(52,212)	
Def Tax Asset	20,316	20,316
Ending Rate Base	(31,896)	20,316
Average Rate Base	(15,948)	10,158
Capitilization @ 55.79%	(8,897)	5,667
Rebalancing	2,500,000	2,500,000
Equity	2,491,103	2,505,667
Net Income	274,021	243,727
ROE	11.0%	9.7%

DOD-RIR-23

Refer to HECO RT-16, page 24, lines 18-21.

Please provide HECO's suggested language for the "sufficient assurances."

HECO Response:

Under Statement of Financial Accounting Standards (SFAS) No. 71, in order for HECO to establish a regulatory asset, the Commission's decision would need to indicate (a) it is probable that future revenue in an amount at least equal to the capitalized cost will result from inclusion of that cost in allowable costs for rate-making purposes; and (b) based on available evidence, the future revenue will be provided to permit recovery of the previously incurred cost rather than to provide for expected levels of similar future costs. In the case of the King Street building lease, the Commission's order will need to clearly indicate that rates in the future will include the higher incremental lease payments over the term of the lease in order for HECO to establish a regulatory asset for the difference between the cash payments and the straight-line lease payments over the term of the lease.

DOD-RIR-24

Refer to HECO RT-16, page 25, lines 1-3.

a. Please quantify the impact on HECO's being able to earn the rate of return that would result from differing ratemaking and financial reporting amounts being used for the King Street lease. Include supporting workpapers.

b. Based on HECO's rebuttal filing figures, what is the impact of a $43,000 pre-tax expense difference on HECO's earned return on equity? Show calculations.

HECO Response:

a. Please see response to DOD-RIR-22 (d) for quantification of impact.

b. The impact of a $43,000 pre-tax expense difference on HECO's total earned return of equity is not significant.

DOD-RIR-25

Refer to HECO RT-16, page 26, lines 14-21 and HECO RT-21.

Please clarify (1) whether HECO imputed King Street lease debt into its capital structure in its rebuttal filing, and (2) quantify exactly the impact of such imputation. Include supporting calculations.

HECO Response:

The Company estimates that there will be approximately $7 million in imputed debt relating to the King Street office building lease. Please see page 2 for the calculation of this amount. Rating agencies consider operating lease obligations to be a debt equivalent in its calculations of financial ratios which are used to evaluate the Company's financial performance. Based on this evaluation, credit ratings and credit outlooks are assigned to the Company. As such, this imputed debt indirectly impacts the capital structure as discussed by Mr. von Gnechten in HECO RT-21, page 4 and 5 as it increases the Company's debt to total capital ratio as seen by the rating agencies. In order to compensate for this, the Company estimates that it will increase its common equity by $2.5 million and correspondingly decrease its short term borrowings by $2.5 million.

In HECO-R-2106 the Company presented the financial ratios used by the rating agencies under a "no rate increase" scenario and a "with rate increase" scenario with the inclusion of imputed debt from purchased power obligations. The imputed debt as a result of the King Street building lease was inadvertently excluded from those calculations. Revised ratios and the supporting workpapers are included in this response in pages 3 through 14 to properly include the impact of this imputed debt.

Hawaiian Electric Company
King Street Building Annual Lease Payments

Computation of Imputed Debt

		Annual Payment A B+C	Excise Tax Payment B C*.04167	Minimum Lease Payment C Per Lease Proposal (a)
1	2005	403,647	16,147	387,500
2	2006	807,294	32,294	775,000
3	2007	807,294	32,294	775,000
4	2008	807,294	32,294	775,000
5	2009	814,022	32,563	781,458
6	2010	888,024	35,524	852,500
7	2011	888,024	35,524	852,500
8	2012	888,024	35,524	852,500
9	2013	888,024	35,524	852,500
10	2014	895,424	35,820	859,604
11	2015	976,826	39,076	937,750
12	2016	976,826	39,076	937,750
13	2017	976,826	39,076	937,750
14	2018	976,826	39,076	937,750
15	2019	984,966	39,402	945,565
16	2020	1,074,509	42,984	1,031,525
17	2021	984,966	39,402	945,565
TOTALS		**15,038,817**	**601,599**	**14,437,218**

Imputed Debt Calculation @ 10%

Net Present Value of Minimum Lease Payments over Term of Lease	$7,021,193
Approximately	**$7,000,000**
TY Average	**$3,500,000**
Interest @ 10%	**$700,000**

(a) Terms per agreement effective July 1, 2005

Monthly Lease Payments	Lease Payment
7/1/2005 to 11/30/2009	64,583

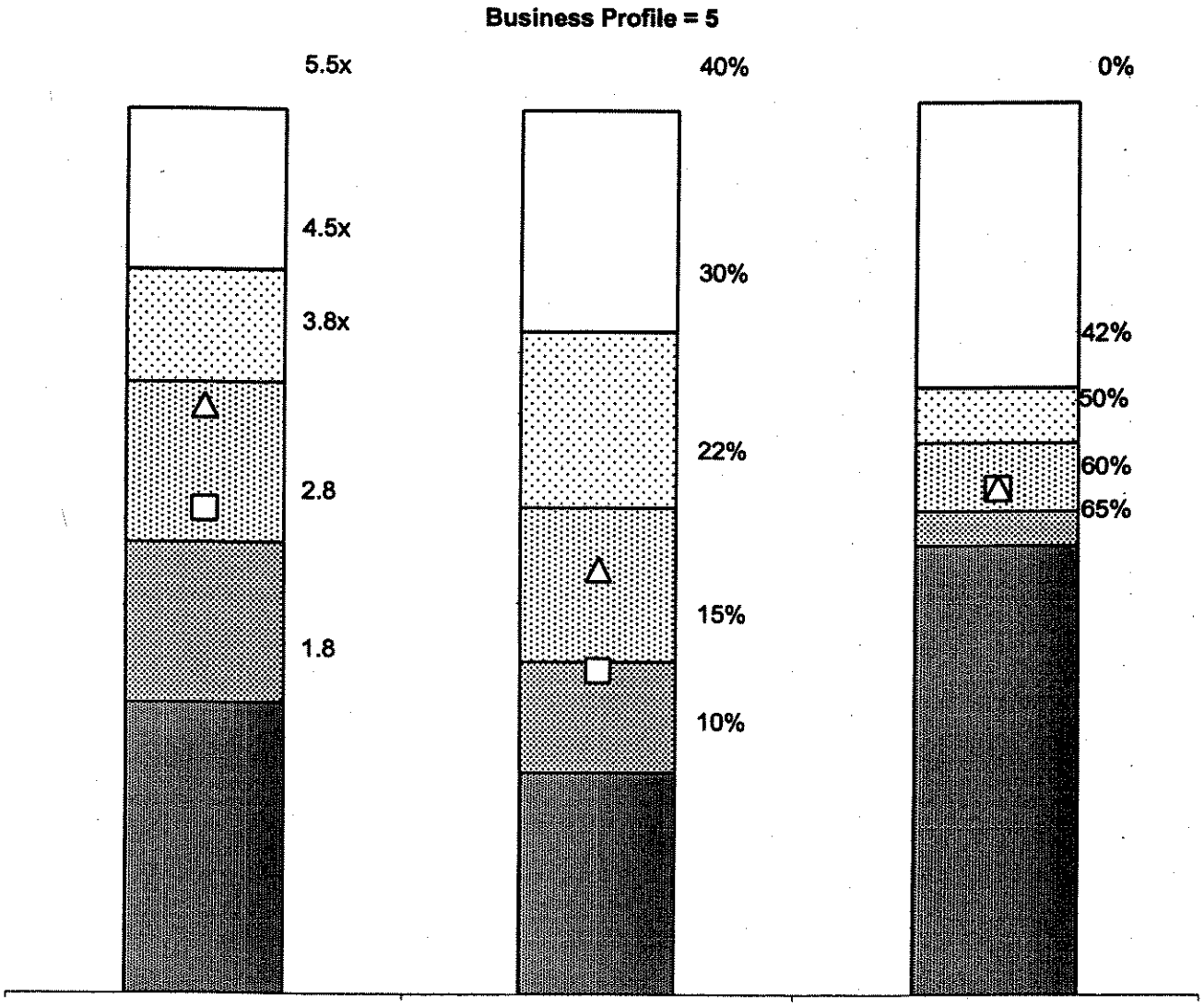
Hawaiian Electric Company, Inc.
Financial Ratios

Test Year 2005	NO Rate Increase	WITH Rate Increase
Funds from Operations Interest Coverage *	3.010 x	3.654 x
Funds from Operations / Average Total Debt *	14.6%	19.2%
Total Debt / Total Capital *	53.1%	53.1%
Total Debt / Total Capital without Debt Equivalent	43.3%	43.3%

2004 Actual	
Total Debt / Total Capital *	55%
Total Debt / Total Capital without Debt Equivalent	44%

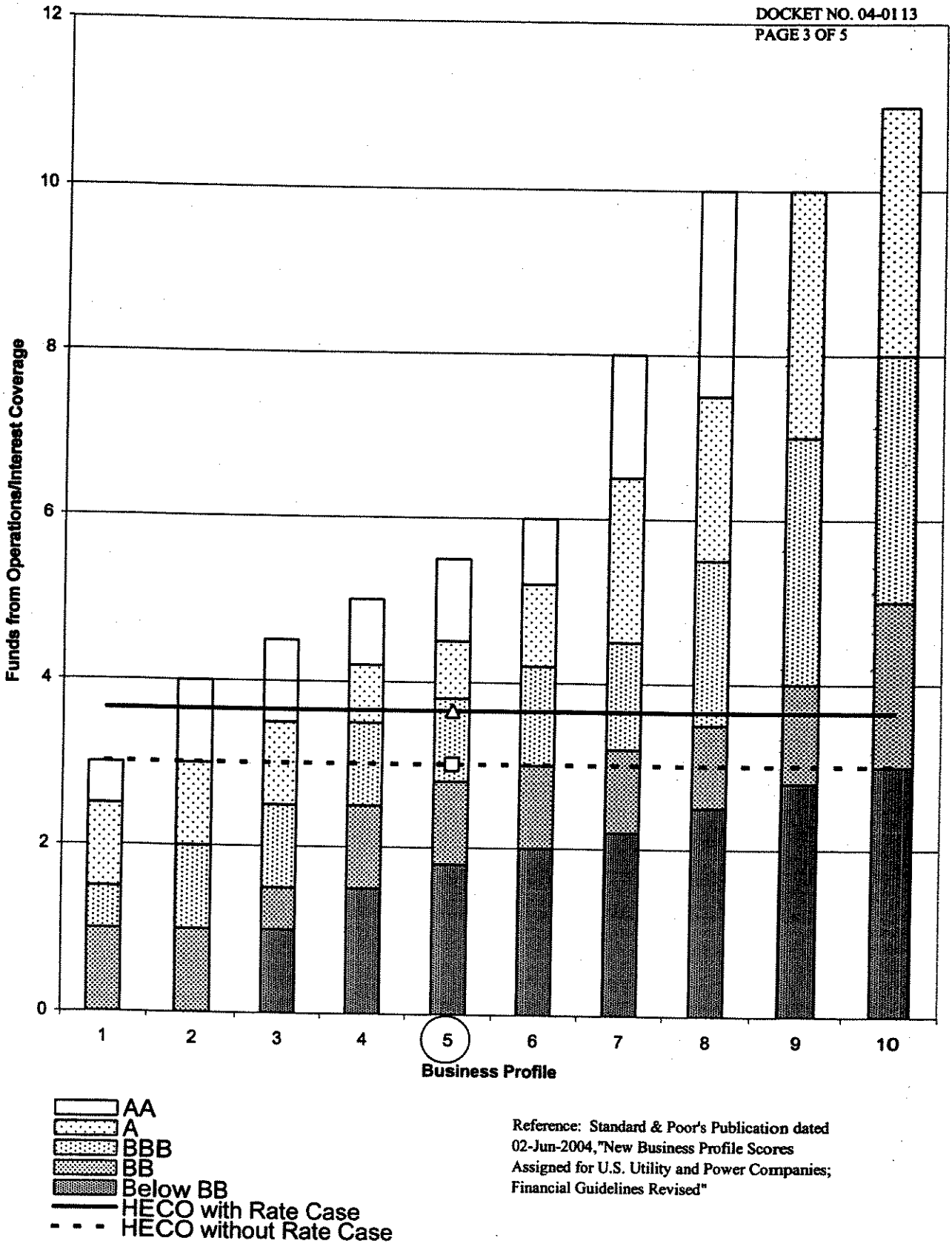
* These ratios take into account the debt equivalent (off-balance sheet purchased power and operating lease obligations).

Financial Ratios in Comparison to S&P Rating Guidelines



HECO w/ Rate Case	3.654 x	19.2%	53.1%
HECO w/out Rate Case	3.010 x	14.6%	53.1%

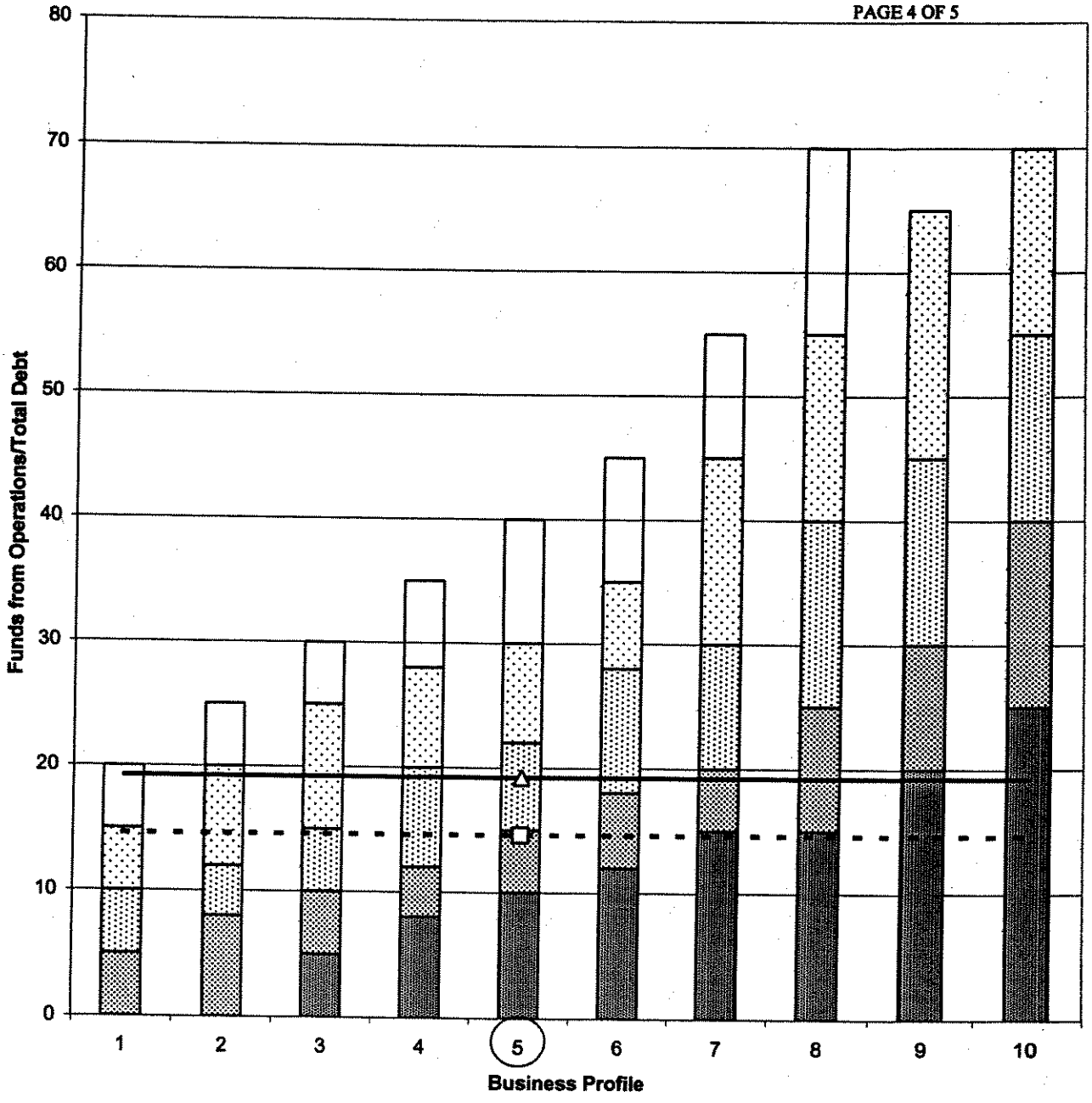
Funds from Operations/Interest Coverage



Reference: Standard & Poor's Publication dated 02-Jun-2004,"New Business Profile Scores Assigned for U.S. Utility and Power Companies; Financial Guidelines Revised"

Funds from Operations/Total Debt

HECO-R-2106
DOCKET NO. 04-0113
PAGE 4 OF 5



Reference: Standard & Poor's Publication dated 02-Jun-2004,"New Business Profile Scores Assigned for U.S. Utility and Power Companies; Financial Guidelines Revised"

Total Debt/Total Capital

HECO-R-2106
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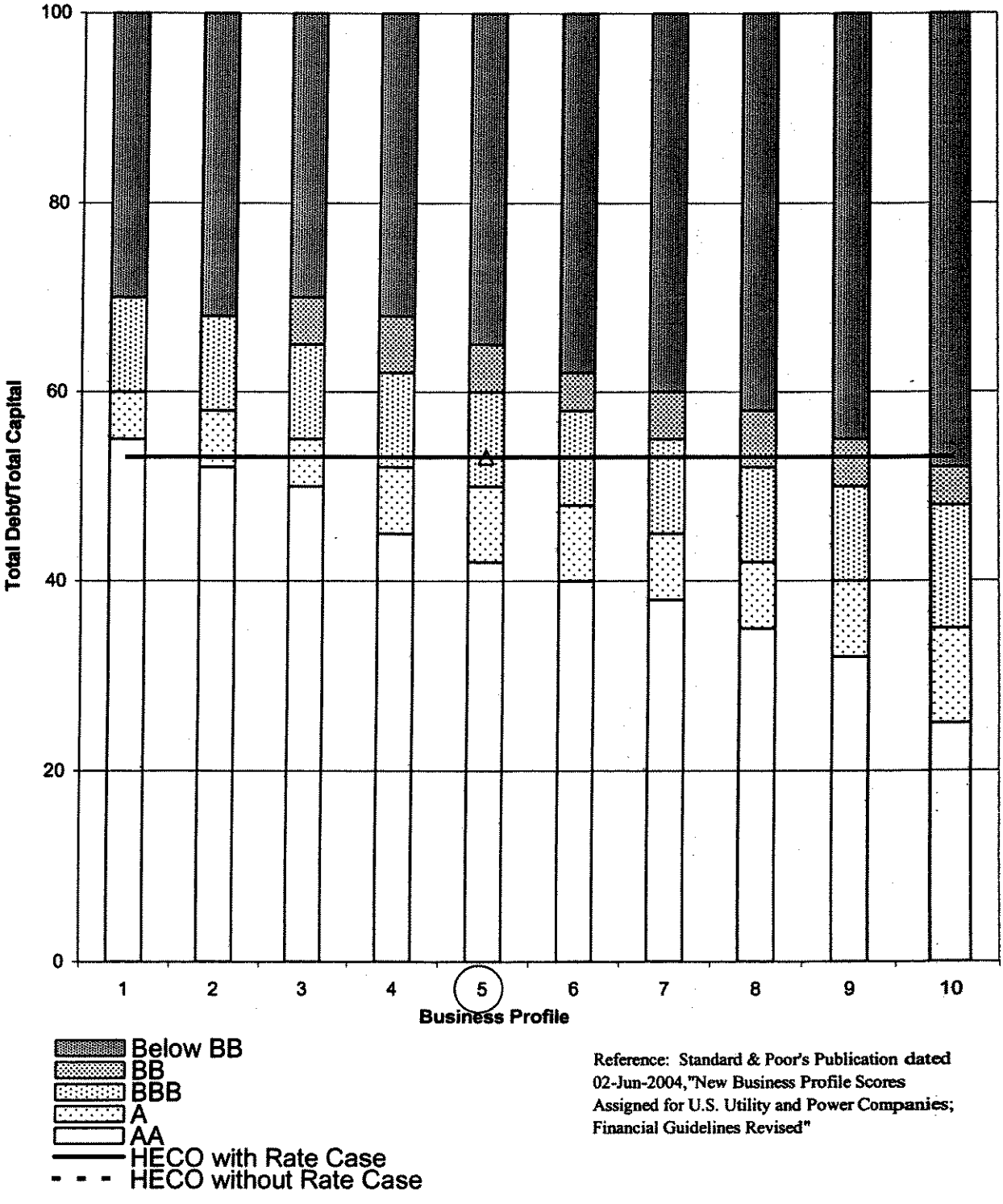

Reference: Standard & Poor's Publication dated 02-Jun-2004,"New Business Profile Scores Assigned for U.S. Utility and Power Companies; Financial Guidelines Revised"

Hawaiian Electric Company, Inc.
Test Year 2005

Funds from Operations Interest Coverage
NO Rate Increase & WITH Debt Equivalent

	$ in thousands		HECO Reference
Revised Operating Income	62,895		RWP-2106, p. 1
Depreciation	70,731		R-2301
Deferred Income Taxes	4,572		R-1704
State Capital Goods Excise Credit ($16,309 - $15,166)	1,143		R-1703
Interest on Debt Equivalent	23,944		WP-2116, p. 11
Interest on Debt Equivalent (Oper Lease)	700		DOD-RIR-25, p. 2
Total	163,985	A	
Total Debt Requirement (ST, LT & Hybrids)	29,835		RWP-2106, p. 1
Interest on Debt Equivalent	23,944		WP-2116 p. 11
Interest on Debt Equivalent (Oper Lease)	700		DOD-RIR-25, p. 2
	54,479	B	
Fund from Operations Interest Coverage (A)/(B)	3.010	x	

Hawaiian Electric Company, Inc.
Test Year 2005

Funds from Operations / Average Total Debt
NO Rate Increase & WITH Debt Equivalent

	$ in thousands		HECO Reference
Revised Operating Income	62,895		RWP-2106, p. 1
Depreciation	70,731		R-2301
Deferred Income Taxes	4,572		R-1704
State Capital Goods Excise Credit	1,143		R-1703
Interest Expense:			
Short-term interest ($37,429 x 3.5%)	(1,310)		R-2102
Long-term interest	(24,953)		R-2103
Hybrid interest	(2,051)		2104
Total Interest Expense	(28,314)		
Total	111,027	A	
Average Debt:			
Short-term Debt	37,429		R-2102
Long-term Debt [1]	445,225		R-2103
Hybrid [1]	30,000		2104
Debt Equivalent (Oper Lease)	3,500		DOD-RIR-25, p. 2
Debt Equivalent (30%)	243,404		WP-2116, p. 11
Average Total Debt	759,558	B	
FFO to Ave Total Debt Ratio (A)/(B)	0.146		

[1] Excludes unamortized costs.

Hawaiian Electric Company, Inc.
Test Year 2005

Total Debt / Total Capital
NO Rate Increase & WITH Debt Equivalent

	$ in thousands		HECO Reference
Capitalization Balances at Year-End:			
Current Total Debt:			
Short-term Debt	27,072		R-2102
Long-term Debt [1]	451,581		R-2103
Hybrid Securities [2]	30,000		2104
Current Total Debt	508,653		
Debt Equivalent (30%)	239,438		WP-2116, p. 11
Debt Equivalent (Oper Lease)	7,000		DOD-RIR-25, p. 2
Revised Total Debt	755,091	A	
Preferred Stock [2]	22,293		2105
Common Stock	644,906		R-2105
Total Capital	1,422,290	B	
Total Debt / Total Capital Ratio (A)/(B)	0.531		

[1] Excludes unamortized costs and assumes Series 2002A to be fully drawn by 12/31/05.

[2] Excludes unamortized costs.

Hawaiian Electric Company, Inc.
Test Year 2005

Funds from Operations Interest Coverage
WITH Rate Increase & WITH Debt Equivalent
Based on a 11% Earned Return on Common Equity

	$ in thousands		HECO Reference
Revised Operating Income	97,958		RWP-2106, p. 6
Depreciation	70,731		R-2301
Deferred Income Taxes	4,572		R-1704
State Capital Goods Excise Credit ($16,309 - $15,166)	1,143		R-1703
Interest on Debt Equivalent	23,944		WP-2116, p. 11
Interest on Debt Equivalent (Oper Lease)	700		DOD-RIR-25, p. 2
Total	199,048	A	
Total Debt Requirement (ST, LT & Hybrids)	29,835		RWP-2106, p. 6
Interest on Debt Equivalent	23,944		WP-2116, p. 11
Interest on Debt Equivalent (Oper Lease)	700		DOD-RIR-25, p. 2
	54,479	B	
Fund from Operations Interest Coverage (A)/(B)	3.654	x	

Hawaiian Electric Company, Inc.
Test Year 2005

Funds from Operations / Average Total Debt
WITH Rate Increase & WITH Debt Equivalent
Based on a 11% Earned Return on Common Equity

	$ in thousands		HECO Reference
Revised Operating Income	97,958		RWP-2106, p. 6
Depreciation	70,731		R-2301
Deferred Income Taxes	4,572		R-1704
State Capital Goods Excise Credit	1,143		R-1703
Interest Expense:			
Short-term interest ($37,429 x 3.5%)	(1,310)		R-2102
Long-term interest	(24,953)		R-2103
Hybrid interest	(2,051)		2104
Total Interest Expense	(28,314)		
Total	146,090	A	
Average Debt:			
Short-term Debt	37,429		R-2102
Long-term Debt [1]	445,225		R-2103
Hybrid [1]	30,000		2104
Debt Equivalent (Oper Lease)	3,500		DOD-RIR-25, p. 2
Debt Equivalent (30%)	243,404		WP-2116, p. 11
Average Total Debt	759,558	B	
FFO to Ave Total Debt Ratio (A)/(B)	0.192		

[1] Excludes unamortized costs.

Hawaiian Electric Company, Inc.
Test Year 2005

Total Debt / Total Capital
WITH Rate Increase & WITH Debt Equivalents

Based on a 11% Earned Return on Common Equity

	$ in thousands		HECO Reference
Capitalization Balances at Year-End:			
Current Total Debt:			
Short-term Debt	27,072		R-2102
Long-term Debt [1]	451,581		R-2103
Hybrid Securities [2]	30,000		2104
Current Total Debt	508,653		
Debt Equivalent (30%)	239,438		WP-2116, p. 11
Debt Equivalent (Oper Lease)	7,000		DOD-RIR-25, p. 2
Revised Total Debt	755,091	A	
Preferred Stock [2]	22,293		2105

HECO-RWP-2106
DOCKET NO. 04-0113
PAGE 11 OF 11

Hawaiian Electric Company, Inc.
Test Year 2005

Funds from Operations / Average Total Debt based on CA Position
WITH Rate Increase & WITH Debt Equivalent
Based on a 9.25% Earned Return on Common Equity

	$ in thousands	HECO Reference
Revised Operating Income	83,623	CA-101 Sch. A
Depreciation	70,690	CA-101 Sch. C; p.1 of 5
Deferred Income Taxes	(1,322)	R-1704/CA-101 (a)
State Capital Goods Excise Credit ($16,356 - $15,166	1,190	R-1703/CA-101 (b)
Interest Expense:		
Short-term interest ($37,429 x 3.5%)	(1,310) [2]	R-2102
Long-term interest	(24,953) [2]	R-2103
Hybrid interest	(2,051) [2]	2104
Total Interest Expense	(28,314)	
Total	125,867 A	
Average Debt:		
Short-term Debt	37,429 [2]	R-2102
Long-term Debt [1]	445,225 [2]	R-2103
Hybrid [1]	30,000 [2]	2104
Debt Equivalent (Oper Lease)	3,500	DOD-RIR-25, p.2
Debt Equivalent (30%)	243,404 [2]	WP-2116, p. 11/CA-413
Average Total Debt	759,558 B	
FFO to Ave Total Debt Ratio (A)/(B)	0.166	

[1] Excludes unamortized costs.

[2] Amounts are consistent with HECO position as the CA has accepted HECO's capital structure and costs for these items.

(a) Amount represents the change in ending CA balance at 12/31/2004 and 12/31/2005. Ending balances derived by adjusting HECO balances presented in direct testimony for adjustments proposed by CA in Exhibit CA-101

(b) Amount represents the change in ending CA balance at 12/31/2004 and 12/31/2005. CA did not propose any adjustments to HECO balances presented in direct testimony as no adjustments were noted in Exhibit CA-101.

DOD-RIR-26

Refer to HECO RT-16, page 27, line 2 through page 30, line 22.

Please identify when HECO first became aware of this "pension background" information and why it was not presented in HECO's direct filing.

HECO Response:

HECO had an understanding of the "pension background" for many years. Information regarding the laws governing the formation and administration of qualified pension plans, and the accounting for such plans under SFAS 87, is generally available, and has been provided in prior rate cases, as has information regarding HECO's pension plan. (See the dockets listed in HECO RT-16, page 31.) It was not presented in HECO's direct filing, because it was not deemed necessary at the time. In Docket No. 99-0207, no party opposed and the Commission ultimately approved the inclusion of the prepaid pension asset in HELCO's rate base. In this case, HECO provided more information on the prepaid pension asset in its direct testimony than the information HELCO provided in Docket No. 99-0207. The Department of Defense had the opportunity to submit information requests if it felt it needed more information on the prepaid pension asset. It submitted none. When the CA and the DOD filed their testimonies recommending exclusion of the prepaid pension asset from rate base, the Company provided more background information on the prepaid pension asset to facilitate a better understanding of the issues involved in light of the departure from prior practice proposed by the CA and DOD.

DOD-RIR-27

Refer to HECO RT-16, page 31, lines 21 through page 33, line 2.

Please confirm that the Commission has never approved in a final order HECO's proposal to include a pension asset in rate base. If your answer is anything other than an unqualified confirmation, please explain fully and provide specific citations to the Commission order in which such approval was granted.

a. Please explain how HECO's semi-annual reports are used to adjust HECO's rates.

b. Please explain fully HECO's understanding of how and whether the Commission approves HECO's semi-annual reports as future ratemaking precedents.

HECO Response:

The Commission approved the inclusion of a prepaid pension asset in the final order (D&O 18365) for HELCO's 2000 test year rate case (Docket No. 99-0207). On page 61 of D&O 18365, the Commission stated:

> "For the test year, HELCO's estimate of average prepaid pension cost is $1,413,000. The Consumer Advocate's year-end estimate of prepaid pension cost is $2,914,000. The difference between the parties arises out of the Consumer Advocate's use of the year-end methodology.
>
> The commission finds reasonable HELCO's estimated amount of $1,413,000."

a. HECO's semi-annual reports are not used to adjust HECO's rates.

b. HECO's understanding is that the Commission does not approve semi-annual reports as future ratemaking precedents. However, HECO's policy is to reflect the Commission's prior orders or related guidance in its semi-annual reporting. In addition, HECO considers the impact of orders from HELCO and MECO rate cases in preparing its semi-annual reports.

DOD-RIR-28

Refer to HECO RT-16, page 31, lines 21-23.

Provide all semi-annual reporting to the Commission from December 1998 through the present

Within each such report, please specifically identify the pension asset or liability that HECO reflected in rate base.

HECO Response:

See attached pages 2 to 43 for the semi-annual reports to the Commission from December 1998 through the present, June 30, 2005, reflecting the Company's calculation of rate base and the supporting documentation. Note that the qualified pension asset was included in the rate base calculation starting from January 2000, and first reported to the Commission in the June 30, 2000 report (see line number 15 of pages 13, 16, 19, 22, 25, 28, 31, 34, 37, 40, and 43).

HAWAIIAN ELECTRIC COMPANY, INC.

RATE OF RETURN ON RATE BASE AND ON COMMON EQUITY
For the 12 months ended December 31, 1998

(In thousands)

Line		Ratemaking This Month	Ratemaking Last Year
	Earnings for most recent 12 months:		
A	Operating income *	$79,969	$75,672
B	Earnings for common stock *	$52,661	$48,039
	Weighted Average:		
C	Rate Base: Amount	$890,925	$866,576
D	Rate of Return (A/C)	8.98%	8.73%
E	Common Equity: Amount	$481,499	$468,879
F	Rate of Return (B/E)	10.94%	10.25%
	Simple Average:		
G	Rate Base: Amount	$899,527	$864,771
H	Rate of Return (A/G)	8.89%	8.75%
I	Common Equity: Amount	$473,255	$468,082
J	Rate of Return (B/I)	11.13%	10.26%
	End of Period:		
K	Rate Base: Amount	$919,399	$879,655
L	Rate of Return (A/K)	8.70%	8.60%
M	Common Equity: Amount	$471,725	$474,785
N	Rate of Return (B/M)	11.16%	10.12%

* These numbers exclude the net of tax amount of shareholder incentives under DSM of $1,313 and $1,404 in 1998 and 1997, respectively.

HECO ADJUSTMENTS
RATEMAKING
1998

Month	Book Rate Base (Sch 1)	Book W/C (Sch 1)	Rate W/C (Sch A)	Adjusted Rate Base	13 Mos. Weighted Avg	Simple Avg	Total Oper Income	WTD Avg (H)/(F)	Simple Avg (H)/(G)	EOP (H)/(E)
Jan	917,784	(32,640)	2,024	887,168	869,444	872,050	74,888	8.61%	8.59%	8.44%
Feb	914,383	(32,443)	1,861	883,801	871,511	870,579	74,068	8.50%	8.51%	8.38%
Mar	909,443	(32,094)	1,771	879,120	873,185	869,248	76,831	8.80%	8.84%	8.74%
Apr	913,759	(31,769)	1,553	883,543	875,044	871,010	74,991	8.57%	8.61%	8.49%
May	910,887	(31,460)	1,441	880,868	876,766	870,433	75,539	8.62%	8.68%	8.58%
June	909,577	(30,958)	1,341	879,960	878,302	869,391	76,155	8.67%	8.76%	8.65%
July	919,356	(30,609)	1,273	890,020	880,702	882,267	75,796	8.61%	8.59%	8.52%
Aug	916,870	(30,209)	1,191	887,852	881,728	881,357	77,908	8.84%	8.84%	8.77%
Sept	931,170	(29,939)	1,081	902,312	883,839	889,163	77,817	8.80%	8.75%	8.62%
Oct	932,449	(29,540)	1,009	903,918	885,986	892,137	77,117	8.70%	8.64%	8.53%
Nov	932,741	(29,255)	927	904,413	887,836	891,827	79,359	8.94%	8.90%	8.77%
Dec	947,621	(29,245)	1,023	919,399	890,925	899,527	79,969	8.98%	8.89%	8.70%
	11,056,040	(370,161)	16,494	10,702,373						

1997 ADJUSTED RATE BASE	
Jan	856,932
Feb	857,357
Mar	859,375
Apr	858,477
May	859,999
Jun	858,823
Jul	874,514
Aug	874,862
Sep	876,013
Oct	880,356
Nov	879,240
Dec	879,655
	10,415,604

Send Monthly to Sharon Hagihara, Budgets

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	December 31, 1998			
Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,188,312		PUC p.10
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(59,752)		PUC p.10
5	Retirement Work in Progress	(2,189)		PUC p.10
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,126,371		
8				
9	REGULATORY ASSETS	38,060		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	7,427		PUC p.10
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,114)		Sch 1E
13				
14	FUEL STOCK	11,114		PUC p.10
15				
16	UNAMORTIZED AM/FM PROJECT COSTS	511		Sch 1D
17				
18	UNAMORTIZED ACCESS COSTS	0		
19				
20	WORKING CASH:			
21	1/24 Fuel Oil & PP Expense	15,188		Sch 1A
22				
23	1/12 Other Operation & Maintenance Expenses	9,908		Sch 1B
24	(Excluding FO & PP)			
25				
26	1/12 Taxes Other than Income, Excl. Franchise Taxes	4,149		Sch 1C
27				
28	TOTAL WORKING CASH	29,245		
29				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	130,191		PUC p.12
33	Customer Advances for Construction	2,292		PUC p.12
34	Deferred Income Taxes (Excluding Reg Assets)	72,782		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	38,060		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	16,959		Sch 1D
37	Rental Premiums - Kamoku	57		Sch 1D
38	Customer Deposits	2,652		Sch 1D
39	Unamortized Gain on Sales	0		Sch 1D
41	TOTAL DEDUCTIONS	262,993		
42				
43	MONTH ENDED RATE BASE	947,621		

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HAWAIIAN ELECTRIC COMPANY, INC.

RATE OF RETURN ON RATE BASE AND ON COMMON EQUITY
For the 12 months ended June 30, 1999

(In thousands)

Line		Ratemaking This Month	Ratemaking Last Year
	Earnings for most recent 12 months:		
A	Operating income *	$82,341	$76,155
B	Earnings for common stock *	$54,691	$47,771
	Weighted Average:		
C	Rate Base: Amount	$905,097	$878,302
D	Rate of Return (A/C)	9.10%	8.67%
E	Common Equity: Amount	$480,863	$475,761
F	Rate of Return (B/E)	11.37%	10.04%
	Simple Average:		
G	Rate Base: Amount	$896,059	$869,391
H	Rate of Return (A/G)	9.19%	8.76%
I	Common Equity: Amount	$484,320	$479,240
J	Rate of Return (B/I)	11.29%	9.97%
	End of Period:		
K	Rate Base: Amount	$912,158	$879,960
L	Rate of Return (A/K)	9.03%	8.65%
M	Common Equity: Amount	$477,662	$490,978
N	Rate of Return (B/M)	11.45%	9.73%

* These numbers exclude the net of tax amount of shareholder incentives under DSM of $1,348 and $1,745 in 1999 and 1998, respectively.

	Total Oper Income	WTD Avg (H)/(F)	Simple Avg (H)/(G)	EOP (H)/(E)
92	79,989	8.95%	8.88%	8.74%
98	81,163	9.06%	9.00%	8.83%
27	80,507	8.96%	9.00%	8.84%
57	81,992	9.11%	9.15%	9.02%
98	82,816	9.17%	9.23%	9.07%
59	82,341	9.10%	9.19%	9.03%
10		0.00%	0.00%	#DIV/0!
26		0.00%	0.00%	#DIV/0!
56		0.00%	0.00%	#DIV/0!
59		0.00%	0.00%	#DIV/0!
57		0.00%	0.00%	#DIV/0!
00		0.00%	0.00%	#DIV/0!

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	June 30, 1999			
Line				
No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,184,360		PUC p.10
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(66,105)		PUC p.10
5	Retirement Work in Progress	(4,440)		PUC p.10
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,113,815		
8				
9	REGULATORY ASSETS	39,231		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	8,055		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(1,951)		Sch 1E
13				
14	FUEL STOCK	18,008		PUC p.8
15				
16	UNAMORTIZED AM/FM PROJECT COSTS	256		Sch 1D
17				
18	UNAMORTIZED ACCESS COSTS	0		
19				
20	WORKING CASH:			
21	1/24 Fuel Oil & PP Expense	14,594		Sch 1A
22				
23	1/12 Other Operation & Maintenance Expenses	9,710		Sch 1B
24	(Excluding FO & PP)			
25				
26	1/12 Taxes Other than Income, Excl. Franchise Taxes	4,096		Sch 1C
27				
28	TOTAL WORKING CASH	28,400		
29				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	130,934		PUC p.9
33	Customer Advances for Construction	2,393		PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	72,199		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	39,691		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	17,815		Sch 1D
37	Rental Premiums - Kamoku	54		Sch 1D
38	Customer Deposits	2,711		Sch 1D
39	Unamortized Gain on Sales	362		Sch 1D
41	TOTAL DEDUCTIONS	266,159		
42				
43	MONTH ENDED RATE BASE	939,655		

HAWAIIAN ELECTRIC COMPANY, INC.

RATE OF RETURN ON RATE BASE AND ON COMMON EQUITY
For the 12 months ended December 31, 1999

(In thousands)

Line		Ratemaking This Month	Ratemaking Last Year
	Earnings for most recent 12 months:		
A	Operating income *	$78,870	$79,969
B	Earnings for common stock *	$49,616	$52,661
	Weighted Average:		
C	Rate Base: Amount	$915,076	$890,925
D	Rate of Return (A/C)	8.62%	8.98%
E	Common Equity: Amount	$477,296	$481,499
F	Rate of Return (B/E)	10.40%	10.94%
	Simple Average:		
G	Rate Base: Amount	$924,688	$899,527
H	Rate of Return (A/G)	8.53%	8.89%
I	Common Equity: Amount	$476,421	$473,255
J	Rate of Return (B/I)	10.41%	11.13%
	End of Period:		
K	Rate Base: Amount	$929,976	$919,399
L	Rate of Return (A/K)	8.48%	8.70%
M	Common Equity: Amount	$481,117	$471,725
N	Rate of Return (B/M)	10.31%	11.16%

* These numbers exclude the net of tax amount of shareholder incentives under DSM of $1,267 and $1,313 in 1999 and 1998, respectively.

HECO ADJUSTMENTS
RATEMAKING
1999

Month	Book Rate Base (Sch 1)	Book W/C (Sch 1)	Rate W/C (Sch A)	Qualified Pension Liab	Adjusted Rate Base	13 Mos. Weighted Avg	Simple Avg	Total Oper Income	WTD Avg (H)/(F)	Simple Avg (H)/(G)	EOP (H)/(E)
Jan	943,067	(28,993)	921		914,995	893,644	901,081	79,999	8.95%	8.88%	8.74%
Feb	946,734	(28,644)	903		918,993	896,092	901,397	81,163	9.06%	9.00%	8.83%
Mar	938,068	(28,358)	823		910,533	898,148	894,826	80,507	8.96%	9.00%	8.84%
Apr	936,249	(28,230)	751		908,770	900,429	896,156	81,992	9.11%	9.15%	9.02%
May	940,305	(28,171)	792		912,926	902,689	896,897	82,816	9.17%	9.23%	9.07%
June	939,655	(28,400)	899		912,154	905,096	896,057	82,341	9.10%	9.19%	9.03%
July	935,837	(28,533)	888	961	909,153	907,341	899,586	82,609	9.10%	9.18%	9.09%
Aug	936,117	(28,816)	968	1,051	909,320	908,826	898,586	80,897	8.90%	9.00%	8.90%
Sept	933,042	(29,112)	1,068	1,140	906,138	910,233	904,225	80,812	8.88%	8.94%	8.92%
Oct	946,573	(29,487)	1,109	1,230	919,425	911,549	911,672	80,693	8.85%	8.85%	8.78%
Nov	951,554	(29,873)	1,200	1,319	924,200	913,109	914,307	78,670	8.62%	8.60%	8.51%
Dec	957,559	(30,176)	1,184	1,409	929,976	915,076	924,688	78,870	8.62%	8.53%	8.48%
	11,304,760	(346,793)	11,505	7,110	10,976,582						

1998 ADJUSTED RATE BASE	
Jan	887,168
Feb	883,801
Mar	879,120
Apr	883,543
May	880,868
Jun	879,960
Jul	890,020
Aug	887,852
Sep	902,312
Oct	903,918
Nov	904,413
Dec	919,399
	10,702,373

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	December 31, 1999			
Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,197,273		PUC p.10
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(69,947)		PUC p.10
5	Retirement Work in Progress	(7,253)		PUC p.10
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,120,073		
8				
9	REGULATORY ASSETS	40,457		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	8,145		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,053)		Sch 1E
13				
14	FUEL STOCK	24,438		PUC p.8
15				
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	7,677		Sch 1D
18	UNAMORTIZED ACCESS COSTS	0		
19				
20	WORKING CASH:			
21	1/24 Fuel Oil & PP Expense	15,715		Sch 1A
22				
23	1/12 Other Operation & Maintenance Expenses	10,170		Sch 1B
24	(Excluding FO & PP)			
25				
26	1/12 Taxes Other than Income, Excl. Franchise Taxes	4,291		Sch 1C
27				
28	TOTAL WORKING CASH	30,176		
29				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	132,643		PUC p.9
33	Customer Advances for Construction	1,874		PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	74,829		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	40,506		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	17,441		Sch 1D
37	Rental Premiums - Kamoku	51		Sch 1D
38	Customer Deposits	3,008		Sch 1D
39	Unamortized Gain on Sales	1,002		Sch 1D
41	TOTAL DEDUCTIONS	271,354		
42				
43	MONTH ENDED RATE BASE	957,559		

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HAWAIIAN ELECTRIC COMPANY, INC.

RATE OF RETURN ON RATE BASE AND ON COMMON EQUITY
For the 12 months ended June 30, 2000

(In thousands)

Line		Ratemaking This Month	Ratemaking Last Year
	Earnings for most recent 12 months:		
A	Operating income *	$85,827	$82,341
B	Earnings for common stock *	$55,968	$54,691
	Weighted Average:		
C	Rate Base: Amount	$918,736	$905,096
D	Rate of Return (A/C)	9.34%	9.10%
E	Common Equity: Amount	$484,020	$480,863
F	Rate of Return (B/E)	11.56%	11.37%
	Simple Average:		
G	Rate Base: Amount	$919,501	$896,057
H	Rate of Return (A/G)	9.33%	9.19%
I	Common Equity: Amount	$485,092	$484,320
J	Rate of Return (B/I)	11.54%	11.29%
	End of Period:		
K	Rate Base: Amount	$926,848	$912,154
L	Rate of Return (A/K)	9.26%	9.03%
M	Common Equity: Amount	$492,521	$477,662
N	Rate of Return (B/M)	11.36%	11.45%

* These numbers exclude the net of tax amount of shareholder incentives under DSM of $897 and $1,348 in 2000 and 1999, respectively.

HECO ADJUSTMENTS
RATEMAKING
2000

Month	Book Rate Base (Sch 1)	Book W/C (Sch 1)	Rate W/C (Sch A)	Adjusted Rate Base	13 Mos. Weighted Avg	Simple Avg	Total Oper Income	WTD Avg (H)/(F)	Simple Avg (H)/(G)	EOP (H)/(E)
Jan	949,777	(30,422)	1,359	920,714	915,177	917,855	79,402	8.68%	8.65%	8.62%
Feb	944,771	(31,079)	1,460	915,152	915,189	917,073	79,555	8.69%	8.67%	8.69%
Mar	953,889	(31,519)	1,787	924,157	915,586	917,345	81,885	8.94%	8.93%	8.86%
Apr	952,638	(31,886)	2,134	922,886	916,536	915,828	84,273	9.19%	9.20%	9.13%
May	953,225	(32,344)	2,563	923,444	917,665	918,185	85,403	9.31%	9.30%	9.25%
June	956,836	(32,810)	2,822	926,848	918,736	919,501	85,827	9.34%	9.33%	9.26%
July	0		0	0	848,570	454,576	82,609	9.74%	18.17%	#DIV/0!
Aug	0		0	0	778,635	454,660	80,897	10.39%	17.79%	#DIV/0!
Sept	0		0	0	708,688	453,069	80,812	11.40%	17.84%	#DIV/0!
Oct	0		0	0	638,985	459,713	80,693	12.63%	17.55%	#DIV/0!
Nov	0		0	0	568,260	462,100	78,670	13.84%	17.02%	#DIV/0!
Dec	0		0	0	497,168	464,988	78,670	15.86%	16.96%	#DIV/0!
	5,711,136	(190,060)	12,125	5,533,201						

1999 ADJUSTED RATE BASE	
Jan	914,995
Feb	918,993
Mar	910,533
Apr	908,770
May	912,926
Jun	912,154
Jul	909,153
Aug	909,320
Sep	906,138
Oct	919,425
Nov	924,200
Dec	929,976
	10,976,582

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	June 30, 2000			
Line				
No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,201,783		PUC p.10
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(82,985)		PUC p.10
5	Retirement Work in Progress	(9,640)		PUC p.10
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,109,158		
8				
9	REGULATORY ASSETS	41,848		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	8,048		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,211)		Sch 1E
13				
14	FUEL STOCK	27,514		PUC p.8
15	QUALIFIED PENSION LIABILITY	10,745		Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	6,819		Sch 1D
18	UNAMORTIZED ACCESS COSTS	0		
19				
20	WORKING CASH:			
21	1/24 Fuel Oil & PP Expense	18,136		Sch 1A
22				
23	1/12 Other Operation & Maintenance Expenses	9,948		Sch 1B
24	(Excluding FO & PP)			
25				
26	1/12 Taxes Other than Income, Excl. Franchise Taxes	4,726		Sch 1C
27				
28	TOTAL WORKING CASH	32,810		
29				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	133,013		PUC p.9
33	Customer Advances for Construction	2,033		PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	78,775		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	41,704		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	18,054		Sch 1D
37	Rental Premiums - Kamoku	47		Sch 1D
38	Customer Deposits	3,280		Sch 1D
39	Unamortized Gain on Sales	989		Sch 1D
41	TOTAL DEDUCTIONS	277,895		
42				
43	MONTH ENDED RATE BASE	956,836		

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HAWAIIAN ELECTRIC COMPANY, INC.

RATE OF RETURN ON RATE BASE AND ON COMMON EQUITY
For the 12 months ended December 31, 2000

(In thousands)

Line		Ratemaking This Month	Ratemaking Last Year
	Earnings for most recent 12 months:		
A	Operating income *	$85,004	$78,870
B	Earnings for common stock *	$56,221	$49,616
	Weighted Average:		
C	Rate Base: Amount	$925,791	$915,076
D	Rate of Return (A/C)	9.18%	8.62%
E	Common Equity: Amount	$493,347	$477,296
F	Rate of Return (B/E)	11.40%	10.40%
	Simple Average:		
G	Rate Base: Amount	$941,817	$924,688
H	Rate of Return (A/G)	9.03%	8.53%
I	Common Equity: Amount	$488,509	$476,421
J	Rate of Return (B/I)	11.51%	10.41%
	End of Period:		
K	Rate Base: Amount	$953,657	$929,976
L	Rate of Return (A/K)	8.91%	8.48%
M	Common Equity: Amount	$495,901	$481,117
N	Rate of Return (B/M)	11.34%	10.31%

* These numbers exclude the net of tax amount of shareholder incentives under DSM of $907 and $1,267 in 2000 and 1999, respectively.

HECO ADJUSTMENTS
RATEMAKING
2000

Month	Book Rate Base (Sch 1)	Book W/C (Sch 1)	Rate W/C (Sch A)	Adjusted Rate Base	13 Mos. Weighted Avg	Simple Avg	Total Oper Income	WTD Avg (H)/(F)	Simple Avg (H)/(G)	EOP (H)/(E)
Jan	949,777	(30,422)	1,359	920,714	915,177	917,855	79,402	8.68%	8.65%	8.62%
Feb	944,771	(31,079)	1,460	915,152	915,189	917,073	79,555	8.69%	8.67%	8.69%
Mar	953,889	(31,519)	1,787	924,157	915,586	917,345	81,885	8.94%	8.93%	8.86%
Apr	952,638	(31,886)	2,134	922,886	916,536	915,828	84,273	9.19%	9.20%	9.13%
May	953,225	(32,344)	2,563	923,444	917,665	918,185	85,403	9.31%	9.30%	9.25%
June	956,836	(32,810)	2,822	926,848	918,736	919,501	85,827	9.34%	9.33%	9.26%
July	952,884	(33,346)	3,173	922,711	919,548	915,932	87,188	9.48%	9.52%	9.45%
Aug	954,410	(33,870)	3,503	924,043	920,693	916,681	87,716	9.53%	9.57%	9.49%
Sept	948,550	(34,358)	3,743	917,935	921,356	912,037	88,016	9.55%	9.65%	9.59%
Oct	956,167	(34,842)	3,993	925,318	922,832	922,372	89,089	9.65%	9.66%	9.63%
Nov	959,744	(35,551)	4,243	928,436	923,525	926,318	87,951	9.52%	9.49%	9.47%
Dec	985,579	(36,383)	4,461	953,657	925,791	941,817	85,004	9.18%	9.03%	8.91%
	11,468,470	(398,410)	35,242	11,105,302						

1999 ADJUSTED RATE BASE	
Jan	914,995
Feb	918,993
Mar	910,533
Apr	908,770
May	912,926
Jun	912,154
Jul	909,153
Aug	909,320
Sep	906,138
Oct	919,425
Nov	924,200
Dec	929,976
	10,976,582

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	December 31, 2000			
Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,220,696		PUC p.10
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(82,105)		PUC p.10
5	Retirement Work in Progress	(7,407)		PUC p.10
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,131,184		
8				
9	REGULATORY ASSETS	42,169		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	7,929		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,383)		Sch 1E
13				
14	FUEL STOCK	24,177		PUC p.8
15	QUALIFIED PENSION LIABILITY	20,731		Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	5,844		Sch 1D
18	UNAMORTIZED ACCESS COSTS	0		
19				
20	WORKING CASH:			
21	1/24 Fuel Oil & PP Expense	20,794		Sch 1A
22				
23	1/12 Other Operation & Maintenance Expenses	10,450		Sch 1B
24	(Excluding FO & PP)			
25				
26	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,139		Sch 1C
27				
28	TOTAL WORKING CASH	36,383		
29				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	135,323		PUC p.9
33	Customer Advances for Construction	2,000		PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	77,931		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	42,202		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	18,419		Sch 1D
37	Rental Premiums - Kamoku	44		Sch 1D
38	Customer Deposits	3,668		Sch 1D
39	Unamortized Gain on Sales	868		Sch 1D
41	TOTAL DEDUCTIONS	280,455		
42				
43	MONTH ENDED RATE BASE	985,579		

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HAWAIIAN ELECTRIC COMPANY, INC.

RATE OF RETURN ON RATE BASE AND ON COMMON EQUITY
For the 12 months ended June 30, 2001

(In thousands)

Line		Ratemaking This Month	Ratemaking Last Year
	Earnings for most recent 12 months:		
A	Operating income *	$81,835	$85,827
B	Earnings for common stock *	$53,819	$55,968
	Weighted Average:		
C	Rate Base: Amount	$945,597	$918,736
D	Rate of Return (A/C)	8.65%	9.34%
E	Common Equity: Amount	$506,910	$484,020
F	Rate of Return (B/E)	10.62%	11.56%
	Simple Average:		
G	Rate Base: Amount	$955,200	$919,501
H	Rate of Return (A/G)	8.57%	9.33%
I	Common Equity: Amount	$513,971	$485,092
J	Rate of Return (B/I)	10.47%	11.54%
	End of Period:		
K	Rate Base: Amount	$983,552	$926,848
L	Rate of Return (A/K)	8.32%	9.26%
M	Common Equity: Amount	$535,420	$492,521
N	Rate of Return (B/M)	10.05%	11.36%

* These numbers exclude the net of tax amount of shareholder incentives under DSM of $1,138 and $885 in 2001 and 2000, respectively.

ate /C h A)	Project Apprise	Deferred Taxes- Project Apprise	Adjusted Rate Base	13 Mos. Weighted Avg	Simple Avg	Total Oper. Income	WTD Avg (H)/(F)	Simple Avg (H)/(G)	EOP (H)/(E)
,626			956,623	927,840	938,669	85,215	9.18%	9.08%	8.91%
,670	(5,519)	(107)	950,433	930,126	932,793	84,963	9.13%	9.11%	8.94%
,650	(5,357)	(107)	948,035	932,656	936,096	83,313	8.93%	8.90%	8.79%
,611	(5,195)	(107)	975,918	936,637	949,402	81,857	8.74%	8.62%	8.39%
,438	(5,032)	(107)	979,251	940,973	951,347	80,932	8.60%	8.51%	8.26%
,282	(4,870)	(107)	983,553	945,597	955,200	81,835	8.65%	8.57%	8.32%
0			0	874,301	461,356		0.00%	0.00%	#DIV/0!
0			0	803,323	462,022		0.00%	0.00%	#DIV/0!
0			0	732,243	458,968		0.00%	0.00%	#DIV/0!
0			0	661,633	462,659		0.00%	0.00%	#DIV/0!
0			0	590,454	464,218		0.00%	0.00%	#DIV/0!
0			0	519,036	476,829		0.00%	0.00%	#DIV/0!
,276			5,793,812						

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	June 30, 2001			
Line				
No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,222,376		PUC p.10
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(60,651)		PUC p.10
5	Retirement Work in Progress	(8,834)		PUC p.10
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,152,891		
8				
9	REGULATORY ASSETS	43,162		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	8,893		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,525)		Sch 1E
13				
14	FUEL STOCK	28,501		PUC p.8
15	QUALIFIED PENSION LIABILITY	30,738		Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	4,870		Sch 1D
18	UNAMORTIZED ACCESS COSTS	0		
19				
20	WORKING CASH:			
21	1/24 Fuel Oil & PP Expense	21,421		Sch 1A
22				
23	1/12 Other Operation & Maintenance Expenses	10,856		Sch 1B
24	(Excluding FO & PP)			
25				
26	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,208		Sch 1C
27				
28	TOTAL WORKING CASH	37,485		
29				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	133,429		PUC p.9
33	Customer Advances for Construction	1,777		PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	80,290		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	43,361		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	18,676		Sch 1D
37	Rental Premiums - Kamoku	41		Sch 1D
38	Customer Deposits	3,962		Sch 1D
39	Unamortized Gain on Sales	746		Sch 1D
41	TOTAL DEDUCTIONS	282,262		
42				
43	MONTH ENDED RATE BASE	1,021,733		

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HAWAIIAN ELECTRIC COMPANY, INC.

RATE OF RETURN ON RATE BASE AND ON COMMON EQUITY
For the 12 months ended December 31,

(In thousands)

Line		Ratemaking 2001	Ratemaking 2000
	Earnings for most recent 12 months:		
A	Operating income *	$87,064	$85,004
B	Earnings for common stock *	$59,436	$56,221
	Weighted Average:		
C	Rate Base: Amount	$974,059	$925,791
D	Rate of Return (A/C)	8.94%	9.18%
E	Common Equity: Amount	$526,696	$493,347
F	Rate of Return (B/E)	11.28%	11.40%
	Simple Average:		
G	Rate Base: Amount	$965,566	$941,817
H	Rate of Return (A/G)	9.02%	9.03%
I	Common Equity: Amount	$518,603	$488,509
J	Rate of Return (B/I)	11.46%	11.51%
	End of Period:		
K	Rate Base: Amount	$977,474	$953,657
L	Rate of Return (A/K)	8.91%	8.91%
M	Common Equity: Amount	$541,304	$495,901
N	Rate of Return (B/M)	10.98%	11.34%

* These numbers exclude the net of tax amount of shareholder incentives under DSM of $1,413 and $907 in 2001 and 2000, respectively.

tal Oper Income	WTD Avg (H)/(F)	Simple Avg (H)/(G)	EOP (H)/(E)
85,215	9.18%	9.08%	8.91%
84,983	9.13%	9.11%	8.94%
83,313	8.93%	8.80%	8.79%
81,857	8.74%	8.62%	8.39%
80,932	8.60%	8.51%	8.26%
81,835	8.65%	8.57%	8.32%
81,918	8.62%	8.57%	8.29%
81,901	8.57%	8.56%	8.27%
83,698	8.72%	8.80%	8.49%
83,479	8.64%	8.73%	8.45%
85,748	8.84%	8.96%	8.70%
87,064	8.94%	9.02%	8.91%

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	December 31, 2001			
Line				
No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,229,061	✓	PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(70,501)	✓	PUC p.8
5	Retirement Work in Progress	(5,007)	✓	PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,153,553		
8				
9	REGULATORY ASSETS	44,003	✓	Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	8,451	✓	PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,513)	✓	Sch 1E
13				
14	FUEL STOCK	15,840	✓	PUC p.8
15	QUALIFIED PENSION LIABILITY	41,196	✓	Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	3,896	✓	Sch 1D
18	E-BUSINESS	291		PA59
19	UNAMORTIZED ACCESS COSTS	0		
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	20,871	✓	Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	9,942	✓	Sch 1B
25	(Excluding FO & PP)			
26				
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,075	✓	Sch 1C
28				
29	TOTAL WORKING CASH	35,888		
30				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	134,898	✓	PUC p.9
33	Customer Advances for Construction	1,698	✓	PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	82,359	✓	Sch 1D
35	Deferred Income Taxes - Regulatory Assets	44,035	✓	Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	19,848	✓	Sch 1D
37	Rental Premiums - Kamoku	37	✓	Sch 1D
38	Customer Deposits	4,185	✓	Sch 1D
39	Unamortized Gain on Sales	625	✓	Sch 1D
40	TOTAL DEDUCTIONS	287,685		
41				
42	MONTH ENDED RATE BASE	1,012,920		

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HAWAIIAN ELECTRIC COMPANY, INC.

RATE OF RETURN ON RATE BASE AND ON COMMON EQUITY
For the 12 months ended June 30,

(In thousands)

Line		Ratemaking 2002	Ratemaking 2001
	Earnings for most recent 12 months:		
A	Operating income *	$86,502	$81,835
B	Earnings for common stock *	$60,047	$53,819
	Weighted Average:		
C	Rate Base: Amount	$985,221	$945,597
D	Rate of Return (A/C)	8.78%	8.65%
E	Common Equity: Amount	$545,661	$506,910
F	Rate of Return (B/E)	11.00%	10.62%
	Simple Average:		
G	Rate Base: Amount	$984,333	$955,200
H	Rate of Return (A/G)	8.79%	8.57%
I	Common Equity: Amount	$546,036	$513,971
J	Rate of Return (B/I)	11.00%	10.47%
	End of Period:		
K	Rate Base: Amount	$985,114	$983,553
L	Rate of Return (A/K)	8.78%	8.32%
M	Common Equity: Amount	$556,652	$535,420
N	Rate of Return (B/M)	10.79%	10.05%

* These amounts exclude the net of tax amount of shareholder incentives under DSM for July 2001-December 2001 of $912 and for July 2000-June 2001 of $1,138.

Commencing with this report, shareholder incentives earned after 2001 are included in operating revenues pursuant to Decision and Order No. 19020, Docket No. 00-0209, dated November 15, 2001.

HECO ADJUSTMENTS
RATEMAKING
2002

Month	Book Rate Base (Sch 1)	Book W/C (Sch 1)	Rate W/C (Sch A)	Project Apprise	E-Business	Deferred Taxes-Project Apprise	Adjusted Rate Base	13 Mos. Weighted Avg	Simple Avg	Total Oper Income	WTD Avg (H)/(F)	Simple Avg (H)/(G)	EOP (H)/(E)
Jan	1,015,547	(35,396)	3,876	(3,734)	(285)	531	980,539	976,127	968,580	86,660	8.88%	8.95%	8.84%
Feb	1,018,002	(34,983)	3,658	(3,571)	(279)	531	983,358	978,183	966,895	86,760	8.87%	8.97%	8.82%
Mar	1,021,642	(34,627)	3,457	(3,409)	(273)	531	987,321	981,021	967,677	86,267	8.79%	8.91%	8.74%
Apr	1,018,792	(34,494)	3,437	(3,247)	(267)	744	984,965	983,862	980,441	86,859	8.83%	8.86%	8.82%
May	1,021,314	(34,394)	3,358	(3,084)	(262)	798	987,730	984,771	983,490	87,018	8.84%	8.85%	8.81%
June	1,018,882	(34,594)	3,153	(2,922)	(256)	851	985,114	985,221	984,333	86,502	8.78%	8.79%	8.78%
July	0		#DIV/0!				#DIV/0!	#DIV/0!	#DIV/0!	78,416	#DIV/0!	#DIV/0!	#DIV/0!
Aug	0		#DIV/0!				#DIV/0!	#DIV/0!	#DIV/0!	70,476	#DIV/0!	#DIV/0!	#DIV/0!
Sept	0		#DIV/0!				#DIV/0!	#DIV/0!	#DIV/0!	61,418	#DIV/0!	#DIV/0!	#DIV/0!
Oct	0		#DIV/0!				#DIV/0!	#DIV/0!	#DIV/0!	53,687	#DIV/0!	#DIV/0!	#DIV/0!
Nov	0		#DIV/0!				#DIV/0!	#DIV/0!	#DIV/0!	46,382	#DIV/0!	#DIV/0!	#DIV/0!
Dec	0		#DIV/0!				#DIV/0!	#DIV/0!	#DIV/0!	42,517	#DIV/0!	#DIV/0!	#DIV/0!
	6,114,179	(208,488)	#DIV/0!				#DIV/0!						

2001 ADJUSTED RATE BASE	
Jan	956,621
Feb	950,431
Mar	948,034
Apr	975,918
May	979,251
Jun	983,552
Jul	988,392
Aug	990,420
Sep	985,288
Oct	988,198
Nov	985,528
Dec	977,474
	11,709,108

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	June 30, 2002			
Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,231,753		PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(75,014)		PUC p.8
5	Retirement Work in Progress	(5,497)		PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,151,242		
8				
9	REGULATORY ASSETS	44,790		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	9,355		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,413)		Sch 1E
13				
14	FUEL STOCK	17,903		PUC p.8
15	QUALIFIED PENSION LIABILITY	49,433		Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	2,922		Sch 1D
18	E-BUSINESS	256		PA59
19	UNAMORTIZED ACCESS COSTS	0		
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	19,702		Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	9,833		Sch 1B
25	(Excluding FO & PP)			
26				
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,059		Sch 1C
28				
29	TOTAL WORKING CASH	34,594		
30				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	134,296		PUC p.9
33	Customer Advances for Construction	1,619		PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	83,158		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	44,894		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	20,331		Sch 1D
37	Rental Premiums - Kamoku	34		Sch 1D
38	Customer Deposits	4,364		Sch 1D
39	Unamortized Gain on Sales	504		Sch 1D
40	TOTAL DEDUCTIONS	289,200		
41				
42	MONTH ENDED RATE BASE	1,018,882		

HAWAIIAN ELECTRIC COMPANY, INC.

RATE OF RETURN ON RATE BASE AND ON COMMON EQUITY
For the 12 months ended December 31,

(In thousands)

Line		Ratemaking 2002	Ratemaking 2001
	Earnings for most recent 12 months:		
A	Operating income	$88,847	$87,064 *
B	Earnings for common stock	$63,111	$59,436 *
	Weighted Average:		
C	Rate Base: Amount	$991,864	$974,059
D	Rate of Return (A/C)	8.96%	8.94%
E	Common Equity: Amount	$558,859	$526,696
F	Rate of Return (B/E)	11.29%	11.28%
	Simple Average:		
G	Rate Base: Amount	$993,499	$965,566
H	Rate of Return (A/G)	8.94%	9.02%
I	Common Equity: Amount	$556,975	$518,603
J	Rate of Return (B/I)	11.33%	11.46%
	End of Period:		
K	Rate Base: Amount	$1,009,524	$977,474
L	Rate of Return (A/K)	8.80%	8.91%
M	Common Equity: Amount	$572,646	$541,304
N	Rate of Return (B/M)	11.02%	10.98%

* These amounts exclude the net of tax amount of shareholder incentives under DSM for January-December 2001 of $1,413.

Commencing with the report for June 2002, shareholder incentives earned after 2001 are included in operating revenues pursuant to Decision and Order No. 19020, Docket No. 00-0209, dated November 15, 2001.

HECO ADJUSTMENTS
RATEMAKING
2002

Month	Book Rate Base (Sch 1)	Book W/C (Sch 1)	Rate W/C (Sch A)	Project Apprise	E-Business	Deferred Taxes-Project Apprise	Adjusted Rate Base	13 Mos. Weighted Avg	Simple Avg	Total Oper Income	WTD Avg (H)/(F)	Simple Avg (H)/(G)	EOP (H)/(E)
Jan	1,015,547	(35,396)	3,876	(3,734)	(285)	531	980,539	976,127	968,580	86,659	8.88%	8.95%	8.84%
Feb	1,018,002	(34,983)	3,658	(3,571)	(279)	531	983,358	978,183	966,895	86,758	8.87%	8.97%	8.82%
Mar	1,021,642	(34,627)	3,457	(3,409)	(273)	531	987,321	981,021	967,677	86,264	8.79%	8.91%	8.74%
Apr	1,018,792	(34,494)	3,437	(3,247)	(267)	744	984,965	983,862	980,441	86,857	8.83%	8.86%	8.82%
May	1,021,314	(34,394)	3,358	(3,084)	(262)	798	987,730	984,771	983,491	87,015	8.84%	8.85%	8.81%
June	1,018,882	(34,594)	3,153	(2,922)	(256)	851	985,114	985,222	984,333	86,499	8.78%	8.79%	8.78%
July	1,019,469	(34,592)	3,030	(2,760)	(250)	904	985,801	985,395	987,097	85,078	8.63%	8.62%	8.63%
Aug	1,024,421	(34,569)	2,963	(2,597)	(244)	957	990,931	985,590	990,675	85,863	8.71%	8.67%	8.66%
Sept	1,041,827	(34,701)	2,861	(2,435)	(239)	964	1,008,277	986,963	986,783	84,450	8.56%	8.47%	8.38%
Oct	1,041,114	(34,793)	2,909	(2,273)	(233)	1,013	1,007,737	988,690	997,968	86,054	8.70%	8.62%	8.54%
Nov	1,038,850	(35,089)	2,972	(2,110)	(227)	1,061	1,005,457	990,018	995,492	86,794	8.77%	8.72%	8.63%
Dec	1,042,301	(35,264)	2,970	(1,948)	(221)	1,686	1,009,524	991,864	993,499	88,647	8.96%	8.94%	8.80%
	12,322,161	(417,498)	38,643				11,916,753						

2001 ADJUSTED RATE BASE	
Jan	956,621
Feb	950,431
Mar	948,034
Apr	975,918
May	979,251
Jun	983,552
Jul	988,392
Aug	990,420
Sep	985,288
Oct	988,198
Nov	985,528
Dec	977,474
	11,709,108

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	December 31, 2002			
Line				
No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,239,230		PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(63,246)		PUC p.8
5	Retirement Work in Progress	(5,069)		PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,170,915		
8				
9	REGULATORY ASSETS	45,728		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	9,187		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,435)		Sch 1E
13				
14	FUEL STOCK	25,701		PUC p.8
15	QUALIFIED PENSION LIABILITY	56,852		Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	1,948		Sch 1D
18	E-BUSINESS	221		PA59
19	UNAMORTIZED ACCESS COSTS	0		
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	19,795		Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	10,322		Sch 1B
25	(Excluding FO & PP)			
26				
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,147		Sch 1C
28				
29	TOTAL WORKING CASH	35,264		
30				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	138,298		PUC p.9
33	Customer Advances for Construction	1,550		PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	89,721		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	45,766		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	20,801		Sch 1D
37	Rental Premiums - Kamoku	30		Sch 1D
38	Customer Deposits	4,485		Sch 1D
39	Unamortized Gain on Sales	429		Sch 1D
40	TOTAL DEDUCTIONS	301,080		
41				
42	MONTH ENDED RATE BASE	1,042,301		

HAWAIIAN ELECTRIC COMPANY, INC.

RATE OF RETURN ON RATE BASE AND ON COMMON EQUITY
For the 12 months ended June 30,

(In thousands)

Line		Ratemaking 2003	Ratemaking 2002
	Earnings for most recent 12 months:		
A	Operating income	$81,578	$86,502 *
B	Earnings for common stock	$55,422	$60,047 *
	Weighted Average:		
C	Rate Base: Amount	$1,004,730	$985,221
D	Rate of Return (A/C)	8.12%	8.78%
E	Common Equity: Amount	$571,289	$545,661
F	Rate of Return (B/E)	9.70%	11.00%
	Simple Average:		
G	Rate Base: Amount	$995,670	$984,333
H	Rate of Return (A/G)	8.19%	8.79%
I	Common Equity: Amount	$565,840	$546,036
J	Rate of Return (B/I)	9.79%	11.00%
	End of Period:		
K	Rate Base: Amount	$1,006,227	$985,114
L	Rate of Return (A/K)	8.11%	8.78%
M	Common Equity: Amount	$575,028	$556,652
N	Rate of Return (B/M)	9.64%	10.79%

* These amounts exclude the net of tax amount of shareholder incentives under DSM for July-December 2001 of $912.

[redacted]

HECO ADJUSTMENTS
RATEMAKING
2003

Month	Book Rate Base (Sch 1)	Book W/C (Sch 1)	Rate W/C (Sch A)	Project Apprise	E-Business	Deferred Taxes- Project Apprise	Adjusted Rate Base	13 Mos. Weighted Avg	Simple Avg	Total Oper Income	WTD Avg (H)/(F)	Simple Avg (H)/(G)	EOP (H)/(E)
Jan	1,035,720	(35,912)	3,112	(1,786)	(215)	1,623	1,002,542	993,792	991,541	87,613	8.82%	8.84%	8.74%
Feb	1,048,751	(36,599)	3,327	(1,623)	(209)	1,560	1,015,207	996,459	999,282	86,615	8.69%	8.67%	8.53%
Mar	1,048,552	(37,614)	3,710	(1,461)	(204)	1,498	1,014,481	998,853	1,000,901	84,250	8.43%	8.42%	8.30%
Apr	1,051,445	(38,363)	3,916	(1,299)	(198)	1,649	1,017,150	1,001,147	1,001,057	82,924	8.28%	8.28%	8.15%
May	1,047,645	(38,965)	4,105	(1,136)	(192)	1,586	1,013,043	1,003,307	1,000,387	82,425	8.22%	8.24%	8.14%
June	1,040,946	(39,272)	4,445	(974)	(441)	1,523	1,006,227	1,004,730	995,670	81,578	8.12%	8.19%	8.11%
July	0		#DIV/0!				#DIV/0!	#DIV/0!	#DIV/0!	75,058	#DIV/0!	#DIV/0!	#DIV/0!
Aug	0		#DIV/0!				#DIV/0!	#DIV/0!	#DIV/0!	66,476	#DIV/0!	#DIV/0!	#DIV/0!
Sept	0		#DIV/0!				#DIV/0!	#DIV/0!	#DIV/0!	58,975	#DIV/0!	#DIV/0!	#DIV/0!
Oct	0		#DIV/0!				#DIV/0!	#DIV/0!	#DIV/0!	49,785	#DIV/0!	#DIV/0!	#DIV/0!
Nov	0		#DIV/0!				#DIV/0!	#DIV/0!	#DIV/0!	41,885	#DIV/0!	#DIV/0!	#DIV/0!
Dec	0		#DIV/0!				#DIV/0!	#DIV/0!	#DIV/0!	36,110	#DIV/0!	#DIV/0!	#DIV/0!
	6,273,059	(226,725)	#DIV/0!				#DIV/0!						

2002 ADJUSTED RATE BASE	
Jan	980,539
Feb	983,358
Mar	987,321
Apr	984,965
May	987,730
Jun	985,114
Jul	985,801
Aug	990,931
Sep	1,008,277
Oct	1,007,737
Nov	1,005,457
Dec	1,009,524
	11,916,753

	HECO			
	AVERATE RATE BASE AND RATE OF RETURN			
	($ Thousands)			
	June 30, 2003			
Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,240,978		PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(72,052)		PUC p.8
5	Retirement Work in Progress	(6,801)		PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,162,125		
8				
9	REGULATORY ASSETS	46,511		Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	9,974		PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,621)		Sch 1E
13				
14	FUEL STOCK	29,556		PUC p.8
15	QUALIFIED PENSION LIABILITY	56,695		Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	974		Sch 1D
18	E-BUSINESS	186		PA59
	E-BUSINESS-HARDWARE	255		PA06
19	UNAMORTIZED ACCESS COSTS	0		
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	22,424		Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	11,466		Sch 1B
25	(Excluding FO & PP)			
26				
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,382		Sch 1C
28				
29	TOTAL WORKING CASH	39,272		
30				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	138,440		PUC p.9
33	Customer Advances for Construction	1,545		PUC p.9
34	Deferred Income Taxes (Excluding Reg Assets)	89,153		Sch 1D
35	Deferred Income Taxes - Regulatory Assets	46,548		Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	21,370		Sch 1D
37	Rental Premiums - Kamoku	27		Sch 1D
38	Customer Deposits	4,595		Sch 1D
39	Unamortized Gain on Sales	303		Sch 1D
40	TOTAL DEDUCTIONS	301,981		
41				
42	MONTH ENDED RATE BASE	1,040,946		

HAWAIIAN ELECTRIC COMPANY, INC.

RATE OF RETURN ON RATE BASE AND ON COMMON EQUITY
For the 12 months ended December 31,

(In thousands)

Line		Ratemaking 2003	Ratemaking 2002
	Earnings for most recent 12 months:		
A	Operating income	$80,370	$88,847
B	Earnings for common stock	$53,257	$83,111
	Weighted Average:		
C	Rate Base: Amount	$1,006,781	$991,864
D	Rate of Return (A/C)	7.98%	8.96%
E	Common Equity: Amount	$579,686	$558,859
F	Rate of Return (B/E)	9.19%	11.29%
	Simple Average:		
G	Rate Base: Amount	$1,011,420	$993,499
H	Rate of Return (A/G)	7.95%	8.94%
I	Common Equity: Amount	$578,668	$556,975
J	Rate of Return (B/I)	9.20%	11.33%
	End of Period:		
K	Rate Base: Amount	$1,013,316	$1,009,524
L	Rate of Return (A/K)	7.93%	8.80%
M	Common Equity: Amount	$584,690	$572,646
N	Rate of Return (B/M)	9.11%	11.02%

Commencing with the report for June 2002, shareholder incentives earned after 2001 are included in operating revenues pursuant to Decision and Order No. 19020, Docket No. 00-0209, dated November 15, 2001.

ted Base	13 Mos. Weighted Avg	Simple Avg	Total Oper Income	WTD Avg (H)/(F)	Simple Avg (H)/(G)	EOP (H)/(E)
02,542	993,792	991,541	87,613	8.82%	8.84%	8.74%
15,207	996,459	999,282	86,615	8.69%	8.67%	8.53%
14,481	998,863	1,000,901	84,223	8.43%	8.41%	8.30%
17,149	1,001,147	1,001,057	82,897	8.28%	8.28%	8.15%
13,042	1,003,307	1,000,386	82,398	8.21%	8.24%	8.13%
06,226	1,004,730	995,670	81,552	8.12%	8.19%	8.10%
98,805	1,005,783	992,303	81,930	8.15%	8.26%	8.20%
98,155	1,006,733	994,543	82,052	8.15%	8.25%	8.22%
01,621	1,007,555	1,004,949	80,558	8.00%	8.02%	8.04%
95,683	1,006,587	1,001,710	79,954	7.94%	7.98%	8.03%
02,406	1,006,177	1,003,931	80,391	7.99%	8.01%	8.02%
13,316	1,006,781	1,011,420	80,370	7.98%	7.95%	7.93%
78,632						

HECO
AVERATE RATE BASE AND RATE OF RETURN
($ Thousands)
December 31, 2003

Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,270,034	✓	PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(93,450)	✓	PUC p.8
5	Retirement Work in Progress	(6,786)	✓	PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,169,798		
8				
9	REGULATORY ASSETS	47,451	✓	Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	10,521	✓	PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(2,739)	✓	Sch 1E
13				
14	FUEL STOCK	32,060	✓	PUC p.8
15	QUALIFIED PENSION LIABILITY	64,352	✓	Sch 1D
16	UNAMORTIZED AM/FM PROJECT COSTS	0		Sch 1D
17	PROJECT APPRISE COSTS	0		Sch 1D
18	E-BUSINESS	151	✓	PA59
	E-BUSINESS-HARDWARE	235	✓	PA06
19	UNAMORTIZED ACCESS COSTS	0		
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	23,269	✓	Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	11,661	✓	Sch 1B
25	(Excluding FO & PP)			

HAWAIIAN ELECTRIC COMPANY, INC.

RATE OF RETURN ON RATE BASE AND ON COMMON EQUITY
For the 12 months ended June 30,

(In thousands)

Line		Ratemaking 2004	Ratemaking 2003
	Earnings for most recent 12 months:		
A	Operating income	$83,903	$81,552
B	Earnings for common stock	$58,532	$55,395
	Weighted Average:		
C	Rate Base: Amount	$1,005,089	$1,004,730
D	Rate of Return (A/C)	8.35%	8.12%
E	Common Equity: Amount	$588,671	$571,289
F	Rate of Return (B/E)	9.94%	9.70%
	Simple Average:		
G	Rate Base: Amount	$1,007,105	$995,670
H	Rate of Return (A/G)	8.33%	8.19%
I	Common Equity: Amount	$589,230	$565,840
J	Rate of Return (B/I)	9.93%	9.79%
	End of Period:		
K	Rate Base: Amount	$1,007,984	$1,006,226
L	Rate of Return (A/K)	8.32%	8.10%
M	Common Equity: Amount	$603,431	$575,028
N	Rate of Return (B/M)	9.70%	9.63%

Per Decision and Order No. 14412 dated December 11, 1995, the allowed rate of return on average rate base and on average common equity is 9.16% and 11.40%, respectively.

ECO ADJUSTMENTS
ATEMAKING
04

onth	Book Rate Base (Sch 1)	Book W/C (Sch 1)	Rate W/C (Sch A)	E-Business	Deferred Taxes- Apprise/ E-Business	Adjusted Rate Base	13 Mos. Weighted Avg	Simple Avg	Total Oper Income	WTD Avg (H)/(F)	Simple Avg (H)/(G)	EOP (H)/(E)
an	1,039,275	(40,355)	4,898	(374)	(132)	1,003,312	1,006,303	1,002,927	82,240	8.17%	8.20%	8.20%
eb	1,042,373	(40,560)	5,053	(362)	(133)	1,006,371	1,006,598	1,010,789	83,229	8.27%	8.23%	8.27%
ar	1,042,161	(40,412)	4,850	(350)	(135)	1,006,114	1,005,899	1,010,298	84,425	8.39%	8.36%	8.39%
or	1,046,835	(40,343)	4,786	(338)	(136)	1,010,804	1,005,616	1,013,976	84,748	8.43%	8.36%	8.38%
ay	1,051,176	(40,377)	5,033	(341)	(137)	1,015,354	1,005,478	1,014,198	85,095	8.46%	8.39%	8.38%
ne	1,043,981	(40,692)	5,148	(332)	(121)	1,007,984	1,005,089	1,007,105	83,903	8.35%	8.33%	8.32%
ly			#DIV/0!			#DIV/0!	#DIV/0!	#DIV/0!		#DIV/0!	#DIV/0!	#DIV/0!
ug			#DIV/0!			#DIV/0!	#DIV/0!	#DIV/0!		#DIV/0!	#DIV/0!	#DIV/0!
ept			#DIV/0!			#DIV/0!	#DIV/0!	#DIV/0!		#DIV/0!	#DIV/0!	#DIV/0!
ct			#DIV/0!			#DIV/0!	#DIV/0!	#DIV/0!		#DIV/0!	#DIV/0!	#DIV/0!
ov			#DIV/0!			#DIV/0!	#DIV/0!	#DIV/0!		#DIV/0!	#DIV/0!	#DIV/0!
ec			#DIV/0!			#DIV/0!	#DIV/0!	#DIV/0!		#DIV/0!	#DIV/0!	#DIV/0!
	6,265,801	(242,739)	#DIV/0!			#DIV/0!						

003 ADJUSTED RATE BASE	
an	1,002,542
eb	1,015,207
lar	1,014,481
pr	1,017,149
lay	1,013,042
un	1,006,226
ul	998,805
ug	998,155
ep	1,001,621
ct	995,683
ov	1,002,406
ec	1,013,316
	12,078,632

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HECO
AVERATE RATE BASE AND RATE OF RETURN
($ Thousands)
June 30, 2004

Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,415,336	/	PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(122,462)	/	PUC p.8
5	Retirement Work in Progress	(6,906)	/	PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,285,968		
8				
9	REGULATORY ASSETS	48,876	/	Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	10,579	/	PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(834)	/	Sch 1E
13				
14	FUEL STOCK	34,398	/	PUC p.8
15	QUALIFIED PENSION LIABILITY	65,125	/	Sch 1D
16				
17	E-BUSINESS	116	/	PA59
18	E-BUSINESS-HARDWARE	216	/	PA06
19				
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	23,684	/	Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	11,397	/	Sch 1B
25	(Excluding FO & PP)			
26				
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	5,611	/	Sch 1C
28				
29	TOTAL WORKING CASH	40,692		
30				
31	DEDUCTIONS:			
32	Unamortized Contributions in Aid of Construction	142,506	/	Sch 1D
33	Customer Advances for Construction	1,550	/	Sch 1D
34	Deferred Income Taxes (Excluding Reg Assets)	96,255	/	Sch 1D
35	Deferred Income Taxes - Regulatory Assets	48,914	/	Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	22,074	/	Sch 1D
37	Rental Premiums - Kamoku	21	/	Sch 1D
38	Customer Deposits	5,146	/	Sch 1D
39	Unamortized Gain on Sales	165	/	Sch 1D
40	Regulatory Liability for Cost of Removal	124,524	/	
41	TOTAL DEDUCTIONS	441,155		
42				
43	MONTH ENDED RATE BASE	1,043,981		

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HAWAIIAN ELECTRIC COMPANY, INC.

RATE OF RETURN ON RATE BASE AND ON COMMON EQUITY
For the 12 months ended December 31,

(In thousands)

Line		Ratemaking 2004	Ratemaking 2003
	Earnings for most recent 12 months:		
A	Operating income	$75,400	$80,370
B	Earnings for common stock	$52,051	$53,257
	Weighted Average:		
C	Rate Base: Amount	$1,018,110	$1,006,781
D	Rate of Return (A/C)	7.41%	7.98%
E	Common Equity: Amount	$606,929	$579,686
F	Rate of Return (B/E)	8.58%	9.19%
	Simple Average:		
G	Rate Base: Amount	$1,058,206	$1,011,420
H	Rate of Return (A/G)	7.13%	7.95%
I	Common Equity: Amount	$612,894	$578,668
J	Rate of Return (B/I)	8.49%	9.20%
	End of Period:		
K	Rate Base: Amount	$1,103,097	$1,013,316
L	Rate of Return (A/K)	6.84%	7.93%
M	Common Equity: Amount	$641,097	$584,690
N	Rate of Return (B/M)	8.12%	9.11%

Per Decision and Order No. 14412 dated December 11, 1995, the allowed rate of return on average rate base and on average common equity is 9.16% and 11.40%, respectively.

EOP (H)/(E)
8.20%
8.27%
8.39%
8.38%
8.38%
8.32%
8.43%
8.28%
8.21%
8.20%
7.75%
6.84%

HECO
AVERATE RATE BASE AND RATE OF RETURN
($ Thousands)
December 31, 2004

Line No.	RATE BASE	Month End	Source
1	NET UTILITY PLANT	1,461,069	PUC p.8
2	Adjustments:		
3	Franchise & Organizational Costs		
4	Construction Work in Progress	(79,532)	PUC p.8
5	Retirement Work in Progress	(7,115)	PUC p.8
6	Other		
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,374,422	
8			
9	REGULATORY ASSETS	50,082	Sch 1D
10			
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	11,039	PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(892)	Sch 1E
13			
14	FUEL STOCK	39,420	PUC p.8
15	QUALIFIED PENSION LIABILITY	81,085	Sch 1D
16			
17	E-BUSINESS	81	PA59
18	E-BUSINESS-HARDWARE	265	PA06
19			
20			
21	WORKING CASH:		
22	1/24 Fuel Oil & PP Expense	26,302	Sch 1A
23			
24	1/12 Other Operation & Maintenance Expenses	12,798	Sch 1B
25	(Excluding FO & PP)		
26			
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	6,017	Sch 1C
28			
29	TOTAL WORKING CASH	45,117	
30			
31	DEDUCTIONS:		
32	Unamortized Contributions in Aid of Construction	144,322	Sch 1D
33	Customer Advances for Construction	1,519	Sch 1D
34	Deferred Income Taxes (Excluding Reg Assets)	100,834	Sch 1D
35	Deferred Income Taxes - Regulatory Assets	50,090	Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	24,759	Sch 1D
37	Rental Premiums - Kamoku	19	Sch 1D
38	Customer Deposits	5,067	Sch 1D
39	Unamortized Gain on Sales	470	Sch 1D
40	Regulatory Liability for Cost of Removal	131,915	25400001
41	TOTAL DEDUCTIONS	458,995	
42			
43	MONTH ENDED RATE BASE	1,141,624	

HAWAIIAN ELECTRIC COMPANY, INC.

RATE OF RETURN ON RATE BASE AND ON COMMON EQUITY
For the 12 months ended June 30,

(In thousands)

Line		Ratemaking 2005	Ratemaking 2004
	Earnings for most recent 12 months:		
A	Operating income	$67,184	$83,903
B	Earnings for common stock	$43,284	$58,532
	Weighted Average:		
C	Rate Base: Amount	$1,069,338	$1,005,089
D	Rate of Return (A/C)	6.28%	8.35%
E	Common Equity: Amount	$631,905	$588,671
F	Rate of Return (B/E)	6.85%	9.94%
	Simple Average:		
G	Rate Base: Amount	$1,068,892	$1,007,105
H	Rate of Return (A/G)	6.29%	8.33%
I	Common Equity: Amount	$625,747	$589,230
J	Rate of Return (B/I)	6.92%	9.93%
	End of Period:		
K	Rate Base: Amount	$1,129,799	$1,007,984
L	Rate of Return (A/K)	5.95%	8.32%
M	Common Equity: Amount	$648,062	$603,431
N	Rate of Return (B/M)	6.68%	9.70%

Per Decision and Order No. 14412 dated December 11, 1995, the allowed rate of return on average rate base and on average common equity is 9.16% and 11.40%, respectively.

HECO ADJUSTMENTS
RATEMAKING
2005

Month	Book Rate Base (Sch 1)	Book W/C (Sch 1)	Rate W/C (Sch A)	Deferred Taxes- Apprise/ E-Business	E-Business	Adjusted Rate Base	13 Mos. Weighted Avg	Simple Avg	Total Oper Income	WTD Avg (H)/(F)	Simple Avg (H)/(G)	EOP (H)/(E)
Jan	1,140,761	(45,710)	7,009	(335)	54	1,101,779	1,024,915	1,052,546	73,786	7.20%	7.01%	6.70%
Feb	1,142,751	(45,741)	6,897	(323)	53	1,103,637	1,032,633	1,055,004	72,906	7.06%	6.91%	6.61%
Mar	1,165,651	(46,202)	6,847	(313)	52	1,126,035	1,041,837	1,066,074	69,158	6.64%	6.49%	6.14%
Apr	1,159,909	(46,596)	7,118	(302)	51	1,120,180	1,050,612	1,065,492	68,699	6.54%	6.45%	6.13%
May	1,180,212	(47,343)	7,171	(293)	50	1,139,797	1,060,534	1,077,575	67,188	6.34%	6.24%	5.89%
June	1,170,686	(48,182)	7,530	(283)	48	1,129,799	1,069,338	1,068,892	67,184	6.28%	6.29%	5.95%
July	0		7,021			7,021	992,341	504,491	59,584	6.00%	11.81%	848.71%
Aug	0		6,450			6,450	915,763	504,065	52,236	5.70%	10.36%	809.90%
Sept	0		5,819			5,819	839,158	515,255	44,950	5.36%	8.72%	772.46%
Oct	0		5,093			5,093	760,727	511,667	36,772	4.83%	7.19%	722.02%
Nov	0		4,364			4,364	682,737	513,436	32,589	4.77%	6.35%	746.74%
Dec	0		3,561			3,561	604,356	553,329	30,534	5.05%	5.52%	857.53%
	6,959,970	(279,774)	74,879			6,753,534						

2004 ADJUSTED RATE BASE	
Jan	1,003,312
Feb	1,006,371
Mar	1,006,114
Apr	1,010,804
May	1,015,354
Jun	1,007,984
Jul	1,001,962
Aug	1,001,680
Sep	1,024,691
Oct	1,018,241
Nov	1,022,508
Dec	1,103,097
	12,222,120

HECO
AVERATE RATE BASE AND RATE OF RETURN
($ Thousands)
June 30, 2005

Line No.	RATE BASE	Month End		Source
1	NET UTILITY PLANT	1,481,411	/	PUC p.8
2	Adjustments:			
3	Franchise & Organizational Costs			
4	Construction Work in Progress	(73,500)	/	PUC p.8
5	Retirement Work in Progress	(4,664)	/	PUC p.8
6	Other			
7	DEPRECIATED COST OF UTILITY PLANT IN SERVICE	1,403,247		
8				
9	REGULATORY ASSETS	50,847	/	Sch 1D
10				
11	MATERIALS & SUPPLIES (Excluding Stores Expense)	12,588	/	PUC p.8
12	MATERIALS & SUPPLIES ADJUSTMENT	(962)	/	Sch 1E
13				
14	FUEL STOCK	44,528	/	PUC p.8
15	QUALIFIED PENSION LIABILITY	78,791	/	Sch 1D
16				
17	E-BUSINESS	47	/	PA59
18	E-BUSINESS-HARDWARE	236	/	PA06
19				
20				
21	WORKING CASH:			
22	1/24 Fuel Oil & PP Expense	27,965	/	Sch 1A
23				
24	1/12 Other Operation & Maintenance Expenses	13,935	/	Sch 1B
25	(Excluding FO & PP)			
26				
27	1/12 Taxes Other than Income, Excl. Franchise Taxes	6,282	/	Sch 1C
28				
29	TOTAL WORKING CASH	48,182		
30				
31	DEDUCTIONS:			
32	Unamortized Contributions In Aid of Construction	143,960	/	Sch 1D
33	Customer Advances for Construction	1,518	/	Sch 1D
34	Deferred Income Taxes (Excluding Reg Assets)	97,892	/	Sch 1D
35	Deferred Income Taxes - Regulatory Assets	50,855	/	Sch 1D
36	Unamortized Investment Tax Cr - 1962 Revenue Act & STC	25,734	/	Sch 1D
37	Rental Premiums - Kamoku	17	/	Sch 1D
38	Customer Deposits	5,154	/	Sch 1D
39	Unamortized Gain on Sales	1,696	/	Sch 1D
40	Regulatory Liability for Cost of Removal	139,992	/	Sch 1D
41	TOTAL DEDUCTIONS	466,818		
42				
43	MONTH ENDED RATE BASE	1,170,686		

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DOD-RIR-29

Refer to HECO RT-16, page 26, line 22, through page 34, line 2.

Please identify all facts and information contained in such rebuttal testimony that HECO did not have at the time of its direct filing.

HECO Response:

See HECO response to DOD-RIR-26.

DOD-RIR-30

Refer to HECO RT-16, page 32, lines 4-9.

Please identify and provide all testimony filed in the HELCO and MECO rate cases that opposed the companies' proposed rate base treatment for the prepaid pension asset (HELCO) or pension liability (MECO). Also, include the related exhibits showing the analysis.

HECO Response:

There was no testimony filed in the HELCO 2000 test year rate case (Docket No. 99-0207) opposing the rate base treatment of the prepaid pension asset.

In the MECO 1999 test year rate case (Docket No. 97-0346), MECO forecasted test year NPPC of $877,000 (revised from direct testimony which forecasted $1.6 million). At that time, MECO also determined that it would not be able to deduct, for income tax purposes, any funding of the NPPC. Recognition of the NPPC with no pension fund contribution increased the pension liability. MECO proposed to include a test year average non-funded pension liability of $1,293,000 as a reduction to rate base. The CA proposed disallowance of the NPPC and elimination of the pension liability. Relevant CA testimony and exhibits from Docket No. 97-0346 are attached. MECO and the CA stipulated to include a test year estimate for non-funded pension liability of $762,000 at year-end 1998 and $1,639,000 at year-end 1999 as a reduction to rate base. The Commission accepted the stipulation in D&O 16922.

docket, but reserves the right to recommend any necessary adjustments in future proceedings. The Consumer Advocate recognizes that MECO has attempted to quantify benefits resulting from Continuous Improvement. However, since MECO expects to continue this program using ratepayer funds, the Consumer Advocate will continue to monitor program expenses and ratepayer benefits. The program should be allowed to continue only if MECO provides adequate documentation to prove that the program is cost-effective and that ratepayers receive a reasonable level of benefits.

V. NON-FUNDED QUALIFIED PENSION LIABILITY

Q. PLEASE EXPLAIN MECO'S TREATMENT OF NON-FUNDED QUALIFIED PENSION LIABILITY IN RATE BASE.

A. MECO is seeking Commission approval to collect ratepayer monies for the qualified pension expense. However, MECO does not intend to use the monies collected to fund the qualified pension trust. Under MECO's proposal, MECO would be allowed to use the monies at its discretion. Since MECO will have the use of ratepayer funds, MECO recognizes these funds as a liability that reduces rate base. MECO forecasts the average consolidated non-funded qualified pension liability for the test year to be $2,286,000.[28]

[28] MECO-1401.

Q. DO YOU AGREE WITH MECO'S RATE BASE TREATMENT OF THE NON-FUNDED PENSION LIABILITY?

A. For the reasons discussed by Mr. Saito in CA-T-7, the Consumer Advocate believes that MECO should not be allowed to collect ratepayer funds if these funds are not deposited into the qualified pension account. If the Commission agrees with the Consumer Advocate's position, no reduction in rate base will be necessary. See exhibit CA-609.

VI. WORKING CASH

Q. BRIEFLY DESCRIBE THE PURPOSE OF CALCULATING WORKING CASH FOR THE TEST YEAR REVENUE REQUIREMENT.

A. The purpose of calculating working cash is to determine the amount of capital provided by shareholders and ratepayers in the course of MECO's operations. If the ratepayers provide a net contribution, this results in a decrease in rate base; if shareholders are required to provide for a net contribution, this results in an increase in rate base. Any issues with respect to working cash and its impact on rate base would be discussed and recommended as an appropriate adjustment.

However, for this proceeding the Consumer Advocate will not raise any issues with respect to working cash, but reserves the right to recommend any necessary adjustments in future proceedings. Any differences between MECO and the Consumer Advocate are due to differing estimates of test year expense levels. See exhibit CA-610.

CA-609
DOCKET NO. 97-0346
Page 1 of 1

MAUI ELECTRIC COMPANY, LTD.
NON-FUNDED QUALIFIED PENSION LIABILITY
1999 TEST YEAR

	Ref	Average Test Year Balance Amount Per MECO	Consumer Advocate Adjustment	Amount Per CA
MAUI	MECO-1402	2,075,000	(2,075,000)	0
MOLOKAI	MECO-1416	139,000	(139,000)	0
LANAI	MECO-1409	73,000	(73,000)	0
CONSOLIDATED	MECO-1401	2,287,000	(2,287,000)	0

premium rates only estimates what HMSA's 1999 premium rates may be. MECO does not consider the HMSA "accounting" procedure at the close of the calendar year.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that the Commission accept my adjustments to MECO's Flex Plan expenses for the 1999 test year. All of these adjustments are based upon the Consumer Advocate's projection of 310 as the average number of employees and salary/wage increase for the 1999 test year, the actual 1998 premium rates, and the updated flex plan participation as of January 1998.

The additional adjustment to Group Medical Expense and Post-Retirement Benefits recognizes refunds and surcharges MECO has received from its medical plan provider for its active employees and retirees historically.

B. PENSION (FUNDED)-EXPENSE

Q. WHAT IS THE ISSUE REGARDING PENSION FUNDED-EXPENSE?

A. The issue is the Company's proposal to include $1,605,000 in pension expense in the test year revenue requirement even though MECO will not be making a contribution to its pension fund trust in the 1999 test year (i.e., not funding the pension expense). As stated on MECO T-10, page 24, lines 2-18, MECO has included the Net Periodic Pension Cost (NPPC) in its revenue requirements. Since contributions will not be made to the pension trust, MECO has made an adjustment to deduct the non-funded pension amounts from rate

base for the test year. Negative deferred taxes related to the non-funded pension amounts are also reflected in the accumulated deferred income tax balances.

Q. WHAT IS YOUR RECOMMENDATION?

A. I recommend that the Commission reject MECO's proposal to include the $1,605,000 pension expense in the 1999 test year revenue requirement. Although the Company is required to recognize the pension expense for financial statement purposes (i.e., for Generally Accepted Accounting Principle (GAAP) purposes), GAAP does not require the funding of the pension expense. MECO has stated that a determination to fund the financial statement liability is based upon the maximum allowable income tax deduction set by the Internal Revenue Code. Since MECO will not be able to deduct any contributions to its pension trust in 1999, MECO has stated that it will not fund (i.e., make a contribution to the pension trust) in the 1999 test year. The Company's proposal is unreasonable and should be disallowed.

Q. PLEASE EXPLAIN WHY YOU ARE RECOMMENDING THE DISALLOWANCE OF THE COMPANY'S ESTIMATED PENSION EXPENSE FOR THE 1999 TEST YEAR.

A. I am recommending a disallowance of MECO's pension expense for the 1999 test year because the Company has not explained, in detail, all the issues surrounding its proposal to collect the $1,605,000 pension expense and not make a contribution to the pension fund

trust. In addition, MECO has not demonstrated that the benefits of the Company's proposal outweighs the costs of the proposal.

Q. HOW IS MECO'S PENSION EXPENSE DETERMINED FOR THE 1999 TEST YEAR?

A. The Company's pension expense, or the NPPC is determined by its Actuary, Watson Wyatt Worldwide, under the provisions of Statement of Financial Accounting Standards (SFAS) No. 87[6]. For GAAP purposes, the NPPC is the amount MECO must recognize on its financial statements as the cost of providing pension benefits to its employees.

Q. IS THE NPPC THE AMOUNT MECO IS REQUIRED TO CONTRIBUTE TO ITS PENSION PLAN TRUST?

A. No. The NPPC is the amount MECO must recognize for GAAP purposes. The amount MECO is required to contribute to the qualified pension plan trust is specified under the Employee Retirement Income Security Act of 1974[7]. The Internal Revenue Code specifies the deductible contribution amount for Federal income tax purposes.

[6] MECO T-10, page 17, lines 18-23,

[7] MECO T-10, page 21, lines 15-24.

Q. WHY IS MECO PROPOSING TO NOT FUND ITS 1999 TEST YEAR PENSION EXPENSE?

A. As stated on MECO T-10, page 22, line 21 through page 23, line 12, MECO explains that it will reach its full funding limitation in 1998, which means that any further contributions to the pension trust will not be deductible for income tax purposes beginning in 1998. Therefore, MECO asserts that it will not be making a contribution to its pension trust in the 1999 test year because the pension expense will not be deductible for income tax purposes. The Company states that its Actuary has estimated that this full funding limitation will apply until approximately 2006[8].

Q. WHAT ARE THE FULL FUNDING LIMITATIONS THAT DETERMINE THE INCOME TAX DEDUCTIBILITY OF MECO'S PENSION CONTRIBUTIONS?

A. As described on pages 47 to 51 of MECO's response to CA-IR-10004, there appears to be four full funding limitations that determine MECO's minimum required and maximum income tax deductible pension contributions. They are:

1. Traditional Full Funding Limitation;
2. Omnibus Budget Reconciliation Act (OMBRA) of 1987 Full Funding Limitation;
3. Retirement Protection Act (RPA) of 1995 Full Funding Limitation Threshold; and
4. 100% Current Liability Deduction.

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[8] MECO T-10, page 25, lines 1-3.

Each of these full funding limitations are described on pages 47 through 51 of MECO's most recent Actuarial Valuation report (as of January 1, 1997) provided in response to CA-IR-10004.

As shown on MECO's response to CA-SIR-1004, page 3, the Traditional Full Funding Limitation is the limitation that determines the minimum required and maximum deductible pension contributions for MECO in this particular instance.

Q. PLEASE EXPLAIN WHY YOU BELIEVE THE COMPANY HAS NOT FULLY EXPLAINED ALL THE ASPECTS OF ITS PROPOSAL TO COLLECT THE $1,605,000 PENSION EXPENSE, BUT NOT MAKE A CONTRIBUTION TO ITS PENSION TRUST FUND.

A. As stated earlier, the Company's proposal is as follows:

1. Collect the pension expense;
2. Reduce rate base for the amount not contributed to the pension trust fund; and
3. Recognize a negative deferred income tax (DIT) related to non-funded pension amounts.

On the surface, the Company's proposal may appear reasonable. However MECO's recommendation does not discuss how the amount to be included in rate base would be reduced, or relieved in the future (if at all). For example, rate base items such as plant in service are reduced by accumulated depreciation, CIAC is amortized, and inventories are used, and change over time. However, the Company does not provide any

explanation on how the non-funded, qualified pension liability would be reduced in future years. In addition, MECO does not explain how the non-funded reserve balance will be treated when MECO is able to make tax deductible contributions to the pension trust in future years.

Q. PLEASE DESCRIBE THE NEGATIVE DIT ASPECT OF THE COMPANY'S PROPOSED INCLUSION OF THE NPPC IN THE REVENUE REQUIREMENT.

A. If the Commission allows MECO to collect the estimated pension cost from ratepayers without making the corresponding contribution to the pension plan trust, the Company must recognize a negative DIT (for both Federal and State purposes) on the $1,605,000. The negative DIT will result because the pension cost is used as a deduction to determine the income tax liability for financial statement and for rate setting purposes. However, this pension expense cannot be recognized for income tax purposes because MECO will have reached its full funding limitation. The negative DIT that is created to reverse [illegible]

In addition, it is not clear whether this negative DIT is truly a timing difference for income tax purposes. For example, if this negative DIT is not going to turn around, or be reduced in the future, then this negative DIT is not a true timing difference. If it is the Company's assertion that the proposed negative DIT will turn around in the future, MECO does not provide any information stating how this will occur. Also, MECO does not explain how it will treat the accumulated pension reserve liability in the future, when pension expense contributions becomes tax deductible again.

These issues need to be addressed and thoroughly analyzed before a determination can be made that MECO's proposed pension expense treatment should be allowed. Because the Company has not provided such information, I believe it is premature to allow MECO's proposed pension expense in rates.

Q. UNDER THE CONSUMER ADVOCATE'S PROPOSAL, WOULD THE NEGATIVE DIT BE RECOGNIZED FOR RATEMAKING PURPOSES?

A, No. If the NPPC pension expense is not recognized for ratemaking purposes, a negative DIT would not be recognized for ratemaking purposes because the difference creating he negative DIT is between financial statement and income tax, not ratemaking and income tax.

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Page 38

Q. HAS THE COMPANY DESCRIBED HOW IT WILL USE THE FUNDS COLLECTED FOR THE PENSION EXPENSE IF THE COMMISSION ALLOWS THE RECOVERY OF THIS PENSION EXPENSE IN THE TEST YEAR REVENUE REQUIREMENT?

A. Yes. In response to CA-SIR-1015, the Company states that it will use the funds as directed by the Commission. However, MECO goes on to state that if the Commission does not provide any guidance regarding the use of the funds, the Company would use the funds (net of related tax payments), to pay for the construction of plant, in lieu of obtaining the funds from investors. Again, the Company does not discuss all the ramifications of its proposal to use the funds to pay for the construction of plant.

Q. YOU MENTIONED EARLIER THAT YOU BELIEVE THAT THE BENEFITS OF ALLOWING MECO'S PROPOSAL DO NOT OUTWEIGH THE COSTS. PLEASE EXPLAIN YOUR POSITION.

A. I believe the benefits of Company's proposal do not outweigh the costs for the following reasons:

1. The negative deferred income taxes related to this amount will reduce the benefit of collecting the pension expense; and
2. MECO will not fund its pension trust which will:
   a. Lower earnings in the Pension Trust; and

As I mentioned earlier, the recognition of both a reduction to rate base for the non-contributed pension amount and the negative DIT on this amount effectively reduces the value of the ratepayers money by the effective composite income tax rate (38.91%).

Q. WHAT IS THE IMPACT OF MECO NOT FUNDING THE NPPC PENSION EXPENSE COLLECTED FROM RATEPAYERS?

A. I believe the impact of MECO's proposal regarding the NPPC pension expense will result in higher costs to MECO's ratepayers in the future. Since the Company will not contribute pension funds into the pension plan trust, the pension trust plan assets and the investment returns on the fund trust will not grow at the same rate as it would if pension contributions had been made to the trust. The reason is because there would be less money upon which earnings could be achieved under the Company's proposal. The result of the lower growth in plan assets would be higher pension expenses in the future years.

Q. HOW DOES THE INVESTMENT RETURN ON THE TRUST FUND AFFECT THE NPPC?

A. As stated on MECO T-10, page 18, lines 5-10, there are basically four factors that determine MECO's NPPC. They are:

1. Benefits provided (plan provisions);
2. Employee demographics;
3. Actuarial assumptions; and

4. Investment returns of the trust.

The Actuary determines the pension expense MECO must recognize for financial statement (or GAAP) purposes based upon the Company's pension plan provisions, demographics, investment returns of the trust, and certain actuarial assumptions as of the valuation date. Under MECO's proposal, the investment returns for the pension plan trust would not include the potential earnings on the non-contributed amount (i.e., the $1,605,000). Therefore, the investment returns would be less for a plan without the contributions and the NPPC for future years would be higher than the NPPC for a plan with continued contributions.

CA-714 provides a comparison of pension plans with and without pension contributions. The exhibit illustrates the contention that if the plan provisions, company demographics, and actuarial assumptions are identical for each plan, the NPPC is higher for the non-contributing plan in the long run because of the lower investment returns of that plan.

This is the situation that would occur based upon the Company's proposal to collect the NPPC from ratepayers, but not make the contribution to the pension plan trust.

Q. DOES THE COMPANY BELIEVE THE PENSION COST WOULD BE HIGHER BASED UPON ITS PROPOSAL?

A. No. In response to CA-SIR-1016(b), MECO believes the pension cost would be the same. It states:

> Over time, the total amount required from ratepayers to pay for NPPC costs will be the same, it's just a matter of timing. If funds are collected now, ratepayers will receive the benefit of MECO holding these funds, as explained in CA-SIR-1018. Whereas, if funds are collected later, it would be immediately contributed into the pension trust.

As my example illustrated on CA-714 shows, however, I believe the Company is incorrect in assuming that the total pension cost will be the same over time.

Q. HAVE YOU ANALYZED THE POSSIBLE IMPACT OF THE COMPANY'S PROPOSAL?

A. Yes. I have provided a simple analysis shown on CA-723. Basically, page 1 of CA-723 is the Company's "benefit", or the cash balance on hand. Page 2 of CA-723 reflects the alleged ratepayers' "benefit", or the ratebase offset, and the impact on revenue requirement. As shown on these schedules, the net cash MECO will have is only $6.2 Million (column l of page 1 of CA-723) as compared to the gross reserve of $11.2 Million (column d). As for ratepayers, a contribution of $8.9 Million (column i of page 2 of CA-723) would be required to fund only $6.2 Million. It should be noted that these exhibits illustrate simplistic analyses with certain variables not reflected. However, as these schedules show, the costs to ratepayers under MECO's proposal outweigh the benefits.

Q. HAS THE COMPANY SET FORTH A SIMILAR TYPE OF PROPOSAL IN ANOTHER DOCKET BEFORE THIS COMMISSION?

A. Yes. A similar type of issue was raised in Docket No. 95-0051, where various utility companies sought Commission approval to establish a Self-Insurance Property Damage Reserve through collections from ratepayers. Briefly, the utility companies proposed to collect an arbitrary level of funds from ratepayers for the purpose of establishing a reserve (that could either be funded into an escrow account or unfunded with the monies available for discretionary use) in the event a catastrophic event impacted one of the utility companies. Similar to that issue, the Consumer Advocate is not convinced that MECO's proposal is in the best interest of the ratepayers. The proposed inclusion of the pension expense in base rates coupled with the Company's proposal to not fund the pension trust with the proceeds appears to represent a situation where the ratepayers will be required to contribute more funds than necessary in future years.

The Company has not thoroughly explained all of the ramifications and procedures that will be required under its proposal. A prime example is how ratepayers will receive the benefits from the $1,605,000 and the earnings that would result from that contribution. As shown on CA-714 and CA-723, it does not appear that the benefits to ratepayers outweigh the costs.

Q. WHAT ARE THE POSSIBLE RAMIFICATIONS IF THE COMMISSION DOES NOT ALLOW THE RECOVERY OF MECO'S NPPC IN RATES?

A. In response to a similar question posed in CA-SIR-1019(f), MECO states:

> If the Commission denies recovery of the NPPC in rates, there would likely be a significant negative impact on MECO's earnings. MECO would still need to record the NPPC as an expense for financial statement purposes. MECO may be allowed to defer all or a portion of the denied NPPC if it is deemed probable that future revenue in an amount at least equal to the deferred NPPC will result from inclusion of that cost in allowable costs for ratemaking purposes (rather than expected levels of similar future costs). In order to conclude on the probability of future revenue as discussed above, a rate order from the Commission would be necessary. This rate order should allow for both the deferral of the unfunded NPPC and for the subsequent inclusion of those deferred costs in MECO's rates. If at any time the deferred costs no longer meet the probability test discussed above, MECO would be required to charge those costs to earnings. In addition to the Commission's rate order, MECO's management would need to be able to conclude, with concurrence by MECO's external auditor, that it is probable that ratepayers would pay the resulting rates in the future, even in light of the growing competition in the industry. In terms of income tax, the consequence of the Commission denying rate recovery for NPPC would be a reduction in revenue, resulting in a reduction of income taxes. There would be no affect on pension plan benefits or the pension trust.

Based upon the response above, it appears that the Company's only concern is with the negative impact on its earnings. However, it is not clear why there will be a negative impact to earnings since MECO is required to recognize the pension expense for financial statement purposes. Thus, the Commission should not allow this pension expense in rates and also deny MECO's potential request at future recovery of this amount.

Q. IF THE COMMISSION DOES NOT AGREE WITH YOUR RECOMMENDATION TO DISALLOW THE TEST YEAR NPPC PENSION EXPENSE FOR RATEMAKING PURPOSES, WHAT RECOMMENDATION DO YOU MAKE REGARDING THE USE OF THE FUNDS COLLECTED FOR THE NPPC PENSION EXPENSE?

A. If the Commission does not agree with my recommendation to disallow the pension expense for the 1999 test year, I recommend two alternatives for the Commission's consideration:

1. Allow the Company to collect the pension expense and direct MECO to segregate the non-funded NPPC pension expense collected from ratepayers and use the funds to satisfy the future pension liability; or

2. Allow the Company to collect the pension expense and direct MECO to contribute the proceeds to its pension trust.

These two alternative recommendations reflect a position that is in accordance with Decision and Order No. 13659 (Docket Nos. 7243/7233 consolidated). Decision and Order No. 13659 dealt with the various issues surrounding the utility companies adoption of Statement of Financial Accounting Standard No. 106, Employers' Accounting for Postretirement Benefits Other Than Pensions (SFAS 106). The discussion on pages 28 through 30 of Decision and Order No. 13659 discussed the parties' positions and the Commission's discussion and decision on the matter. If the Commission is inclined to allow recovery of the pension expense in this docket, the Consumer Advocate

recommends that the funds collected for pension expense should be placed in an acceptable funding vehicle.

Q. PLEASE ELABORATE ON YOUR FIRST ALTERNATIVE RECOMMENDATION.

A. If the Commission allows the first alternative, the following issues need to be addressed:

1. How will the concerns regarding the negative DIT be resolved;
2. How will the principal and earnings from the NPPC expense collected from ratepayers be used to offset the future pension expense;
3. How will the segregated NPPC pension expense funds be invested; and
4. Will the Actuary consider these segregated funds in determining MECO's future NPPC.

In response to CA-SIR-1018, MECO states that if the funds are deposited into an interest bearing escrow account, the funds would earn interest to the benefit of MECO's ratepayers at the passbook or certificate of deposit interest rates in effect during the time the funds are deposited. However, MECO does not elaborate on how the principal and interest earned on the invested NPPC funds would be used to offset future pension expense. Furthermore, it should be noted that under this alternative, any earnings on the segregated pension expense funds will not be tax deferred in the same manner as if the funds were contributed to the pension trust fund.

Q. WITH REGARDS TO YOUR SECOND ALTERNATIVE RECOMMENDATION, IS THE COMPANY ALLOWED TO CONTRIBUTE TO A FULLY FUNDED PENSION PLAN?

A. Yes. In response to CA-SIR-1019(g), MECO states that it is allowed to make pension contributions to a fully funded pension plan without losing any income tax advantage for the plan. However, a 10% tax on the non-deductible portion of the contribution will be assessed for each year that the contributed amount is non-deductible[10]. In other words, if MECO made the $1,605,000 contribution to its pension fund trust, a $16,050 tax would be incurred on this amount for every year that MECO cannot make a tax deductible

plan trust in unreasonable. Although the Company is required to recognize this expense on its financial statements for GAAP purposes, GAAP does not require the expense to be recognized for ratemaking purposes. Furthermore, the Company's proposal to not fund the pension trust will be more costly to ratepayers and will result in a higher pension expense in future years.

If the Commission does not agree with my recommendation, I have offered two alternatives for consideration. However, these alternatives also have certain issues that need to be addressed before implementation. .

C. EMPLOYEE BENEFITS TRANSFERRED TO CONSTRUCTION AND EMPLOYEE BENEFITS TRANSFERRED TO OTHER THAN CONSTRUCTION

Q. ARE ADJUSTMENTS TO ACCOUNT NO. 92690 EMPLOYEE BENEFITS TRANSFERRED TO CONSTRUCTION AND ACCOUNT NO. 92691 EMPLOYEE BENEFITS TRANSFERRED TO OTHER THAN CONSTRUCTION NECESSARY?

A. Yes. Based upon my proposed adjustments to MECO's Flex Plan and other components of employee Benefits, adjustments to employee benefits transferred to construction (Account No. 92690) and employee benefits transferred to other than construction (Account No. 92691) are necessary because the employee benefit group of accounts represent the pool of costs eligible for transfer.

Docket No. 97-0346
Maui Electric Company, Limited
Pension Expense Illustration
Test Year Ended December 31, 1999

Assumed ROR:
10%

	Year 0 Beg. Balance*	Contribution**	Earnings	Year 1	Contribution	Earnings	Year 2	Contribution	Earnings	Year 3	Contribution	Earnings	Year 4	Contribution	Earnings	Year 5	Total Earnings
With Contribution	$52,649,000	1,605,000	5,264,900	59,518,900	1,605,000	5,951,890	67,075,790	1,605,000	6,707,579	75,388,369	1,605,000	7,538,837	84,532,206	1,605,000	8,453,221	94,590,426	33,916,426
Without Contribution	$52,649,000	0	5,264,900	57,913,900	0	5,791,390	63,705,290	0	6,370,529	70,075,819	0	7,007,582	77,083,401	0	7,708,340	84,791,741	32,142,741
Difference	0			1,605,000			3,370,500			5,312,550			7,448,805			9,798,686	1,773,686

* MECO response to CA-SIR-1004 Asset Valuation Value of MECO's pension fund.
** 1999 test year NPPC forecast MECO-1008.

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Docket No. 97-0346
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MAUI ELECTRIC COMPANY, LTD.
NON-FUNDED QUALIFIED PENSION LIABILITY
AFTER-TAX CASH BALANCE
1999 TEST YEAR

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)	(j)	(k)	(l)
	YEAR	MECO REVENUE	RESERVE	REV TAX @ 6.885%	UNCOLLECT @ .161%	(d)-(e)-(f) PRETAX INCOME	PAYOUTS	(g)-(h) TAXABLE INCOME	INC TAX @ 38.91%	(i)-(j) RESERVE AFTER TAX	CUM RESERVE
1	1999	0	1,605,000	142,604	2,584	1,459,812	0	1,459,812	568,013	891,799	891,799
2	2000	0	1,605,000	142,604	2,584	1,459,812	0	1,459,812	568,013	891,799	1,783,598
3	2001	0	1,605,000	142,604	2,584	1,459,812	0	1,459,812	568,013	891,799	2,675,397
4	2002	0	1,605,000	142,604	2,584	1,459,812	0	1,459,812	568,013	891,799	3,567,196
5	2003	0	1,605,000	142,604	2,584	1,459,812	0	1,459,812	568,013	891,799	4,458,995
6	2004	0	1,605,000	142,604	2,584	1,459,812	0	1,459,812	568,013	891,799	5,350,794
7	2005	0	1,605,000	142,604	2,584	1,459,812	0	1,459,812	568,013	891,799	6,242,593
8	2006	0	0	0	0	0	0	0	0	0	0
9	2007	0	0	0	0	0	0	0	0	0	0
10	2008	0	0	0	0	0	0	0	0	0	0
11	2009	0	0	0	0	0	0	0	0	0	0
12	2010	0	0	0	0	0	0	0	0	0	0
			11,235,000	998,230	18,088	10,218,682	0	10,218,682	3,976,089	6,242,593	

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Page 2 of 2

MAUI ELECTRIC COMPANY, LTD.
NON-FUNDED QUALIFIED PENSION LIABILITY
NET REVENUE REQUIRED FROM RATEPAYERS
1999 TEST YEAR

(a)	(b)	(c)	(d)	(e)	(f)	(g)	(h)	(i)
		RESERVE	CUM RESERVE	ADIT	(d) - (e) NET RB	beg+end/2 AVG RB	9.75%*(g) MECO	(c)-(h) REVENUE
1	1999	1,605,000	1,605,000	624,506	980,495	490,247	47,799	1,557,201
2	2000	1,605,000	3,210,000	1,249,011	1,960,989	1,470,742	143,397	1,461,603
3	2001	1,605,000	4,815,000	1,873,517	2,941,484	2,451,236	238,996	1,366,004
4	2002	1,605,000	6,420,000	2,498,022	3,921,978	3,431,731	334,594	1,270,406
5	2003	1,605,000	8,025,000	3,122,528	4,902,473	4,412,225	430,192	1,174,808
6	2004	1,605,000	9,630,000	3,747,033	5,882,967	5,392,720	525,790	1,079,210
7	2005	1,605,000	11,235,000	4,371,539	6,863,462	6,373,214	621,388	983,612
8	2006	0	0	0	0	0	0	0
9	2007	0	0	0	0	0	0	0
10	2008	0	0	0	0	0	0	0
1	2009	0	0	0	0	0	0	0
12	2010	0	0	0	0	0	0	0
		11,235,000				24,022,115	2,342,156	8,892,844

DOD-RIR-32

Refer to HECO RT-16, page 47, line 19-21.

Please Confirm that nowhere in any of the CA or DOD testimony is it stated that "utilities are guaranteed their authorized rate of return." If your answer is anything other than an unqualified confirmation, please explain fully and provide specific citations to each provision in CA and DOD testimony in which such a statement was asserted.

HECO Response:

Mr. Carver implies that utilities are guaranteed their authorized rate of return at CA-T-2, page 16, lines 1-2.

DOD-RIR-33

Refer to HECO RT-16, page 51, lines 17-25.

Does HECO fully agree with the test year concept as quoted? If not, explain fully why not.

HECO Response:

The purpose of citing the above referenced statement in RT-16 was to show that the testimonies of Mr. Brosch and Mr. Carver are not consistent. It was not intended to express the Company's agreement or disagreement with this statement. However, the Company agrees to the extent that revenues and costs will change over time and that the use of the test year in ratemaking is to establish a revenue level and ultimately rates that will allow the Company the opportunity to earn the rate of return determined to be fair and reasonable during the period that the rates are in effect. This will not happen if certain costs that will be on-going, such as those associated with the DG units being installed in the third and fourth quarters of 2005 and with employees that will be hired for newly created positions over the course of 2005, are not annualized in the test year revenue requirement to reflect what those costs would be incurred for a full year going forward.

DOD-RIR-34

Refer to HECO RT-16, page 52, line 19.

Provide citations to all Commission orders that HECO is relying upon for its interpretation of "retroactive ratemaking."

HECO Response:

HECO RT-16 did not cite any particular Commission order for an interpretation of retroactive ratemaking.

DOD-RIR-35

Refer to HECO RT-16, page 53, lines 3-4.

Please quantify all benefit to ratepayers "from the prepaid pension asset." Include all supporting calculations.

HECO Response:

HECO has not quantified the benefits that have arisen or been created since the last rate case as a result of the prepaid pension asset. Benefits such as maintaining the financial integrity of the pension fund and the Company are not easily quantified, but exist nonetheless.

DOD-RIR-36

Refer to HECO RT-16, pages 55-57.

a. Please describe fully and provide the documentation related to all searches HECO

b. Please list every contact HECO made in its less than exhaustive search of state commission orders.

c. Is HECO aware of any cases in which pension assets were proposed by the utility for rate

11. Alliant Energy
12. Aquila
13. Empire District Electric
14. Kansas City Power & Light Company
15. PPL Electric
16. PacifiCorp/Utah Power & Light
17. Puget Sound Energy

c. See the response to HECO/CA-IR-204(d). See also the response to a. above.

d. See the response to a.

e. See the response to a.

f. See the response to a.

Due to the voluminous nature of the information, one copy (pages 3 – 446 and Attachment, pages 1-149 of this response) will be provided to the Consumer Advocate, Department of Defense and the Public Utilities Commission under separate transmittal.

DOD-RIR-37

Refer to HECO RT-16, page 58, lines 23-24.

a. Since the inception of FAS 87 accounting for book purposes, please list the amount of cash each year that investors have provided to the pension plan.

b. Since the inception of FAS 87 accounting for book purposes, please list the amount of pension expense that was included in HECO's revenue requirement each year.

c. Please provide source references for the annual amounts listed in response to parts a and b.

HECO Response:

a. The amount of cash provided to the pension plan each year is shown on HECO-R-1609, page 1 of 2, column B.

b. The NPPC each year is shown on HECO-R-1609, page 1 of 2, column C.

c. Column B (net periodic pension cost) on HECO-R-1609 was obtained from response to CA-IR-337. Column C (the annual contributions to the pension fund) on HECO-R-1609 was obtained from response to CA-IR-337. Note that column D (ending prepaid pension asset) on HECO-R-1609 agrees to HECO's general ledger (through 2004).

DOD-RIR-38

Refer to HECO RT-16, page 63, lines 2-8.

Please provide a copy of all documents reviewed and/or exchanged during the meeting with S&P.

HECO Response:

See HECO's response to CA-RIR-14.

DOD-RIR-39

Refer to HECO RT-16, page 65, lines 2-6.

Please provide a copy of all documents reviewed and/or exchanged during the meeting with Moody's.

HECO Response:

See HECO's response to CA-RIR-14.

DOD-RIR-40

Refer to HECO RT-16, page 68, line 15, and HECO RT-23, page 2, line 1.

What is the lowest amount of rate relief that would be "meaningful"? Please quantify and explain the amount.

HECO Response:

HECO has justified the revenue increase reflected in HECO-R-2301. Please see HECO's rebuttal testimonies, exhibits, and workpapers which provide the support for the requested rate relief.

DOD-RIR-41

Refer to HECO RT-23, pages 6, lines 21-23.

Please identify specifically each adjustment wherein HECO believes that "the CA or DOD is proposing to disallow an expense that has been previously approved by the Commission" and provide a citation to where HECO believes that such expense has been approved.

HECO Response:

HECO's rebuttal testimonies address areas where the CA or DOD is proposing to disallow an expense that has been previously approved by the Commission. For example, HECO RT-10, page 18, discusses the CA's and DOD's misinterpretation of the Commission's D&O No. 21698 (Docket No. 05-0069) which states that "HECO may temporarily continue in the manner currently employed" its existing two residential DSM programs and three C&I DSM programs. HECO has continued to include in base rates (in the manner currently employed) the portion of DSM costs that represents labor expenses for HECO employees already included in base rates that are involved in DSM program implementation. However, the CA and DOD proposed exclusion and removal of all DSM expenses from HECO's 2005 test year expenses. See response to CA-RIR-63.

DOD-RIR-42

Refer to HECO RT-23, pages 7, lines 1-5.

a. Please identify specifically each adjustment and the associated impact wherein HECO believes that "the CA or DOD made a computational or input error in arriving at its estimate." Include supporting calculations.

b. Please identify specifically each adjustment and the associated impact wherein HECO believes that "later available information demonstrates the unreasonableness of the CA or DOD estimate, or where the CA or DOD estimate is clearly too low." Include supporting calculations.

HECO Response:

a. HECO discusses computational or input errors of the CA and for DOD in HECO's rebuttal testimonies. For example, HECO RT-10, discussed how the proposed labor expense adjustment of the CA and DOD double counted the reduction for vacant DSM positions and overestimated the impact on Customer Service Expense.

b. At this time HECO has not yet obtained "later available information" that demonstrates the unreasonableness of the CA or DOD estimate, or where the CA or DOD estimate is clearly too low.

DOD-RIR-43

Refer to HECO RT-23.

What is the specific amount of interim rate increase HECO proposing? Please identify the amount and show in detail how it is calculated.

HECO Response:

As stated on page 6, lines 4 to 8 of HECO RT-23, HECO proposes an Interim Step increase in an amount equal to the increase in rates to which the Commission believes HECO is "probably entitled" based on the evidentiary record before it in accordance with H.R.S. Section 269-16(d). As further stated by Mr. Alm at HECO RT-1, page 8, lines 1 to 3, HECO will determine the amount that it is requesting as an interim increase at the close of evidentiary hearing, based on the evidence before the Commission.

DOD-RIR-44

Refer to HECO RT-17, page 3, lines 3-8.

Is HECO aware of any regulatory jurisdictions in which the "interest synchronization" methodology for calculating the interest expense adjustment in the income tax calculation is utilized? If so, please list the jurisdictions of which HECO is aware that use the "interest synchronization" methodology.

HECO Response:

The Company is not aware of any regulatory jurisdictions in which the interest synchronization methodology is used in the income tax calculation. Given our opposing position and the Commission's past agreement with our method as reasonable, a survey of other jurisdictions was not deemed necessary.

DOD-RIR-45

Refer to HECO RT-18 pages 3-4.

a. Is the $5,636,000 a 12/31/05 estimate? If not, explain fully.

b. Is the impact on average 2005 test year rate base one-half of the $5,636,000. If not, quantify the impact on average 2005 test year rate base from this item.

c. Provide by month the actual expenditures on the New Kuahua Substation project through the present.

d. What is the in-service date of the New Kuahua Substation project?

e. When were the annual expenditures on the New Kuahua Substation project revised?

f. Please identify and explain all changes to the anticipated in-service date for the New Kuahua Substation project that have occurred since HECO's original filing in November 2004.

g. What other changes to plant additions beside the May 5, 2005 update and the June 15, 2005 update does HECO intend to propose? Please identify, quantify and describe all such changes.

HECO Response:

a. The $5,636,000 is the difference in the 2005 plant addition estimate between the June 15, 2005 update and the rebuttal estimate. The total plant addition estimate for 2005 for the New Kuahua Substation project is $7,500,000.

b. The impact on average 2005 test year rate base for the $5,636,000 change in estimate is one-half of the $5,636,000 or $2,818,000.

c. The actual expenditures, by month, for the New Kuahua Substation through August 16, 2005 are provided on page 3.

d. The in-service date for the New Kuahua Substation project is September 2005.

e. The annual expenditures for the New Kuahua Substation project have not changed significantly from the Company's direct testimony estimate. See Grandparent Y00021 on HECO-WP-1801 page 4, and HECO-RWP-1801, pages 2-3 for the annual expenditures

estimates used for the 2005 plant addition estimate for direct and rebuttal, respectively. As explained in HECO RT-18, pages 3 through 4, the change in the estimates between the June 15, 2005 update and the rebuttal testimony was due to an error.

f. The anticipated in-service date for the New Kuahua Substation project at the time of HECO's original filing in November 2004 was September 2005, which is the current estimated in-service date.

g. Presently, besides the May 5, 2005 update, the June 15, 2005 update, and the correction to plant addition estimate for the New Kuahua Substation project, the Company does not have any other changes to its 2005 plant addition estimate.

ACCOUNT_PRJ	thru 1999	Jan-00	Feb-00	Mar-00	Apr-00	May-00	Jun-00	Jul-00	Aug-00	Sep-00	Oct-00	Nov-00	Dec-00	Total
New Kuahua Substation Y00021	0	0	0	0	0	0	0	0	0	0	10,512	2,410	1,108	14,030

ACCOUNT_PRJ	thru 2000	Jan-01	Feb-01	Mar-01	Apr-01	May-01	Jun-01	Jul-01	Aug-01	Sep-01	Oct-01	Nov-01	Dec-01	Total
New Kuahua Substation	14,030	3,589	5,038	6,177	8,903	10,430	2,164	6,449	877	496	966	95	425	59,639

ACCOUNT_PRJ	thru 2001	Jan-02	Feb-02	Mar-02	Apr-02	May-02	Jun-02	Jul-02	Aug-02	Sep-02	Oct-02	Nov-02	Dec-02	Total
New Kuahua Substation	59,639	431	512	646	780	1,528	6,326	3,945	2,499	4,480	5,800	15,362	16,973	118,921

ACCOUNT_PRJ	thru 2002	Jan-03	Feb-03	Mar-03	Apr-03	May-03	Jun-03	Jul-03	Aug-03	Sep-03	Oct-03	Nov-03	Dec-03	Total
New Kuahua Substation	118,921	31,477	17,287	22,591	19,757	12,870	41,254	24,777	17,343	15,354	17,544	12,788	23,652	375,615

ACCOUNT_PRJ	thru 2003	Jan-04	Feb-04	Mar-04	Apr-04	May-04	Jun-04	Jul-04	Aug-04	Sep-04	Oct-04	Nov-04	Dec-04	Total
New Kuahua Substation	375,615	35,713	14,366	25,839	21,636	71,551	80,083	93,679	65,142	52,664	322,781	53,885	302,075	1,515,029

ACCOUNT_PRJ	thru 2004	Jan-05	Feb-05	Mar-05	Apr-05	May-05	Jun-05	Jul-05	08/16/05	Sep-05	Oct-05	Nov-05	Dec-05	Total
New Kuahua Substation	1,515,029	65,842	283,247	402,467	729,665	873,575	1,411,028	913,576	309,601					**6,504,030**

DOD-RIR-46

Refer to HECO RT-18, page 6.

a. Please provide the supporting documentation for HECO's revised expectations concerning when and in what amount Ford Island Substation project CIAC would be received.

b. Please provide a copy of the agreement, which specifies when, and in what amount CIAC for the Ford Island Substation project would be received by HECO.

HECO Response:

a. The CIAC payment schedule is based on a progress payment schedule that was agreed upon between HECO and the U.S. Navy (see response b below). At the time the progress payment schedule was approved by HECO and the U.S. Navy in April 2004, the estimated service date of the project was December 2005. This service date was estimated before bids were issued and evaluated for the 46kV line installations, which are the most significant components of the project in terms of cost and schedule.

After bids were received and evaluated (April 2005) from the 46kV line bidders, it was determined that none of the bidders could realistically meet the December 2005 service date. An excerpt of the bid evaluation conducted by HECO's consultant regarding the various schedules of the three short-listed contractors is attached as page 4. Based on this evaluation and re-evaluating the integration of the other project components (e.g. substation and communications) with the 46kV lines, it was determined that February 2006 was a reasonable service date for the project. The timing of the CIAC payments were then adjusted accordingly.

b. The portion of the agreement between the U.S. Navy and HECO for the project, which was filed as Exhibit 1 "Amendment of Solicitation/Modification of Contract," page 2, Docket

No. 04-0278, Y00040, Ford Island Substation, pertaining to the CIAC payment schedule and amounts are provided on page 6. Note that the handwritten annotations which show the estimated timing of the CIAC receipt were added to the excerpt.

HECO BIDDERS EVALUATION

I. POWER's Scope

II. Project Description

[redacted]

c. Financial

V. Cost Analysis
   a. Actual
   b. Evaluated
   c. Analysis

VI. Technical Analysis
   a. Schedule
   b. Subcontractor
   c. Safety
   d. Materials / Equipment
   e. Construction Management

VII. Commercial
   a. Payment / Retention

VI. Technical Analysis

a. Schedule:

	HECO	Hawaiian Dredge	Underground Construction	Michels
1. Project Completion	12/01/05	01/13/06	02/10/06	12/26/05
2. Steel casing at site	07/01/05	09/01/05	08/01/05	08/02/05
3. Steel casing installed	09/01/05	#1 – 11/27/05 #2 – 12/23/05	#1 – 10/18/05 #2 – 12/06/05	#1 – 09/03/05 #2 – 10/03/05
4. Duct Bank installed	08/01/05	09/29/05	12/05/05	08/25/05
5. Cable and Accessories to site	08/01/05	09/01/05	09/01/05	09/07/05
6. Cable and Accessories installed	11/30/05	01/13/05	02/04/06	12/26/05

Of the three evaluated bidders, none of the bidders will make the 12/01/05 energization. UG states it will be approximately two months later. Michels states it will be approximately one month later. HDCC state it will be approximately one and a half months late. All bidders required an April 25, 2005 Notice to Proceed to order major materials.

All bidders are close and the interview process solidified an actual schedule the contractors are willing to accept. It appears all bidders feel an early 2006 energization is realistic and they have taken that requirement into consideration in the bid price.

b. Subcontractors

1. Hawaiian Dredge: HDCC will self perform all civil / duct bank tasks. They will utilize Laney Direction Drilling for the horizontal Directional Drill from Ford Island to Oahu and American Electric for the cable work with assistance from cable manufacturer Southwire (Forte). HDCC first tier subcontractors are all experienced successful suppliers of the service or the equipment / materials required for the Ford Island project.
2. Michels Corporation: Michels will self perform the Horizontal Directional Drill. They will utilize Henkles and McCoy for the civil and duct bank tasks and American Electric for the cable work with assistance from cable manufacturer Southwire (Forte). Michels first tier subcontractors are all experienced successful suppliers of the service or equipment/materials required for the Ford Island project.
3. Underground Construction Co., Inc.: UG will self perform the civil and duct bank tasks. Mears a sister company to UG will provide the direction drill and PAR Electric another sister

EXHIBIT I
PAGE 1 OF 6

AMENDMENT OF SOLICITATION/MODIFICATION OF CONTRACT

1. CONTRACT ID CODE	PAGE	OF	PAGES
J	1		3

2. AMENDMENT/MODIFICATION NO.	3. EFFECTIVE DATE	4. REQUISITION/PURCHASE REQ. NO.	5. PROJECT NO. (If applicable)
P00342	See Block 16C		

6. ISSUED BY	CODE	7. ADMINISTERED BY (If other than Item 6)	CODE
N62742			

COMMANDER, PACIFIC DIVISION
NAVAL FACILITIES ENGINEERING COMMAND
258 MAKALAPA DRIVE, SUITE 100
PEARL HARBOR, HI 96860-3134
(ACQ 02521 SHARLAINE E. N. IKEDA (808) 474-6319

8. NAME AND ADDRESS OF CONTRACTOR (No., street, county, State and ZIP Code)	(X)	9A. AMENDMENT OF SOLICITATION NO.
Hawaiian Electric Company, Inc. P.O. Box 2750 Honolulu, HI 96840-0001		9B. DATED (SEE ITEM 11)
	X	10A. MODIFICATION OF CONTRACT/ORDER NO. N62742-68-C-0001
		10B. DATED (SEE ITEM 11) 07/01/48

CODE 6P939 FACILITY CODE 03-175-4690

11. THIS ITEM ONLY APPLIES TO AMENDMENTS OF SOLICITATIONS

☐ The above numbered solicitation is amended as set forth in Item 14. The hour and date specified for receipt of Offers ☐ is extended, ☐ is not extended.

Offers must acknowledge receipt of this amendment prior to the hour and date specified in the solicitation or as amended, by one of the following methods: (a) By completing Items 8 and 15, and returning _____ copies of the amendment; (b) By acknowledging receipt of this amendment on each copy of the offer submitted; or (c) By separate letter or telegram which includes a reference to the solicitation and amendment numbers. FAILURE OF YOUR ACKNOWLEDGMENT TO BE RECEIVED AT THE PLACE DESIGNATED FOR THE RECEIPT OF OFFERS PRIOR TO THE HOUR AND DATE SPECIFIED MAY RESULT IN REJECTION OF YOUR OFFER. If by virtue of this amendment your desire to change an offer already submitted, such change may be made by telegram or letter, provided each telegram or letter makes reference to the solicitation and this amendment, and is received prior to the opening hour and date specified.

12. ACCOUNTING AND APPROPRIATION DATA (If required)

17 04081205 2541 0252 40240 0 068732 2A 020374 D10203740000P Net Increase $12,964,500.00

13. THIS ITEM ONLY APPLIES TO MODIFICATION OF CONTRACTS/ORDERS. IT MODIFIES THE CONTRACT/ORDER NO. AS DESCRIBED IN ITEM 14.

CHECK ONE	
	A. THIS CHANGE ORDER IS ISSUED PURSUANT TO: (Specify authority) THE CHANGES SET FORTH IN ITEM 14 ARE MADE IN THE CONTRACT ORDER NO. IN ITEM 10A.
	B. THE ABOVE NUMBERED CONTRACT/ORDER IS MODIFIED TO REFLECT THE ADMINISTRATIVE CHANGES (such as changes in paying office, appropriation data, etc.) SET FORTH IN ITEM 14, PURSUANT TO THE AUTHORITY OF FAR 43.103(b).
X	C. THIS SUPPLEMENTAL AGREEMENT IS ENTERED INTO PURSUANT TO AUTHORITY OF: FAR 43.103 (a)(3) Mutual Agreement of the Contracting Parties
	D. OTHER (Specify type of modification and authority)

E. IMPORTANT: Contractor ☐ is not, ☒ is required to sign this document and return 1 signature copies to the issuing office.

14. DESCRIPTION OF AMENDMENT/MODIFICATION (Organized by UCF section headings, including solicitation/contract subject matter where feasible.)

CONTRACT NO. N62742-68-C-0001, ELECTRIC UTILITY SERVICE CONTRACT FOR ALL ACTIVITIES OF THE NAVY, ARMY, AND AIR FORCE, OAHU, HAWAII

(SEE PAGE 2 & 3)

Except as provided herein, all terms and conditions of the document referenced in Item 9A or 10A, as heretofore changed, remains unchanged and in full force and effect.

15A. NAME AND TITLE OF SIGNER (Type or print)	16A. NAME AND TITLE OF CONTRACTING OFFICER (Type or print)
Chris M. Shirai / Thomas L. Joaquin Vice President Sr. Vice President	JILL E. K. NII CONTRACTING OFFICER

15B. CONTRACTOR/OFFEROR	15C. DATE SIGNED	16B. UNITED STATES OF AMERICA	16C. DATE SIGNED
Chris M. Shirai / Thomas L. Joaquin (Signature of person authorized to sign)	30 Apr 04	Jill E. K. Nii (Signature of Contracting Officer)	30 Apr 04

NSN 7540-01-152-8070
Previous edition unusable

STANDARD FORM 30 (REV. 10-83)
Prescribed by GSA FAR (48 CFR) 53.243

EXHIBIT I
PAGE 2 OF 6
N62742-04-C-0001
Modification No. P00042
Page 2 of 5

BLOCK NO. 14. DESCRIPTION OF MODIFICATION

1. The Contractor shall design and construct Hawaiian Electric Company (HECO) facilities to provide new electric service from Pearl Harbor main side to Ford Island to support the existing and planned development of Ford Island. The capacity should be adequate to accommodate the existing load of 6.9 MVA (Oct 7, 2002 peak) as well as the projected load increase to 14.2 MVA (2010) and final build-out to 33.7 MVA (2013+). The Contractor shall perform the work in accordance with the attached Scope of Work dated 24 Sep 03 and Electric Service Specifications dated 24 Sep 03. The Government has fully relied upon the statements, information and attachments set forth in the contractor's revised proposal dated 28 April 2004 in determining the above price fair and reasonable. HECO's proposal dated 28 April 2004 is hereby incorporated in this modification, unless stated otherwise within this modification.

2. HECO agrees to submit invoices to the Navy upon verification of completion of specified construction task(s) by the Government (ROICC Officer). The following progress payment schedule is hereby incorporated in this modification:

Construction Task	Amount	Estimated CIAC Receipt
Completion of design drawings	$ 490,000 ①	Apr 2005
Completion of Segment 1 ductline system (CSA portion only, no cabling work)	$ 725,000 ①	Sept 2005
Completion of Segment 2 underchannel bore (CSA portion only, no cabling work)	$4,835,000	Jan 2006
Completion of Segment 3 ductline system (CSA portion only, no cabling work)	$1,135,000 ①	Aug 2005
Arrival and posting of payment on substa tsfs	$ 810,000 ①	Oct 2005
Completion of Project (final energization)	$4,969,500	Feb 2006
Total Amount	$12, 964,500	

HECO remains responsible for substation equipment paid for by the Navy both before and after it is incorporated into the project.

3. The attached Subcontracting Plan dated 23 April 2004 and List of Clauses are hereby made a part of this modification for this contracting effort.

4. The total amount of this modification is $12,964,500. This amount is the Contribution-In-Aid of Construction (CIAC) required from the Navy for this work. The CIAC is for additional costs incurred for the installation of special facilities that are in addition to the standard facilities normally provided by HECO.

2005 Estimated CIAC Receipts:

Σ ① = $3,160,000 - $126,000 = $3,034,000.
(GET)

DOD-RIR-47

Refer to HECO RT-19, page 9.

a. Please explain why HECO did not reflect the "correct" amount of OPEB liability for the average 2005 test-year of $9,739,000 in its rebuttal testimony rate base.

b. Please explain what the "next available opportunity to determine revenue requirements" is, and what changes HECO will make at that time.

HECO Response:

a. The error in the calculation (as explained in RT-19, pages 8-9) was discovered after the rebuttal revenue requirement calculation was finalized. The $2,000 understatement of the average OPEB liability balance was not revised in HECO-R-1901, and the correction was noted in rebuttal testimony (RT-19, pages 8-9 and HECO-R-1904).

b. The Company will incorporate the corrected average OPEB liability balance estimate of $9,739,000 in the calculation of the 2005 test year average rate base at the next available opportunity to determine revenue requirements, which could possibly occur at the conclusion of settlement discussions with the CA and DOD.

DOD-RIR-48

Refer to HECO RT-19, page 13, lines 16-25.

[redacted]

to record expense and to record payments.

b. Please provide the debits and credits for each month of 2004 and 2005 for OPEB expense to record expense and to record payments.

HECO Response:

a. See page 2 of this response.

b. See page 3 of this response.

Hawaiian Electric Company, Inc.

PENSION

	To record Pension EXPENSE (i.e. accrual of NPPC)		To record Pension PAYMENTS (i.e. Trust Contribution)	
	DEBIT NARUC Acct # 926 Employee Benefit - Pension (A&G Oper Exp)	CREDIT NARUC Acct # 242 Retirement Plan Liability	DEBIT NARUC Acct # 242 Retirement Plan Liability	CREDIT NARUC Acct # 131 Cash
Jan-04	(86,167)	(86,167)		
Feb-04	(86,167)	(86,167)		
Mar-04	(86,167)	(86,167)		
Apr-04	(86,167)	(86,167)		
May-04	(86,167)	(86,167)		
Jun-04	(342,626)	(342,626)		
Jul-04	(128,910)	(128,910)		
Aug-04	(128,910)	(128,910)		
Sep-04	(128,910)	(128,910)	9,686,494	9,686,494
Oct-04	(128,910)	(128,910)		
Nov-04	(128,910)	(128,910)		
Dec-04	(128,910)	(128,910)	5,500,000	5,500,000
Total 2004	(1,546,921)	(1,546,921)	15,186,494	15,186,494
Jan-05	368,000	368,000		
Feb-05	368,000	368,000		
Mar-05	368,000	368,000		
Apr-05	368,000	368,000		
May-05	368,000	368,000		
Jun-05	453,831	453,831		
Jul-05	382,305	382,305		
Aug-05	382,305	382,305		
Sep-05	382,305	382,305		
Oct-05	382,305	382,305		
Nov-05	382,305	382,305		
Dec-05	382,306	382,306		
Total 2005	4,587,662	4,587,662	-	-

Note:
Data reflects recorded till June 2005. July through December 2005 based on forecast amounts.

Hawaiian Electric Company, Inc.

OPEB

	To record OPEB EXPENSE (i.e. accrual of NPPC)		To record OPEB PAYMENTS (i.e. Trust Contribution)	
	DEBIT NARUC Acct # 926	CREDIT NARUC Acct # 2532	DEBIT NARUC Acct # 2532	CREDIT NARUC Acct # 131
	Employee Benefit - Pension (A&G Oper Exp)	OPEB Liability	OPEB Liability	Cash
Jan-04	631,583	631,583	75,000	75,000
Feb-04	631,583	631,583		
Mar-04	631,583	631,583	2,005,710	2,005,710
Apr-04	631,583	631,583		
May-04	631,583	631,583		
Jun-04	(41,171)	(41,171)	1,825,597	1,825,597
Jul-04	519,457	519,457		
Aug-04	519,457	519,457		
Sep-04	519,457	519,457	1,385,799	1,385,799
Oct-04	519,457	519,457		
Nov-04	519,457	519,457		
Dec-04	519,458	519,458	1,387,825	1,387,825
Total 2004	6,233,487	6,233,487	6,679,931	6,679,931
Jan-05	584,542	584,542	87,500	87,500
Feb-05	584,542	584,542		
Mar-05	584,542	584,542	1,857,585	1,857,585
Apr-05	584,542	584,542		
May-05	584,542	584,542		
Jun-05	594,133	594,133	1,860,065	1,860,065
Jul-05	586,140	586,140		
Aug-05	586,140	586,140		
Sep-05	586,140	586,140	1,871,324	1,871,324
Oct-05	586,140	586,140		
Nov-05	586,140	586,140		
Dec-05	586,144	586,144	1,758,827	1,758,827
Total 2005	7,033,687	7,033,687	7,435,301	7,435,301

Note:
Data reflects recorded till June 2005. July through December 2005 based on forecast amounts.

DOD-RIR-49

Refer to HECO RT-19, page 15, lines 18-20, where it states: "HECO's position is that the revenues associated with NPPC are subject to the same revenue collection lag as any other item forming the basis of its revenue requirement."

a. Please explain fully why HECO did not include depreciation expense in its cash working capital calculation.

b. Please explain fully why HECO did not include interest payments based on its proposed weighted cost of debt in its cash working capital calculation.

c. Please identify all components of the revenue requirement that HECO did not include in its cash working capital calculation.

d. For each item identified in response to part c, please explain fully HECO's rationale for excluding each such item from its cash working capital calculation.

HECO Response:

a. As stated in HECO T-19, page 16, the Company believes that all revenues should be included in the revenue collection lag and all payments should be included in the payment lag in the calculation of working cash. However, the Company has excluded those items (i.e. depreciation expense, interest expense, preferred dividends, return on common equity, and deferred income tax expense) that have been excluded by the Commission in previous decisions in the determination of working cash to simplify the issues and to speed the regulatory process in this case.

b. See response to part (a) above.

c. The working cash calculation excludes depreciation and amortization, interest on customer deposits, deferred income tax expense, allowance for uncollectible accounts, interest expense, preferred dividends and return on common equity.

d. The Commission has previously ruled that depreciation and amortization, deferred income tax expense, interest expense, preferred dividends and return on common equity should be

excluded from the working cash calculation. Interest on customer deposits and allowance for uncollectible accounts were not sufficiently large to investigate as new items in the working cash calculation.

DOD-RIR-50

Refer to HECO RT-19, page 15, lines 23-25.

Please explain fully how HECO's calculation of cash working capital is consistent with "its position that all revenue should be included in the revenue collection lag" and identify each "non-cash item" that HECO excluded in its cash working capital calculation.

HECO Response:

The Company believes that all revenues should be included in the calculation of working cash needs associated with the revenue collection lag. However, the Company also recognizes that the Commission has disallowed the revenue collection for certain other "non-cash" items (i.e. depreciation expense, deferred income tax expense, and return on common equity). Therefore, the Company's calculation of working cash excludes these "non-cash" items (depreciation expense, deferred income tax expense, and return on common equity) to simplify the issues and to speed the regulatory process.

DOD-RIR-51

Ref: HECO RT-4, page 34, line 19.

Is the $44.484 million HECO's final amount for fuel inventory for purposes of this rate case? If not, please specify in detail all additional changes that would change this amount.

HECO Response:

DOD-RIR-52

Ref: HECO RT-4 and RT-5.

a. Please explain fully why HECO used May 2005 fuel prices.

b. Please confirm that HECO will not be proposing any additional adjustments to fuel or purchased power expense or to fuel inventory in this case.

c. If the answer to b is anything less than an unequivocal confirmation, please identify, quantify and describe all additional changes that HECO will propose to fuel and purchased power expense and to fuel inventory in this case.

d. Include supporting workpapers and calculations for all quantifications included in part c.

HECO Response:

a. Generally, HECO's practice is to use the latest available fuel prices in preparing its production simulations for rate case purposes. In HECO's direct testimony, HECO used the fuel prices as of May 1, 2004, which were the latest available contract prices at the time the testimony in HECO T-4 was being prepared. (Please refer to HECO T-4, page 7, lines 10 to 13.) In HECO's rebuttal testimony, HECO used May 2005 fuel prices, which were the latest available prices at the time the production simulation for rebuttal testimony was prepared. (Please refer to HECO RT-4, page 9, lines 10 to 13.) The May fuel prices were provided as part of HECO's update on the May 5, 2005 transmittal.

The rebuttal testimony for Purchased Power Expense (HECO RT-5) used May 2005 fuel price for the calculation of the fuel component of the energy charge for Kalaeloa purchased power expense. The May 2005 fuel price assumed for the Kalaeloa purchased power expense in HECO RT-5 is $51.802/bbl, as compared to the May 2004 fuel price of $36.28/bbl assumed for Kalaeloa purchased power expense in HECO T-5. The actual fuel price used to calculate current Kalaeloa purchased power expenses is in the $50 to $55/bbl

range.

b. At this time, HECO is not proposing any additional adjustments to fuel or purchased power expense or to fuel inventory in this case.

c. Not applicable.

d. Not applicable.

DOD-RIR-53

Refer to HECO RT-6.

Please clarify: are there any additional adjustments being proposed by this HECO witness that were not identified by HECO in its May 5, 2005 and June 15, 2005 update transmittals? If so, please clearly identify each additional or revised adjustment proposed by the witness beyond those identified by HECO in its May 5, 2005 and June 15, 2005 update transmittals.

HECO Response:

The additional or revised adjustments proposed by HECO T-6 beyond those identified by HECO in the May 5, 2005 and June 15, 2005 update transmittals were:

1) Identified for Production Operations – Nonlabor in HECO RT-6, page 3, lines 10 to 14. The adjustments include:
    a. A reduction of $20,000 for EPRI R&D expenses from $500,000 to $480,000. This is discussed further in CA-RIR-70.
    b. A reduction of $4,000 for Operation Nonlabor Ellipse expenses. This amount is discussed in HECO RT-13 and is reflected in HECO-R-1301. The total reduction of $4,000 is the sum of:
        i. ($1,436.83) charged to NARUC Account 514
        ii. ($2,296.16) charged to NARUC Account 502
        iii. ($1,909.27) charged to NARUC Account 505
2) Identified for Production Maintenance – Nonlabor in HECO RT-6, page 4, lines 17 to 22. The adjustments include:
    a. An addition of $63,000 to reflect higher Substation DG Maintenance Nonlabor expense estimates. This increase is discussed in HECO RT-7. It is the increase in costs for DG Non-Fuel O&M costs from $1,403,000 (shown in the May 5, 2005

Update transmittal, Attachment 1A, page 8, the sum of line 5 and line 11) to $1,466,000 (shown in HECO-R-701, line 14).

b. A reduction of $6,000 for Maintenance Nonlabor Ellipse expenses. This amount is discussed in HECO RT-13 and is reflected in HECO-R-1301. The total reduction of $6,000 is the sum of:

   i. ($1,436.83) charged to NARUC Account 514

   ii. ($2,905.08) charged to NARUC Account 512

   iii. ($1,743.05) charged to NARUC Account 513

DOD-RIR-54

Refer to HECO RT-10, pages 10-11.

Please identify, quantify and explain what portion of the $321,000 informational advertising (before the increase to $1,071,000) was used for each of the following:

a. The importance of using energy wisely at all times.

b. That it makes special sense to reduce energy use at peak.

c. To create a basis for dramatically cutting the use of electricity during an emergency.

d. Please provide copies of the ads HECO has run for the objectives identified in a, b and c.

e. Has HECO conducted any customer services which indicate that customers do not understand that using energy wisely at all times, during the peak and during an emergency, is important? If so, please provide the documentation.

f. What percentage of its customer base does HECO think does not understand that using energy wisely at all times, during the peak and during an emergency, is important? Provide the documentation relied upon by HECO for this answer.

g. Please provide a copy of all advertisements, including the text of all radio and television scripts, that HECO intends to run that are related to the cost increase from the $321,000 original amount to the new HECO proposed amount of $1,071,000.

h. Does HECO have any basis for believing that customers would not be motivated to conserve energy given the pending increases from:

   i. The base rate increase from this case,

   ii. The additional DSM surcharge that could result from the Energy Efficiency case,

   iii. And the large fuel cost increase that its customers will be experiencing?

   If so, explain fully and provide the documents relied upon

HECO response:

a, b, and c: Of the $321,000 originally forecast for informational advertising, $250,000 was estimated to be used for general energy conservation information advertising. No funds were

forecast for increasing awareness of the importance of reducing energy use at peak periods or for cutting use during a system emergency.

d: Copies of two new TV spots ("Groove" and "Cool Tips") created with the objective of providing general energy conservation information are included on the attached DVD. Also included are scripts for several radio spots which have been aired thus far during 2005 (pages 4-10) as well as one print ad which attempts to accomplish the objectives of increasing general energy conservation awareness while providing information about the specific benefits of solar water heating (page 11). As discussed above, no ads have been produced that are directly target the objectives noted in b. and c.

e. Using the services of Ward Research, HECO conducted Focus Groups in 2004 for the primary purpose of testing public reaction to messages about power system emergencies, such as a generation shortage. As documented in the Executive Summary of the report on pages 12-15 of this response, Ward Research reported that:

> *"It was clear that many of the participants do not understand the "peak" load concept, which leads to some misunderstanding of the EAM (emergency alert messages)."*
>
> *"It was also clear that the masses will need some urgency in order to motivate a change in behaviors, particularly change that may result in somewhat less comfort or convenience."*
>
> *"High users admitted that their comfort and convenience are important to them and, having adjusted to their monthly bill, they were unlikely to change. Many of the Medium/Low users thought that they were already doing everything they can to conserve.*

f. HECO has not quantified the specific percentage of its customer base that does not believe it is important to use energy wisely at all times, during the peak and during emergencies. However, the focus groups discussed in e. above were conducted using the professional expertise of a reputable research firm which attempted to obtain a cross section of participants in the groups, to support the conclusions noted in response to item e. above.

g. HECO plans to continue to run the advertising identified in part d. above. Additional TV and radio scripts and print ads which would help build on the existing general conservation advertising and focus on the remaining two messages – that it makes sense to reduce energy use at peak, and to create a basis for dramatically cutting the use of electricity during an emergency – have not yet been developed. The additional funding requested would provide the development, production, and other costs to air or print the actual ads.

h. Yes, the findings of focus group conducted in 2004, described in response to item e. above, indicate that high energy costs alone are not enough to move some customers to meaningful conservation behaviors. These customers will need some sense of urgency to motivate a change, and many users, including high and medium/low users, have reasons not to change.

CLIENT: **HECO** **DATE:** **03/28/05**
SPOT: **PERRY & PRICE LIVE** **WEEK OF MARCH 28**
TITLE: **CONSERVATION TIPS #1** **JOB #: 364-053**

PERRY: Okay, I'll bite... Why do you have that lightbulb above your head.

PRICE: Just another bright idea!

PERRY: Ahh, from the mind of the illustrious Dr. Price.

PRICE: Yes, thank you.

PERRY: So, what's on your mind?

PRICE: Well, I was thinking... We all need to work together to conserve electricity and keep Hawaii's energy future bright, right?

PERRY: Absolutely correct.

PRICE: So I came up with a simple formula – ahem...
X minus 2

PERRY: Huh??? X minus 2.

PRICE: Allow me to translate... X is the amount of time you spend in the shower. Minus 2 minutes from your shower time and you'll conserve electricity!

PERRY: Hey, wait a minute – or 2 minutes... That's Tip Number 3 on Hawaiian Electric's Top Ten Tips for Energy Conservation.
Tip number 3 says, "Cutting just two minutes per shower could save up to 1,533 kWh and $215 per year."

PRICE: Oh, you know about the Top Ten Tips for Energy Conservation, huh...

PERRY: Yup. Everyone will! HECO's Top Ten Tips list will be coming to them in the mail with their April Electric bill.
It's all part of HECO's "Live Energy LITE" program – easy, everyday ways to conserve electricity.

PRICE: So I guess you won't need my other 9 energy conservation formulas.

PERRY: Thanks, Larry but I think I'll just check out HECO.com for the Live Energy LITE Top Ten Tips for Energy Conservation.
It's time for all of us to do our part in keeping Hawaii's energy future bright.

Ogilvy&Mather
HECO RADIO :60 General Conservation (Groove)
05-26-05
06-01-05
06-08-05: FINAL

MUSIC: :60 HIROSHIMA MUSIC BED, UNDER THROUGHOUT.

MOM: In our family, we make saving electricity part of our everyday life.

DAUGHTER: I'm always reminding dad to turn off the garage lights...

DAD: [redacted]

ANNCR: Everyone has a part when it comes to saving energy. Because even the little things make a big difference.

DAD: Like shutting down our computer...

DAUGHTER: and then switching off the power strip.

MOM: Washing clothes in cold water, even whites.

DAD: And using fans instead of air conditioners.

DAUGHTER: Yeah, Murphy likes the breeze from our living room fan.

SFX: (Dog barking)

MOM: From switching to compact fluorescent light bulbs...

CLIENT: HECO **DATE:** 06/13/05
SPOT: PERRY & PRICE LIVE **WEEK OF JUNE 13**
TITLE: GENERAL CONSERVATION **JOB #:** 364-060

PRICE: Click... Flicky, flick... Clickity-click-click... (like a percussive rhythmic beat)

PERRY: Now what?

PRICE: I'm getting in the groove!

PERRY: Ahh... I get it. You're getting in the groove of clicking off the lights when you don't need them.

PRICE: Yup. It's just one simple way to get in the groove of saving energy – turn off your lights when you don't need them.

PERRY: That's easy enough to do... But as simple as it seems, it's a really important way for all of us to conserve electricity.

PRICE: There's lots of easy ways to save electricity. Conserving isn't hard.

PERRY: And more than ever, it is the right thing to do. We're so used to having electricity with a simple flick of our fingertip. Now, we also need to remember to flick things off if we're not using them.

PRICE: Besides, saving electricity can also save you money. There's other easy ways to save electricity. Check out HECO.com.

PERRY: Yup. HECO.com for the Live Energy LITE Top Ten Tips for Energy Conservation.

PRICE: It's so simple to do the right thing with these10 easy, everyday ways to save electricity.

PERRY: Check out HECO.com. It's time for all of us to get in the groove of saving energy.

Ogilvy&Mather
HECO 60 sec. radio: A.C. Tutu
05-29-05
06-01-05
06-10-05
06-13-05
06-14-05: FINAL

MUSIC: :60 HIROSHIMA MUSIC BED, UNDER THROUGHOUT.

MOTHER: Kids...we're leaving for auntie's house!

SON: Do we have to?

DAUGHTER: It's so cold there.

ANNCR: Do you crank up the air conditioner during the hot summer months?

MOTHER: Got your jacket?

KIDS: Jackets.

ANNCR: Try this energy saving tip from Hawaiian Electric instead.

MOTHER: Gloves?

KIDS: Gloves.

ANNCR: Whenever you can, use fans instead of air conditioners.

DOG: Woof!

MOTHER: Puppy sweater?

KIDS: Puppy sweater.

ANNCR: Replacing one 8,000 BTU air conditioner with a couple of fans for just four hours a day will save Hawaii over 1,150 kilowatt hours. And save you about $160 a year!

TUTU: Hi kids!

KIDS: Hi auntie.

ANNCR: So remember, open your windows and use fans instead of air conditioners at least four hours a day.

GIRL: Hey auntie—how come your house isn't freezing?

TUTU: I'm saving money so I can help send you two to college.

ANNCR: For more energy saving tips, visit HECO.COM.
Hawaiian Electric. Giving you the power.

CLIENT: **HECO** **DATE:** **08/01/05**
SPOT: **PERRY & PRICE LIVE** **WEEK OF AUGUST 1, 2005 (TUES-THURS)**
TITLE: **TOP TEN LIST**

PRICE: Number 1... **Light with Compact Fluorescents.**

PERRY: What's up, Larry?

PRICE: I'm writing a list. Ways to save on electricity... Number 2... **Use Fans instead of Air Conditioners.**

PERRY: You mean, as in ways to conserve energy?

PRICE: Yup! Number 3... **Shorten Showers.**

PERRY: Wait a minute! This sounds familiar... Sounds a lot like HECO's Top 10 Tips for Energy Conservation.

PRICE: Hawaiian Electric has Tips for Energy Conservation? ((innocently))

PERRY: Uh huh, like you didn't know about the Top 10 Tips for Energy Conservation list at HECO.com.

PRICE: Oh, yeah, right. Well, we all need to work together to conserve electricity and keep Hawaii's energy future bright.

PERRY: Absolutely correct. Even simple things will conserve energy and also same you money on your electric bill!

PRICE: Like shorter showers! Cutting just two minutes per shower could save up to $215 per year.

PERRY: And changing your bulbs to CFL's – that's compact fluorescents – will help conserve electricy too! Just check out the Top 10 Tips for conserving energy at HECO.com

PRICE: It really is time for all of us to do our part in keeping Hawaii's energy future bright.

PERRY: Go to HECO.com and get into the groove of saving energy.

CLIENT: **HECO** **DATE:** **08/01/05**
SPOT: **PERRY & PRICE LIVE** **WEEK OF AUGUST 1, 2005(TUES-THURS)**
TITLE: **TOP TEN LIST – Version 2**

PRICE: Number 1...

PERRY: Check.

PRICE: Number 2...

PERRY: Check.

PRICE: Number 3...

PERRY: Uh, well okay...

PRICE: Hold on there. Did I here some hesitation? You know how important this is, don't you?

PERRY: Sure I do. I know saving electricity is more important than ever on Oahu. And using HECO's Top 10 Tips for Energy Conservation is a great way to save.

PRICE: Yup. Follow HECO's Top 10 Tips and we'll conserve energy AND save money on our monthly electricity bill.

PERRY: I know. I know. Number 1... Change lightbulbs to Compact Fluorescents. DONE!
Number 2... Use Fans instead of Air Conditioners. We do that a lot!

PRICE: Number 3... Shorten Showers?

PERRY: I know... Cutting just two minutes per shower could save up to $215 per year. But I really like my long hot showers after a hard, dirty, stressful day at work.

PRICE: Just 2 minutes shorter on your shower. How hard is that?

PERRY: Yeah, that isn't much to ask. In fact, it's a really easy way to help conserve electricity.

PRICE: Even simple things will conserve energy and also save you money on your electric bill!

PERRY: It's the Top 10 Tips for Energy Conservation at HECO.COM

PRICE: It really is time for all of us to do our part in keeping Hawaii's energy future bright.

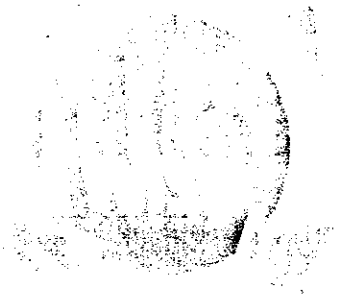
PERRY: Go to HECO.com and get into the groove of saving energy.

EXPLORE THE **SAVINGS** IN OUR **SOLAR SYSTEM.**

With your own solar water heating system, you can put the sun to work for you. The savings start with the installation of the system, then continue to add up month after month, year after year.

- **$750 Instant Rebate when you use a HECO-approved solar contractor. Call 94-POWER for our approved contractors.**
- **35% Hawaii State Energy Tax Credit.**
- **Savings of up to $480 a year for a family of four on their electric bill.**
- **Up to 100% financing available on the installed system.**
- **Free HECO 100-point quality control inspection after installation.**

When the sun's energy heats your water, you can take showers and wash clothes in hot water without worrying about your electric bill.



EASY, EVERYDAY TIPS FOR **SAVING ENERGY.**

The simple things you can do at home to save energy also save you money. Start today and you'll see the difference on your next electric bill.

- **Switch to Compact Fluorescents (CFL).** Based on four hours of use per day, changing just one 100-watt bulb to a CFL equivalent can save you $15 per year. Switch more than one bulb in your home, and your savings will increase.
- **Use fans instead of air conditioners.** Two fans running for four hours per day in place of an 8,000 BTU room air conditioner can save you $161 per year.

- **Wash clothes in cold water.** Switch to Cold Wash/Cold Rinse from the Hot/ Warm cycle for just two loads a week, and you can save $32 per year when you use a standard, top-loading washing machine.

SAVE UP TO 45% WITH HECO'S INSTANT REBATE AND THE STATE TAX CREDIT.

SAVE ENERGY. SAVE RESOURCES.

In Hawaii, we live in a delicate balance with nature. Using electricity wisely helps to save resources. And that has a positive impact on our environment. Let's all do our part to create a brighter energy future for Hawaii.

LOOK FOR OUR "TOP 10 TIPS FOR ENERGY CONSERVATION" IN YOUR APRIL ELECTRIC BILL.

For more information on solar call **94-POWER** and log on to HECO.com for more energy conservation tips.

ENERGY**$**OLUTIONS
FOR HAWAII
Hawaiian Electric • *Giving you the power*

EXECUTIVE SUMMARY

This summary presents the highlights from four focus groups conducted for Hawaiian Electric Company on September 14 and 15, 2004. Two of these groups comprised high users (monthly bill $120+) and two were conducted among low/medium users (<$120). The overall objective of the groups was to test the proposed Electricity Alert Messages (EAM) and the communications designed to inform residents about the program (a newspaper article, radio alert announcements, and a flyer for the bill were tested).

The most important finding is the urgency message that residents took away from this program and its surrounding communications. There was almost a sense of shock when the idea of "possible rolling blackouts" really sank in; a sense of disbelief. The reaction of many was an almost incredulous, *"How did we get to this point? How did HECO let this happen?"* Then, as an extension of this "W[illegible] HECO[illegible]

Similarly, the initial "warning" level of the EAM, tested via simulated radio announcement, is not likely to motivate much change in behavior. Measures most likely to be taken at this point, if any, include turning off some lights, turning off the television when it is not being watched, turning off the computer monitor when it is not being used, and, perhaps, setting the air conditioner thermostat just a little higher.

Reactions to the message that "blackouts are imminent or perhaps already occurring" --- the second stage of the EAM --- were much more acute. There was an almost visceral response to this level of urgency, coming from a place of disbelief (*"How did we get here? I thought everything was fine!"*). At this point, residents will move into a "protection" mode; taking steps to protect their loved ones and their property/sensitive equipment. Almost universally, the first thought was to "get home and turn off the computer," echoing some of the instructions from the announcement. They worried about the fish tank, the pets in the air conditioned home (with no windows open), the loved one with necessary medical equipment, and other hardships. With the urgency heard in this message, though, more were likely to delay running the dishwasher than were willing to do so in the first warning message.

It must be said that there is a segment of the population that will take all of this communication very seriously and will make more significant change. In the focus groups, these were the individuals who spoke more about individual responsibility and "the common good", "each of us doing our part." These folks clearly were in the minority, however, as others spoke of the realities of ninety degree heat and humidity.

Upon hearing the "all clear" announcement, participants in all four groups reacted strongly to the suggestion that "electricity use can now return to normal." *"How can HECO tell us to return to normal? It's like pretending that the crisis went away. Do we have enough power or not?"* Some assumed that this announcement would be made in order to protect HECO revenues. Those who doubted HECO's motives all along felt vindicated upon hearing this "all clear" announcement. The recommendation, then, was that HECO should thank everyone for their cooperation and encourage residents to continue conserving, where possible.

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Key to understanding the focus group reactions and tailoring the program to address the issues are the following observations:

- It was clear that many of the participants do not understand the "peak" load concept, which leads to some misunderstanding of the EAM. Some asked why they should delay the dishwasher until 9:00pm (*"What's so magic about 9:00?" "Won't that just create another peak?" "That will just delay usage, rather than truly conserve or cut back."*). This, too, helps explain the reaction to the "return to normal usage" in the all clear announcement. Residents in the focus groups believed that HECO was warning Oahu about entering a new period of ongoing electricity shortfall, 24/7, not one organized around peak loads.

- These residents took great offense that the messages appeared to target only Residential Customers and Small Businesses. *"Where are the big businesses and big users?"*, they asked. They felt as if residential users and small business were being asked unfairly to shoulder the burden.

- It was also clear that the masses will need some urgency in order to motivate a change in behaviors, particularly change that may result in somewhat less comfort or convenience. Currently, the decision that most high users make is one related to the dollar value of this comfort and convenience. They have decided to pay for it, and see no reason to include any other variables in their consideration, at present.

- The perceived failure of HECO to prepare us for this crisis is a serious underlying issue. This is an extension of the "How did we get to this point?" question --- how did we go from "everything's fine" to "rolling blackouts are imminent?" The "how's" and "why's" are a very important part of HECO's needed communications, through mass media channels to reach the broadest range of residents.

- This perceived HECO failure also provides an opportunity for residents to point to alternative energy sources as the solution --- *"If only they had developed wind/solar/ wave action/geothermal, etc."*

- Given the start of the Board of Water Supply's recent conservation campaign, participants contrasted the BWS approach with this HECO program. They felt that the BWS campaign provided more information (*"25 years to make a glass of water,"*

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"90% of water is lost when watering lawn in heat of day"), incorporated messages in restaurants, suggested xeroscape plants, etc. Many talked of altering their behaviors as a result of this campaign. BWS, they said, is "taking the baby steps" to change our behaviors *before* it becomes a crisis. Importantly, too, some of the younger group participants, who reportedly had not seen or heard HECO talking about energy conservation, could play back the particulars of the BWS campaign and reported some behavioral change as a result.

In summary, the research firm believes that the Electricity Alert Messages, as tested, *will* assist HECO in managing demand in capacity shortfall situations. Oahu residents will rise to the occasion as they begin to understand the situation better. The bigger question, we believe, is what other impacts HECO will experience, as a result of the shock of this message. We believe that HECO must build an ongoing, mass media foundation, such that this message of urgency has context. It is the lack of that context, currently, that was so troubling to focus group participants.

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DOD-RIR-55

Refer to HECO RT-10, pages 18-19.

a. Please explain fully why it makes a difference to HECO if its DSM expenses are addressed in the current rate case or in the Energy Efficiency proceeding established in D&O No. 21698.

b. As long as HECO's legitimate DSM costs are recovered either in base rates or in a DSM surcharge, why is HECO concerned about where such costs are recovered? Explain fully.

HECO Response:

a. There are three reasons why HECO proposes to include a portion of DSM expenses in base rates through the current rate case:

1. This reflects the commission's Decision and Order ("D&O") No. 21698, as discussed in HECO RT-10, page 2, line 23 through page 3, line 10.
2. This reflects the commission's D&O Nos. 21415 and 21421, in the Residential Direct Load Control ("RDLC") and Commercial & Industrial Direct Load Control ("CIDLC") Dockets, as discussed in HECO RT-10, page 4, lines 4 - 29.
3. HECO is currently incurring costs to implement the RDLC and CIDLC Programs which, per D&O Nos. 21415 and 21421, HECO cannot recover through the IRP Clause. HECO was permitted to seek the recovery of such costs in base rates in its next rate case. However, should these costs be removed from this rate case, which would be in conflict with the existing orders of the Commission, HECO would be precluded from recovering these costs through base rates and would have no recourse for cost recovery. Instead, HECO's would need to wait for the outcome of the Energy Efficiency Docket, the procedural schedule for which has not been determined.

DOD-RIR-56

Refer to HECO RT-10, page 20, lines 11-14.

a. Please identify exactly where HECO first identified the amount of reduction to Customer Assistance Expense for the removal of Green Pricing Program costs.

b. Did HECO clearly reflect the removal of Green Pricing Program costs in its May 5, 2005 or June 15, 2005 update filings?

HECO Response:

a. HECO first identified the removal of the Green Pricing Program costs in rebuttal testimony, HECO RT-10, page 9, lines 10-17.

b. HECO did not reflect the removal of the Green Pricing Program costs in its May 5, 2005 or June 15, 2005 update filings. The removal of the Green Pricing Program costs was in response to the CA's direct testimony received on June 28, 2005.

DOD-RIR-57

Refer to HECO RT-10, page 37.

a. Provide the specific basis for HECO's interpretation that: "the Energy Efficiency Docket was established to address issues surrounding the demand-side management programs and not IRP expenses."

b. Does HECO agree that DSM is a part of the IRP? If not, explain fully why not.

c. Does HECO agree that Energy Efficiency subjects are a part of IRP? IF not, explain fully why not.

HECO Response:

a. The Energy Efficiency Docket was established by Decision and Order No. 21698, Docket No. 04-0113. On page 12 of the Decision and Order, the Commission lists numerous issues relating to energy efficiency and DSM programs that are to be examined in the docket, but the issue of the appropriate level of incremental IRP General Planning expense is not included in those issues. Furthermore, on page 19, the D&O states "1. The commission, on its own motion, hereby separates HECO's requests for approval and/or modification of DSM and load management programs and recovery of such program costs and DSM utility incentives from this docket and opens a new Energy Efficiency Docket in which it will consider these matters."

b. Yes, demand-side management programs are one of the many different types of resources considered in the integrated resource planning process. There are numerous other resources and planning considerations that are considered in the IRP process.

c. Yes, however, IRP is not a subset of DSM. See response to part b above.

DOD-RIR-58

Refer to HECO RT-10, page 36, in the HELCO rate case cited on page 36, lines 2-6, did HELCO have a concurrent case in which the Commission had opened to address Energy Efficiency subjects? If not, explain fully why not.

HECO Response:

During the referenced HELCO rate case docket, the Commission did not open a separate docket to address DSM issues. HECO is not aware of the PUC's reasons for their actions, other than what the PUC states in their order.

DOD-RIR-59

Refer to HECO RT-10, pages 36-37.

Is it HECO's position that after addressing HECO energy efficiency matters comprehensively in the Energy Efficiency Docket the Commission could not decide in that docket which costs HECO should recover in the DSM surcharge and which costs HECO should recover in base rates? If so, please state fully the basis for HECO's position and include citations to the authority relied upon.

HECO Response:

No, that is not HECO's position. The Commission could decide in the Energy Efficiency Docket which incremental DSM program costs HECO should recover through the DSM Surcharge (IRP Clause) and which incremental program costs HECO should recover in base rates. Previous Commission Decision and Orders have determined that the remaining DSM Program costs (base labor costs currently being recovered in base rates, and certain load management program costs defined per D&O Nos. 21415 and 21421) should be included in base rates as discussed in HECO RT-10.

DOD-RIR-60

Refer to HECO RT-13, pages 21-2, re DSM consultant costs.

a. Please identify the consultants to which the $80,000 DSM consultant costs relate.

b. Please indicate whether the consultants identified in part a have prepared any reports, documents or testimony for HECO, and identify all such reports, documents and testimony.

c. Please indicate in which docket (the rate case, or the Energy Efficiency Docket) the reports, documents and testimony that were prepared by HECO's DSM consultants are being addressed.

HECO Response:

a. The two DSM consultants are Mr. Greg Wikler of Global Energy Partners, and Mr. Dan Violette, of Summit Blue.

b. HECO objects to this information request as the request to "identify all such reports, documents, and testimony" is overly broad and unduly burdensome. However, without waiving this objection, HECO responds that under the $80,000 of DSM consultant costs in this docket Mr. Wikler sponsored HECO T-11 and associated exhibits and workpapers, and Mr. Violette sponsored HECO T-12 and associated exhibits and workpapers.

c. Thus far, under the $80,000 in DSM consultant costs for this docket, HECO's two DSM consultants have prepared documents and testimony for the rate case only. However, due to the creation of the Energy Efficiency Docket, Mr. Wikler's and Mr. Violette's documents and testimonies will now be addressed in that docket.

DOD-RIR-61

Refer to HECO RT-13, page 23, lines 12-18.

a. Please identify the range of base rate revenue increases resulting from this case that would cause HECO to file another rate case within 3 years.

b. Please identify the range of base rate revenue increases resulting from this case that would cause HECO to file its next rate case in four or more years.

HECO Response:

a. The amount of the rate increase resulting from this case would be a factor in determining when HECO needs to file its next rate case. As stated in HECO RT-13, page 23, lines 12 to 18, the level of rate increase supported by the Consumer Advocate and Department of Defense, and the rate increase ultimately approved by the Commission in this proceeding, could have a bearing on the timing of HECO's next rate case filing. An approved increase significantly lower than HECO's requested increase would tend to shorten the time before the Company's next rate case filing. On the other hand, an approved increase closer to HECO's requested amount could make a four year period before HECO's next rate case filing more realistic.

The next rate case could be filed as early as the end of 2005, if a 2006 test year rate case appears to be necessary, or perhaps in the second half of 2008, if a 2009 test year rate case is deemed necessary because of the addition of new generation in 2009. It will be a challenge to defer the need for another rate case in the near-term, although HECO recognizes that that would be desirable due to the magnitude of current rates (reflecting currently high fuel and purchased energy expenses) and the impact of a major rate case on the utility, the CA and intervenors such as the DOD. It will be a challenge given factors such as (1) the expectation

that sales growth in 2006 over the 2005 test year sales will be relatively low (as noted in HECO RT-2, actual sales for 2005 are expected to be lower than the assumed test year sales), (2) potential increases in pension expenses, and (3) additional staffing requirements that are not reflected in HECO's test year estimates (or in the estimates of the CA and DOD).

b. See response to part a.

DOD-RIR-62

Ref: HECO RT-13 at pages 26-27

a. Please quantify exactly how "The Company has reduced its overall test year revenue requirements with respect to the King Street office building lease" as stated on page 26, lines 20-22. Include all supporting calculations, and the amount of overall test year revenue requirement reduction.

b. Please identify where in the May 5, 2005 and June 15, 2005 the $43,000 increase related to Kamehameha Schools Bishop Estate was identified. If this was not identified in the HECO updates, explain fully why not.

c. Provide a copy of the lease agreement related to the $43,000 increase related to Kamehameha Schools Bishop Estate.

HECO Response:

a. The update transmittal dated June 15, 2005, included a proposed King Street building lease as a capital lease with recovery based on lease payments. As discussed by Ms. Sekimura in HECO RT-16 the Company completed negotiations with Bishop Estate and executed a modified negotiated lease agreement on July 1, 2005. The executed lease is deemed to be an operating lease and the Company proposes ratemaking treatment be consistent with financial accounting treatment. This has resulted in a reduced test year revenue requirement versus the Company's previously proposed capital lease ratemaking treatment as illustrated in the attached pages.

Under the capital lease with recovery based on lease payment proposal the estimated test year revenue requirement is $1,874,000. Under the operating lease with recovery based on straight-line lease expense proposal the estimated test year revenue requirement is $1,186,000.

b. The $43,000 increase related to the King Street office lease with Kamehameha Schools

Bishop Estate was explained in HECO RT-16 on page 21. The increase was not identified in the May 5, 2005 and June 15, 2005 updates to Rents expense (in response to CA-IR 260) because it was not until in July 2005 that HECO and Bishop Estate agreed to modifications to the initially negotiated lease and executed a modified agreement effective July 1, 2005 (see HECO RT-16, page 20).

c. A copy of the executed modified lease agreement with Kamehameha Schools Bishop Estate is included in the Workpapers in Support of Rebuttal Testimonies (see HECO-RWP-1607, page 1 to 76). Please note that the $43,000 increase is the result of a calculation shown on HECO-R-1307 (see footnote 6). The $43,000 increase is not evident from the executed modified lease agreement alone.

Capital Lease for Books with Recovery based on Lease Payments

Assumptions Input

Cost of Capital Assumptions	Weight	Rate	Weighted Average	After-tax Weighted Average	Weighted Average Revenue Requirement	Rev Req
ST Debt	3.25%	3.50%	0.114%	0.069%	0.125%	
Taxable Debt	36.81%	6.25%	2.301%	1.405%	2.525%	6.859%
Hybrid	2.37%	7.55%	0.179%	0.179%	0.321%	
Preferred Stock	1.78%	5.54%	0.099%	0.099%	0.177%	
Common Stock	55.79%	11.00%	6.137%	6.137%	11.025%	
			8.829%	7.889%	14.174%	

Tax Assumptions:		
Federal	35.00%	32.89%
State	6.40%	6.02%
		38.91%

Public Service Company Ta:	5.885%	(on gross receipts)
PUC Fee	0.500%	(on gross receipts)
Franchise Tax	2.500%	(on electricity sales)
Revenue Tax Rate	8.885%	

	Total	GET	Total including GET
Appraisal	3,470,000		
		4.0000%	
Monthly Lease Payments		4.1670%	
Effective Date to 11/30/200	64,583.34	2,691.19	67,274.53

Annual Lease Payments			
Effective Date to 11/30/200	775,000	32,294	807,294
HEI sq. ft.	8,874		
Total building sq. ft.	58,313		
HEI %	15%		
Capitalized Leased Property	10,209,077		

NOTE: Revenue requirement calculation is based on revised response to CA-IR-615 submitted on 6/15/05. Assumptions and calculation are consistent except to reflect the new capital structure and including the rebalancing of $2.5 million to common equity and reducing short term borrowings by $2.5 million (as presented in HECO RT-21)

Year			1
Number of Months in Year			12
Total Payments			807,294
Excise Tax Pmt			32,294
Lease Pmt			775,000
HEI Payments			129,353
Capital Lease for Books with Rates based on Lease Payments			
Cash Flow			
Lease Payment			807,294
Excise Tax Expense			-
Interest Expense on Lease Obligation			582,315
Principal Repayment			192,685
Total Debits			775,000
Current Tax Deduction			807,294
Book Expense			807,294
Deferred Tax Base			-
Deferred Tax			-
Accumulated Deferred Tax			-
Financial Statements Adjusted to Reflect Ratemaking based on Lease Payments			
Leased Property			10,209,077
Adjusted Amortization Expense			224,979
Accumulated Amortization			224,979
Net Leased Plant		10,209,077	9,984,098
Ending Net Assets		10,209,077	9,984,098
Average Rate Base			10,096,587
Beginning Lease Obligation			10,209,077
Lease Interest Expense			582,315
Principal Repayments			192,685
Rebalancing (HECO-RT-21)		2,500,000	2,500,000
Ending Lease Obligation		10,209,077	10,016,392
ST Debt	3%	331,795	324,483
Taxable Debt	37%	(6,451,116)	(6,308,951)
Hybrid	2%	241,955	236,623
Preferred Stock	2%	181,722	177,717
Common Stock	56%	5,695,644	5,570,128
Total Ending Capitalization		10,209,077	10,016,392
Average ST Debt			(2,171,861)
Average Taxable Debt			(6,380,034)
Average Hybrid			239,289
Average Preferred Stock			179,719
Average Common Stock			8,132,886
Average Capitalization			10,112,734
ST Interest Expense	3.50%		(76,015)
Taxable Debt Interest Expense	6.25%		(398,752)
Hybrid Dividends	7.55%		13,569
Preferred Dividends	5.54%		9,956
Return on Common	11.00%		894,617
Revenue Requirements (with Capital Structure Rebalancing in Rates)			
Revenue Requirement			1,872,472
Revenue Taxes			166,369
Lease Payments			807,294
HEI Rent Payments			(129,353)
Interest Expense			(474,767)
Income Before Taxes			1,502,929
Income Taxes			584,786
Preferred & Hybrid Dividends			23,525
Net Income (Ratemaking)			894,617

Operating Lease with Recovery based on Straight-Line Lease Expense

Assumptions Input

Cost of Capital Assumption:	Weight	Rate	Weighted Average	After-tax Weighted Average	Weighted Average Revenue Requirement	Rev Req
ST Debt	3.25%	3.50%	0.114%	0.069%	0.125%	3.841%
Taxable Debt	36.81%	6.25%	2.301%	1.405%	2.525%	6.859%
Hybrid	2.37%	7.55%	0.179%	0.179%	0.321%	
Preferred Stock	1.78%	5.54%	0.099%	0.099%	0.177%	
Common Stock	55.79%	11.00%	6.137%	6.137%	11.025%	19.762%
			8.829%	7.889%	14.174%	

Tax Assumptions:		
Federal	35.00%	32.89%
State	6.40%	6.02%
		38.91%

Public Service Company Ta	5.885% (on gross receipts)
PUC Fee	0.500% (on gross receipts)
Franchise Tax	2.500% (on electricity sales)
Revenue Tax Rate	8.885%

	Total	GET 4.0000% 4.1667%	Total including GET
Monthly Lease Payments			
Effective Date to 11/30/200	64,583.34	2,690.97	67,274.31
Annual Lease Payments			
Effective Date to 11/30/200	775,000	32,292	807,292

HEI Payment (See HECO-R-1307)	
Monthly Base Rent/sq ft.	1.23
Composite PUC fee & PSC	6.820%
PSC tax and PUC fees	0.08
Base Rent + Tax/Fees	1.31
x HEI Sq Ft	8,874
Monthly HEI Rent	11,659
Test Year HEI Payment	139,914

Year		1
Calendar Year		TY 2005
New Lease Months in Year		
Month-to-Month Lease with Excise Tax (1/05 - 6/05)		403,646
Excise Tax on Month-to-Month		16,146
Month-to-Month Lease	$64,583 x 6 mos.	387,500
Total Payments (7/05 - 12/05)		403,646
Excise Tax Pmt		16,146
Lease Payment	$64,583 x 6 mos.	387,500
HEI Payments		139,914
Operating Lease Treatment with Deferred Rent		
Cash Flow		
Lease Payment (excl. GIT)		387,500
SL Expense (excl. GIT)	DOD-RIR-87 ($73,285 x 6 mos)	439,712
Def Rent Asset (Liability)		(52,212)
Accumulated Asset (Liability)		(52,212)
Current Tax Deduction		387,500
Book Expense		439,712
Deferred Tax Base		(52,212)
Deferred Tax		(20,316)
Accumulated Deferred Tax		(20,316)
Ending Rate Base		(31,896)
Average Rate Base		(15,948)
Capitalization Before Rebalancing		
Average ST Debt	3%	(518)
Average Taxable Debt	37%	(5,871)
Average Hybrid	2%	(378)
Average Preferred Stock	2%	(284)
Average Common Stock	56%	(8,898)
Average Capitalization		(15,948)
Imputed Debt (Ending Balance)		-
Average Imputed Debt		-
Average Rebalancing	HECO RT-21	2,500,000
Adjusted Capitalization with Rebalancing		
Average ST Debt		(2,500,518)
Average Taxable Debt		(5,871)
Average Hybrid		(378)
Average Preferred Stock		(284)
Average Common Stock		2,491,102
Average Capitalization		(15,948)
Net Taxable Debt (check)		36.8%
ST Interest Expense	3.5%	(87,518)
Taxable Debt Interest Expense	6.3%	(367)
Hybrid Dividends	7.6%	(29)
Preferred Dividends	5.5%	(16)
Return on Common	11.0%	274,021
Revenue Requirements		1,185,517
Revenue Taxes		105,333
Lease Expense		439,712
Excise Tax Expense		32,292
Month-to-Month Expense		387,500
HEI Rent Expense		(139,914)

DOD-RIR-63

Ref: HECO RT-13 at pages 28-30

a. Please confirm that HECO's proposal for the Kahe Unit 7 amortization is to continue a $900,000 per year amortization. If this is not the case, explain fully.

b. Please confirm that the result of HECO's proposal is that the $900,000 of Kahe Unit 7 amortization would be included in HECO's proposed revenue requirement until HECO's next rate case. If this is not he case, explain fully.

c. Assuming that "the Company's next rate case is more likely to be filed in three, rather than four, year after the conclusion of this instant proceeding" (as stated on HECO RT-13, page 30, lines 17-19), when does HECO expect that its next base rate case would be filed?

d. Assuming that "the Company's next rate case is more likely to be filed in three, rather than four, year after the conclusion of this instant proceeding" (as stated on HECO RT-13, page 30, lines 17-19), when does HECO expect that the rates established in its next base rate case would become effective?

HECO Response:

a. Yes, HECO's proposal for the amortization of Kahe Unit 7 Project costs is to continue the $900,000 per year amortization for 2005.

b. Yes, the DOD's statement in part b. above is accurate. Unilaterally changing the $900,000 amortization cost which was previously agreed upon between the Company and the Consumer Advocate, and approved by the Commission, is inappropriate and unacceptable to HECO. Please also see the Company's response to CA-RIR-71.

c. See HECO's response to DOD-RIR-61, part a.

d. Based on the time period to process a rate case, and the statutory requirements, an interim decision is generally rendered by the commission between 9 and 11 months following the filing of a rate case. While there is no time requirement for the rendering of a final decision, the final decisions in rate cases in the last fifteen years for the electric utilities have been

rendered between 11 months and 24 months from the filing of the rate increase application.

DOD-RIR-64

Please explain why HECO filed RT-14.

HECO Response:

RT-14 was filed to confirm that 2005 test year estimates presented in T-14 were in agreement with the CA and DOD.

DOD-RIR-65

Refer to HECO RT-15, page 5, line 1.

For what pension plan year was the $15,186,494 contribution made, and as of what exact date in December 2004 was this contribution made?

HECO Response:

The $15,186,494 contribution to the trust was applicable to the 2004 year. Although HECO RT-15, page 5, line 1, indicates the contribution was made in December, 2004, it was actually made in two payments: $ 9,686,494 on September 15, 2004, and $5,500,000 on December 29, 2004.

Please refer to HECO-R-1905, page 4 of 5.

DOD-RIR-66

Refer to HECO RT-15, page 7.

a. Please identify the cost-benefit analysis associated with the new position.

b. Please identify all savings in outside services costs including outside legal and auditor costs associated with the new position.

c. Provide a complete job description for the new position.

d. Provide the portion of the internal control review document that caused the new position to be created.

HECO Response:

a. A cost-benefit analysis associated with this additional position was not performed. The need for the additional employee followed a review of internal controls related to the processes in place for determining benefit costs. Benefits administration is currently performed using a 14-year old welfare benefits administration system and a co-sourced pension system. The welfare system has been enhanced over the years with in-house developed applications and shortcomings have been accommodated with manual worksheets. Integration between these different applications and manual worksheets is a concern. In the internal review process, the need for additional testing, manual checks and documentation was identified to ensure accuracy and completeness of the increasing volume of manually maintained data. The position will provide additional support for administering the benefit systems and overall data maintenance. The risk of incomplete data that could affect the financial results of the Company partially justified the need for the position.

b. Savings in outside services costs associated with the new position are not anticipated since these are internal processes.

c. The position description is attached as pages 3 to 6 to this response. This is not a new

position but is an additional employee in such a position.

d. See the response to a above. The internal control review documents describe the processes and are considered internal company confidential documents. Copies will be provided under protective order.

Confidential Information Deleted Pursuant
To Protective Order No. 21859

Pages 7 to 21 intentionally left blank.

DOD-RIR-67

Refer to HECO RT-15, page 7, lines 20-21.

a. Please confirm that for its own 2005 budgeting process HECO reflects a "hiring lag" adjustment. If this is not the case, explain fully.

b. Please confirm that HECO agrees with and reflects a "hiring lag" adjustment for its 2005 budgeting purposes. If this is not the case, explain fully.

HECO Response:

a. As described in the response to CA-IR-14, the Company's 2005 operating budget includes adjustments made subsequent to the development of the test year estimates for the rate case. Adjustments were made for additional staffing and for a "hiring lag adjustment". There also have been additional staffing positions that were approved subsequent to the development of the Company's 2005 operating budget.

b. As indicated in HECO RT-15 and RT-16, HECO does not agree with the "hiring lag"

DOD-RIR-68

Refer to HECO RT-15.

Has HECO reflected any changes to pension or OPEB expense in its rebuttal testimony that were not identified in HECO's June 15, 2005 update transmittal? If so, please identify all changes to pension or OPEB expense in its rebuttal testimony that were not identified in HECO's June 15, 2005 update transmittal.

HECO Response:

No. HECO's pension and OPEB expense in rebuttal testimony were not changed from those submitted in Attachment 8, page 1, of the June 15, 2005 update transmittal.

DOD-RIR-69

Please provide complete copies of the following articles referenced by Dr. Morin in his Rebuttal Testimony:

- Robert F. Bruner, Kenneth M. Eades, Robert S. Harris, and Robert C. Higgins, "Best Practices in Estimating the Cost of Capital: Survey and Synthesis", *Financial Practice and Education*, Vol. 8, Number 1, Spring/Summer 1998,

- Dimson, Elroy, Paul Marsh and Mike Staunton (2000) "Risk and Return in the 20th and 21s centuries." Business Strategy Review 11(2): 1-18

- Harris, R. S., Marston, F. C., Mishra, D. R., and O'Brien, T. J., "*Ex Ante* Cost of Equity Estimates of S&P 500 Firms: The Choice Between Global and Domestic CAPM," Financial Management, Autumn 2003, pp. 51-66,

- Welch, Ivo (2000, 2001), "Views of Financial Economists on the Equity Premium and on Professional Controversies," Journal of Business 73(4): 501-537,

- Chan, L.K.C. and Lakonishok, J., "Are Reports of Beta's Death Premature?" Journal of Portfolio Management, Summer 1993,

- Black, F., "Beta and Return," Journal of Portfolio Management, Summer 1993,

- Kothari, S.P., Shanken, J., and Sloan, R.G., "Another Look at the Cross-Section of Expected Stock Returns," Journal of Finance, Vol. 50, No. 1,

- Kim, D., "The Errors in the Variables Problem in the Cross-Section of Expected Stock Returns," Journal of Finance, December 1995, Vol. 50, No. 5,

- Jagannathan, R. and Wang. Z., "The Conditional CAPM and the Cross-Section of Expected Returns," Journal of Finance, March 1996, Vol. 51, No. 1.

Dr. Morin's Response:

Copies of nearly all these articles were provided in response to Questions CA-RIR-17 to CA-RIR-20. Dr. Morin does not have access to the other articles requested as they were consulted at the university library, for example the Black article.

DOD-RIR-70

Please provide complete copies of all source documents from which Dr. Morin derived the parameters used in his updated cost of equity analysis (e.g., growth rates, bond yields, bond yield projections).

Dr. Morin's Response:

Other than the materials provided in the response to DOD-RIR-69 and the updated exhibits, the data in Dr. Morin's exhibits are constructed from commercially available information services obtained on a paid subscription basis on CD-ROMs updated monthly, primarily the Value Line Investment Analyzer. The information contained in the Value Line Investment Analyzer software cannot be supplied electronically in order to avoid violation of copyright laws. Dr. Morin notes that much of the information contained in the Value Line Investment Analyzer software is available in paper format from the latest edition of the traditional Value Line Investment Survey coinciding with the month of publication of the software version. Such reports are available at most university libraries in paper format.

Analysts' growth forecasts are obtained directly online from Zacks Investment Research Web site and are available by commercial paid subscription to members. Material that is [redacted]

disseminated without violating copyright laws, and can be made available for inspection upon reasonable prior notice at the Company's premises.

Current bond yields were obtained from the on-line August edition of Value Line's Selection & Opinion document and from the Bondsonline.com Web site. Forecast bond yields are available on-line from the Blue Chip Forecast.

DOD-RIR-71

Please provide complete copies of all source documents from which Dr. Morin derived the parameters used in his updated cost of equity analysis (e.g., growth rates, bond yields, bond yield projections).

Dr. Morin's Response:

See response to DOD-RIR-70.

DOD-RIR-72

Ref. Morin Rebuttal, pp. 9, 10.

Please provide a complete copy of the IRUC Final Order in Cause No. 39871, cited in part by Dr. Morin.

Dr. Morin's Response:

The IURC final order is a matter of public record and is available from the Lexis data base.

DOD-RIR-73

[Von Gnetchen Rebuttal, p. 29]

a. Please provide the data available that shows the purchased power expense for "HECO-only" and "HECO consolidated" as a percentage of revenues for each entity. Please provide supporting documentation (income statements, etc.).

b. Please provide any documents originated by Standard & Poor's (i.e., not created by the Company) that show HECO's purchased power "long-term fixed obligations" represents 40% of HECO's base-load generation. If unable to provide any such documents, please explain why and provide supporting documentation for the calculation.

HECO Response:

a. The purchase power expense for the preceding three years for HECO-only and HECO consolidated are provided on page 3. This information was obtained from HEI's most recent 10-K (pages 5 to 8). The critical point, however, is that because HECO operates in an island environment and is not inter-connected with any other utility or even to another island, purchase power used to meet its firm capacity needs must be obtained by entering into fixed, long-term purchase power agreements. The fixed long-term nature of the agreements causes the rating agencies to impute debt in evaluating HECO's financial performance. Mainland utilities, such as the entities suggested by Mr. Hill, are inter-connected and therefore can much more readily obtain purchase power when needed or as-available. Their purchased power would show up on their income statement as purchased power but may not require a long-term, fixed obligation and thus may not trigger an imputed debt calculation by the rating agencies. Therefore, it is unreasonable to suggest HECO has the same purchase power risk compared to mainland companies by simply comparing the level of purchase power expenditure without first determining the nature of the purchase power agreements behind such expenditures.

b. Mr. von Gnechten has indicated to HECO that he is not aware of any Standard and Poor's calculation of percentage of base load generation supplied by long-term fixed obligations. S&P calculates imputed debt based on the company's long-term purchase power obligations which equaled $243,404,000 of imputed debt and applies a 10% interest factor to this imputed debt. The critical point is, for the reasons noted above, that HECO must enter into fixed, long-term agreements which cause the rating agencies to impute debt to HECO's capital structure for purposes of evaluating the company's financial ratios. As illustrated on page 4, purchased power represents approximately 40% of HECO's net generated and purchased energy. Also on page 4 purchased power obligations represent 48.6% of base-load generation capacity on HECO's system.

Purchased Power Expense as a % of Revenue

HECO Consolidated		2004	2003	2002
Purchased Power Expense ($000)	(A)	398,836	368,076	326,455
Operating Revenues ($000)	(B)	1,546,875	1,393,038	1,252,929
Purchase Power Expense as a % of Revenue [(A)/(B)]		25.78%	26.42%	26.06%
HECO Only				
Purchased Power Expense ($000)	(C)	295,963	284,549	261,000
Operating Revenues ($000)	(D)	1,053,100	963,500	868,383
Purchase Power Expense as a % of Revenue [(C)/(D)]		28.10%	29.53%	30.06%

Source: (A), (B), (C) and (D) per 2004 HEI Form 10-K

GWH net generated and purchased

HECO Consolidated		2004	2003	2002
Purchased	(A)	4,067	4,054	3,830
Net generated and purchased	(B)	10,639	10,335	10,079
Purchased GWH/Net generated and purchased GWH [(A)/(B)]		38.23%	39.23%	38.00%

Source: 2004 HEI Form 10-K, page 4.

HECO Only				
Purchased	(C)	3,208	3,240	3,120
Net generated and purchased	(D)	8,127	7,909	7,758
Purchased GWH/Net generated and purchased GWH [(C)/(D)]		39.47%	40.97%	40.22%

Source: Year to date totals per December monthly financial report submitted to PUC

Consolidated Statements of Income

Hawaiian Electric Company, Inc. and Subsidiaries

Years ended December 31 (In thousands)	2004	2003	2002
Operating revenues	$1,546,875	$1,393,038	$1,252,929
Operating expenses			
Fuel oil	483,423	388,560	310,595
Purchased power	398,836	368,076	326,455
Other operation	157,198	155,531	131,910
Maintenance	77,313	64,621	66,541
Depreciation	114,920	110,560	105,424
Taxes, other than income taxes	143,834	130,677	120,118
Income taxes	50,059	50,175	56,729
	1,425,583	1,268,200	1,117,772
Operating income	121,292	124,838	135,157
Other income			
Allowance for equity funds used during construction	5,794	4,267	3,954
Other, net	3,132	1,903	3,141
	8,926	6,170	7,095
Income before interest and other charges	130,218	131,008	142,252
Interest and other charges			
Interest on long-term debt	42,543	40,698	40,720
Amortization of net bond premium and expense	2,289	2,131	2,014
Preferred securities distributions of trust subsidiaries	–	7,675	7,675
Other interest charges	4,756	1,512	4,498
Allowance for borrowed funds used during construction	(2,542)	(1,914)	(1,855)
Preferred stock dividends of subsidiaries	915	915	915
	47,961	51,017	50,967
Income before preferred stock dividends of HECO	82,257	79,991	91,285
Preferred stock dividends of HECO	1,080	1,080	1,080
Net income for common stock	$ 81,177	$ 78,911	$ 90,205

Consolidated Statements of Retained Earnings

Hawaiian Electric Company, Inc. and Subsidiaries

Years ended December 31 (In thousands)	2004	2003	2002
Retained earnings, January 1	$563,215	$542,023	$495,961
Net income for common stock	81,177	78,911	90,205
Common stock dividends	(11,613)	(57,719)	(44,143)
Retained earnings, December 31	$632,779	$563,215	$542,023

See accompanying "Notes to Consolidated Financial Statements."

Consolidating statement of income

	Year ended December 31, 2004					
(In thousands)	HECO	HELCO	MECO	Renewable Hawaii, Inc.	Reclassifications and Eliminations	HECO Consolidated
Operating revenues	$1,053,100	241,630	252,145	--	--	$1,546,875
Operating expenses						
Fuel oil	335,281	38,072	110,070	--	--	483,423
Purchased power	295,963	91,024	11,849	--	--	398,836
Other operation	106,138	24,572	26,488	--	--	157,198
Maintenance	47,847	15,145	14,321	--	--	77,313
Depreciation	69,467	21,163	24,290	--	--	114,920
Taxes, other than income taxes	97,974	22,391	23,469	--	--	143,834
Income taxes	29,484	8,204	12,371	--	--	50,059
	982,154	220,571	222,858	--	--	1,425,583
Operating income	70,946	21,059	29,287	--	--	121,292
Other income						
Allowance for equity funds used during construction	5,226	162	406	--	--	5,794
Equity in earnings of subsidiaries	31,746	--	--	--	(31,746) [2]	--
Other, net	3,652	210	(43)	(53)	(634) [1]	3,132
	40,624	372	363	(53)	(32,380)	8,926
Income before interest and other charges	111,570	21,431	29,650	(53)	(32,380)	130,218
Interest and other charges						
Interest on long-term debt	26,566	7,184	8,793	--	--	42,543
Amortization of net bond premium and expense	1,464	403	422	--	--	2,289
Other interest charges	3,595	1,063	712	--	(634) [1]	4,756
Allowance for borrowed funds used during construction	(2,312)	(75)	(155)	--	--	(2,542)
Preferred stock dividends of subsidiaries	--	--	--	--	915 [3]	915
	29,313	8,595	9,772	--	281	47,961
Income before preferred stock dividends of HECO	[illegible]	[illegible]	[illegible]	(53)	(32,661)	82,257

Consolidating statement of income

	Year ended December 31, 2003							
(In thousands)	HECO	HELCO	MECO	Renewable Hawaii, Inc.	HECO Capital Trust I	HECO Capital Trust II	Reclassifications and Eliminations	HECO Consolidated
Operating revenues	$963,500	214,243	215,295	–	–	–	–	$1,393,038
Operating expenses								
Fuel oil	273,905	31,853	82,802	–	–	–	–	388,560
Purchased power	284,549	75,042	8,485	–	–	–	–	368,076
Other operation	102,441	25,643	27,447	–	–	–	–	155,531
Maintenance	38,505	13,737	12,379	–	–	–	–	64,621
Depreciation	67,121	20,293	23,146	–	–	–	–	110,560
Taxes, other than income taxes	90,150	20,105	20,422	–	–	–	–	130,677
Income taxes	31,113	7,120	11,942	–	–	–	–	50,175
	887,784	193,793	186,623	–	–	–	–	1,268,200
Operating income	75,716	20,450	28,672	–	–	–	–	124,838
Other income								
Allowance for equity funds used during construction	3,652	170	445	–	–	–	–	4,267
Equity in earnings of subsidiaries	29,459	–	–	–	–	–	(29,459) [2]	–
Other, net	2,667	315	(557)	(133)	4,149	3,763	(8,301) [1]	1,903
	35,778	485	(112)	(133)	4,149	3,763	(37,760)	6,170
Income before interest and other charges	111,494	20,935	28,560	(133)	4,149	3,763	(37,760)	131,008
Interest and other charges								
Interest on long-term debt	25,284	7,016	8,398	–	–	–	–	40,698
Amortization of net bond premium and expense	1,371	364	396	–	–	–	–	2,131
Preferred securities distributions of trust subsidiaries	–	–	–	–	–	–	7,675 [3]	7,675
Other interest charges	6,506	1,952	1,354	1	–	–	(8,301) [1]	1,512
Allowance for borrowed funds used during construction	(1,658)	(80)	(176)	–	–	–	–	(1,914)
Preferred stock dividends of subsidiaries	–	–	–	–	–	–	915 [3]	915
	31,503	9,252	9,972	1	–	–	289	51,017
Income before preferred stock dividends of HECO	79,991	11,683	18,588	(134)	4,149	3,763	(38,049)	79,991
Preferred stock dividends of HECO	1,080	534	381	–	4,025	3,650	(8,590) [3]	1,080
Net income for common stock	$ 78,911	11,149	18,207	(134)	124	113	(29,459)	$ 78,911

Consolidating statement of retained earnings

	Year ended December 31, 2003							
(In thousands)	HECO	HELCO	MECO	Renewable Hawaii, Inc.	HECO Capital Trust I	HECO Capital Trust II	Reclassifications and Eliminations	HECO Consolidated
Retained earnings, beginning of period	$542,023	71,414	87,092	–	–	–	(158,506) [2]	$542,023
Net income for common stock	78,911	11,149	18,207	(134)	124	113	(29,459) [2]	78,911
Common stock dividends	(57,719)	(7,934)	(12,390)	–	(124)	(113)	20,561 [2]	(57,719)
Retained earnings, end of period	$563,215	74,629	92,909	(134)	–	–	(167,404)	$563,215

Consolidating statement of income

(in thousands)	Year ended December 31, 2002						
	HECO	HELCO	MECO	HECO Capital Trust I	HECO Capital Trust II	Reclassifications and Eliminations	HECO Consolidated
Operating revenues	$868,383	192,209	192,337	–	–	–	$1,252,929
Operating expenses							
Fuel oil	214,067	31,333	65,195	–	–	–	310,595
Purchased power	261,000	58,058	7,397	–	–	–	326,455
Other operation	83,190	21,697	27,023	–	–	–	131,910
Maintenance	41,411	13,437	11,693	–	–	–	66,541

DOD-RIR-74

[Von Gnetchen Rebuttal, p. 29]

a. Are expected purchased power expenses included in HECO's cost of service in this proceeding? If so, why; if not, why not?

b. Are expected interest costs included in HECO's cost of service in this proceeding? If so, why; if not, why not?

c. Is the cost of debt included in the overall cost of capital calculation in this proceeding? If so, why; if not, why not?

d. Is the cost of imputed debt related to purchased power obligations included in the overall cost of capital calculation in this proceeding? If so, why; if not, why not?

HECO Response:

a. Yes, the expected purchase power expenses are included in HECO's cost of service calculation of this proceeding. See Mr. Young's rebuttal testimony under HECO RT-22 for further elaboration of these expenses.

b. If the term "expected interest cost" includes imputed interest costs, no, the rating agencies' imputed interest costs are not reflected in the cost of service of this proceeding because it is not an expense that will be directly incurred by the Company. However, this $243,404,000 in imputed debt and approximately $24,340,400 in imputed interest expense (at 10%) must be used in calculating the Company's financial ratios and credit rating impact and therefore must be considered in evaluating the Company's capital structure and risk. If the term "expected interest cost" does not include imputed interest cost, see response to (c).

c. Yes, cost of (actual and forecast) debt is included in the overall cost of capital.

d. No, the imputed debt associated with purchase power is not reflected in the Company's capital structure. It is, however, part of the reason the Company has had to increase its equity level to maintain its financial ratios and credit ratings. It is unreasonable to suggest

HECO's capital structure reflects lower financial risk without also considering the capital structure with the imputed debt that the rating agencies use to determine the Company's credit rating.