HAWAIIAN ELECTRIC CO INC
Form 10-Q
May 10, 2011
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D. C. 20549

FORM 10-Q

x QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2011

OR

o TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

Exact Name of Registrant as Specified in Its Charter	Commission File Number	I.R.S. Employer Identification No.
HAWAIIAN ELECTRIC INDUSTRIES, INC.	**1-8503**	**99-0208097**
and Principal Subsidiary		
HAWAIIAN ELECTRIC COMPANY, INC.	**1-4955**	**99-0040500**

State of Hawaii

(State or other jurisdiction of incorporation or organization)

900 Richards Street, Honolulu, Hawaii 96813

(Address of principal executive offices and zip code)

Hawaiian Electric Industries, Inc. ----- (808) 543-5662

Hawaiian Electric Company, Inc. ------- (808) 543-7771

(Registrant s telephone number, including area code)

Not applicable

(Former name, former address and former fiscal year, if changed since last report)

Indicate by check mark whether Registrant Hawaiian Electric Industries, Inc. (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o

Indicate by check mark whether Registrant Hawaiian Electric Company, Inc. (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No o

Indicate by check mark whether Registrant Hawaiian Electric Industries, Inc. has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes x No o

Indicate by check mark whether Registrant Hawaiian Electric Company, Inc. has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes o No o

Indicate by check mark whether Registrant Hawaiian Electric Industries, Inc. is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No x

Indicate by check mark whether Registrant Hawaiian Electric Company, Inc. is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes o No x

APPLICABLE ONLY TO CORPORATE ISSUERS:

Indicate the number of shares outstanding of each of the issuers classes of common stock, as of the latest practicable date.

Class of Common Stock	Outstanding April 29, 2011
Hawaiian Electric Industries, Inc. (Without Par Value)	95,323,855 Shares
Hawaiian Electric Company, Inc. ($6-2/3 Par Value)	13,830,823 Shares (not publicly traded)

Indicate by check mark whether Registrant Hawaiian Electric Industries, Inc. is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large accelerated filer x	Accelerated filer o
Non-accelerated filer o (Do not check if a smaller reporting company)	Smaller reporting company o

Indicate by check mark whether Registrant Hawaiian Electric Company, Inc. is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act.

Large accelerated filer o	Accelerated filer o
Non-accelerated filer x (Do not check if a smaller reporting company)	Smaller reporting company o

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Hawaiian Electric Industries, Inc. and Subsidiaries

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Hawaiian Electric Industries, Inc. and Subsidiaries

Hawaiian Electric Company, Inc. and Subsidiaries

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GLOSSARY OF TERMS

Terms	Definitions
AFUDC	Allowance for funds used during construction
AOCI	Accumulated other comprehensive income
AOS	Adequacy of supply
ARO	Asset retirement obligation
ASB	American Savings Bank, F.S.B., a wholly-owned subsidiary of American Savings Holdings, Inc. American Savings Investment Services Corp. and its subsidiary, Bishop Insurance Agency of Hawaii, Inc. (dissolved in 2010) are former subsidiaries.
ASHI	American Savings Holdings, Inc., a wholly owned subsidiary of Hawaiian Electric Industries, Inc. and the parent company of American Savings Bank, F.S.B.
CIP CT-1	Campbell Industrial Park 110 MW combustion turbine No. 1
Company	When used in Hawaiian Electric Industries, Inc. sections, the Company refers to Hawaiian Electric Industries, Inc. and its direct and indirect subsidiaries, including, without limitation, Hawaiian Electric Company, Inc. and its subsidiaries (listed under HECO); American Savings Holdings, Inc. and its subsidiary, American Savings Bank, F.S.B. and its former subsidiaries (listed under ASB); Pacific Energy Conservation Services, Inc. (dissolved on April 1, 2011); HEI Properties, Inc.; Hawaiian Electric Industries Capital Trust II and Hawaiian Electric Industries Capital Trust III (inactive financing entities); and The Old Oahu Tug Service, Inc. (formerly Hawaiian Tug & Barge Corp.).
Consumer Advocate	Division of Consumer Advocacy, Department of Commerce and Consumer Affairs of the State of Hawaii
DBEDT	State of Hawaii Department of Business, Economic Development and Tourism
DBF	State of Hawaii Department of Budget and Finance
D&O	Decision and order
DG	Distributed generation
Dodd-Frank Act	Dodd-Frank Wall Street Reform and Consumer Protection Act
DOH	Department of Health of the State of Hawaii
DRIP	HEI Dividend Reinvestment and Stock Purchase Plan
DSM	Demand-side management
ECAC	Energy cost adjustment clauses
EIP	2010 Equity and Incentive Plan
Energy Agreement	Agreement dated October 20, 2008 and signed by the Governor of the State of Hawaii, the State of Hawaii Department of Business, Economic Development and Tourism, the Division of Consumer Advocacy of the Department of Commerce and Consumer Affairs, and HECO, for itself and on behalf of its electric utility subsidiaries committing to actions to develop renewable energy and reduce dependence on fossil fuels in support of the HCEI
EPA	Environmental Protection Agency federal
EPS	Earnings per share
Exchange Act	Securities Exchange Act of 1934
FDIC	Federal Deposit Insurance Corporation
federal	U.S. Government
FHLB	Federal Home Loan Bank
FHLMC	Federal Home Loan Mortgage Corporation
FNMA	Federal National Mortgage Association

FSS	Forward Starting Swaps

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Terms	Definitions
GAAP	U.S. generally accepted accounting principles
GHG	Greenhouse gas
GNMA	Government National Mortgage Association
HCEI	Hawaii Clean Energy Initiative
HECO	Hawaiian Electric Company, Inc., an electric utility subsidiary of Hawaiian Electric Industries, Inc. and parent company of Hawaii Electric Light Company, Inc., Maui Electric Company, Limited, HECO Capital Trust III (unconsolidated subsidiary), Renewable Hawaii, Inc. and Uluwehiokama Biofuels Corp.
HEI	Hawaiian Electric Industries, Inc., direct parent company of Hawaiian Electric Company, Inc., American Savings Holdings, Inc., Pacific Energy Conservation Services, Inc. (dissolved on April 1, 2011), HEI Properties, Inc., Hawaiian Electric Industries Capital Trust II, Hawaiian Electric Industries Capital Trust III and The Old Oahu Tug Service, Inc. (formerly Hawaiian Tug & Barge Corp.)
HEIRSP	Hawaiian Electric Industries Retirement Savings Plan
HELCO	Hawaii Electric Light Company, Inc., an electric utility subsidiary of Hawaiian Electric Company, Inc.
HPOWER	City and County of Honolulu with respect to a power purchase agreement for a refuse-fired plant
IPP	Independent power producer
IRP	Integrated resource plan
Kalaeloa	Kalaeloa Partners, L.P.
KWH	Kilowatthour
MECO	Maui Electric Company, Limited, an electric utility subsidiary of Hawaiian Electric Company, Inc.
MW	Megawatt/s (as applicable)
NII	Net interest income
NPV	Net portfolio value
NQSO	Nonqualified stock option
O&M	Operation and maintenance
OPEB	Postretirement benefits other than pensions
OTS	Office of Thrift Supervision, Department of Treasury
PBF	Public benefits fund
PPA	Power purchase agreement
PRPs	Potentially responsible parties
PUC	Public Utilities Commission of the State of Hawaii
RAM	Revenue adjustment mechanism
RBA	Revenue balancing account
REG	Renewable Energy Group Marketing & Logistics, LLC
RFP	Request for proposal
REIP	Renewable Energy Infrastructure Program
RHI	Renewable Hawaii, Inc., a wholly owned subsidiary of Hawaiian Electric Company, Inc.
ROACE	Return on average common equity
ROR	Return on average rate base
RPS	Renewable portfolio standards
SAR	Stock appreciation right
SEC	Securities and Exchange Commission
See	Means the referenced material is incorporated by reference
SOIP	1987 Stock Option and Incentive Plan, as amended
SPRBs	Special Purpose Revenue Bonds
TDR	Troubled debt restructuring
UBC	Uluwehiokama Biofuels Corp., a non-regulated subsidiary of Hawaiian Electric Company, Inc.
VIE	Variable interest entity

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FORWARD-LOOKING STATEMENTS

This report and other presentations made by Hawaiian Electric Industries, Inc. (HEI) and Hawaiian Electric Company, Inc. (HECO) and their subsidiaries contain forward-looking statements, which include statements that are predictive in nature, depend upon or refer to future events or conditions, and usually include words such as expects, anticipates, intends, plans, believes, predicts, estimates or similar expressions. I addition, any statements concerning future financial performance, ongoing business strategies or prospects or possible future actions are also forward-looking statements. Forward-looking statements are based on current expectations and projections about future events and are subject to risks, uncertainties and the accuracy of assumptions concerning HEI and its subsidiaries (collectively, the Company), the performance of the industries in which they do business and economic and market factors, among other things. **These forward-looking statements are not guarantees of future performance.**

Risks, uncertainties and other important factors that could cause actual results to differ materially from those described in forward-looking statements and from historical results include, but are not limited to, the following:

- international, national and local economic conditions, including the state of the Hawaii tourism and construction industries, the strength or weakness of the Hawaii and continental U.S. real estate markets (including the fair value and/or the actual performance of collateral underlying loans held by American Savings Bank, F.S.B. (ASB), which could result in higher loan loss provisions and write-offs), decisions concerning the extent of the presence of the federal government and military in Hawaii, and the implications and potential impacts of capital and credit market conditions and federal and state responses to those conditions;

- weather and natural disasters (e.g., hurricanes, earthquakes, tsunamis, lightning strikes and the potential effects of global warming, such as more severe storms and rising sea levels), including their impact on Company operations and the economy (e.g., the effect of the March 2011 natural disasters in Japan on its economy and tourism in Hawaii);

- global developments, including unrest and conflict in North Africa and the Middle East, terrorist acts, the war on terrorism, continuing U.S. presence in Afghanistan and potential conflict or crisis with North Korea;

- the timing and extent of changes in interest rates and the shape of the yield curve;

- the ability of the Company to access credit markets to obtain commercial paper and other short-term and long-term debt financing (including lines of credit) and to access capital markets to issue HEI common stock under volatile and challenging market conditions, and the cost of such financings, if available;

- the risks inherent in changes in the value of pension and other retirement plan assets and securities available for sale;

- changes in laws, regulations, market conditions and other factors that result in changes in assumptions used to calculate retirement benefits costs and funding requirements;

- the impact of the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010 (Dodd-Frank Act) and of the rules and regulations that the Dodd-Frank Act requires to be promulgated;

- increasing competition in the banking industry (e.g., increased price competition for deposits, or an outflow of deposits to alternative investments, which may have an adverse impact on ASB s cost of funds);

- the implementation of the Energy Agreement with the State of Hawaii and Consumer Advocate (Energy Agreement) setting forth the goals and objectives of a Hawaii Clean Energy Initiative (HCEI), revenue decoupling and the fulfillment by the electric utilities of their commitments under the Energy Agreement (given the Public Utilities Commission of the State of Hawaii (PUC) approvals needed; the PUC s potential delay in considering HCEI-related costs; reliance by the Company on outside parties like the state, independent power producers (IPPs) and developers; potential changes in political support for the HCEI; and uncertainties surrounding wind power, the proposed undersea cable (to bring power to Oahu from Lanai and/or Molokai), biofuels, environmental assessments and the impacts of implementation of the HCEI on future costs of electricity);

- capacity and supply constraints or difficulties, especially if generating units (utility-owned or IPP-owned) fail or measures such as demand-side management (DSM), distributed generation (DG), combined heat and power or other firm capacity supply-side resources fall short of achieving their forecasted benefits or are otherwise insufficient to reduce or meet peak demand;

- the risk to generation reliability when generation peak reserve margins on Oahu are strained;

- fuel oil price changes, performance by suppliers of their fuel oil delivery obligations and the continued availability to the electric utilities of their energy cost adjustment clauses (ECACs);

- the impact of fuel price volatility on customer satisfaction and political and regulatory support for the utilities;

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- the risks associated with increasing reliance on renewable energy, as contemplated under the Energy Agreement, including the availability and cost of non-fossil fuel supplies for renewable energy generation and the operational impacts of adding intermittent sources of renewable energy to the electric grid;

- the ability of IPPs to deliver the firm capacity anticipated in their power purchase agreements (PPAs);

- the ability of the electric utilities to negotiate, periodically, favorable fuel supply and collective bargaining agreements;

- new technological developments that could affect the operations and prospects of HEI and its subsidiaries (including HECO and its subsidiaries and ASB) or their competitors;

- federal, state, county and international governmental and regulatory actions, such as changes in laws, rules and regulations applicable to HEI, HECO, ASB and their subsidiaries (including changes in taxation, increases in capital requirements, regulatory changes resulting from the HCEI, environmental laws and regulations, the regulation of greenhouse gas (GHG) emissions, governmental fees and assessments (such as Federal Deposit Insurance Corporation assessments), and potential carbon cap and trade legislation that may fundamentally alter costs to produce electricity and accelerate the move to renewable generation);

- decisions by the PUC in rate cases and other proceedings (including the risks of delays in the timing of decisions, adverse changes in final decisions from interim decisions and the disallowance of project costs);

- decisions by the PUC and by other agencies and courts on land use, environmental and other permitting issues (such as required corrective actions and restrictions and penalties that may arise, such as with respect to environmental conditions or renewable portfolio standards (RPS));

- potential enforcement actions by the Office of Thrift Supervision (OTS) (or its regulatory successors, the Office of the Comptroller of the Currency and the Federal Reserve Board) and other governmental authorities (such as consent orders, required corrective actions, restrictions and penalties that may arise, for example, with respect to compliance deficiencies under existing or new banking and consumer protection laws and regulations or with respect to capital adequacy);

- ability to recover and earn on increasing costs and capital investments not covered by revenue adjustment mechanisms;

- the risks associated with the geographic concentration of HEI s businesses and ASB s loans, ASB s concentration in a single product type (i.e., first mortgages) and ASB s significant credit relationships (i.e., concentrations of large loans and/or credit lines with certain customers);

- changes in accounting principles applicable to HEI, HECO, ASB and their subsidiaries, including the adoption of International Financial Reporting Standards or new U.S. accounting standards, the potential discontinuance of regulatory accounting and the effects of potentially required consolidation of variable interest entities (VIEs) or required capital lease accounting for PPAs with IPPs;

- changes by securities rating agencies in their ratings of the securities of HEI and HECO and the results of financing efforts;

- faster than expected loan prepayments that can cause an acceleration of the amortization of premiums on loans and investments and the impairment of mortgage-servicing assets of ASB;

- changes in ASB s loan portfolio credit profile and asset quality which may increase or decrease the required level of allowance for loan losses and charge-offs;

- changes in ASB s deposit cost or mix which may have an adverse impact on ASB s cost of funds;

- the final outcome of tax positions taken by HEI, HECO, ASB and their subsidiaries;

- the risks of suffering losses and incurring liabilities that are uninsured or underinsured; and

- other risks or uncertainties described elsewhere in this report and in other reports (e.g., Item 1A. Risk Factors in the Company s Annual Report on Form 10-K) previously and subsequently filed by HEI and/or HECO with the Securities and Exchange Commission (SEC).

Forward-looking statements speak only as of the date of the report, presentation or filing in which they are made. Except to the extent required by the federal securities laws, HEI, HECO, ASB and their subsidiaries undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

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PART I - FINANCIAL INFORMATION

Item 1. Financial Statements

Hawaiian Electric Industries, Inc. and Subsidiaries

Consolidated Statements of Income (unaudited)

Three months ended March 31 (in thousands, except per share amounts)	2011	2010
Revenues		
Electric utility	$ 645,335	$ 548,111
Bank	65,313	70,914
Other	(15)	15
	710,633	619,040
Expenses		
Electric utility	600,127	505,502
Bank	43,559	49,143
Other	3,572	3,688
	647,258	558,333
Operating income (loss)		
Electric utility	45,208	42,609
Bank	21,754	21,771
Other	(3,587)	(3,673)
	63,375	60,707
Interest expense other than on deposit liabilities and other bank borrowings	(20,140)	(20,381)
Allowance for borrowed funds used during construction	520	779
Allowance for equity funds used during construction	1,244	1,773
Income before income taxes	44,999	42,878
Income taxes	16,064	15,279
Net income	28,935	27,599
Preferred stock dividends of subsidiaries	473	473
Net income for common stock	$ 28,462	$ 27,126
Basic earnings per common share	$ 0.30	$ 0.29
Diluted earnings per common share	$ 0.30	$ 0.29
Dividends per common share	$ 0.31	$ 0.31
Weighted-average number of common shares outstanding	94,817	92,572
Dilutive effect of share-based compensation	365	276
Adjusted weighted-average shares	95,182	92,848

The accompanying notes are an integral part of these consolidated financial statements.

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Hawaiian Electric Industries, Inc. and Subsidiaries

Consolidated Balance Sheets (unaudited)

(dollars in thousands)		March 31, 2011		December 31, 2010
Assets				
Cash and cash equivalents	$	316,254	$	330,651
Accounts receivable and unbilled revenues, net		286,876		266,996
Available-for-sale investment and mortgage-related securities		670,949		678,152
Investment in stock of Federal Home Loan Bank of Seattle		97,764		97,764
Loans receivable held for investment, net		3,549,750		3,489,880
Loans held for sale, at lower of cost or fair value		4,308		7,849
Property, plant and equipment, net of accumulated depreciation of $2,032,500 in 2011 and $2,037,598 in 2010		3,175,375		3,165,918
Regulatory assets		481,812		478,330
Other		462,258		487,614
Goodwill		82,190		82,190
Total assets	$	9,127,536	$	9,085,344
Liabilities and shareholders equity				
Liabilities				
Accounts payable	$	162,748	$	202,446
Interest and dividends payable		27,496		27,814
Deposit liabilities		4,035,255		3,975,372
Short-term borrowings other than bank				24,923
Other bank borrowings		244,674		237,319
Long-term debt, net other than bank		1,439,974		1,364,942
Deferred income taxes		291,470		278,958
Regulatory liabilities		304,375		296,797
Contributions in aid of construction		338,070		335,364
Other		752,630		823,479
Total liabilities		7,596,692	$	7,567,414
Preferred stock of subsidiaries - not subject to mandatory redemption		34,293		34,293
Shareholders equity				
Preferred stock, no par value, authorized 10,000,000 shares; issued: none				
Common stock, no par value, authorized 200,000,000 shares; issued and outstanding: 95,288,966 shares in 2011 and 94,690,932 shares in 2010		1,329,901		1,314,199
Retained earnings		180,960		181,910
Accumulated other comprehensive loss, net of tax benefits		(14,310)		(12,472)
Total shareholders equity		1,496,551		1,483,637
Total liabilities and shareholders equity	$	9,127,536	$	9,085,344

The accompanying notes are an integral part of these consolidated financial statements.

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Hawaiian Electric Industries, Inc. and Subsidiaries

Consolidated Statements of Changes in Shareholders Equity (unaudited)

(in thousands, except per share amounts)	Common stock Shares	Common stock Amount	Retained earnings	Accumulated other comprehensive loss	Total
Balance, December 31, 2010	**94,691**	**$ 1,314,199**	**$ 181,910**	**$ (12,472)**	**$ 1,483,637**
Comprehensive income (loss):					
Net income for common stock			28,462		28,462
Net unrealized losses on securities:					
Net unrealized losses on securities arising during the period, net of tax benefits of $414				(626)	(626)
Losses on derivatives qualified as cash flow hedges:					
Holding losses arising during the period, net of tax benefits of $6				(9)	(9)
Less: reclassification adjustment to net income, net of tax benefits of $3				5	5
Retirement benefit plans:					
Less: amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of tax benefits of $631				1,039	1,039
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of taxes of $1,431				(2,247)	(2,247)
Other comprehensive income				(1,838)	
Comprehensive income					26,624
Issuance of common stock, net	598	15,702			15,702
Common stock dividends ($0.31 per share)			(29,412)		(29,412)
Balance, March 31, 2011	**95,289**	**$ 1,329,901**	**$ 180,960**	**$ (14,310)**	**$ 1,496,551**
Balance, December 31, 2009	**92,521**	**$ 1,265,157**	**$ 184,213**	**$ (7,722)**	**$ 1,441,648**
Comprehensive income (loss):					
Net income for common stock			27,126		27,126
Net unrealized gains on securities arising during the period, net of taxes of $696				1,053	1,053
Retirement benefit plans:					
Less: amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of tax benefits of $609				958	958
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of taxes of $526				(825)	(825)
Other comprehensive income				1,186	
Comprehensive income					28,312
Issuance of common stock, net	575	12,176			12,176
Common stock dividends ($0.31 per share)			(28,693)		(28,693)
Balance, March 31, 2010	**93,096**	**$ 1,277,333**	**$ 182,646**	**$ (6,536)**	**$ 1,453,443**

The accompanying notes are an integral part of these consolidated financial statements.

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Hawaiian Electric Industries, Inc. and Subsidiaries

Consolidated Statements of Cash Flows (unaudited)

Three months ended March 31 **(in thousands)**	**2011**	**2010**
Cash flows from operating activities		
Net income	$ 28,935	$ 27,599
Adjustments to reconcile net income to net cash provided by (used in) operating activities		
Depreciation of property, plant and equipment	37,708	39,798
Other amortization	2,354	1,565
Provision for loan losses	4,550	5,359
Loans receivable originated and purchased, held for sale	(35,015)	(78,685)
Proceeds from sale of loans receivable, held for sale	43,048	82,814
Changes in deferred income taxes	16,687	(129)
Changes in excess tax benefits from share-based payment arrangements	(22)	(43)
Allowance for equity funds used during construction	(1,244)	(1,773)
Increase (decrease) in cash overdraft	(2,688)	681
Changes in assets and liabilities		
Decrease (increase) in accounts receivable and unbilled revenues, net	(19,880)	7,231
Increase in fuel oil stock	(3,513)	(26,506)
Increase (decrease) in accounts, interest and dividends payable	(40,016)	2,155
Changes in prepaid and accrued income taxes and utility revenue taxes	(1,594)	(48,689)
Changes in other assets and liabilities	(42,544)	(1,508)
Net cash provided by (used in) operating activities	**(13,234)**	**9,869**
Cash flows from investing activities		
Available-for-sale investment and mortgage-related securities purchased	(109,307)	(170,385)
Principal repayments on available-for-sale investment and mortgage-related securities	114,529	48,338
Net decrease (increase) in loans held for investment	(70,269)	38,072
Proceeds from sale of real estate acquired in settlement of loans	1,253	1,279
Capital expenditures	(38,491)	(34,816)
Contributions in aid of construction	5,749	3,729
Other	145	
Net cash used in investing activities	**(96,391)**	**(113,783)**
Cash flows from financing activities		
Net increase (decrease) in deposit liabilities	59,883	(50,369)
Net increase (decrease) in short-term borrowings with original maturities of three months or less	(24,923)	18,249
Net increase (decrease) in retail repurchase agreements	7,368	(3,461)
Proceeds from issuance of long-term debt	125,000	
Repayment of long-term debt	(50,000)	
Changes in excess tax benefits from share-based payment arrangements	22	43
Net proceeds from issuance of common stock	5,674	5,557
Common stock dividends	(23,593)	(23,048)
Preferred stock dividends of subsidiaries	(473)	(473)
Other	(3,730)	(4,474)
Net cash provided by (used in) financing activities	**95,228**	**(57,976)**
Net decrease in cash and cash equivalents	(14,397)	(161,890)
Cash and cash equivalents, beginning of period	330,651	503,922
Cash and cash equivalents, end of period	**$ 316,254**	**$ 342,032**

The accompanying notes are an integral part of these consolidated financial statements.

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Hawaiian Electric Industries, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1 • Basis of presentation

The accompanying unaudited consolidated financial statements have been prepared in conformity with U.S. generally accepted accounting principles (GAAP) for interim financial information, the instructions to SEC Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the information and footnotes required by GAAP for complete financial statements. In preparing the financial statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the balance sheet and the reported amounts of revenues and expenses for the period. Actual results could differ significantly from those estimates. The accompanying unaudited consolidated financial statements and the following notes should be read in conjunction with the audited consolidated financial statements and the notes thereto included in HEI s Form 10-K for the year ended December 31, 2010.

In the opinion of HEI s management, the accompanying unaudited consolidated financial statements contain all material adjustments required by GAAP to fairly state the Company s financial position as of March 31, 2011 and December 31, 2010, the results of its operations and cash flows for the three months ended March 31, 2011 and 2010. All such adjustments are of a normal recurring nature unless otherwise disclosed in this Form 10-Q or other referenced material. Results of operations for interim periods are not necessarily indicative of results for the full year. When required, certain reclassifications are made to the prior period s consolidated financial statements to conform to the current presentation.

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2 • Segment financial information

(in thousands)	Electric Utility	Bank	Other	Total
Three months ended March 31, 2011				
Revenues from external customers	$ 645,299	$ 65,313	$ 21	$ 710,633
Intersegment revenues (eliminations)	36		(36)	
Revenues	645,335	65,313	(15)	710,633
Income (loss) before income taxes	31,267	21,727	(7,995)	44,999
Income taxes (benefit)	11,579	7,876	(3,391)	16,064
Net income (loss)	19,688	13,851	(4,604)	28,935
Preferred stock dividends of subsidiaries	499		(26)	473
Net income (loss) for common stock	19,189	13,851	(4,578)	28,462
Tangible assets (at March 31, 2011)	4,211,560	4,769,234	57,710	9,038,504
Three months ended March 31, 2010				
Revenues from external customers	$ 548,075	$ 70,914	$ 51	$ 619,040
Intersegment revenues (eliminations)	36		(36)	
Revenues	548,111	70,914	15	619,040
Income (loss) before income taxes	29,512	21,736	(8,370)	42,878
Income taxes (benefit)	10,961	8,000	(3,682)	15,279
Net income (loss)	18,551	13,736	(4,688)	27,599
Preferred stock dividends of subsidiaries	499		(26)	473
Net income (loss) for common stock	18,052	13,736	(4,662)	27,126
Tangible assets (at December 31, 2010)	4,285,680	4,707,870	2,905	8,996,455

Intercompany electricity sales of the electric utilities to the bank and other segments are not eliminated because those segments would need to purchase electricity from another source if it were not provided by consolidated HECO, the profit on such sales is nominal and the elimination of electric sales revenues and expenses could distort segment operating income and net income for common stock.

Bank fees that ASB charges the electric utility and other segments are not eliminated because those segments would pay fees to another financial institution if they were to bank with another institution, the profit on such fees is nominal and the elimination of bank fee income and expenses could distort segment operating income and net income for common stock.

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3 • Electric utility subsidiary

For consolidated HECO financial information, including its commitments and contingencies, see pages 22 through 36 (HECO and Subsidiaries Consolidated Statements of Income (Unaudited) through Note 10).

4 • Bank subsidiary

Selected financial information

American Savings Bank, F.S.B. and Subsidiaries

Consolidated Statements of Income Data (unaudited)

Three months ended March 31 (in thousands)	2011	2010
Interest and dividend income		
Interest and fees on loans	$ 46,097	$ 49,745
Interest and dividends on investment and mortgage-related securities	3,769	3,317
	49,866	53,062
Interest expense		
Interest on deposit liabilities	2,593	4,423
Interest on other borrowings	1,367	1,426
	3,960	5,849
Net interest income	45,906	47,213
Provision for loan losses	4,550	5,359
Net interest income after provision for loan losses	41,356	41,854
Noninterest income		
Fee income on deposit liabilities	4,449	7,520
Fees from other financial services	6,946	6,414
Fee income on other financial products	1,673	1,525
Other income	2,379	2,393
	15,447	17,852
Noninterest expense		
Compensation and employee benefits	17,505	17,402
Occupancy	4,240	4,225
Data processing	1,970	4,338
Services	1,771	1,728
Equipment	1,657	1,709
Other expense	7,933	8,568
	35,076	37,970
Income before income taxes	21,727	21,736
Income taxes	7,876	8,000
Net income	$ 13,851	$ 13,736

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American Savings Bank, F.S.B. and Subsidiaries

Consolidated Balance Sheets Data (unaudited)

(in thousands)	March 31, 2011	December 31, 2010
Assets		
Cash and cash equivalents	$ 220,066	$ 204,397
Federal funds sold	374	1,721
Available-for-sale investment and mortgage-related securities	670,949	678,152
Investment in stock of Federal Home Loan Bank of Seattle	97,764	97,764
Loans receivable held for investment, net	3,549,750	3,489,880
Loans held for sale, at lower of cost or fair value	4,308	7,849
Other	232,865	234,806
Goodwill	82,190	82,190
Total assets	$ 4,858,266	$ 4,796,759
Liabilities and shareholder s equity		
Deposit liabilities noninterest-bearing	$ 907,444	$ 865,642
Deposit liabilities interest-bearing	3,127,811	3,109,730
Other borrowings	244,674	237,319
Other	87,030	90,683
Total liabilities	4,366,959	4,303,374
Common stock	330,898	330,562
Retained earnings	168,962	169,111
Accumulated other comprehensive loss, net of tax benefits	(8,553)	(6,288)
Total shareholder s equity	491,307	493,385
Total liabilities and shareholder s equity	$ 4,858,266	$ 4,796,759
Other assets		
Bank-owned life insurance	$ 118,679	$ 117,565
Premises and equipment, net	55,772	56,495
Prepaid expenses	18,282	18,608
Accrued interest receivable	14,871	14,887
Mortgage-servicing rights	6,842	6,699
Real estate acquired in settlement of loans, net	5,797	4,292
Other	12,622	16,260
	$ 232,865	$ 234,806
Other liabilities		
Accrued expenses	$ 10,761	$ 16,426
Federal and state income taxes payable	33,139	28,372
Cashier s checks	22,830	22,396
Advance payments by borrowers	6,489	10,216
Other	13,811	13,273
	$ 87,030	$ 90,683

Other borrowings consisted of securities sold under agreements to repurchase and advances from the Federal Home Loan Bank (FHLB) of Seattle of $180 million and $65 million, respectively, as of March 31, 2011 and $172 million and $65 million, respectively, as of December 31, 2010.

Bank-owned life insurance is life insurance purchased by ASB on the lives of certain key employees, with ASB as the beneficiary. The insurance is used to fund employee benefits through tax-free income from increases in the cash value of the policies and insurance proceeds paid to ASB upon an insured s death.

As of March 31, 2011, ASB had total commitments to borrowers for undisbursed loan funds, loan commitments and unused lines and letters of credit of $1.2 billion.

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Investment and mortgage-related securities portfolio.

Available-for-sale securities. The book value and aggregate fair value by major security type were as follows:

	March 31, 2011				December 31, 2010			
(in thousands)	Amortized cost	Gross unrealized gains	Gross unrealized losses	Estimated fair value	Amortized cost	Gross unrealized gains	Gross unrealized losses	Estimated fair value
Federal agency obligations	$ 288,393	$ 51	$ (3,122)	$ 285,322	$ 317,945	$ 171	$ (2,220)	$ 315,896
Mortgage-related securities FNMA, FHLMC and GNMA	334,157	8,928	(481)	342,604	310,711	9,570	(311)	319,970
Municipal bonds	43,575	77	(629)	43,023	43,632	7	(1,353)	42,286
	$ 666,125	$ 9,056	$ (4,232)	$ 670,949	$ 672,288	$ 9,748	$ (3,884)	$ 678,152

The following table details the contractual maturities of available-for-sale securities. All positions with variable maturities (e.g. callable debentures and mortgage-related securities) are disclosed based upon the bond s contractual maturity.

March 31, 2011 (in thousands)	Amortized cost	Fair value
Due in one year or less	$ 20,800	$ 20,835
Due after one year through five years	258,393	255,966
Due after five years through ten years	42,308	41,323
Due after ten years	10,467	10,221
	331,968	328,345
Mortgage-related securities-FNMA,FHLMC and GNMA	334,157	342,604
Total available-for-sale securities	$ 666,125	$ 670,949

Gross unrealized losses and fair value. The gross unrealized losses and fair values (for securities held in available for sale by duration of time in which positions have been held in a continuous loss position) were as follows:

	Less than 12 months		12 months or more		Total	
(in thousands)	Gross unrealized losses	Fair value	Gross unrealized losses	Fair value	Gross unrealized losses	Fair value
March 31, 2011						
Federal agency obligations	$ (3,122)	$ 239,090	$	$	$ (3,122)	$ 239,090
Mortgage-related securities FNMA, FHLMC and GNMA	(481)	24,352			(481)	24,352
Municipal bonds	(629)	32,390			(629)	32,390

	$ (4,232)	$ 295,832	$	$	$ (4,232)	$ 295,832
December 31, 2010						
Federal agency obligations	$ (2,220)	$ 205,316	$	$	$ (2,220)	$ 205,316
Mortgage-related securities FNMA, FHLMC and GNMA	(311)	30,986			(311)	30,986
Municipal bonds	(1,353)	41,479			(1,353)	41,479
	$ (3,884)	$ 277,781	$	$	$ (3,884)	$ 277,781

The unrealized losses on ASB s investments in obligations issued by federal agencies were caused by interest rate movements. The contractual terms of these investments do not permit the issuer to settle the securities at a price less than the amortized cost bases of the investments. Because ASB does not intend to sell the securities and has determined it is more likely than not that it will not be required to sell the investments before recovery of their amortized costs bases, which may be at maturity, ASB does not consider these investments to be other-than-temporarily impaired at March 31, 2011.

The fair values of ASB s investment securities could decline if interest rates rise or spreads widen.

Allowance for loan losses. ASB must maintain an allowance for loan losses that is adequate to absorb estimated probable credit losses associated with its loan portfolio. The allowance for loan losses consists of an allocated portion, which estimates credit losses for specifically identified loans and pools of loans, and an unallocated portion.

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The allowance for loan losses was comprised of the following:

March 31, 2011 (in thousands)	Residential 1-4 family	Commercial real estate	Home equity line of credit	Residen-tial land	Commercial construction	Residential construction	Commer-cial loans	Consu-mer loans	Unallo-cated	Total
Allowance for loan losses:										
Beginning balance	$ 6,497	$ 1,474	$ 4,269	$ 6,411	$ 1,714	$ 7	$ 16,015	$ 3,325	$ 934	$ 40,646
Charge-offs	1,791		115	971			1,023	833		4,733
Recoveries	23		2	5			177	144		351
Provision	3,336	66	(876)	1,086	84	(2)	(59)	866	49	4,550
Ending balance	$ 8,065	$ 1,540	$ 3,280	$ 6,531	$ 1,798	$ 5	$ 15,110	$ 3,502	$ 983	$ 40,814
Ending balance: individually evaluated for impairment	$ 230	$	$	$ 2,940	$	$	$ 1,454	$	$	$ 4,624
Ending balance: collectively evaluated for impairment	$ 7,835	$ 1,540	$ 3,280	$ 3,591	$ 1,798	$ 5	$ 13,656	$ 3,502	$ 983	$ 36,190
Financing Receivables:										
Ending balance	$ 2,051,945	$ 300,248	$ 444,684	$ 60,671	$ 39,960	$ 3,568	$ 617,800	$ 86,895	$	$ 3,605,771
Ending balance: individually evaluated for impairment	$ 30,534	$ 10,135	$ 1,405	$ 41,843	$	$	$ 44,224	$ 25	$	$ 128,166
Ending balance: collectively evaluated for impairment	$ 2,021,411	$ 290,113	$ 443,279	$ 18,828	$ 39,960	$ 3,568	$ 573,576	$ 86,870	$	$ 3,477,605

[redacted]										
Allowance for loan losses:										
[redacted]										
Charge-offs	6,142		2,517	6,487			6,261	3,408		24,815
[redacted]										
Provision	6,373	$ 613	2,044	8,583	(1,354)	(12)	1,241	$ 3,662	(256)	20,894
[redacted]										
Ending balance: individually evaluated for impairment	$ 230	$	$	$ 1,642	$	$	$ 1,588	$	$	$ 3,460
[redacted]										
[redacted]										
Ending balance	$ 2,087,813	$ 300,689	$ 416,453	$ 65,599	$ 38,079	$ 5,602	$ 551,683	$ 80,138	$	$ 3,546,056
[redacted]										
Ending balance: collectively evaluated for impairment	$ 2,053,198	$ 288,533	$ 415,626	$ 25,968	$ 38,079	$ 5,602	$ 522,797	$ 80,062	$	$ 3,429,865

Credit quality. ASB performs an internal loan review and grading on an ongoing basis. The review provides management with periodic information as to the quality of the loan portfolio and effectiveness of its lending policies and procedures. The objectives of the loan review and grading procedures are to identify, in a timely manner, existing or emerging credit quality problems so that appropriate steps can be initiated to avoid or minimize future losses. Loans subject to grading include commercial and CRE loans.

A ten-point risk rating system is used to determine loan grade and is based on borrower loan risk. The risk rating is a numerical representation of risk based on the overall assessment of the borrower s financial and operating strength including earnings, operating cash flow, debt service capacity, asset and liability structure, competitive issues, experience and quality of management, financial reporting issues and industry/economic factors.

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The loan grade categories are:

1- Substantially risk free

2- Minimal risk

3- Modest risk

4- Better than average risk

5- Average risk

6- Acceptable risk

7- Special mention

8- Substandard

9- Doubtful

10- Loss

Grades 1 through 6 are considered pass grades. Pass exposures generally are well protected by the current net worth and paying capacity of the obligor or by the value of the asset or underlying collateral.

The credit risk profile by internally assigned grade for loans was as follows:

	March 31, 2011			December 31, 2010		
(in thousands)	Commercial real estate	Commercial construction	Commercial	Commercial real estate	Commercial construction	Commercial
Grade:						
Pass	$ 286,912	$ 39,960	$ 533,985	$ 285,624	$ 38,079	$ 462,078
Special mention	1,079		24,485	526		44,759
Substandard	12,257		59,222	14,539		44,259
Doubtful			108			556
Loss						31
Total	$ 300,248	$ 39,960	$ 617,800	$ 300,689	$ 38,079	$ 551,683

The credit risk profile based on payment activity for loans was as follows:

Recorded

March 31, 2011 (in thousands)	**30-59 days past due**	**60-89 days past due**	**Greater than 90 days**	**Total past due**	**Current**	**Total financing receivables**	**Investment> 90 days and accruing**
Real estate loans:							
Residential 1-4 family	$ 5,740	$ 4,608	$ 35,402	$ 45,750	$ 2,006,195	$ 2,051,945	$
Commercial real estate					300,248	300,248	
Home equity line of credit	1,316	490	1,444	3,250	441,434	444,684	
Residential land	221	2,270	16,688	19,179	41,492	60,671	136
Commercial construction					39,960	39,960	
Residential construction					3,568	3,568	
Commercial loans	1,333	511	2,481	4,325	613,475	617,800	114
Consumer loans	536	309	570	1,415	85,480	86,895	420
Total loans	$ 9,146	$ 8,188	$ 56,585	$ 73,919	$ 3,531,852	$ 3,605,771	$ 670

December 31, 2010 (in thousands)	**30-59 days past due**	**60-89 days past due**	**Greater than 90 days**	**Total past due**	**Current**	**Total financing receivables**	**Recorded Investment> 90 days and accruing**
Real estate loans:							
Residential 1-4 family	$ 8,245	$ 3,719	$ 36,419	$ 48,383	$ 2,039,430	$ 2,087,813	$
Commercial real estate		4		4	300,685	300,689	
Home equity line of credit	1,103	227	1,659	2,989	413,464	416,453	
Residential land	1,543	1,218	16,060	18,821	46,778	65,599	581
Commercial construction					38,079	38,079	
Residential construction					5,602	5,602	
Commercial loans	892	1,317	3,191	5,400	546,283	551,683	64
Consumer loans	629	410	617	1,656	78,482	80,138	320
Total loans	$ 12,412	$ 6,895	$ 57,946	$ 77,253	$ 3,468,803	$ 3,546,056	$ 965

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The credit risk profile based on nonaccrual loans, accruing loans 90 days or more past due and troubled debt restructured loans was as follows:

	March 31, 2011			December 31, 2010		
(in thousands)	Nonaccrual loans	Accruing loans 90 days or more past due	Trouble debt restructured loans	Nonaccrual loans	Accruing loans 90 days or more past due	Trouble debt restructured loans
Real estate loans:						
Residential 1-4 family	$ 36,339	$	$ 4,584	$ 36,420	$	$ 5,150
Commercial real estate						1,963
Home equity line of credit	1,628			1,659		
Residential land	17,712	136	27,896	15,479	581	27,689
Commercial construction						
Residential construction						
Commercial loans	5,107	114	11,060	4,956	64	4,035
Consumer loans	243	420		341	320	
Total	$ 61,029	$ 670	$ 43,540	$ 58,855	$ 965	$ 38,837

The total carrying amount and the total unpaid principal balance of impaired loans was as follows:

	March 31, 2011					December 31, 2010				
(in thousands)	Recorded invest-ment	Unpaid principal balance	Related Allow-ance	Average recorded investment	Interest income recognized	Recorded invest-ment	Unpaid principal balance	Related allow-ance	Average recorded investment	Interest income recognized
With no related allowance recorded										
Real estate loans:										
Residential 1-4 family	$ 18,880	$ 26,129	$	$ 19,697	$ 60	$ 18,205	$ 24,692	$	$ 14,609	$ 278
Commercial real estate	10,135	10,135		10,155	148	12,156	12,156		14,276	979
Home equity line of credit	710	1,622		575						
Residential land	32,102	39,660		34,261	519	33,777	40,802		29,914	1,499
Commercial construction										
Residential construction										
Commercial loans	38,331	38,331		35,150	659	22,041	22,041		29,636	1,846
Consumer loans										
	100,158	115,877		99,838	1,386	86,179	99,691		88,435	4,602
With an allowance recorded										
Real estate loans:										
Residential 1-4 family	3,900	3,900	230	3,906	60	3,917	3,917	230	2,807	175
Commercial real estate										
Home equity line of credit										
Residential land	8,476	8,536	2,940	6,243	170	5,041	5,090	1,642	3,753	327
Commercial construction										
Residential construction										
Commercial loans	5,893	5,893	1,454	5,941	100	6,845	6,845	1,588	2,796	182
Consumer loans										
	18,269	18,329	4,624	16,090	330	15,803	15,852	3,460	9,356	684

Total										
Real estate loans:										
Residential 1-4 family	22,780	30,029	230	23,603	120	22,122	28,609	230	17,416	453
Commercial real estate	10,135	10,135		10,155	148	12,156	12,156		14,276	979
Home equity line of credit	710	1,622		575						
Residential land	40,578	48,196	2,940	40,504	689	38,818	45,892	1,642	33,667	1,826
Commercial construction										
Residential construction										
Commercial loans	44,224	44,224	1,454	41,091	759	28,886	28,886	1,588	32,432	2,028
Consumer loans										
	$ 118,427	$ 134,206	$ 4,624	$ 115,928	$ 1,716	$ 101,982	$ 115,543	$ 3,460	$ 97,791	$ 5,286

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5 • Retirement benefits

Defined benefit plans. For the three months of 2011, the utilities contributed $30.7 million and HEI contributed $0.5 million to their respective retirement benefit plans, compared to $8.4 million and 0.2 million, respectively, in the first three months of 2010. The Company s current estimate of contributions to its retirement benefit plans in 2011 is $64 million ($63 million to be made by the utilities and $1 million by HEI), compared to contributions of $32 million in 2010 ($31 million made by the utilities and $1 million by HEI). In addition, the Company expects to pay directly $2 million of benefits in 2011, comparable to the $2 million paid in 2010.

The components of net periodic benefit cost were as follows:

	Pension benefits		Other benefits	
Three months ended March 31	**2011**	**2010**	**2011**	**2010**
(in thousands)				
Service cost	$ 8,917	$ 6,953	$ 1,267	$ 1,123
Interest cost	16,309	16,040	2,461	2,684
Expected return on plan assets	(17,101)	(17,194)	(2,648)	(2,752)
Amortization of unrecognized transition obligation	1	1		
Amortization of prior service cost (gain)	(97)	(97)	(224)	(52)
Recognized actuarial loss (gain)	4,405	1,716	15	(1)
Net periodic benefit cost	12,434	7,419	871	1,002
Impact of PUC D&Os	(1,544)	3,008	1,018	1,288
Net periodic benefit cost (adjusted for impact of PUC D&Os)	$ 10,890	$ 10,427	$ 1,889	$ 2,290

The Company recorded retirement benefits expense of $10 million in each of the first quarters of 2011 and 2010, and charged the remaining amounts primarily to electric utility plant.

Also, see Note 4, Retirement benefits, of HECO s Notes to Consolidated Financial Statements.

Defined contribution plan. For the first quarters of 2011 and 2010, ASB s expense for its employees participating in the ASB 401(k) Plan was $0.9 million and $0.8 million, respectively. For the first quarters of 2011 and 2010, ASB s cash contributions to the plan were $2.4 million and $2.3 million, respectively.

6 • Share-based compensation

Under the 2010 Equity and Incentive Plan (EIP), HEI can issue an aggregate of 4 million shares of common stock as incentive compensation to selected employees in the form of stock options, stock appreciation rights, restricted shares, restricted stock units, performance shares and other share-based and cash-based awards.

Through March 31, 2011, grants under the EIP consisted of 18,009 restricted shares (counted as four shares for every share issued, or 72,036 shares), 161,517 restricted stock units and 375,319 shares that may be issued under the 2011-2013 long-term incentive plan (LTIP) at maximum levels.

Under the 1987 Stock Option and Incentive Plan, as amended (SOIP), grants and awards of an estimated 0.9 million shares of common stock (based on various assumptions, including LTIP awards at maximum levels and the use of the March 31, 2011 market price of shares as the price on the exercise/payment dates) were outstanding as of March 31, 2011 to selected employees in the form of nonqualified stock options (NQSOs), stock appreciation rights (SARs), restricted stock units, LTIP performance and other shares and dividend equivalents. As of May 11, 2010, no new awards may be granted under the SOIP. After the shares of common stock for the outstanding SOIP grants and awards are issued or such grants and awards expire, the remaining shares registered under the SOIP will be deregistered and delisted.

The Company s share-based compensation expense and related income tax benefit are as follows:

Three months ended March 31 **($ in millions)**	**2011**	**2010**
Share-based compensation expense (1)	1.2	0.6
Income tax benefit	0.4	0.2

(1) The Company has not capitalized any share-based compensation cost.

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Nonqualified stock options. Information about HEI s NQSOs is summarized as follows:

March 31, 2011			Outstanding & Exercisable (Vested)	
Year of grant	Range of exercise prices	Number of options	Weighted-average remaining contractual life	Weighted-average Exercise price
2001	$ 17.96	7,500	0.1	$ 17.96
2002	21.68	70,000	1.1	21.68
2003	20.49	105,500	1.9	20.49
	$ 17.96 21.68	183,000	1.5	$ 20.84

As of December 31, 2010, NQSOs outstanding totaled 215,500 (representing the same number of underlying shares), with a weighted-average exercise price of $20.76. As of March 31, 2011, all NQSOs outstanding were exercisable and had an aggregate intrinsic value (including dividend equivalents) of $1.3 million.

NQSO activity and statistics are summarized as follows:

Three months ended March 31 (dollars in thousands, except prices)	2011	2010
Shares expired		2,000
Weighted-average price of shares expired		$ 20.49
Shares exercised	32,500	46,000
Weighted-average exercise price	$ 20.27	$ 14.74
Cash received from exercise	$ 659	$ 678
Intrinsic value of shares exercised (1)	$ 258	$ 549
Tax benefit realized for the deduction of exercises	$ 101	$ 214

(1) Intrinsic value is the amount by which the fair market value of the underlying stock and the related dividend equivalents exceeds the exercise price of the option.

Stock appreciation rights. Information about HEI s SARs is summarized as follows:

March 31, 2011			Outstanding & Exercisable (Vested)	
Year of grant	Range of exercise prices	Number of shares underlying SARs	Weighted-average remaining contractual life	Weighted-average exercise price
2004	$ 26.02	132,000	2.1	$ 26.02
2005	26.18	282,000	2.7	26.18
	$ 26.02 26.18	414,000	2.5	$ 26.13

As of December 31, 2010, the shares underlying SARs outstanding totaled 450,000, with a weighted-average exercise price of $26.13. As of March 31, 2011, all SARs outstanding were exercisable and had no intrinsic value.

SARs activity and statistics are summarized as follows:

Three months ended March 31 **(dollars in thousands, except prices)**		**2011**		**2010**
Shares forfeited				
Weighted-average price of shares forfeited				
Shares expired		36,000		6,000
Weighted-average price of shares expired	$	26.10	$	26.18
Shares exercised				

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Restricted shares and restricted stock awards. Information about HEI s grants of restricted shares and restricted stock awards is summarized as follows:

	2011			2010		
Three months ended March 31	**Shares**		**(1)**	**Shares**		**(1)**
Outstanding, beginning of period	89,709	$	24.64	129,000	$	25.50
Granted						
Vested				(1,565)		25.97
Forfeited	(1,000)		25.36	(6,735)		25.75
Outstanding, end of period	88,709	$	24.63	120,700	$	25.48

(1) Weighted-average grant-date fair value per share. The grant date fair value of a restricted stock award share was the closing or average price of HEI common stock on the date of grant.

As of March 31, 2011, 18,009 restricted shares were outstanding under the EIP and 70,700 shares of restricted stock were outstanding under the SOIP

As of March 31, 2011, there was $0.5 million of total unrecognized compensation cost related to nonvested restricted shares and restricted stock awards. The cost is expected to be recognized over a weighted-average period of 2.6 years.

Restricted stock units. Information about HEI s grants of restricted stock units is summarized as follows:

	2011			2010		
Three months ended March 31	**Shares**		**(1)**	**Shares**		**(1)**
Outstanding, beginning of period	146,500	$	19.80	70,500	$	16.99
Granted	85,017(2)		24.95			
Vested				(250)	$	16.99
Forfeited	(1,000)		22.60	(1,250)	$	16.99
Outstanding, end of period	230,517	$	21.69	69,000	$	16.99

(1) Weighted-average grant-date fair value per share. The grant date fair value of the restricted stock units was the average price of HEI common stock on the date of grant.

(2) Total weighted-average grant-date fair value of $2.1 million.

As of March 31, 2011, 161,517 restricted stock units were outstanding under the EIP and 69,000 restricted stock units were outstanding under the SOIP.

As of March 31, 2011, there was $3.4 million of total unrecognized compensation cost related to the nonvested restricted stock units. The cost is expected to be recognized over a weighted-average period of 3.3 years.

LTIP payable in stock. The 2011-2013 LTIP provides for performance awards under the EIP and the 2009-2011 LTIP and the 2010-2012 LTIP provide for performance awards under the SOIP of shares of HEI common stock based on the satisfaction of performance goals and service conditions over a three-year performance period. The number of shares of HEI common stock that may be awarded is fixed on the date the grants are made subject to the achievement of specified performance levels. The payout varies from 0% to 200% of the number of target shares depending on achievement of the goals. The LTIP performance goals for both LTIP periods include awards with a market goal based on total return to shareholders (TRS) of HEI stock as a percentile to the Edison Electric Institute Index over the applicable three-year period. In addition, the 2009-2011 LTIP has performance goals based on HEI return on average common equity (ROACE) and the 2010-2012 LTIP has performance goals related to levels of HEI consolidated net income, HECO consolidated ROACE, ASB net income and ASB return on assets all based on two-year averages (2011-2012) and the 2011-2013 LTIP has performance goals related to levels of HEI consolidated net income, HECO consolidated ROACE, HECO 3-year average consolidated net income, ASB return on assets and ASB 3-year average net income.

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LTIP linked to TRS. Information about HEI s LTIP grants linked to TRS is summarized as follows:

Three months ended March 31	2011 Shares		(1)	2010 Shares		(1)
Outstanding, beginning of period	126,782	$	20.33	36,198	$	14.85
Granted	74,540		35.46	97,191(2)	$	22.45
Vested						
Forfeited	(587)		22.45	(801)	$	14.85
Outstanding, end of period	200,735	$	25.94	132,588	$	20.42

(1) Weighted-average grant-date fair value per share determined using a Monte Carlo simulation model.

(2) Total weighted-average grant-date fair value of $2.2 million.

On February 4, 2011, LTIP grants (under the 2011-2013 LTIP) were made payable in 74,540 shares of HEI common stock (based on the grant date price of $24.95 and target TRS performance levels) with a weighted-average grant date fair value of $2.6 million based on the weighted-average grant date fair value per share of $35.46.

The following table summarizes the assumptions used to determine the fair value of the LTIP linked to TRS and the resulting fair value of LTIP granted:

	2011	2010
Risk-free interest rate	1.25%	1.30%
Expected life in years	3	3
Expected volatility	27.8 %	27.9 %
Range of expected volatility for Peer Group	21.2% to 82.6%	22.3% to 52.3%
Grant date fair value (per share)	$35.46	$22.45

As of March 31, 2011, there was $3.4 million of total unrecognized compensation cost related to the nonvested performance awards payable in shares linked to TRS. The cost is expected to be recognized over a weighted-average period of 1.9 years.

LTIP linked to other performance conditions. Information about HEI s LTIP awards payable in shares linked to other performance conditions is summarized as follows:

Three months ended March 31	2011 Shares	(1)	2010 Shares	(1)

Outstanding, beginning of period	161,310	$	18.66	24,131	$	16.99
Granted	113,119		24.95	160,939(2)	$	18.95
Vested						
Forfeited	(879)		18.95	(535)	$	16.99
Outstanding, end of period	273,550	$	21.26	184,535	$	18.69

(1) Weighted-average grant-date fair value per share based on the average price of HEI common stock on the date of grant.

(2) Total weighted-average grant-date fair value of $3.0 million.

On February 4, 2011, LTIP grants (under the 2011-2013 LTIP) were made payable in 113,119 shares of HEI common stock (based on the grant date price of $24.95 and target performance levels relating to performance goals other than TRS), with a weighted-average grant date fair value of $2.8 million based on the weighted-average grant date fair value per share of $24.95.

As of March 31, 2011, there was $4.2 million of total unrecognized compensation cost related to the nonvested shares linked to performance conditions other than TRS. The cost is expected to be recognized over a weighted-average period of 2.1 years.

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7 • Interest rate swap agreements

In June 2010, HEI entered into multiple Forward Starting Swaps (FSS) with notional amounts totaling $125 million to hedge against interest rate fluctuations on a portion of the $150 million of medium-term notes expected to be issued by HEI in 2011, thereby enabling HEI to better forecast its future interest expense. In January 2011, HEI settled FSS with notional amounts totaling $50 million and a negative fair value of $1.3 million as of December 31, 2010 for a payment of $1.0 million, which amount less the previously recognized ineffective portion of $0.3 million is being amortized to interest expense over five years beginning March 24, 2011. The remaining $75 million notional amount of FSS terminate in June 2011 and entitle HEI to receive/(pay) the present value of the positive/(negative) difference between three-month LIBOR and a fixed rate at termination applied to the notional amount over a five-year period. The outstanding FSS were designated and accounted for as cash flow hedges and had a negative fair value of $1.6 million as of March 24, 2011 and $2.8 million as of December 31, 2010 (recorded in Other liabilities on the consolidated balance sheet). Changes in fair value were recognized (1) in other comprehensive income to the extent that they are considered effective, and (2) in net income for any portion considered ineffective.

On March 24, 2011, HEI issued $125 million of Senior Notes via a private placement ($75 million of 4.41% notes due March 24, 2016 and $50 million of 5.67% notes due March 24, 2021).

For the first quarter of 2011, the change in the ineffective portion of the change in fair value of the remaining FSS, or $0.1 million, was recorded as a derivative gain in Interest expense other than on deposit liabilities and other bank borrowings and the change in the effective portion, or $0.1 million, was recorded as a net gain in accumulated other comprehensive income (AOCI). The $1.3 million net loss in AOCI as of March 24, 2011 for the remaining FSS is being amortized to interest expense over five years (similar to the $0.7 million net loss in AOCI for the settled FSS). Further changes in fair value of the remaining FSS will be recorded as a derivative gain or loss in interest expense other than on deposit liabilities and other bank borrowings, such as the $0.3 million derivative gain for March 24 to 31, 2011.

8 • Earnings per share (EPS)

For the quarters ended March 31, 2011 and 2010, under the two-class method of computing basic and diluted EPS, distributed earnings were $0.31 per share and undistributed losses were $0.01 and $0.02 per share, respectively, for both unvested restricted stock awards and unrestricted common stock.

As of March 31, 2011 and 2010, the antidilutive effects of SARs of 414,000 shares and 474,000 shares of HEI common stock, respectively, for which the exercise prices were greater than the closing market price of HEI s common stock were not included in the computation of diluted EPS.

9 • Commitments and contingencies

See Note 4, Bank subsidiary, above and Note 5, Commitments and contingencies, of HECO s Notes to Consolidated Financial Statements, below.

10 • Fair value measurements

Fair value estimates are based on the price that would be received to sell an asset, or paid upon the transfer of a liability, in an orderly transaction between market participants at the measurement date. The fair value estimates are generally determined based on assumptions that market participants would use in pricing the asset or liability and are based on market data obtained from independent sources. However, in certain cases, the Company uses its own assumptions about market participant assumptions based on the best information available in the circumstances. These valuations are estimates at a specific point in time, based on relevant market information, information about the financial instrument and judgments regarding future expected loss experience, economic conditions, risk characteristics of various financial instruments and other factors. These estimates do not reflect any premium or discount that could result if the Company were to sell its entire holdings of a particular financial instrument at one time. Because no active trading market exists for a portion of the Company s financial instruments, fair value estimates cannot be determined with precision. Changes in the underlying assumptions used, including discount rates and estimates of future cash flows, could significantly affect the estimates. Fair value

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estimates are provided for certain financial instruments without attempting to estimate the value of anticipated future business and the value of assets and liabilities that are not considered financial instruments. In addition, the tax ramifications related to the realization of the unrealized gains and losses could have a significant effect on fair value estimates and have not been considered.

The Company used the following methods and assumptions to estimate the fair value of each applicable class of financial instruments for which it is practicable to estimate that value:

Cash and cash equivalents and short term borrowings other than bank. The carrying amount approximated fair value because of the short maturity of these instruments.

Investment and mortgage-related securities. Fair value was based on observable inputs using market-based valuation techniques.

Loans receivable. For residential real estate loans, fair value is calculated by discounting estimated cash flows using discount rates based on current industry pricing for loans with similar contractual characteristics.

For other types of loans, fair value is estimated by discounting contractual cash flows using discount rates that reflect current industry pricing for loans with similar characteristics and remaining maturity. Where industry pricing is not available, discount rates are based on ASB s current pricing for loans with similar characteristics and remaining maturity.

The fair value of all loans was adjusted to reflect current assessments of loan collectability.

Deposit liabilities. The fair value of savings, negotiable orders of withdrawal, demand and money market deposits was the amount payable on demand at the reporting date. The fair value of fixed-maturity certificates of deposit was estimated by discounting the future cash flows using the rates currently offered for deposits of similar remaining maturities.

Other bank borrowings. Fair value was estimated by discounting the future cash flows using the current rates available for borrowings with similar credit terms and remaining maturities.

Long-term debt. Fair value was obtained from a third-party financial services provider based on the current rates offered for debt of the same or similar remaining maturities.

Forward Starting Swaps. Fair value was estimated by discounting the expected future cash flows of the swaps, using the contractual terms of the swaps, including the period to maturity, and observable market-based inputs, including forward interest rate curves. Fair value incorporates credit valuation adjustments to appropriately reflect nonperformance risk.

Off-balance sheet financial instruments. The fair value of loans serviced for others was calculated by discounting expected net income streams using discount rates that reflect industry pricing for similar assets. Expected net income streams are estimated based on industry assumptions regarding prepayment speeds and income and expenses associated with servicing residential mortgage loans for others. The fair value of commitments to originate loans was estimated based on the change in current primary market prices of new commitments. Since lines of credit can expire without being drawn and customers are under no obligation to utilize the lines, no fair value was assigned to unused lines of credit. The fair value of letters of credit was estimated based on the fees currently charged to enter into similar agreements, taking into account the remaining terms of the agreements. The fair value of HECO-obligated preferred securities of trust subsidiaries was based on quoted market prices.

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The estimated fair values of certain of the Company s financial instruments were as follows:

(in thousands)	March 31, 2011 Carrying or notional amount	March 31, 2011 Estimated fair value	December 31, 2010 Carrying or notional amount	December 31, 2010 Estimated fair value
Financial assets				
Cash and cash equivalents, excluding money market accounts	$ 314,279	$ 314,279	$ 329,553	$ 329,553
Money market accounts	1,975	1,975	1,098	1,098
Available-for-sale investment and mortgage-related securities	670,949	670,949	678,152	678,152
Investment in stock of Federal Home Loan Bank of Seattle	97,764	97,764	97,764	97,764
Loans receivable, net	3,554,058	3,678,043	3,497,729	3,639,983
Financial liabilities				
Deposit liabilities	4,035,255	4,037,308	3,975,372	3,979,027
Short-term borrowings other than bank			24,923	24,923
Other bank borrowings	244,674	257,362	237,319	251,822
Long-term debt, net other than bank	1,439,974	1,373,642	1,364,942	1,345,770
Forward starting swaps	1,317	1,317	2,762	2,762
Off-balance sheet items				
HECO-obligated preferred securities of trust subsidiary	50,000	50,800	50,000	52,500

As of March 31, 2011 and December 31, 2010, loan commitments and unused lines and letters of credit issued by ASB had notional amounts of $1.2 billion and their estimated fair value on such dates were $0.3 million and $0.4 million, respectively. As of March 31, 2011 and December 31, 2010, loans serviced by ASB for others had notional amounts of $838 million and $818 million and the estimated fair value of the servicing rights for such loans was $9.8 million and $8.8 million, respectively.

Bank and other segments

Fair value measurements on a recurring basis. While securities held in ASB s investment portfolio trade in active markets, they do not trade on listed exchanges nor do the specific holdings trade in quoted markets by dealers or brokers. All holdings are valued using market-based approaches that are based on exit prices that are taken from identical or similar market transactions, even in situations where trading volume may be low when compared with prior periods as has been the case during the recent market disruption. Inputs to these valuation techniques reflect the assumptions that consider credit and nonperformance risk that market participants would use in pricing the asset based on market data obtained from independent sources. Available-for-sale securities were comprised of federal agency obligations and mortgage-backed securities and municipal bonds.

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Assets measured at fair value on a recurring basis were as follows:

	Fair value measurements using		
(in thousands)	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
March 31, 2011			
Money market accounts (other segment)	$	$ 1,975	$
Available-for-sale securities (bank segment)			
Mortgage-related securities-FNMA, FHLMC and GNMA	$	$ 342,604	$
Federal agency obligations		285,322	
Municipal bonds		43,023	
	$	$ 670,949	$
Forward starting swaps (other segment)	$	$ (1,317)	$
December 31, 2010			
Money market accounts (other segment)	$	$ 1,098	$
Available-for-sale securities (bank segment)			
Mortgage-related securities-FNMA, FHLMC and GNMA	$	$ 319,970	$
Federal agency obligations		315,896	
Municipal bonds		42,286	
	$	$ 678,152	$
Forward starting swaps (other segment)	$	$ (2,762)	$

Fair value measurements on a nonrecurring basis. From time to time, the Company may be required to measure certain assets at fair value on a nonrecurring basis in accordance with GAAP. These adjustments to fair value usually result from the write-downs of individual assets. ASB does not record loans at fair value on a recurring basis. However, from time to time, ASB records nonrecurring fair value adjustments to loans to reflect specific reserves on loans based on the current appraised value of the collateral or unobservable market assumptions. Unobservable assumptions reflect ASB s own estimate of the fair value of collateral used in valuing the loan. Specific reserves as of March 31, 2011 and December 31, 2010 were $4.6 million and $3.5 million, respectively, and were included in loans receivable held for investment, net. ASB may also be required to measure goodwill at fair value on a nonrecurring basis. During the first quarters of 2011 and 2010, goodwill was not measured at fair value. For the first quarters of 2011 and 2010, there were no adjustments to fair value for assets measured at fair value on a nonrecurring basis in accordance with GAAP other than the specific reserves on loans receivable held for investment.

From time to time, the Company may be required to measure certain liabilities at fair value on a nonrecurring basis in accordance with GAAP. The fair value of HECO s asset retirement obligations (Level 3) was determined by discounting the expected future cash flows using market-observable risk-free rates as adjusted by HECO s credit spread (also see Note 3).

11 • Cash flows

Supplemental disclosures of cash flow information. For the quarters ended March 31, 2011 and 2010, the Company paid interest to non-affiliates amounting to $23 million and $24 million, respectively.

For the quarters ended March 31, 2011 and 2010, the Company paid/(received) income taxes amounting to $(30) million and $8 million, respectively. Income taxes were received in 2011 primarily due to the refunding of estimated tax payments made prior to the extension of bonus depreciation provisions.

Supplemental disclosures of noncash activities. Under the HEI Dividend Reinvestment and Stock Purchase Plan (DRIP), common stock dividends reinvested by shareholders in HEI common stock in noncash transactions amounted to $6 million for each of the quarters ended March 31, 2011 and 2010.

Noncash increases in common stock for director and officer compensatory plans of the Company were $4.2 million and $0.9 million for the quarters ended March 31, 2011 and 2010, respectively.

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Real estate acquired in settlement of loans in noncash transactions amounted to $3 million and $2 million for the quarters ended March 31, 2011 and 2010, respectively.

12 • Recent accounting pronouncements and interpretations

Troubled debt restructuring (TDR). In April 2011, the Financial Accounting Standards Board issued Accounting Standards Update No. 2011-2, A Creditor s Determination of Whether a Restructuring Is a Troubled Debt Restructuring, which clarifies which loan modifications constitute TDRs and is intended to assist creditors in determining whether a modification of the terms of a receivable meets the criteria to be considered a TDR, both for purposes of recording an impairment loss and for disclosure of TDRs. In evaluating whether a restructuring constitutes a TDR, a creditor must separately conclude that both (a) the restructuring constitutes a concession by the creditor; and (b) the debtor is experiencing financial difficulties. Clarifying guidance is provided on a creditor s evaluation of whether it has granted a concession and whether a debtor is experiencing financial difficulties.

The Company will adopt this standard in the third quarter of 2011 and does not expect the adoption to have a material impact on the Company s results of operations, financial condition or liquidity.

13 • Credit agreement

Effective May 7, 2010, HEI entered into a revolving noncollateralized credit agreement establishing a line of credit facility of $125 million, with a letter of credit sub-facility, expiring on May 7, 2013, with a syndicate of eight financial institutions. Any draws on the facility bear interest at the Adjusted LIBO Rate plus 225 basis points or the greatest of (a) the Prime Rate, (b) the sum of the Federal Funds Rate plus 50 basis points and (c) the Adjusted LIBO Rate for a one month Interest Period plus 100 basis points per annum, as defined in the agreement. Annual fees on undrawn commitments are 40 basis points. The agreement contains provisions for revised pricing in the event of a ratings change. The agreement does not contain clauses that would affect access to the lines by reason of a ratings downgrade, nor does it have broad material adverse change clauses. However, the agreement does contain customary conditions which must be met in order to draw on it, including compliance with its covenants.

HEI s $125 million credit facility will be maintained to support the issuance of commercial paper, but also may be drawn to repay HEI s short-term and long-term indebtedness, to make investments in or loans to subsidiaries and for HEI s working capital and general corporate purposes. HEI s $100 million syndicated credit facility expiring March 31, 2011 was terminated concurrently with the effectiveness of this $125 million syndicated credit facility.

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidated Statements of Income (unaudited)

Three months ended March 31 (in thousands)		2011		2010
Operating revenues	$	644,301	$	546,712
Operating expenses				
Fuel oil		260,860		211,752
Purchased power		147,958		116,782
Other operation		65,531		59,244
Maintenance		29,196		27,053
Depreciation		36,432		38,642
Taxes, other than income taxes		59,995		51,791
Income taxes		11,610		11,041
		611,582		516,305
Operating income		32,719		30,407
Other income				
Allowance for equity funds used during construction		1,244		1,773
Other, net		910		1,241
		2,154		3,014
Interest and other charges				
Interest on long-term debt		14,383		14,383
Amortization of net bond premium and expense		783		667
Other interest charges		539		599
Allowance for borrowed funds used during construction		(520)		(779)
		15,185		14,870
Net income		19,688		18,551
Preferred stock dividends of subsidiaries		229		229
Net income attributable to HECO		19,459		18,322
Preferred stock dividends of HECO		270		270
Net income for common stock	$	19,189	$	18,052

HEI owns all of the common stock of HECO. Therefore, per share data with respect to shares of common stock of HECO are not meaningful.

The accompanying notes for HECO are an integral part of these consolidated financial statements.

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidated Balance Sheets (unaudited)

(dollars in thousands, except par value)	March 31, 2011	December 31, 2010
Assets		
Utility plant, at cost		
Land	$ 51,440	$ 51,364
Plant and equipment	4,909,393	4,896,974
Less accumulated depreciation	(1,946,072)	(1,941,059)
Construction in progress	104,300	101,562
Net utility plant	3,119,061	3,108,841
Current assets		
Cash and cash equivalents	45,354	122,936
Customer accounts receivable, net	149,486	138,171
Accrued unbilled revenues, net	113,786	104,384
Other accounts receivable, net	9,332	9,376
Fuel oil stock, at average cost	156,218	152,705
Materials and supplies, at average cost	37,782	36,717
Prepayments and other	18,931	55,216
Regulatory assets	8,320	7,349
Total current assets	539,209	626,854
Other long-term assets		
Regulatory assets	473,492	470,981
Unamortized debt expense	13,583	14,030
Other	66,215	64,974
Total other long-term assets	553,290	549,985
Total assets	$ 4,211,560	$ 4,285,680
Capitalization and liabilities		
Capitalization		
Common stock ($6 2/3 par value, authorized 50,000,000 shares; outstanding 13,830,823 shares)	$ 92,224	$ 92,224
Premium on capital stock	389,609	389,609
Retained earnings	856,405	854,856
Accumulated other comprehensive income, net of income taxes	736	709
Common stock equity	1,338,974	1,337,398
Cumulative preferred stock not subject to mandatory redemption	34,293	34,293
Long-term debt, net	1,057,974	1,057,942
Total capitalization	2,431,241	2,429,633
Current liabilities		
Accounts payable	137,956	178,959
Interest and preferred dividends payable	20,476	20,603
Taxes accrued	146,136	175,960
Other	50,078	56,354
Total current liabilities	354,646	431,876
Deferred credits and other liabilities		
Deferred income taxes	281,422	269,286
Regulatory liabilities	304,375	296,797
Unamortized tax credits	59,454	58,810
Retirement benefits liability	333,518	355,844
Other	108,834	108,070
Total deferred credits and other liabilities	1,087,603	1,088,807
Contributions in aid of construction	338,070	335,364

Total capitalization and liabilities	$ 4,211,560	$ 4,285,680

The accompanying notes for HECO are an integral part of these consolidated financial statements.

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidated Statements of Changes in Common Stock Equity (unaudited)

(in thousands)	Common stock Shares	Common stock Amount	Premium on capital stock	Retained earnings	Accumulated other comprehensive income (loss)	Total
Balance, December 31, 2010	**13,831**	**$ 92,224**	**$ 389,609**	**$ 854,856**	**$ 709**	**$ 1,337,398**
Comprehensive income (loss):						
Net income for common stock				19,189		19,189
Retirement benefit plans:						
Less: amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of tax benefits of $1,448					2,274	2,274
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of taxes of $1,431					(2,247)	(2,247)
Other comprehensive income					27	
Comprehensive income						19,216
Common stock dividends				(17,640)		(17,640)
Common stock issue expenses						
Balance, March 31, 2011	**13,831**	**$ 92,224**	**$ 389,609**	**$ 856,405**	**$ 736**	**$ 1,338,974**
Balance, December 31, 2009	**13,787**	**$ 91,931**	**$ 385,659**	**$ 827,036**	**$ 1,782**	**$ 1,306,408**
Comprehensive income:						
Net income for common stock				18,052		18,052
Retirement benefit plans:						
Less: amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of tax benefits of $563					882	882
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of taxes of $526					(825)	(825)
Other comprehensive income					57	
Comprehensive income						18,109
Common stock dividends				(15,150)		(15,150)
Common stock issue expenses			(1)			(1)
Balance, March 31, 2010	**13,787**	**$ 91,931**	**$ 385,658**	**$ 829,938**	**$ 1,839**	**$ 1,309,366**

The accompanying notes for HECO are an integral part of these consolidated financial statements.

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidated Statements of Cash Flows (unaudited)

Three months ended March 31 **(in thousands)**	**2011**	**2010**
Cash flows from operating activities		
Net income	$ 19,688	$ 18,551
Adjustments to reconcile net income to net cash used in operating activities		
Depreciation of property, plant and equipment	36,432	38,642
Other amortization	2,288	2,097
Changes in deferred income taxes	13,521	(1,834)
Changes in tax credits, net	755	776
Allowance for equity funds used during construction	(1,244)	(1,773)
Increase (decrease) in cash overdraft	(2,688)	681
Changes in assets and liabilities		
Decrease (increase) in accounts receivable	(11,271)	7,328
Increase in accrued unbilled revenues	(9,402)	(486)
Increase in fuel oil stock	(3,513)	(26,506)
Increase in materials and supplies	(1,065)	(1,248)
Increase in regulatory assets	(7,872)	(1,143)
Increase (decrease) in accounts payable	(42,123)	3,175
Changes in prepaid and accrued income taxes and utility revenue taxes	240	(51,243)
Changes in other assets and liabilities	(21,378)	3,276
Net cash used in operating activities	**(27,632)**	**(9,707)**
Cash flows from investing activities		
Capital expenditures	(37,556)	(34,189)
Contributions in aid of construction	5,749	3,729
Net cash used in investing activities	**(31,807)**	**(30,460)**
Cash flows from financing activities		
Common stock dividends	(17,640)	(15,150)
Preferred stock dividends of HECO and subsidiaries	(499)	(499)
Net increase in short-term borrowings from nonaffiliates and affiliate with original maturities of three months or less		13,748
Other	(4)	
Net cash used in financing activities	**(18,143)**	**(1,901)**
Net decrease in cash and cash equivalents	(77,582)	(42,068)
Cash and cash equivalents, beginning of period	122,936	73,578
Cash and cash equivalents, end of period	**$ 45,354**	**$ 31,510**

The accompanying notes for HECO are an integral part of these consolidated financial statements.

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Hawaiian Electric Company, Inc. and Subsidiaries

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(Unaudited)

1 • Basis of presentation

The accompanying unaudited consolidated financial statements have been prepared in conformity with GAAP for interim financial information, the instructions to SEC Form 10-Q and Article 10 of Regulation S-X. Accordingly, they do not include all of the information and footnotes required by GAAP for complete financial statements. In preparing the financial statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the balance sheet and the reported amounts of revenues and expenses for the period. Actual results could differ significantly from those estimates. The accompanying unaudited consolidated financial statements and the following notes should be read in conjunction with the audited consolidated financial statements and the notes thereto incorporated by reference in HECO s Form 10-K for the year ended December 31, 2010.

In the opinion of HECO s management, the accompanying unaudited consolidated financial statements contain all material adjustments required by GAAP to fairly state the financial position of HECO and its subsidiaries as of March 31, 2011 and December 31, 2010 and the results of their operations and their cash flows for the three months ended March 31, 2011 and 2010. All such adjustments are of a normal recurring nature unless otherwise disclosed in this Form 10-Q or other referenced material. Results of operations for interim periods are not necessarily indicative of results for the full year. When required, certain reclassifications are made to the prior period s consolidated financial statements to conform to the current presentation.

2 • Unconsolidated variable interest entities

HECO Capital Trust III. HECO Capital Trust III (Trust III) was created and exists for the exclusive purposes of (i) issuing in March 2004 2,000,000 6.50% Cumulative Quarterly Income Preferred Securities, Series 2004 (2004 Trust Preferred Securities) ($50 million aggregate liquidation preference) to the public and trust common securities ($1.5 million aggregate liquidation preference) to HECO, (ii) investing the proceeds of these trust securities in 2004 Debentures issued by HECO in the principal amount of $31.5 million and issued by Hawaii Electric Light Company, Inc. (HELCO) and Maui Electric Company, Limited (MECO) each in the principal amount of $10 million, (iii) making distributions on these trust securities and (iv) engaging in only those other activities necessary or incidental thereto. The 2004 Trust Preferred Securities are mandatorily redeemable at the maturity of the underlying debt on March 18, 2034, which maturity may be extended to no later than March 18, 2053; and are currently redeemable at the issuer s option without premium. The 2004 Debentures, together with the obligations of HECO, HELCO and MECO under an expense agreement and HECO s obligations under its trust guarantee and its guarantee of the obligations of HELCO and MECO under their respective debentures, are the sole assets of Trust III. Trust III has at all times been an unconsolidated subsidiary of HECO. Since HECO, as the common security holder, does not absorb the majority of the variability of Trust III, HECO is not the primary beneficiary and does not consolidate Trust III in accordance with accounting rules on the consolidation of VIEs. Trust III s balance sheets as of March 31, 2011 and December 31, 2010 each consisted of $51.5 million of 2004 Debentures; $50.0 million of 2004 Trust Preferred Securities; and $1.5 million of trust common securities. Trust III s income statements for the three months ended March 31, 2011 and 2010 each consisted of $0.8 million of interest income received from the 2004 Debentures, $0.8 million of distributions to holders of the Trust Preferred Securities, and $25,000 of common dividends on the trust common securities to HECO. So long as the 2004 Trust Preferred Securities are outstanding, HECO is not entitled to receive any funds from Trust III other than pro-rata distributions, subject to certain subordination provisions, on the trust common securities. In the event of a default by HECO in the performance of its obligations under the 2004 Debentures or under its Guarantees, or in the event HECO, HELCO or MECO elect to defer payment of interest on any of their respective 2004 Debentures, then HECO will be subject to a number of restrictions, including a prohibition on the payment of dividends on its common stock.

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Power purchase agreements. As of March 31, 2011, HECO and its subsidiaries had six PPAs totaling 540 megawatts (MW) of firm capacity and other PPAs with smaller independent power producers (IPPs) and Schedule Q providers (i.e., customers with cogeneration and/or small power production facilities with a capacity of 100 kW or less who buy power from or sell power to the utilities), none of which are currently required to be consolidated as VIEs. Approximately 91% of the 540 MW of firm capacity is pursuant to PPAs entered into before December 31, 2003, with AES Hawaii, Inc. (AES Hawaii), Kalaeloa Partners, L.P. (Kalaeloa), Hamakua Energy Partners, L.P. (HEP) and HPOWER. Purchases from all IPPs for the quarter ended March 31, 2011 totaled $148 million, with purchases from AES Hawaii, Kalaeloa, HEP and HPOWER totaling $35 million, $62 million, $14 million and $13 million, respectively.

Some of the IPPs have provided sufficient information for HECO to determine that the IPP was not a VIE, or was either a business or governmental organization (e.g., HPOWER), and thus excluded from the scope of accounting standards for VIEs. A windfarm and Kalaeloa provided sufficient information, as required under their PPAs or amendments, such that HECO could determine that consolidation was not required. Management has concluded that the consolidation of some IPPs is not required as HECO and its subsidiaries do not have variable interests in the IPPs because the PPAs do not require them to absorb any variability of the IPPs.

An enterprise with an interest in a VIE or potential VIE created before December 31, 2003 and not thereafter materially modified is not required to apply accounting standards for VIEs to that entity if the enterprise is unable to obtain the necessary information after making an exhaustive effort. HECO and its subsidiaries have made and continue to make exhaustive efforts to get the necessary information, but have been unsuccessful to date as it was not a contractual requirement prior to 2004. If the requested information is ultimately received from these IPPs, a possible outcome of future analyses of such information is the consolidation of one or more of such IPPs. The consolidation of any significant IPP could have a material effect on the Company s and HECO s consolidated financial statements, including the recognition of a significant amount of assets and liabilities and the potential recognition of losses. If HECO and its subsidiaries determine they are required to consolidate the financial statements of such an IPP and the consolidation has a material effect, HECO and its subsidiaries would retrospectively apply accounting standards for VIEs.

3 • Revenue taxes

HECO and its subsidiaries operating revenues include amounts for various revenue taxes. Revenue taxes are generally recorded as an expense in the period the related revenues are recognized. However, HECO and its subsidiaries revenue tax payments to the taxing authorities are based on the prior year s revenues. For the three months ended March 31, 2011 and 2010, HECO and its subsidiaries included approximately $57 million and $49 million, respectively, of revenue taxes in operating revenues and in taxes, other than income taxes expense.

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4 • Retirement benefits

Defined benefit plans. For the first quarter of 2011, HECO and its subsidiaries contributed $31 million to their retirement benefit plans, compared to $8 million in the first quarter of 2010. HECO and its subsidiaries current estimate of contributions to their retirement benefit plans in 2011 is $63 million, compared to contributions of $31 million in 2010. In addition, HECO and its subsidiaries expect to pay directly $2 million of benefits in 2011, compared to $1 million paid in 2010.

The components of net periodic benefit cost were as follows:

	Pension benefits		Other benefits	
Three months ended March 31 (in thousands)	**2011**	**2010**	**2011**	**2010**
Service cost	$ 8,565	$ 6,610	$ 1,223	$ 1,088
Interest cost	14,849	14,579	2,384	2,596
Expected return on plan assets	(15,284)	(15,324)	(2,608)	(2,715)
Amortization of net transition obligation			(2)	(2)
Amortization of net prior service cost (gain)	(187)	(187)	(227)	(55)
Amortization of net actuarial loss (gain)	4,120	1,685	18	3
Net periodic benefit cost	12,063	7,363	788	915
Impact of PUC D&Os	(1,544)	3,008	1,018	1,288
Net periodic benefit cost (adjusted for impact of PUC D&Os)	$ 10,519	$ 10,371	$ 1,806	$ 2,203

HECO and its subsidiaries recorded retirement benefits expense of $9 million and $10 million for the first quarters of 2011 and 2010, respectively. The electric utilities charged a portion of the net periodic benefit cost to plant.

On March 11, 2011, the utilities union members ratified a new benefit agreement (see Note 5), which includes changes to retirement benefits for employees. Changes to retirement benefits for all employees commencing employment on or after May 1, 2011 include a reduction of benefits provided through the defined benefit plan and the addition of a 50% match by the applicable utility on the first 6% of employee deferrals to the defined contribution plan. In addition, new eligibility rules and contribution levels applicable to existing and new employees were adopted for postretirement welfare benefits.

5 • Commitments and contingencies

Hawaii Clean Energy Initiative. In January 2008, the State of Hawaii (State) and the U.S. Department of Energy signed a memorandum of understanding establishing the Hawaii Clean Energy Initiative (HCEI). In October 2008, the Governor of the State, the State Department of Business, Economic Development and Tourism, the Division of Consumer Advocacy of the State Department of Commerce and Consumer Affairs, and HECO, on behalf of itself and its subsidiaries, HELCO and MECO (collectively, the parties), signed an agreement setting forth goals and objectives under the HCEI and the related commitments of the parties (the Energy Agreement), including pursuing a wide range of actions to decrease the State s dependence on imported fossil fuels through substantial increases in renewable energy and programs intended to secure greater energy efficiency and conservation. Many of the actions and programs included in the Energy Agreement require approval of the PUC.

Among the major provisions of the Energy Agreement are the following: (a) pursuing a Renewable Portfolio standard of 40% by 2030; (b) pursuing an Energy Efficiency Portfolio standard of 30% by 2030; (c) developing a feed-in tariff system with standardized purchase prices for renewable energy; (d) replacing system-wide caps on net energy metering (NEM) with per circuit thresholds that require a further study before a proposed interconnection that would take the circuit over the threshold may proceed; (e) adopting a regulatory rate-making model under which the utilities revenues would be decoupled from kilowatthour (KWH) sales; (f) continuing the existing ECACs, subject to periodic review by the PUC; (g) establishing a surcharge to allow the utilities to pass through all reasonably incurred purchased power costs; (h) supporting the development and use of renewable biofuels; (i) promoting greater use of renewable energy, including wind power and solar energy; (j) providing for the retirement or placement on reserve standby status of older and less efficient fossil fuel fired generating units as

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new, renewable generation is installed; (k) improving and expanding load management and demand response programs that allow the utilities to control customer loads to improve grid reliability and cost management; (l) the filing of PUC applications for approval of the installation of Advanced Metering Infrastructure, coupled with time-of-use or dynamic rate options for customers; (m) supporting prudent and cost effective investments in smart grid technologies; (n) delinking prices paid under all new renewable energy contracts from oil prices; and (o) exploring establishment of lifeline rates for low-income customers.

Many actions have been taken, and continue to be taken, to further the goals of the HCEI. For example, in May 2010, HECO received PUC approval of its power purchase agreement with Kahuku Wind Power, LLC for the purchase of as-available energy, which became operational in March 2011. In October 2010, the PUC approved the implementation of feed-in tariffs for renewable energy generators, including applicable pricing, other terms and conditions and a standard form contract. In December 2010, the PUC allowed HECO to implement the decoupling mechanism approved in August 2010. The PUC also approved HECO s proposed Purchase Power Adjustment Clause to recover non-energy purchased power agreement costs and ordered that the existing ECAC continue. In January 2011, the PUC approved the replacement of the present system-wide caps for NEM, with a 15% per circuit distribution threshold for DG penetration.

Renewable energy projects. HECO and its subsidiaries continue to negotiate with developers of proposed projects (identified in the Energy Agreement) to integrate into its grid approximately 1,100 MW from a variety of renewable energy sources, including solar, biomass, wind, ocean thermal energy conversion, wave and others. This includes HECO s commitment to integrate, with the assistance of the State, up to 400 MW of wind power into the Oahu electrical grid that would be imported via a yet-to-be-built undersea transmission cable system from windfarms proposed by developers to be built on the islands of Lanai and/or Molokai. The State and HECO have agreed to work together to ensure the supporting infrastructure needed is in place to reliably accommodate this large increment of wind power, including appropriate additional storage capacity investments and any required utility system connections or interfaces with the cable and the windfarm facilities. In December 2009, the PUC issued a decision and order (D&O) that allows HECO to defer the costs of studies for this large wind project for later review of prudence and reasonableness.

Interim increases. As of March 31, 2011, HECO and its subsidiaries had recognized $8 million of revenues with respect to interim orders related to general rate increase requests. Revenue amounts recorded pursuant to interim orders are subject to refund, with interest, if they exceed amounts allowed in a final order.

Major projects. Many public utility projects require PUC approval and various permits from other governmental agencies. Difficulties in obtaining, or the inability to obtain, the necessary approvals or permits can result in significantly increased project costs or even cancellation of projects. Further, completion of projects is subject to various risks, such as problems or disputes with vendors. In the event a project does not proceed, or if it becomes probable the PUC will disallow cost recovery for all or part of a project, project costs may need to be written off in amounts that could result in significant reductions in HECO s consolidated net income. Significant projects whose costs (or costs in excess of estimates) have not yet been allowed in rate base by a final PUC order include those described below.

In May 2011, based upon recommendations solicited from the Consumer Advocate, the PUC ordered that independently conducted regulatory audits on the reasonableness of costs incurred for HECO s East Oahu Transmission Project, Campbell Industrial Park combustion turbine project, and Customer Information System Project be undertaken. Any revenue requirements arising from specific project subject costs being audited shall either remain interim and subject to refund until audit completion, or remain within regulatory deferral accounts.

Campbell Industrial Park 110 MW combustion turbine No. 1 (CIP CT-1) and transmission line. In a second interim D&O to HECO s 2009 test year rate case issued in February 2010, the PUC granted HECO an increase of $12.7 million in annual revenues to recover $163 million of the costs of this project. As of March 31, 2011, HECO s cost estimate for this project was $195 million (of which $195 million had been incurred, including $9 million of allowance for funds used during construction (AFUDC)). In its 2011 test year rate case, HECO is seeking to recover actual project costs in excess of the $163 million being recovered. Management believes no adjustment to project costs is required as of March 31, 2011.

East Oahu Transmission Project (EOTP). HECO had planned a project to construct a partially underground transmission line to a major substation. However, in 2002, an application for a permit, which would have allowed construction in a route through conservation district lands, was denied. In 2007, the PUC approved HECO s request to expend funds (then estimated at $56 million - $42 million for Phase 1 and $14 million for Phase 2) for a revised EOTP using different routes requiring the construction of subtransmission lines, but stated that the issue of recovery of the EOTP costs would be determined in a subsequent rate case, after the project is installed and in service.

Phase 1 was placed in service on June 29, 2010 and is currently estimated to cost $58 million (as a result of higher costs and the project delays). In its 2011 test year rate case, HECO is seeking to recover Phase 1 costs. In April 2010, HECO proposed a modification of Phase 2 that uses smart grid technology and is estimated to cost $10 million (total cost of $15 million less $5 million of funding through the Smart Grid Investment Grant Program of the American Recovery and Reinvestment Act of 2009). In October 2010, the PUC approved HECO s modification request for Phase 2, which is projected for completion in 2012.

As of March 31, 2011, the accumulated costs recorded for the EOTP amounted to $61 million ($58 million for Phase 1 and $3 million for Phase 2), including (i) $12 million of planning and permitting costs incurred prior to the 2002 denial of the permit, (ii) $25 million of planning, permitting and construction costs incurred after the denial of the permit and (iii) $24 million for AFUDC. Management believes no adjustment to project costs is required as of March 31, 2011.

HELCO generating unit. On June 22, 2009, an 18 MW heat recovery steam generator (ST-7) was placed into service by HELCO. As of March 31, 2011, HELCO s cost estimate, and incurred costs, for ST-7 were both $92 million. The costs of ST-7 were included in HELCO s 2010 test year rate case interim increase. Management believes no adjustment to project costs is required as of March 31, 2011.

Customer Information System Project. In 2005, the PUC approved the utilities request to (i) expend the then-estimated $20 million for a new Customer Information System (CIS), provided that no part of the project costs may be included in rate base until the project is in service and is used and useful for public utility purposes, and (ii) defer certain computer software development costs, accumulate AFUDC during the deferral period, amortize the deferred costs over a specified period and include the unamortized deferred costs in rate base, subject to specified conditions.

HECO signed a contract with a software company in March 2006 with a transition to the new CIS originally scheduled to occur in February 2008, which transition did not occur. Disputes over the parties contractual obligations resulted in litigation, which subsequently was settled. HECO subsequently contracted with a new CIS software vendor and a new system integrator. The CIS project is proceeding with the implementation of the new software system. As of March 31, 2011, HECO s total deferred and capital cost estimate for the CIS was $57 million (of which $25 million was recorded). Management believes no adjustment to project costs is required as of March 31, 2011.

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Environmental regulation. HECO and its subsidiaries are subject to environmental laws and regulations that regulate the operation of existing facilities, the construction and operation of new facilities and the proper cleanup and disposal of hazardous waste and toxic substances. In recent years, legislative and regulatory activity related to the environment, including proposals and rulemaking under the Clean Air Act (CAA) and Clean Water Act (CWA), has increased significantly and management anticipates that such activity will continue.

On April 20, 2011, the Federal Register published the EPA s proposed regulations required by section 316(b) of the CWA designed to protect aquatic organisms from adverse impacts associated with existing power plant cooling water intake structures. The proposed regulations would apply to the cooling water systems for the steam generating units at the utilities Honolulu, Kahe and Waiau power plants on the island of Oahu. Although the proposed regulations provide some flexibility, management believes they do not adequately focus on site-specific conditions and cost-benefit factors and, if adopted as proposed, would require significant capital and annual operations and maintenance (O&M) expenditures. As proposed, the regulations would require facilities to come into compliance within 8 years of the effective date of the final rule, which the EPA expects to issue in 2012.

Subsequently, on May 3, 2011, the Federal Register published the EPA s proposed National Emission Standards for Hazardous Air Pollutants for fossil-fuel fired steam electrical generating units (EGUs) that would establish Maximum Achievable Control Technology (MACT) standards for the control of hazardous air pollutant (HAP) in emissions from new and existing EGUs. The proposed rules, also known as EGU MACT, would apply to the 14 EGUs at the utilities Honolulu, Kahe and Waiau power plants. As proposed, the regulations would require significant capital and annual expenditures for the installation and operation of emission control equipment on the utilities EGUs. The CAA requires that facilities come into compliance with final MACT standards within 3 years of the final rule, although facilities may be granted a 1 year extension to install emission control technology. In view of the islolated nature of HECO s electrical system and the proposed requirement to install control equipment on all HECO steam generating units while maintaining system reliability, the EGU MACT compliance schedule poses a significant challenge to HECO. Under the terms of a settlement agreement, the EPA is required to issue the final rule by November 16, 2011.

Depending upon the final outcome of the CWA 316(b) regulations, possible changes in CWA effluent standards, the EGU MACT regulations, the tightening of the National Ambient Air Quality Standards, and the Regional Haze rule under the CAA, HECO and its subsidiaries may be required to incur material capital expenditures and other compliance costs. Additionally, the combined effects of these regulatory initiatives may result in a decision to retire certain generating units earlier than anticipated.

HECO, HELCO and MECO, like other utilities, periodically experience petroleum or other chemical releases into the environment associated with current operations and report and take action on these releases when and as required by applicable law and regulations. Except as otherwise disclosed herein, the HECO and its subsidiaries believe the costs of responding to their releases identified to date will not have a material adverse effect, individually or in the aggregate, on HECO s consolidated results of operations, financial condition or cash flows.

Honolulu Harbor investigation. HECO has been involved since 1995 in a working group with several other potentially responsible parties (PRPs) identified by the State of Hawaii Department of Health (DOH), including oil companies, in investigating and responding to historical subsurface petroleum contamination in the Honolulu Harbor area. A subset of the PRPs (the Participating Parties) entered into a joint defense agreement and ultimately entered into an Enforceable Agreement with the DOH to address petroleum contamination at the site. The Participating Parties are funding the investigative and remediation work using an interim cost allocation method (subject to a final allocation) and have organized a limited liability company to perform the work. Although the Honolulu Harbor investigation involves four units Iwilei, Downtown, Kapalama and Sand Island to date all the investigative and remedial work has focused on the Iwilei unit.

The Participating Parties have conducted subsurface investigations, assessments and preliminary oil removal, and anticipate finalizing remedial design work for the Iwilei unit in 2011.

As of March 31, 2011, HECO s remaining accrual for its estimated share of environmental costs for the Iwilei unit was $1.2 million. Because (1) the full scope of work remains to be determined, (2) the final cost allocation method among the Participating Parties has not yet been established and (3) management cannot estimate the

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costs to be incurred (if any) for the sites other than the Iwilei unit (such as its Honolulu power plant located in the Downtown unit), the cost estimate may be subject to significant change and additional material costs may be incurred.

Global climate change and greenhouse gas (GHG) emissions reduction. National and international concern about climate change and the contribution of GHG emissions (including carbon dioxide emissions from the combustion of fossil fuels) to global warming have led to action by the State and to federal legislative and regulatory proposals to reduce GHG emissions.

In July 2007, Act 234, which requires a statewide reduction of GHG emissions by January 1, 2020 to levels at or below the statewide GHG emission levels in 1990, became law in Hawaii. The electric utilities are participating in a Task Force established under Act 234, which is charged with developing a work plan and regulatory approach to reduce GHG emissions, as well as in initiatives aimed at reducing their GHG emissions, such as those being implemented under the Energy Agreement. Because the regulations implementing Act 234 have not yet been promulgated, management cannot predict the impact of Act 234 on the electric utilities, but compliance costs could be significant.

Several approaches (e.g., cap and trade) to GHG emission reduction have been either introduced or discussed in the U.S. Congress; however, no legislation has yet been enacted.

On September 22, 2009, the federal Environmental Protection Agency (EPA) issued its Final Mandatory Reporting of Greenhouse Gases Rule, which requires that sources emitting GHGs above certain threshold levels monitor and report GHG emissions. The utilities reports for 2010 are due on September 30, 2011. In December 2009, the EPA made the finding that motor vehicle GHG emissions endanger public health or welfare. Management believes the EPA will make the same or similar endangerment finding regarding GHG emissions from stationary sources like the utilities generating units.

In June 2010, the EPA issued its Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule (GHG Tailoring Rule) that created new thresholds for GHG emissions from new and existing facilities. States may need to increase fees to cover the increased level of activity caused by this rule. Effective January 2, 2011, under the Prevention of Significant Deterioration program, permitting of new or modified stationary sources (such as utility electrical generating units) that have the potential to emit GHGs in greater quantities than the thresholds in the GHG Tailoring Rule will entail GHG emissions evaluation, analysis and, potentially, control requirements. In January 2011, the EPA announced that it plans to defer, for three years, GHG permitting requirements for carbon dioxide (CO2) emissions from biomass-fired and other biogenic sources. The utilities are evaluating the impact of this deferral on their generation units that are or will be fired on biofuels.

HECO and its subsidiaries have taken, and continue to identify opportunities to take, direct action to reduce GHG emissions from their operations, including, but not limited to, supporting DSM programs that foster energy efficiency, using renewable resources for energy production and purchasing power from IPPs generated by renewable resources, committing to burn renewable biodiesel in HECO s CIP CT-1, using biodiesel for startup and shutdown of selected MECO generation units, and testing biofuel blends in other HECO and MECO generating units. Management is unable to evaluate the ultimate impact on the utilities operations of eventual comprehensive GHG regulation. However, management believes that the various initiatives it is undertaking will provide a sound basis for managing the electric utilities carbon footprint and meeting GHG reduction goals that will ultimately emerge.

While the timing, extent and ultimate effects of climate change cannot be determined with any certainty, climate change is predicted to result in sea level rise, which could potentially impact coastal and other low-lying areas (where much of the utilities electric infrastructure is sited), and could cause erosion of beaches, saltwater intrusion into aquifers and surface ecosystems, higher water tables and increased flooding and storm damage due to heavy rainfall. The effects of climate change on the weather (for example, floods or hurricanes), sea levels, and water availability and quality have the potential to materially adversely affect the results of operations, financial condition and cash flows of the electric utilities. For example, severe weather could cause significant harm to the electric utilities physical facilities.

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Given Hawaii s unique geographic location and its isolated electric grids, physical risks of the type associated with climate change have been considered by the utilities in the planning, design, construction, operation and maintenance of their facilities. To ensure the reliability of each island s grid, the utilities design and construct their electric generation systems with greater levels of redundancy than is typical for U.S. mainland, interconnected systems. Although a major natural disaster could have severe financial implications, such risks have existed since the inception of the utilities and they make a concerted effort to prepare for a fast response in the event of an emergency.

The utilities are undertaking an adaptation survey of their facilities as a step in developing a longer-term strategy for responding to the consequences of global climate change.

Apollo Energy Corporation/Tawhiri Power LLC. HELCO purchases energy generated at the Kamao a windfarm pursuant to the Restated and Amended PPA for As-Available Energy (the RAC) dated October 13, 2004 between HELCO and Apollo Energy Corporation (Apollo), later assigned to Apollo s affiliate, Tawhiri Power LLC (Tawhiri). The maximum allowed output of the windfarm is 20.5 MW.

In June 2010, HELCO and Tawhiri participated in an arbitration relating to disputes surrounding HELCO s ownership and possessory interest in the switching station and reimbursement of certain interconnection costs. In December 2010, the arbitration panel issued its final award and order finding in favor of HELCO. In February 2011, the award was confirmed and entered as a judgment in the Hawaii circuit court. Thus, Tawhiri transferred title to the switching station and rights to the land to HELCO and paid HELCO $0.6 million (which included reimbursement of certain interconnection costs, prejudgment interest and HELCO s attorneys fees and costs). Tawhiri has appealed to the Hawaii Intermediate Court of Appeals both a decision by the PUC not to hear the issues that were presented to the arbitration panel and the circuit court s confirmation of the arbitration panel s award.

Asset retirement obligations. Asset retirement obligations (AROs) represent legal obligations associated with the retirement of certain tangible long-lived assets, are measured as the present value of the projected costs for the future retirement of specific assets and are recognized in the period in which the liability is incurred if a reasonable estimate of fair value can be made. HECO and its subsidiaries recognition of AROs have no impact on its earnings. Regulatory assets are established to recognize future recoveries through depreciation rates for accretion and depreciation expenses related to AROs and associated assets. AROs recognized by HECO and its subsidiaries relate to obligations to retire plant and equipment, including removal of asbestos and other hazardous materials. In September 2009, HECO recorded an estimated ARO of $23 million related to removing retired generating units at its Honolulu power plant, including abating asbestos and lead-based paint. The obligation was subsequently increased in June 2010, due to an increase in the estimated costs of the removal project. In August 2010, HECO recorded a similar estimated ARO of $12 million related to removing retired generating units at HECO s Waiau power plant.

Changes to the ARO liability included in Other liabilities on HECO s balance sheet were as follows:

(in thousands)	**2011**	**2010**
Balance, January 1	$ 48,630	$ 23,746
Accretion expense	566	239
Liabilities incurred		
Liabilities settled	(482)	
Revisions in estimated cash flows		
Balance, March 31	$ 48,714	$ 23,985

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Collective bargaining agreements. As of March 31, 2011, approximately 55% of the electric utilities employees were members of the International Brotherhood of Electrical Workers, AFL-CIO, Local 1260, Unit 8, which is the only union representing employees of the electric utilities. The collective bargaining agreement between the union and the electric utilities expired on October 31, 2010, but had been extended through January 31, 2011 while negotiations for a new agreement continued. A tentative new agreement was reached with the union on January 31, 2011, but the agreement was conditioned on ratification by the union s members and the union s members did not ratify the new agreement. On March 4, 2011 the union declared a strike on HECO and its subsidiaries. On March 11, 2011, the union s members ratified a new collective bargaining agreement and a new benefit agreement and the union s work stoppage ended. The new collective bargaining agreement covers a term from January 1, 2011 to October 31, 2013 and provides for non-compounded wage increases (1.75%, 2.5%, and 3.0% for 2011, 2012 and 2013, respectively). The new benefit agreement covers a term from January 1, 2011 to October 31, 2014 and includes changes to medical, dental and vision plans with increased employee contributions and changes to retirement benefits for employees. See Note 4.

Limited insurance. HECO and its subsidiaries purchase insurance to protect themselves against loss or damage to their properties and against claims made by third-parties and employees. However, the protection provided by such insurance is limited in significant respects and, in some instances, there is no coverage. HECO, HELCO and MECO s transmission and distribution systems (excluding substations) have a replacement value roughly estimated at $5 billion and are uninsured. Similarly, HECO, HELCO and MECO have no business interruption insurance. If a hurricane or other uninsured catastrophic natural disaster were to occur, and if the PUC were not to allow the utilities to recover from ratepayers restoration costs and revenues lost from business interruption, their results of operations, financial condition and liquidity could be materially adversely impacted. Also, if a series of losses occurred, each of which were subject to an insurance deductible amount, or if the maximum limit of the available insurance were substantially exceeded, the utilities could incur losses in amounts that would have a material adverse effect on their results of operations, financial condition and liquidity.

6 • Cash flows

Supplemental disclosures of cash flow information. For the quarters ended March 31, 2011 and 2010, HECO and its subsidiaries paid interest amounting to $15 million and $14 million, respectively.

For the quarters ended March 31, 2011 and 2010, HECO and its subsidiaries paid/(received) income taxes amounting to $(33) million and $8 million, respectively. Income taxes were received in 2011 primarily due to the refunding of estimated tax payments made prior to the extension of bonus depreciation provisions.

Supplemental disclosure of noncash activities. The allowance for equity funds used during construction, which was charged to construction in progress as part of the cost of electric utility plant, amounted to $1.2 million and $1.8 million for the quarters ended March 31, 2011 and 2010, respectively.

7 • Recent accounting pronouncements and interpretations

For a discussion of recent accounting pronouncements and interpretations, see Note 12 of HEI s Notes to Consolidated Financial Statements.

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8 • Fair value measurements

Fair value estimates are based on the price that would be received to sell an asset, or paid upon the transfer of a liability, in an orderly transaction between market participants at the measurement date. The fair value estimates are generally determined based on assumptions that market participants would use in pricing the asset or liability and are based on market data obtained from independent sources. However, in certain cases, the electric utilities use their own assumptions about market participant assumptions based on the best information available in the circumstances. These valuations are estimates at a specific point in time, based on relevant market information, information about the financial instrument and judgments regarding future expected loss experience, economic conditions, risk characteristics of various financial instruments and other factors. These estimates do not reflect any premium or discount that could result if the electric utilities were to sell their entire holdings of a particular financial instrument at one time. Because no market exists for a portion of the electric utilities financial instruments, fair value estimates cannot be determined with precision. Changes in the underlying assumptions used, including discount rates and estimates of future cash flows, could significantly affect the estimates. Fair value estimates are provided for certain financial instruments without attempting to estimate the value of anticipated future business and the value of assets and liabilities that are not considered financial instruments. In addition, the tax ramifications related to the realization of the unrealized gains and losses could have a significant effect on fair value estimates, but have not been considered in determining such fair values.

The electric utilities used the following methods and assumptions to estimate the fair value of each applicable class of financial instruments for which it is practicable to estimate that value:

Cash and cash equivalents and short-term borrowings. The carrying amount approximated fair value because of the short maturity of these instruments.

Long-term debt. Fair value was obtained from a third-party financial services provider or the BLOOMBERG PROFESSIONAL service based on the current rates offered for debt of the same or similar remaining maturities.

Off-balance sheet financial instruments. Fair value of HECO-obligated preferred securities of trust subsidiaries was based on quoted market prices.

The estimated fair values of the financial instruments held or issued by the electric utilities were as follows:

Financial assets				
Cash and cash equivalents	$ 45,354	$ 45,354	$ 122,936	$ 122,936
Financial liabilities				
	1,057,974	975,916	1,057,942	1,020,550

Long-term debt, net, including amounts due within one year				
Off-balance sheet item				
HECO-obligated preferred securities of trust subsidiary	50,000	50,800	50,000	52,500

Fair value measurements on a nonrecurring basis. From time to time, the utilities may be required to measure certain assets at fair value on a nonrecurring basis in accordance with GAAP. These adjustments to fair value usually result from the application of lower-of-cost-or-market accounting or write-downs of individual assets. As of March 31, 2011, there were no adjustments to fair value for assets measured at fair value on a nonrecurring basis in accordance with GAAP.

From time to time, the utilities may be required to measure certain liabilities at fair value on a nonrecurring basis in accordance with GAAP. The fair value of the utilities ARO (Level 3) was determined by discounting the expected future cash flows using market-observable risk-free rates as adjusted by HECO s credit spread. See Note 5.

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9 • Credit agreement

Effective May 7, 2010, HECO entered into a revolving noncollateralized credit agreement establishing a line of credit facility of $175 million, with a letter of credit sub-facility expiring on May 6, 2011, with a syndicate of eight financial institutions. The agreement s termination date was extended to May 7, 2013 after having received PUC approval. Any draws on the facility bear interest at the Adjusted LIBO Rate plus 225 basis points or the greatest of (a) the Prime Rate, (b) the sum of the Federal Funds Rate plus 50 basis points and (c) the Adjusted LIBO Rate for a one month Interest Period plus 100 basis points per annum, as defined in the agreement. Annual fees on the undrawn commitments are 40 basis points. The agreement contains provisions for revised pricing in the event of a long-term ratings change (such as when S&P lowered its long-term ratings for HECO, HELCO and MECO in November 2010). The agreement does not contain clauses that would affect access to the lines by reason of a ratings downgrade, nor does it have broad material adverse change clauses. However, the agreement does contain customary conditions that must be met in order to draw on it, including compliance with several covenants.

HECO s $175 million credit facility will be maintained to support the issuance of commercial paper, but also may be drawn to repay HECO s short-term indebtedness, to make loans to subsidiaries and for HECO s capital expenditures, working capital and general corporate purposes. HECO s $175 million syndicated credit facility expiring March 31, 2011 was terminated concurrently with the effectiveness of this replacement syndicated credit facility.

10 • Reconciliation of electric utility operating income per HEI and HECO consolidated statements of income

Three months ended March 31 **(in thousands)**	**2011**	**2010**
Operating income from regulated and nonregulated activities before income taxes (per HEI consolidated statements of income)	$ 45,208	$ 42,609
Deduct:		
Income taxes on regulated activities	(11,610)	(11,041)
Revenues from nonregulated activities	(1,034)	(1,399)
Add:		
Expenses from nonregulated activities	155	238
Operating income from regulated activities after income taxes (per HECO consolidated statements of income)	$ 32,719	$ 30,407

11 • Consolidating financial information

HECO is not required to provide separate financial statements or other disclosures concerning HELCO and MECO to holders of the 2004 Debentures issued by HELCO and MECO to Trust III since all of their voting capital stock is owned, and their obligations with respect to these securities have been fully and unconditionally guaranteed, on a subordinated basis, by HECO. Consolidating information is provided below for these and other HECO subsidiaries for the periods ended and as of the dates indicated.

HECO also unconditionally guarantees HELCO s and MECO s obligations (a) to the State of Hawaii for the repayment of principal and interest on Special Purpose Revenue Bonds issued for the benefit of HELCO and MECO and (b) relating to the trust preferred securities of Trust III (see

Note 2 above). HECO is also obligated, after the satisfaction of its obligations on its own preferred stock, to make dividend, redemption and liquidation payments on HELCO s and MECO s preferred stock if the respective subsidiary is unable to make such payments.

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Income (Loss) (unaudited)

Three months ended March 31, 2011

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassi-fications and elimina-tions	HECO Consolidated
Operating revenues	$ 449,824	99,635	94,842				$ 644,301
Operating expenses							
Fuel oil	183,266	26,491	51,103				260,860
Purchased power	112,751	30,022	5,185				147,958
Other operation	47,255	8,268	10,008				65,531
Maintenance	21,192	3,851	4,153				29,196
Depreciation	22,883	8,323	5,226				36,432
Taxes, other than income taxes	41,889	9,173	8,933				59,995
Income taxes	4,698	3,769	3,143				11,610
	433,934	89,897	87,751				611,582
Operating income	15,890	9,738	7,091				32,719
Other income							
Allowance for equity funds used during construction	960	83	201				1,244
Equity in earnings of subsidiaries	11,490					(11,490)	
Other, net	732	106	92	(2)	(3)	(15)	910
	13,182	189	293	(2)	(3)	(11,505)	2,154
Interest and other charges							
Interest on long-term debt	9,130	2,985	2,268				14,383
Amortization of net bond premium and expense	513	143	127				783
Other interest charges	378	81	95			(15)	539
Allowance for borrowed funds used during construction	(408)	(33)	(79)				(520)
	9,613	3,176	2,411			(15)	15,185
Net income (loss)	19,459	6,751	4,973	(2)	(3)	(11,490)	19,688
Preferred stock dividend of subsidiaries		134	95				229
Net income (loss) attributable to HECO	19,459	6,617	4,878	(2)	(3)	(11,490)	19,459
Preferred stock dividends of HECO	270						270
Net income (loss) for common stock	$ 19,189	6,617	4,878	(2)	(3)	(11,490)	$ 19,189

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Income (Loss) (unaudited)

Three months ended March 31, 2010

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassi-fications and Elimina-tions	HECO Consolidated
Operating revenues	$ 376,104	89,032	81,576				$ 546,712
Operating expenses							
Fuel oil	146,342	23,479	41,931				211,752
Purchased power	85,861	25,702	5,219				116,782
Other operation	41,626	9,017	8,601				59,244
Maintenance	17,074	3,395	6,584				27,053
Depreciation	21,913	9,126	7,603				38,642
Taxes, other than income taxes	35,723	8,328	7,740				51,791
Income taxes	7,905	2,647	489				11,041
	356,444	81,694	78,167				516,305
Operating income	19,660	7,338	3,409				30,407
Other income							
Allowance for equity funds used during construction	1,559	95	119				1,773
Equity in earnings of subsidiaries	5,293					(5,293)	
Other, net	1,114	115	45	(2)	(5)	(26)	1,241
	7,966	210	164	(2)	(5)	(5,319)	3,014
Interest and other charges							
Interest on long-term debt	9,130	2,985	2,268				14,383
Amortization of net bond premium and expense	433	117	117				667
Other interest charges	425	101	99			(26)	599
Allowance for borrowed funds used during construction	(684)	(49)	(46)				(779)
	9,304	3,154	2,438			(26)	14,870
Net income (loss)	18,322	4,394	1,135	(2)	(5)	(5,293)	18,551
Preferred stock dividend of subsidiaries		134	95				229
Net income (loss) attributable to HECO	18,322	4,260	1,040	(2)	(5)	(5,293)	18,322
Preferred stock dividends of HECO	270						270
Net income (loss) for common stock	$ 18,052	4,260	1,040	(2)	(5)	(5,293)	$ 18,052

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Balance Sheet (unaudited)

March 31, 2011

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassi-fications and Elimina-tions	HECO Consolidated
Assets							
Utility plant, at cost							
Land	$ 43,242	5,182	3,016				$ 51,440
Plant and equipment	3,005,933	1,019,463	883,997				4,909,393
Less accumulated depreciation	(1,146,151)	(400,502)	(399,419)				(1,946,072)
Construction in progress	80,330	10,022	13,948				104,300
Net utility plant	1,983,354	634,165	501,542				3,119,061
Investment in wholly owned subsidiaries, at equity	505,256					(505,256)	
Current assets							
Cash and cash equivalents	42,824	1,617	821	87	5		45,354
Advances to affiliates		30,800	17,000			(47,800)	
Customer accounts receivable, net	100,010	25,773	23,703				149,486
Accrued unbilled revenues, net	81,839	16,532	15,415				113,786
Other accounts receivable, net	8,982	2,222	2,105			(3,977)	9,332
Fuel oil stock, at average cost	114,899	16,436	24,883				156,218
Materials and supplies, at average cost	18,928	4,913	13,941				37,782
Prepayments and other	14,114	2,640	2,877			(700)	18,931
Regulatory assets	6,069	1,142	1,109				8,320
Total current assets	387,665	102,075	101,854	87	5	(52,477)	539,209
Other long-term assets							
Regulatory assets	355,064	60,611	57,817				473,492
Unamortized debt expense	8,940	2,598	2,045				13,583
Other	42,456	8,768	14,991				66,215
Total other long-term assets	406,460	71,977	74,853				553,290
Total assets	$ 3,282,735	808,217	678,249	87	5	(557,733)	$ 4,211,560
Capitalization and liabilities							
Capitalization							
Common stock equity	$ 1,338,974	273,159	232,011	84	2	(505,256)	$ 1,338,974
Cumulative preferred stock not subject to mandatory redemption	22,293	7,000	5,000				34,293
Long-term debt, net	672,285	211,287	174,402				1,057,974
Total capitalization	2,033,552	491,446	411,413	84	2	(505,256)	2,431,241
Current liabilities							
Short-term borrowings-affiliate	47,800					(47,800)	
Accounts payable	103,469	19,008	15,479				137,956
Interest and preferred dividends payable	12,656	4,113	3,711			(4)	20,476
Taxes accrued	95,655	26,104	25,077			(700)	146,136
Other	31,372	9,586	13,087	3	3	(3,973)	50,078
Total current liabilities	290,952	58,811	57,354	3	3	(52,477)	354,646
Deferred credits and other liabilities							
Deferred income taxes	205,482	47,625	28,315				281,422
Regulatory liabilities	206,979	57,835	39,561				304,375

Unamortized tax credits	34,157	13,005	12,292				59,454
Retirement benefits liability	253,541	37,565	42,412				333,518
Other	67,988	28,372	12,474				108,834
Total deferred credits and other liabilities	768,147	184,402	135,054				1,087,603
Contributions in aid of construction	190,084	73,558	74,428				338,070
Total capitalization and liabilities	$ 3,282,735	808,217	678,249	87	5	(557,733)	$ 4,211,560

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Balance Sheet (unaudited)

December 31, 2010

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassi-fications and Elimina-tions	HECO Consolidated
Assets							
Utility plant, at cost							
Land	$ 43,240	5,108	3,016				$ 51,364
Plant and equipment	2,984,887	1,030,520	881,567				4,896,974
Less accumulated depreciation	(1,134,423)	(408,704)	(397,932)				(1,941,059)
Construction in progress	78,934	9,828	12,800				101,562
Net utility plant	1,972,638	636,752	499,451				3,108,841
Investment in wholly owned subsidiaries, at equity	500,801					(500,801)	
Current assets							
Cash and cash equivalents	121,019	1,229	594	89	5		122,936
Advances to affiliates		30,950	29,500			(60,450)	
Customer accounts receivable, net	93,474	23,484	21,213				138,171
Accrued unbilled revenues, net	71,712	16,018	16,654				104,384
Other accounts receivable, net	11,536	3,319	668			(6,147)	9,376
Fuel oil stock, at average cost	121,280	15,751	15,674				152,705
Materials and supplies, at average cost	18,890	4,498	13,329				36,717
Prepayments and other	36,974	9,825	8,417				55,216
Regulatory assets	5,294	1,064	991				7,349
Total current assets	480,179	106,138	107,040	89	5	(66,597)	626,854
Other long-term assets							
Regulatory assets	352,038	61,051	57,892				470,981
Unamortized debt expense	9,240	2,681	2,109				14,030
Other	41,236	8,257	15,481				64,974
Total other long-term assets	402,514	71,989	75,482				549,985
Total assets	$ 3,356,132	814,879	681,973	89	5	(567,398)	$ 4,285,680
Capitalization and liabilities							
Capitalization							
Common stock equity	$ 1,337,398	270,573	230,137	86	5	(500,801)	$ 1,337,398
Cumulative preferred stock not subject to mandatory redemption	22,293	7,000	5,000				34,293
Long-term debt, net	672,268	211,279	174,395				1,057,942
Total capitalization	2,031,959	488,852	409,532	86	5	(500,801)	2,429,633
Current liabilities							
Short-term borrowings-affiliate	60,450					(60,450)	
Accounts payable	135,739	22,888	20,332				178,959
Interest and preferred dividends payable	13,648	4,196	2,762			(3)	20,603
Taxes accrued	116,840	31,229	27,891				175,960
Other	35,784	13,065	13,646	3		(6,144)	56,354
Total current liabilities	362,461	71,378	64,631	3		(66,597)	431,876
Deferred credits and other liabilities							

Deferred income taxes	198,753	44,971	25,562				269,286
Regulatory liabilities	201,587	56,190	39,020				296,797
Unamortized tax credits	33,661	12,857	12,292				58,810
Retirement benefits liability	271,499	39,811	44,534				355,844
Other	66,898	28,739	12,433				108,070
Total deferred credits and other liabilities	772,398	182,568	133,841				1,088,807
Contributions in aid of construction	189,314	72,081	73,969				335,364
Total capitalization and liabilities	$ 3,356,132	814,879	681,973	89	5	(567,398)	$ 4,285,680

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Changes in Common Stock Equity (unaudited)

Three months ended March 31, 2011

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassi-fications and elimina-tions	HECO Consoli-dated
Balance, December 31, 2010	$ 1,337,398	270,573	230,137	86	5	(500,801)	$ 1,337,398
Comprehensive income (loss):							
Net income (loss) for common stock	19,189	6,617	4,878	(2)	(3)	(11,490)	19,189
Retirement benefit plans:							
Less: amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of tax benefits	2,274	357	283			(640)	2,274
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of taxes	(2,247)	(357)	(286)			643	(2,247)
Comprehensive income (loss)	19,216	6,617	4,875	(2)	(3)	(11,487)	19,216
Common stock dividends	(17,640)	(4,031)	(3,001)			7,032	(17,640)
Balance, March 31, 2011	$ 1,338,974	273,159	232,011	84	2	(505,256)	$ 1,338,974

Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Changes in Common Stock Equity (unaudited)

Three months ended March 31, 2010

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassi-fications and elimina-tions	HECO Consoli-dated
Balance, December 31, 2009	$ 1,306,408	240,576	221,319	94	17	(462,006)	$ 1,306,408
Comprehensive income (loss):							
Net income (loss) for common stock	18,052	4,260	1,040	(2)	(5)	(5,293)	18,052
Retirement benefit plans:							
Less: amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of tax benefits	882	189	161			(350)	882
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of taxes	(825)	(185)	(154)			339	(825)
Comprehensive income (loss)	18,109	4,264	1,047	(2)	(5)	(5,304)	18,109
Common stock dividends	(15,150)	(3,434)	(1,600)			5,034	(15,150)
Common stock issue expenses	(1)						(1)
Balance, March 31, 2010	$ 1,309,366	241,406	220,766	92	12	(462,276)	$ 1,309,366

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Cash Flows (unaudited)

Three months ended March 31, 2011

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Elimination addition to (deduction from) cash flows	HECO Consolidated
Cash flows from operating activities:							
Net income (loss)	$ 19,459	6,751	4,973	(2)	(3)	(11,490)	$ 19,688
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:							
Equity in earnings	(11,515)					11,490	(25)
Common stock dividends received from subsidiaries	7,057					(7,032)	25
Depreciation of property, plant and equipment	22,883	8,323	5,226				36,432
Other amortization	1,167	660	461				2,288
Changes in deferred income taxes	7,674	2,849	2,998				13,521
Changes in tax credits, net	592	154	9				755
Allowance for equity funds used during construction	(960)	(83)	(201)				(1,244)
Decrease in overdraft		(2,527)	(161)				(2,688)
Changes in assets and liabilities:							
Increase in accounts receivable	(3,982)	(1,192)	(3,927)			(2,170)	(11,271)
Decrease (increase) in accrued unbilled revenues	(10,127)	(514)	1,239				(9,402)
Decrease (increase) in fuel oil stock	6,381	(685)	(9,209)				(3,513)
Increase in materials and supplies	(38)	(415)	(612)				(1,065)
Increase in regulatory assets	(6,518)	(708)	(646)				(7,872)
Decrease in accounts payable	(35,481)	(1,603)	(5,039)				(42,123)
Changes in prepaid and accrued income taxes and utility revenue taxes	(2,688)	270	2,658				240
Changes in other assets and liabilities	(19,159)	(2,247)	(2,145)		3	2,170	(21,378)
Net cash provided by (used in) operating activities	(25,255)	9,033	(4,376)	(2)		(7,032)	(27,632)
Cash flows from investing activities:							
Capital expenditures	(25,594)	(6,752)	(5,210)				(37,556)
Contributions in aid of construction	3,218	2,122	409				5,749
Advances from (to) affiliates		150	12,500			(12,650)	
Net cash provided by (used in) investing activities	(22,376)	(4,480)	7,699			(12,650)	(31,807)
Cash flows from financing activities:							
Common stock dividends	(17,640)	(4,031)	(3,001)			7,032	(17,640)
Preferred stock dividends of HECO and subsidiaries	(270)	(134)	(95)				(499)
	(12,650)					12,650	

Net decrease in short-term borrowings from nonaffiliates and affiliate with original maturities of three months or less							
Other	(4)						(4)
Net cash used in financing activities	(30,564)	(4,165)	(3,096)			19,682	(18,143)
Net increase (decrease) in cash and cash equivalents	(78,195)	388	227	(2)			(77,582)
Cash and cash equivalents, beginning of period	121,019	1,229	594	89	5		122,936
Cash and cash equivalents, end of period	$ 42,824	1,617	821	87	5		$ 45,354

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Cash Flows (unaudited)

Three months ended March 31, 2010

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Elimination addition to (deduction from) cash flows	HECO Consolidated
Cash flows from operating activities:							
Net income (loss)	$ 18,322	4,394	1,135	(2)	(5)	(5,293)	$ 18,551
Adjustments to reconcile net income (loss) to net cash provided by (used in) operating activities:							
Equity in earnings	(5,318)					5,293	(25)
Common stock dividends received from subsidiaries	5,059					(5,034)	25
Depreciation of property, plant and equipment	21,913	9,126	7,603				38,642
Other amortization	1,124	862	111				2,097
Changes in deferred income taxes	(939)	(294)	(601)				(1,834)
Changes in tax credits, net	804	60	(88)				776
Allowance for equity funds used during construction	(1,559)	(95)	(119)				(1,773)
Increase in cash overdraft			681				681
Changes in assets and liabilities:							
Decrease in accounts receivable	2,454	1,026	463			3,385	7,328
Decrease (increase) in accrued unbilled revenues	(641)	(156)	311				(486)
Decrease (increase) in fuel oil stock	(26,075)	918	(1,349)				(26,506)
Decrease (increase) in materials and supplies	(1,215)	(299)	266				(1,248)
Increase in regulatory assets	(771)	(293)	(79)				(1,143)
Increase (decrease) in accounts payable	2,123	(67)	1,119				3,175
Changes in prepaid and accrued income taxes and utility revenue taxes	(38,496)	(6,680)	(6,067)				(51,243)
Changes in other assets and liabilities	3,883	3,533	(755)	(1)	1	(3,385)	3,276
Net cash provided by (used in) operating activities	(19,332)	12,035	2,631	(3)	(4)	(5,034)	(9,707)
Cash flows from investing activities:							
Capital expenditures	(25,488)	(4,212)	(4,489)				(34,189)
Contributions in aid of construction	1,339	1,546	844				3,729
Advances from (to) affiliates	4,400		3,000			(7,400)	
Net cash used in investing activities	(19,749)	(2,666)	(645)			(7,400)	(30,460)
Cash flows from financing activities:							

Common stock dividends	(15,150)	(3,434)	(1,600)			5,034	(15,150)
Preferred stock dividends of HECO and subsidiaries	(270)	(134)	(95)				(499)
Net increase (decrease) in short-term borrowings from nonaffiliates and affiliate with original maturities of three months or less	10,748	(4,400)				7,400	13,748
Net cash used in financing activities	(4,672)	(7,968)	(1,695)			12,434	(1,901)
Net increase (decrease) in cash and cash equivalents	(43,753)	1,401	291	(3)	(4)		(42,068)
Cash and cash equivalents, beginning of period	70,981	2,006	474	98	19		73,578
Cash and cash equivalents, end of period	$ 27,228	3,407	765	95	15		$ 31,510

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Item 2. Management s Discussion and Analysis of Financial Condition and Results of Operations

The following discussion updates Management s Discussion and Analysis of Financial Condition and Results of Operations included in HEI s and HECO s Form 10-K for 2010 and should be read in conjunction with the 2010 annual consolidated financial statements of HEI and HECO and notes thereto included and incorporated by reference, respectively, in HEI s and HECO s Form 10-K for 2010, as well as the quarterly (as of and for the three months ended March 31, 2011) financial statements and notes thereto included in this Form 10-Q.

HEI Consolidated

RESULTS OF OPERATIONS

Revenues	$	710,633	$	619,040	15	Increase for the electric utility segment, partly offset by a decrease for the bank segment
Operating income		63,375		60,707	4	Increase for the electric utility segment, partly offset by a decrease for the bank segment
Net income for common stock		28,462		27,126	5	Higher operating income, lower interest expense other than on deposit liabilities and other bank borrowings , partly offset by higher income taxes** and lower AFUDC
Basic earnings per common share	$	0.30	$	0.29	3	Higher net income, partly offset by higher weighted average shares outstanding
Weighted-average number of common shares outstanding		94,817		92,572	2	Issuances of shares under the HEI Dividend Reinvestment and Stock Purchase Plan and Company employee plans

* Also, see segment discussions which follow.

** The Company s effective tax rates (combined federal and state) for the first quarters of 2011 and 2010 were 36%.

In 2008, the Company initiated aggressive strategies to set both the utilities and ASB on a new course the utilities entered into an agreement with the State to create a clean energy future for Hawaii and ASB set new performance standards. In 2010 and the first quarter 2011, the Company made major progress on these strategies and the bank demonstrated improved profitability and reduced risk (see segment discussions below). Together, HEI s unique combination of a utility and bank continues to provide the Company with a strong balance sheet and the financial resources to invest in the strategic growth of its subsidiaries while providing an attractive dividend for investors. Challenges for 2011 include the impact on the Hawaii economy and tourism of the devastating March 2011 earthquakes and tsunami in Japan and the volatile interest rate environment which followed.

Dividends. The payout ratios for 2010 and the first quarter of 2011 were 102% and 103%, respectively. HEI currently expects to maintain the dividend at its present level; however, the HEI Board of Directors evaluates the dividend quarterly and considers many factors in the evaluation, including but not limited to the Company s results of operations, the long-term prospects for the Company, and current and expected future economic conditions.

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Economic conditions.

Note: The statistical data in this section is from public third-party sources (e.g., Department of Business, Economic Development and Tourism (DBEDT); University of Hawaii Economic Research Organization (UHERO); U.S. Bureau of Labor Statistics; Blue Chip Economic Indicators; U.S. Energy Information Administration; Hawaii Tourism Authority (HTA); Honolulu Board of REALTORS®; Bureau of Economic Analysis and national and local newspapers).

The U.S. economy, as measured by gross domestic product (GDP), is estimated to increase by 2.6% and 3.2% for the first and second quarters of 2011, respectively, compared to the immediately preceding quarter, respectively, according to the April 2011 Blue Chip Economic Indicators, marking the second consecutive month the consensus forecast of growth has been lowered. According to the advance estimate released by the Bureau of Economic Analysis on April 28, 2011, real GDP increased at an annual rate of 1.8% in the first quarter of 2011 from the fourth quarter of 2010. The decline in the forecast of real GDP growth is likely from a combination of several factors such as the increase in the projections for inflation, looming cuts in government spending and a variety of monthly economic activity indicators that failed to meet consensus expectations such as consumer spending, construction activity and business investments.

Crude oil prices are currently at their highest level since 2008. The price of a barrel of West Texas Intermediate crude oil averaged $89 in February 2011 and $103 in March 2011 and settled at $113.93 on April 29, 2011. The U.S. Energy Information Administration April 2011 Short-Term Energy Outlook is projecting an average of $106 in 2011.

Meanwhile, the Hawaii economy received an unexpectedly strong boost from the visitor industry in 2010. Through the first quarter of 2011, tourism continued its strong recovery posting a 9.1% increase in visitor arrivals and a 16.9% increase in visitor expenditures compared to the first quarter of 2010. The strong gain in the first two months of the year was followed by significant decreases in visitor bookings from Japan following the devastating events of the March 11, 2011 earthquake, tsunami and nuclear crisis. All other markets continued to see an increase in arrivals over 2010. The long-term global and local effects of these tragic events in Japan remain uncertain. In light of these events, the visitor industry has taken initiatives to target growth from other major markets to offset the decline from Japan, including in connection with the Asia Pacific Economic Cooperation summit in November 2011 that is anticipated to bring about 15,000 world government and business leaders from 21 economies to Hawaii.

The strong boost in visitor spending before the tsunami-related slowdown were positives for the economy, but economic growth has been slow to spread to other areas. In particular, construction activity and the job market have not realized similar improvements.

Hawaii s seasonally adjusted unemployment rate through March 2011 was 6.3%, which remains well below the national unemployment rate of 8.8%. Furloughs for state and county employees, which were implemented for the fiscal year beginning July 1, 2010, continue for some state agencies and three out of the four counties. However, six of seven bargaining units of the state s largest public union recently ratified a new contract that will end furloughs as of July 1, 2011 in exchange for a reduction in pay and an increased share of health care premiums as a step towards balancing the state and county budgets.

According to local economists, private construction has stabilized and is headed for limited growth. The big driver in construction on Oahu is expected to be rail transit and other government infrastructure spending. The rail project is projected to lead to a sharp increase in construction later in 2011, assuming no additional delays to the schedule.

Hawaii s housing market continues to be mixed with first quarter 2011 home and condominiums sales higher across the state while prices continue to fall.

Interest rates during the first quarter of 2011, while volatile, fluctuated within a narrow range. Despite inflationary pressures from higher commodity prices and increasing momentum in the global economic recovery, U.S. prices (excluding-food and energy) increased modestly. Excess capacity within the U.S. economy allowed Federal Open Market Committee members to retain a very accommodative monetary policy, which also kept short-term rates low. Bloomberg US forecast of economists project slightly higher rates by the end of 2011 with short-term rates rising faster than long-term rates. This compression in the yield curve could pressure bank net interest margins if the changes are more than transitory shifts in the shape of the yield curve.

Hawaii s economic recovery is expected to grow in strength during 2011, albeit modest by historical standards, as it spreads beyond the visitor industry. Risks to Hawaii s economic improvement could come from delays in the Oahu rail project, rising energy and consumer prices, government spending curtailments as the federal and local governments are challenged with balancing their budgets and political unrest and other shocks to the U.S. or world economies.

Major tax legislation in 2010. Congress enacted several bills in 2010 dealing with health care reform, job creation and economic stimulus. Two bills enacted contained major tax provisions directly affecting the Company. The first was the Small Business Jobs Act of 2010, which included the extension of 50% bonus depreciation for all businesses retroactive to January 1, 2010. The second was the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010, which included an extension of 50% bonus depreciation for property placed into service before January 1, 2013 and 100% bonus depreciation for property acquired between September 8, 2010 and January 1, 2012. For the Company, the bonus depreciation provisions result in an estimated increase in federal tax depreciation of $75 million for 2010 and $165 million for 2011, primarily attributable to HECO and its subsidiaries. The Company continues to evaluate the impacts of bonus depreciation in light of the Internal Revenue Services guidance issued on March 29, 2011, regarding bonus depreciation, qualifying property and its transition rules. A number of energy-related tax breaks were also extended, including the biodiesel credit through 2012 and the grants in lieu of the electricity production credit through 2011.

The Company will continue to analyze these 2010 Acts for their impacts on results of operations, financial condition and cash flows and for the opportunities they present.

Retirement benefits. For the first quarter of 2011, the Company s and HECO and its subsidiaries defined benefit retirement plans assets generated a gain, after investment management fees, of 4.2%. The market value of the defined benefit retirement plans assets of the Company as of March 31, 2011 was $1.0 billion compared to $983 million at December 31, 2010, an increase of $57 million. The market value of the defined benefit retirement plans assets of HECO and its subsidiaries as of March 31, 2011 was $944 million compared to $891 million at December 31, 2010, an increase of $53 million.

HEI and HECO and its subsidiaries estimate that the cash funding for their qualified defined benefit pension plans in 2011 will be about $1 million and $59 million, respectively, which should fully satisfy the minimum required contribution, including requirements of the utilities pension tracking mechanisms and the plans funding policy. The increase in expected contributions is driven by the minimum funding requirements under the Pension Protection Act of 2006. The increase is a combination of the effect of funding the plan based on high-quality bond rates as of the valuation date, including a 7-year amortization of the excess of target liability over valuation assets, the decrease in discount rates from 2010 to 2011 that increased the measure of target liability and the depletion of credit balances that were used to moderate the increases in minimum funding related to prior years.

Other factors could cause changes to the required contribution levels. The Pension Protection Act provides that if a pension plan s funded status falls below certain levels more conservative assumptions must be used to value obligations and restrictions on participant benefit accruals may be placed on the plans. If the plans fall below these thresholds, then, to avoid adverse consequences, funds in excess of the minimum required contribution may be contributed to the plan trust.

Commitments and contingencies. See Note 9 of HEI s Notes to Consolidated Financial Statements.

Recent accounting pronouncements and interpretations. See Note 12 of HEI s Notes to Consolidated Financial Statements.

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Other segment.

(in thousands)	Three months ended March 31 2011	2010	% change	Primary reason(s) for significant change
Revenues	$ (15)	$ 15	NM	
Operating loss	(3,587)	(3,673)	NM	Lower administrative and general expenses
Net loss	(4,578)	(4,662)	NM	See explanation for operating loss

NM Not meaningful.

The other business segment includes results of the stand-alone corporate operations of HEI and American Savings Holdings, Inc. (ASHI), both holding companies; Pacific Energy Conservation Services, Inc., a contract services company which provided windfarm operational and maintenance services to an affiliated electric utility until the windfarm was dismantled in the fourth quarter of 2010 (dissolved in April 2011); HEI Properties, Inc., a company holding passive, venture capital investments; and The Old Oahu Tug Service, Inc., a maritime freight transportation company that ceased operations in 1999; as well as eliminations of intercompany transactions.

FINANCIAL CONDITION

Liquidity and capital resources. The Company believes that its ability to generate cash, both internally from electric utility and banking operations and externally from issuances of equity and debt securities, commercial paper and bank borrowings, is adequate to maintain sufficient liquidity to fund its contractual obligations and commercial commitments, its forecasted capital expenditures and investments, its expected retirement benefit plan contributions and other cash requirements for the foreseeable future.

The consolidated capital structure of HEI (excluding deposit liabilities and other bank borrowings) was as follows:

(dollars in millions)	March 31, 2011		December 31, 2010	
Short-term borrowings other than bank	$	%	$ 25	1%
Long-term debt, net other than bank	1,440	49	1,365	47
Preferred stock of subsidiaries	34	1	34	1
Common stock equity	1,497	50	1,484	51
	$ 2,971	100%	$ 2,908	100%

HEI s short-term borrowings and HEI s line of credit facility were as follows:

(in millions)	Three months ended March 31, 2011 Average balance	Balance March 31, 2011	Balance December 31, 2010
Short-term borrowings(1)			
HEI commercial paper	$ 22	$	$ 25
HEI line of credit draws			
	$ 22	$	$ 25
Line of credit facility (expiring May 7, 2013)		$ 125	$ 125
Undrawn capacity under HEI s line of credit facility		125	125

(1) This table does not include HECO s separate commercial paper issuances and line of credit facilities and draws, which are discussed below under Electric utility Financial Condition Liquidity and capital resources. At April 29, 2011, HEI had no outstanding commercial paper and its line of credit facility was undrawn.

HEI utilizes short-term debt, typically commercial paper, to support normal operations, to refinance commercial paper, to retire long-term debt, to pay dividends and for other temporary requirements. HEI also periodically makes short-term loans to HECO to meet HECO s cash requirements, including the funding of loans by HECO to HELCO and MECO, but no such short-term loans to HECO were outstanding as of March 31, 2011. HEI periodically utilizes long-term debt, historically consisting of medium-term notes and other unsecured indebtedness, to fund

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investments in and loans to its subsidiaries to support their capital improvement or other requirements, to repay long-term and short-term indebtedness and for other corporate purposes.

Effective May 7, 2010, HEI entered into a revolving noncollateralized credit agreement establishing a line of credit facility of $125 million, with a letter of credit sub-facility, expiring on May 7, 2013, with a syndicate of eight financial institutions. See Note 13 of HEI s Notes to Consolidated Financial Statements.

The agreement contains provisions for revised pricing in the event of a ratings change. For example, a ratings downgrade of HEI s Issuer Rating (e.g., from BBB/Baa2 to BBB-/Baa3 by Standard & Poor s (S&P) and Moody s Investors Service (Moody s), respectively) would result in a commitment fee increase of 5 basis points and an interest rate increase of 25 basis points on any drawn amounts. On the other hand, a ratings upgrade (e.g., from BBB/Baa2 to BBB+/Baa1 by S&P or Moody s, respectively) would result in a commitment fee decrease of 10 basis points and an interest rate decrease of 25 basis points on any drawn amounts. The agreement contains customary conditions which must be met in order to draw on it, including compliance with its covenants (such as covenants preventing its subsidiaries from entering into agreements that restrict the ability of the subsidiaries to pay dividends to, or to repay borrowings from, HEI). In addition to customary defaults, HEI s failure to maintain its financial ratios, as defined in its agreement, or meet other requirements may result in an event of default. For example, under its agreement, it is an event of default if HEI fails to maintain a nonconsolidated Capitalization Ratio (funded debt) of 50% or less (ratio of 20% as of March 31, 2011, as calculated under the agreement) and Consolidated Net Worth of at least $975 million (actual Net Worth of $1.5 billion as of March 31, 2011, as calculated under the agreement).

In addition to their impact on pricing under HEI s credit agreement, the rating of HEI s commercial paper and debt securities could significantly impact the ability of HEI to sell its commercial paper and issue debt securities and/or the cost of such debt. The rating agencies use a combination of qualitative measures (i.e., assessment of business risk that incorporates an analysis of the qualitative factors such as management, competitive positioning, operations, markets and regulation) as well as quantitative measures (e.g., cash flow, debt, interest coverage and liquidity ratios) in determining the ratings of HEI securities. On July 30, 2010, Moody s changed HEI s rating outlook to stable from negative and affirmed HEI s long-term and short-term (commercial paper) ratings, indicating that the ratings affirmation and outlook change reflects the progress being made by the company and various stakeholders to transform the regulatory framework for HEI s electric utilities to a decoupling structure that will reduce sales volume risk and produce more timely recovery of invested capital and operations and maintenance (O&M) costs. Moody s indicated that the rating could be downgraded if the PUC does not follow through with the regulatory transformation contemplated under the HCEI, including all elements of the decoupling mechanism, or if HEI s cash flow to debt declined to below 15% and its cash flow coverage of interest fell below 3.3 times on a sustainable basis. On November 15, 2010, S&P issued an update in which it lowered its long-term ratings for HEI to BBB- from BBB, and indicated the outlook as stable. In addition, S&P affirmed its A-3 short-term rating on HEI and revised HEI s financial profile to aggressive from significant. S&P indicated the rating downgrade reflects an aggressive financial profile combined with weak cash flow generation at HEI s electric utilities, delays in implementing new utility rate recovery mechanisms, the growing risks of regulatory disallowances in future rate cases, and a protracted recession.

As of April 29, 2011, the Standard & Poor s (S&P) and Moody s Investors Service s (Moody s) ratings of HEI securities were as follows:

	S&P	**Moody s**
Commercial paper	A-3	P-2
Senior unsecured debt	BBB-	Baa2

The above ratings reflect only the view, at the time the ratings are issued, of the applicable rating agency, from whom an explanation of the significance of such ratings may be obtained. Such ratings are not recommendations to buy, sell or hold any securities; such ratings may be subject to revision or withdrawal at any time by the rating agencies; and each rating should be evaluated independently of any other rating.

Management believes that, if HEI s commercial paper ratings were to be downgraded, or if credit markets for commercial paper with HEI s ratings or in general were to tighten, it would be difficult and expensive for HEI to sell commercial paper or secure other short-term borrowings or HEI might not be able to sell commercial paper in the future. Such limitations could cause HEI to draw on its syndicated credit facility instead, and the costs of such

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borrowings could increase under the terms of the credit agreement as a result of any such ratings downgrades. Similarly, if HEI s long-term debt ratings were to be downgraded, it would be difficult and more expensive for HEI to issue long-term debt. Such limitations and/or increased costs could materially adversely affect the results of operations, financial condition and cash flows of HEI and its subsidiaries.

Issuances of common stock through the DRIP, the HEIRSP and the ASB 401(k) Plan are important sources of capital for HEI. HEI raised $11 million through the issuance of approximately 0.4 million shares under these plans during the first quarter of 2011. HEI also makes registered public offerings of its common stock from time to time.

On March 24, 2011, HEI issued $125 million of Senior Notes via a private placement ($75 million of 4.41% notes due March 24, 2016 and $50 million of 5.67% notes due March 24, 2021). HEI used part of the net proceeds from the issuance of the notes to pay down commercial paper (originally issued to refinance $50 million of 4.23% medium-term notes that matured on March 15, 2011) and will ultimately use the remaining proceeds to refinance part of the $100 million of 6.141% medium-term notes that will mature on August 15, 2011. The notes contain customary representation and warranties, affirmative and negative covenants, and events of default (the occurrence of which may result in some or all of the notes then outstanding becoming immediately due and payable) and provisions requiring the maintenance by HEI of certain financial ratios generally consistent with those in HEI s revolving noncollateralized credit agreement, expiring on May 7, 2013 (see Note 13 of HEI s Notes to Consolidated Financial Statements). For example, it is an event of default if HEI fails to maintain an unconsolidated Capitalization Ratio (funded debt) of 50% or less or Consolidated Net Worth of at least $975 million.

For the first quarter of 2011, net cash used by operating activities of consolidated HEI was $13 million. Net cash used by investing activities for the same period was $96 million, primarily due to net increases in ASB s loans held for investment and HECO s consolidated capital expenditures, partly offset by a net decrease in ASB investment securities and mortgage-related securities. Net cash provided by financing activities during this period was $95 million as a result of several factors, including net increases in long-term debt, deposit liabilities and retail repurchase agreements and proceeds from the issuance of common stock under HEI plans, partly offset by decreases in short-term borrowings and the payment of common stock dividends. Other than capital contributions from their parent company, intercompany services (and related intercompany payables and receivables), HECO s periodic short-term borrowings from HEI (and related interest) and the payment of dividends to HEI, the electric utility and bank segments are largely autonomous in their operating, investing and financing activities. (See the electric utility and bank segments discussions of their cash flows in their respective Financial condition Liquidity and capital resources sections below.) During the first quarter of 2011, HECO and ASB paid dividends to HEI of $18 million and $14 million, respectively.

Forecasted HEI consolidated net cash used in investing activities (excluding investing cash flows from ASB) for 2011 through 2013 consists primarily of the net capital expenditures of HECO and its subsidiaries. In addition to the funds required for the electric utilities construction programs, approximately $207 million will be required during 2011 through 2013 to repay maturing HEI medium-term notes (or an additional $82 million after consideration of the $125 million of notes issued via a private placement on March 24, 2011), which maturing medium-term notes are expected to be repaid with the proceeds from the issuance of commercial paper, bank borrowings, other medium- or long-term debt, common stock issued under the Company s plans and/or dividends from subsidiaries. In addition, $57.5 million of HECO special purpose revenue bonds will be maturing in 2012, which bonds are expected to be repaid with proceeds from issuances of long-term debt. Additional debt and/or equity financing may be utilized to pay down commercial paper or other short-term borrowings or may be required to fund unanticipated expenditures not included in the 2011 through 2013 forecast, such as increases in the costs of or an acceleration of the construction of capital projects of the utilities, unanticipated utility capital expenditures that may be required by the HCEI or new environmental laws and regulations, unbudgeted acquisitions or investments in new businesses, significant increases in retirement benefit funding requirements and higher tax payments that would result if certain tax positions taken by the Company do not prevail or if taxes are increased by federal or state legislation. In addition, existing debt may be refinanced prior to maturity (potentially at more favorable rates) with additional debt or equity financing (or both).

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CERTAIN FACTORS THAT MAY AFFECT FUTURE RESULTS AND FINANCIAL CONDITION

The Company s results of operations and financial condition can be affected by numerous factors, many of which are beyond the Company s control and could cause future results of operations to differ materially from historical results. For information about certain of these factors, see pages 52 to 53, 72 to 76, and 86 to 89 of HEI s MD&A included in Part II, Item 7 of HEI s 2010 Form 10-K.

Additional factors that may affect future results and financial condition are described above on pages iv and v under Forward-Looking Statements.

MATERIAL ESTIMATES AND CRITICAL ACCOUNTING POLICIES

In preparing financial statements, management is required to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities and the reported amounts of revenues and expenses. Actual results could differ significantly from those estimates.

In accordance with SEC Release No. 33-8040, Cautionary Advice Regarding Disclosure About Critical Accounting Policies, management has identified the accounting policies it believes to be the most critical to the Company s financial statements that is, management believes that these policies are both the most important to the portrayal of the Company s financial condition and results of operations, and currently require management s most difficult, subjective or complex judgments.

For information about these material estimates and critical accounting policies, see pages 53 to 54, 76 to 77, and 89 of HEI s MD&A included in Part II, Item 7 of HEI s 2010 Form 10-K.

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Following are discussions of the results of operations, liquidity and capital resources of the electric utility and bank segments.

Electric utility

RESULTS OF OPERATIONS

(dollars in thousands, except per barrel amounts)	Three months ended March 31 2011	2010	% change	Primary reason(s) for significant change
Revenues	$ 645,335	$ 548,111	18	Higher fuel oil and purchased power costs, the effects of which are generally passed on to customers ($83 million), higher KWH sales ($10 million), HECO test year 2009 ($2 million), HELCO test year 2010 ($1 million) and MECO test year 2010 ($2 million) interim rate increases, partly offset by the decoupling revenue adjustment at HECO ($1 million).
Expenses				
Fuel oil	260,860	211,752	23	Higher fuel oil costs and more KWHs generated
Purchased power	147,958	116,782	27	Higher fuel costs and more KWHs purchased
Other operation	65,531	59,244	11	See Results three months ended March 31, 2011 below
Maintenance	29,196	27,053	8	See Results three months ended March 31, 2011 below
Depreciation	36,432	38,642	(6)	Lower depreciation rates implemented in conjunction with the HELCO and MECO test year 2010 interim D&Os
Taxes, other than income taxes	59,995	51,791	16	Increase in revenues
Other	155	238	(35)	
Operating income	45,208	42,609	6	See Results three months ended March 31, 2011 below
Net income for common stock	19,189	18,052	6	Higher operating income, partly offset by lower AFUDC
Kilowatthour sales (millions)	2,350	2,273	3	Warmer, more humid weather
Wet-bulb temperature (Oahu average; degrees Fahrenheit)	67.1	65.7	2	
Cooling degree days (Oahu)	920	857	7	
Average fuel oil cost per barrel	$ 101.03	$ 81.95	23	
Customer accounts (end of period)	445,151	443,294		

Note: The electric utilities had an effective tax rate for the first quarters of 2011 and 2010 of 37%.

See Economic conditions in the HEI Consolidated section above.

Recent developments. In 2010 and the first quarter of 2011, the utilities made significant progress in implementing their clean energy strategies and the PUC issued several important regulatory decisions, all of which are key steps to support Hawaii s efforts to reduce its dependence on oil. Included in the PUC decisions were a number of interim and final rate case decisions.

With PUC approval, HECO implemented on March 1, 2011 a new regulatory model that is intended to facilitate meeting the State s goals to transition to a clean energy economy and achieve an aggressive renewable portfolio

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standard. The model, referred to as decoupling, delinks revenues from sales and includes annual revenue adjustments for O&M expenses and rate base additions. Decoupling provides for more timely cost recovery and earning on investments and should result in a significant improvement from the utilities under-earning situation over the last several yearsHECO s goal is to achieve an ROACE within 100 basis points of its 10% allowed ROACE by the end of 2012.

Under decoupling, the most significant drivers for improving the ROACE are:

1. spending within PUC approved amounts for major projects and completing projects on schedule;

2. managing O&M expenses relative to authorized O&M adjustments, especially during periods of increasing demand; and

3. rate case outcomes that cover O&M requirements and rate base items not included in the revenue adjustment mechanisms (RAMs).

Also critical to closing the ROACE gap are HECO s 2011 rate case, decoupling implementation for HELCO and MECO, and getting timely recovery of completed software project costs. The HECO 2011 rate case will reset base sales revenues, O&M and rate base for the decoupling mechanisms going forward. The utilities expect 2011 O&M expenses to increase by about 7%, excluding DSM, primarily reflecting higher costs to execute the clean energy plan. The 2011 O&M increase is largely included in the O&M RAM and HECO s 2011 rate request.

Many other actions have been taken and continue to be taken to increase renewable energy in Hawaii. The utilities have the opportunity to stabilize and lower customer bills over time as they become less dependent on costly oil for generation. See Renewable energy strategy below for examples of such actions, which will help the utilities to continue to meet or exceed their clean energy goals and provides rate base growth to support these renewables.

The utilities have increased their five-year 2011-2015 capital expenditures forecast to $2.2 billion from $1.6 billion for the 2010-2014 forecast, with an expected compounded annual rate base growth rate of approximately 5%. Many of the major initiatives within this forecast are expected to be completed beyond the 5-year period. Four major initiatives comprise approximately 40% of the 5-year plan: (1) replacing aging infrastructure; (2) environmental compliance; (3) fuel infrastructure investments; and (4) infrastructure investments to integrate renewables into the system. Estimates for these projects could change with time, based on external factors such as the timing and technical requirements for environmental compliance.

Results three months ended March 31, 2011. Operating income for the first quarter of 2011 was higher by 6% when compared to the same quarter in 2010 due primarily to higher sales and interim rate increases for HECO, HELCO and MECO, partly offset by higher Other operation and Maintenance (O&M) expenses. Kilowatthour sales increased 3.4% due primarily to warmer, more humid weather and resulted in an estimated net income increase of $3.5 million, net of the sales decoupling adjustment. Other operation expenses increased by $6.3 million in the first quarter of 2011 compared to the same period in 2010 primarily due to higher emissions fees as prior year fees were waived in 2010

($2 million) and $1.3 million higher DSM expense (see Demand-side management programs below) that are generally passed on to customers through surcharges. Maintenance expenses increased $2.1 million due to higher transmission and distribution maintenance including higher vegetation, substation and overhead and underground line maintenance.

O&M expenses (excluding DSM program costs) for 2011 are expected to be approximately 7% higher than 2010 as the electric utilities expect higher production expenses to improve the operational flexibility of their generating units. Transmission and distribution expenses are expected to increase consistent with new asset management initiatives to modernize infrastructure. In addition, additional expenses are expected to continue to execute the provisions of the Energy Agreement.

Renewable energy strategy. The electric utilities have been taking actions intended to protect Hawaii s island ecology and reduce GHG emissions, while continuing to provide reliable power to customers, and committed to a number of related actions in the Energy Agreement. A three-pronged strategy supports attainment of the requirements and goals of the State of Hawaii Renewable Portfolio Standards (RPS), the Hawaii Global Warming Solutions Act of 2007 and the HCEI by: (1) the greening of existing assets, (2) the expansion of renewable energy

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generation and (3) the acceleration of energy efficiency and load management programs. Major initiatives are being pursued in each category.

In 2009, Hawaii s RPS law was amended to require electric utilities to meet an RPS of 10%, 15%, 25% and 40% by December 31, 2010, 2015, 2020 and 2030, respectively. HECO met the 10% RPS for 2010 with a consolidated RPS of 20.7%, including DSM energy savings. This was accomplished through a combination of municipal solid waste, geothermal, wind, biomass, hydro, photovoltaic and biodiesel renewable generation resources; renewable energy displacement technologies; and energy savings from efficiency technologies. DSM programs contributed significantly to achieving the RPS level and, without including the DSM energy savings, the RPS would have been 9.5%. Energy savings resulting from energy efficiency programs will not count toward the RPS after 2014.

In January 2007, the PUC opened a docket (RPS Docket) to examine Hawaii s RPS law. In December 2007, the PUC issued a D&O approving a stipulated RPS framework to govern electric utilities compliance with the RPS law. In the D&O, the PUC deferred an RPS incentive framework to a new generic docket (Renewable Energy Infrastructure Program (REIP) Docket). In December 2008, the PUC approved a potential penalty of $20 for every megawatthour that an electric utility is deficient under the RPS law. The PUC must evaluate the standards every five years, beginning in 2013, to determine whether the standards remain effective and achievable or should be revised.

The electric utilities are actively pursuing the use of biofuels for existing and planned company-owned generating units. HECO s new 110 MW generating unit began on-going operations in 2010 with 100% biodiesel supplied under a two-year biodiesel supply contract with Renewable Energy Group Marketing & Logistics, LLC (REG) as approved by the PUC in June 2010. HECO is also moving toward operating some of its steam-generating units with a blend of fossil and biofuels (co-firing). In June 2010, the PUC approved HECO s and MECO s biofuel supply contracts for their respective biofuel demonstration projects. In February 2011, HECO successfully demonstrated that Unit 3 at its Kahe Power Plant could be powered using up to 100% biofuel. MECO is currently testing biodiesel at its Maalaea Power Plant.

In March 2010, HECO and its subsidiaries issued a request for proposal (RFP) for biofuels produced from feedstock grown in, made in, or otherwise originating in Hawaii (local biofuel) to potentially supply multiple locations. In January 2011, HELCO signed a 20-year contract, subject to PUC approval, with Aina Koa Pono-Ka u LLC to supply 16 million gallons of biodiesel per year with initial consumption to begin by 2015. HECO is continuing negotiations with other bidders. In January 2011, HECO issued a RFP for biodiesel to supply CIP CT-1 upon the expiration of the REG contract in July 2012 and is currently evaluating proposals received. HECO expects to issue a RFP in 2011 for commercial supplies of biofuel to co-fire with fossil fuel at HECO s Kahe Power Plant by 2015. Under current RPS law, biofuel use in existing and new generating units counts toward the RPS.

The electric utilities also support renewable energy through the negotiation and execution of PPAs with non-utility generators using renewable sources (e.g., refuse-fired, geothermal, hydroelectric, photovoltaic and wind turbine generating systems).

On April 30, 2009, HECO filed an application with the PUC for approval of a Photovoltaic (PV) Host Pilot Program, which would be a two-year pilot program whereby HECO, HELCO and MECO would lease rooftops or other space from property owners, with a focus on governmental facilities, for the installation of third-party owned PV systems. The PV developer would own, operate and maintain the system and sell the energy to the utilities at a fixed rate under a long-term contract. On August 31, 2010, HECO proposed several modifications to the pilot program, including deferment of HELCO s and MECO s participation in the program and utilization of select PV Host projects on Oahu as test platforms to evaluate grid integration technologies (as well as to help address grid integration issues associated with existing and growing penetration levels of distributed intermittent generation). Pilot program implementation is pending PUC approval.

In 2008, HECO issued an Oahu Renewable Energy Request for Proposals (2008 RFP) for combined renewable energy projects up to 100 MW. In February 2011, HECO executed a PPA with Kalaeloa Solar Two for a 5 MW PV project. Negotiations continue with a proposed wind project (70 MW).

Included in the bids received in response to the 2008 RFP were proposals for two large scale neighbor island wind projects that would produce energy to be imported from Lanai and Molokai to Oahu via a yet-to-be-built

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undersea transmission cable system (Interisland Wind Projects). In accordance with the Energy Agreement, the proposals for the Interisland Wind Projects were bifurcated from the Oahu Renewable Energy RFP for separate negotiation. Subsequently, HECO received a PUC waiver from the competitive bidding framework for the two nonconforming proposals and HECO reached agreement on a term sheet by the PUC deadline in March 2011 with only one of the two project developers (for a 200 MW to 400 MW windfarm to be built on Lanai). Since agreement on a term sheet with the other developer could not be reached by the PUC deadline, no further consideration is being given to the other proposal. The term sheet that was executed with the Lanai developer allows for the possibility that the developer may elect to arrange with another developer to build a portion of the total 400 MW on the island of Molokai, subject to certain conditions including PUC acceptance of the arrangement. In April 2011, the Lanai developer informed HECO of its intent to exercise this option. The developer who initially proposed the Molokai windfarm, but failed to execute a term sheet, has since filed a letter to the PUC indicating its objection to the arrangement.

In September 2010 and January 2011, MECO executed PPAs with Kaheawa Wind Power II, LLC (PPA approved by the PUC) and Auwahi Wind Energy, LLC (PPA pending PUC approval), respectively, for the purchase of 21 MW (each) of as available wind energy. In February 2011, the PUC opened dockets related to MECO s and HECO s plans to proceed with competitive bidding processes to acquire up to approximately 50 MW and 300 MW, respectively, of new, renewable firm dispatchable capacity generation resources, with the initial increments expected to come on line in the 2015 and 2016 timeframes, respectively.

On September 30, 2010, the PUC approved the electric utilities proposed Electric Vehicle (EV) Charging Time of Use Pilot Rates for three years, which are now available to a total of 1,600 customers in all 3 service territories and are designed to encourage early adoption of EVs and incentivize customers to charge EVs during off-peak times of the day. EV charge stations have been installed at various HECO and customer sites. HECO received its first EV in March 2011 and more EVs are expected to be added to HECO s fleet.

The electric utilities promote research and development in the areas supporting renewable energy such as biofuels, ocean energy, energy storage, smart grids and integration of non-firm power into the separate island electric grids. The utilities are evaluating several potential energy storage and smart grid demonstration projects, and conducting various integration studies.

Competition. Although competition in the generation sector in Hawaii has been moderated by the scarcity of generation sites, various permitting processes and lack of interconnections to other electric utilities, HECO and its subsidiaries face competition from IPPs and customer self-generation, with or without cogeneration.

Competitive bidding proceeding. In December 2006, the PUC issued a decision that included a final competitive bidding framework, which became effective immediately. The final framework states, among other things, that under the framework: (1) a utility is required to use competitive bidding to acquire a future generation resource or a block of generation resources unless the PUC finds bidding to be unsuitable; (2) the framework does not apply in certain situations identified in the framework; (3) waivers from competitive bidding for certain circumstances will be considered; (4) the utility is required to select an independent observer from a list approved by the PUC whenever the utility or its affiliate seeks to advance a project proposal (i.e., in competition with those offered by bidders); (5) the utility may consider its own self-bid proposals in response to generation needs identified in its RFP; and (6) for any resource to which competitive bidding does not apply (due to waiver or exemption), the utility retains its traditional obligation to offer to purchase capacity and energy from a Qualifying Facility (QF) at avoided cost upon reasonable terms and conditions approved by the PUC.

Management cannot currently predict the ultimate effect of the framework on the ability of the utilities to acquire or build additional generating capacity in the future.

The utilities received approval for waivers from the competitive framework to negotiate modifications to existing PPAs that generate electricity from renewable resources. Also, certain renewable energy projects were grandfathered from the competitive bidding process. The PUC can also grant waivers on its own volition to renewable energy projects that are not exempt from the Competitive Bidding Framework (as was done in December 2010 for four 5 MW solar facilities proposed for Oahu).

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In February 2011, the PUC opened dockets to administer the competitive bidding processes for HECO and MECO.

Distributed generation proceeding. In January 2006, the PUC issued a D&O which affirmed the ability of the utilities to procure and operate distributed generation (DG) for utility purposes at utility sites. The D&O allows the utility to provide DG services on a customer-owned site as a regulated service when (1) the DG resolves a legitimate system need, (2) the DG is the lowest cost (lowest reasonable cost) alternative to meet that need and (3) it can be shown that, in an open and competitive process acceptable to the PUC, the customer operator was unable to find another entity ready and able to supply the proposed DG service at a price and quality comparable to the utility s offering.

In March 2010, the PUC approved the amended agreement between HECO and the State of Hawaii Department of Transportation to develop a dispatchable standby generation facility at the Honolulu International Airport that will be owned by the State and operated by HECO. The PUC also waived the project from the Competitive Bidding Framework. The dispatchable standby generation facility is projected to be in operation in October 2012.

HECO is also evaluating the potential to develop utility-owned DG at Oahu military bases in order to meet utility system needs and the energy objectives of the federal Department of Defense.

In February 2008, the PUC approved a MECO agreement for the installation at a hotel site on the island of Lanai of a combined heat and power system, which was placed in service in September 2009.

DG tariff proceeding. In 2008, the PUC approved modifications to the utilities interconnection tariffs and a standby service tariff. In January 2010, the utilities requested modifications of the DG interconnection tariff. In May 2010, the PUC approved certain modifications that had been stipulated to by the parties, including (1) modifying requirements for conducting detailed interconnection studies; (2) establishing a standard three-party interconnection agreement; (3) including cross-limitation of liability and non-indemnification language with respect to projects where a State of Hawaii agency is the customer; and (4) requiring additional information regarding the customer s generating facility. The remaining issues continue to be evaluated in the proceeding.

DG and distributed energy storage under the Energy Agreement. Under the Energy Agreement, the utilities committed to facilitate planning for distributed energy resources through a new Clean Energy Scenario Planning process. Under this process, Locational Value Maps were developed in 2009 to identify areas where DG and distributed energy storage would provide utility system benefits and can be reasonably accommodated.

The utilities also agreed to power utility-owned DG using sustainable biofuels or other renewable technologies and fuels, and to support either customer-owned or utility-owned distributed energy storage. The utilities are currently planning distributed energy storage research, development and demonstration projects for installation in 2011-2012.

The parties to the Energy Agreement support reconsideration of the PUC s restrictions on utility-owned DG where it is proven that utility ownership and dispatch clearly benefits grid reliability and ratepayer interests, and the equipment is competitively procured. The parties also support HECO s dispatchable standby generation units upon showing reasonable ratepayer benefits.

The utilities may contract with third parties to aggregate fleets of DG or standby generators for utility dispatch or under PPAs, or may undertake such aggregation themselves if no third parties respond to a solicitation for such services.

The Energy Agreement also provides that to the degree that transmission and distribution automation and other smart grid technology investments are needed to facilitate distributed energy resource utilization, those investments should be recoverable through a Clean Energy Infrastructure Surcharge (which was replaced by the Renewable Energy Infrastructure Program (REIP) Surcharge) and later placed in rate base in the next rate case proceeding.

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Most recent rate requests. The electric utilities initiate PUC proceedings from time to time to request electric rate increases to cover rising operating costs and the cost of plant and equipment, including the cost of new capital projects to maintain and improve service reliability. The PUC may grant an interim increase within 10 to 11 months following the filing of an application, but there is no guarantee of such an interim increase and interim amounts collected are refundable, with interest, to the extent they exceed the amount approved in the PUC s final D&O. The timing and amount of any final increase is determined at the discretion of the PUC. The adoption of revenue, expense, rate base and cost of capital amounts (including the return on average common equity (ROACE) and return on rate base (ROR)) for purposes of an interim rate increase does not commit the PUC to accept any such amounts in its final D&O.

For the 12 months ended March 31, 2011, the actual ROACEs (calculated under the rate-making method, which excludes the effects of items not included in determining electric utility rates) for HECO, HELCO and MECO were 5.63%, 7.26% and 5.59%, respectively. The utilities actual ROACEs were lower than their final and interim D&O ROACEs primarily due to lower KWH sales than the sales used to determine the interim rates and increased O&M expenses.

For the 12 months ended March 31, 2011, the actual RORs (calculated under the rate-making method, which excludes the effects of items not included in determining electric utility rates) for HECO, HELCO and MECO were 5.63%, 6.55% and 5.81%, respectively.

In the most recent interim and final rate decisions, the PUC allowed the use by each utility of pension and postretirement benefits other than pensions (OPEB) tracking mechanisms (with varied treatment of the pension assets of each utility) and allowed the continuation of each utility s ECAC.

The following table summarizes certain details of each utility s most recent rate cases, including the details of the increases requested, whether the utility and the Consumer Advocate reached a settlement that they proposed to the PUC, the details of increases granted in interim and final PUC D&Os or whether an interim or final PUC D&O remains pending.

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Test year (dollars in millions)	Date (applied/ implemented)	Amount	% over rates in effect	ROACE	RORB	Ratebase	% Common equity	Stipulated agreement reached with Consumer Advocate	Reflects decoupling
HECO									
2007									
Request	12/22/06	$ 99.6	7.1%	11.25%	8.92%	$ 1,214	55.10%	Yes	No
Interim increase	10/22/07	70.0	5.0	10.70	8.62	1,158	55.10		No
Interim increase (adjusted)	6/20/08	77.9	5.6	10.70	8.62	1,158	55.10		No
Final increase	3/1/11	77.5	5.5	10.70	8.62	1,158	55.10		No
2009									
Request (1)	7/3/08	$ 97.0	5.2%	11.25%	8.81%	$ 1,408	54.30%	Yes	No
Interim increase (1st)	8/3/09	61.1	4.7	10.50	8.45	1,169	55.81		No
Interim increase (2nd, plus 1st)	2/20/10	73.8	5.7	10.50	8.45	1,251	55.81		No
Final increase (2)	3/1/11	66.4	5.1	10.00	8.16	1,250	55.81		Yes
2011									
Request (3)	7/30/10	$ 94.0	5.4%	10.75%	8.54%	$ 1,569	56.29%		Yes
Interim increase	Pending								
HELCO									
2006									
Request	5/5/06	$ 29.9	9.2%	11.25%	8.65%	$ 369	50.83%	Yes	No
Interim increase	4/5/07	24.6	7.6	10.70	8.33	357	51.19		No
Final increase (4)	1/14/11	24.6	7.6	10.70	8.33	357	51.19		No
2010									
Request (5)	12/9/09	$ 20.9	6.0%	10.75%	8.73%	$ 487	55.91%	Yes	Yes
Interim increase	1/14/11	6.0	1.7	10.50	8.59	465	55.91		No
Final increase	Pending								
MECO									
2007									
Request	2/23/07	$ 19.0	5.3%	11.25%	8.98%	$ 386	54.89%	Yes	No
Interim increase	12/21/07	13.2	3.7	10.70	8.67	383	54.89		No
Final increase	1/12/11	13.2	3.7	10.70	8.67	383	54.89		No
2010									
Request (6)	9/30/09	$ 28.2	9.7%	10.75%	8.57%	$ 390	56.86%	Yes	Yes
Interim increase	8/1/10	10.3	3.3	10.50	8.43	387	56.86		No
Interim increase (adjusted)	1/12/11	8.5	2.7	10.50	8.43	387	56.86		No
Final increase	Pending								

Note: The Request Date reflects the filing date for the rate proceeding. All other line items reflect the effective dates of the revised schedules and tariffs as a result of PUC-approved increases.

(1) In April 2009, HECO reduced this rate increase request by $6.2 million because a new Customer Information System would not be placed in service as originally planned (see Note 5 of HECO s Notes to Consolidated Financial Statements).

(2) Because the final increase was $7.4 million less in annual revenues, HECO refunded $2.1 million to customers (including interest) in February 2011.

(3) HECO s request was primarily to pay for major capital projects and higher O&M costs to maintain and improve service reliability and to recover the costs for several proposed programs to help reduce Hawaii s dependence on imported oil, and to further increase reliability and fuel security.

(4) Final D&O appealed by a participant in the rate case proceeding. The appeal is pending, but has not affected implementation of the rate increase.

(5) HELCO s request was primarily to cover investments for system upgrade projects, two major transmission line upgrades and increasing O&M expenses.

(6) MECO s request was primarily to cover investment to improve service reliability and higher O&M expenses.

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Decoupling proceeding. In the Energy Agreement, the parties agreed to seek approval from the PUC to implement a decoupling mechanism, similar to that in place for several California utilities, which decouples revenues from KWH sales and provides for revenue adjustments between rate cases.

In October 2008, the PUC opened an investigative proceeding to examine implementing a decoupling mechanism for the utilities. In May 2009, the utilities and the Consumer Advocate filed their joint proposal (Joint Decoupling Proposal) for a decoupling mechanism with three components: (1) a sales decoupling component via a revenue balancing account (RBA), (2) a revenue escalation component via a revenue adjustment mechanism (RAM) and (3) an earnings sharing mechanism. The RBA mechanism provides for revenue adjustments (increases or decreases) between rate cases to account for the difference between the revenues allowed in the most recent rate case (target revenues) and the revenues actually received by the utility. The RAM provides for changes in revenue requirements between rate cases for inflation-indexed changes in O&M expenses (other than expenses recovered through surcharges) and to allow for the return on and return of changes in certain elements of rate base (e.g., plant additions excluding plant additions recovered through the REIP Surcharge) between rate cases. The RAM provides more timely recovery of invested capital and O&M costs since some portion of the increased costs between rate cases will be recovered without the need for a rate proceeding. The earnings sharing mechanism provides for a reduction of rates between rate cases in the event the utility exceeds the ROACE allowed in its most recent rate case.

On August 31, 2010, the PUC issued a Final D&O, which approved the decoupling mechanism proposed in the Joint Decoupling Proposal, subject to certain modifications. Those modifications excluded from the RAM merit wage increases and cost overruns for major capital projects (capital projects greater than or equal to $2.5 million), with recovery of such increases and overruns to be considered in the utility s next rate case.

In the Final D&O in HECO s 2009 test year rate case issued on December 29, 2010, the PUC approved a reduced ROACE due to decoupling and other new cost recovery mechanisms, and allowed HECO to implement the approved decoupling mechanism. Effective March 1, 2011, HECO established the RBA and started recording the difference between target revenues from its HECO 2009 rate case and actual revenues. On March 31, 2011, HECO submitted its revised tariff to enable the RAM revenue adjustment of $12.7 million ($4.7 million for O&M costs and $8.0 million for invested capital) for the period from March 1, 2011 (the effective date for decoupling) through December 31, 2011. The collection period for the RAM revenue adjustment is 12 months and, unless the tariff is suspended by the PUC, HECO will begin billing customers on June 1, 2011. HECO s understanding is that, when an interim D&O is issued in its 2011 rate case, the accrual of revenues would end, and the tariff would be adjusted to reflect the RAM revenue accrual from March 1, 2011 to the effective date of the interim rate increase authorized by the interim D&O. However, the Consumer Advocate submitted comments in April 2011 on HECO s revised tariff, taking the position that HECO is not entitled to RAM revenues prior to the effective date of the revised tariff of June 1, 2011 (if not suspended), and the RAM revenue adjustment would end when an interim D&O is issued in the 2011 rate case. Because there is uncertainty on how the PUC will decide the issue, HECO has not recorded RAM revenues for March 2011 of approximately $1.3 million.

Authorizations for the implementation of decoupling for HELCO and MECO are pending final D&Os or other action by the PUC in their pending 2010 test year rate cases. Per the decoupling D&O, the utilities will file staggered rate cases every three years, the first being HECO s 2011 test year filed in July 2010. In May 2011, MECO filed a Notice of Intent to file an application for a general rate increase, using a 2012 test year.

Energy Cost Adjustment Clauses (ECACs). The rate schedules of the electric utilities include ECACs under which electric rates are adjusted for changes in the weighted-average price paid for fuel oil and certain components of purchased power, and the relative amounts of company-generated power and purchased power.

The HECO (2011 test year), HELCO (2010 test year) and MECO (2010 test year) rate increase applications requested the continuation of their ECACs. In the final D&Os for the HELCO 2006, MECO and HECO 2007 and HECO 2009 test year rate cases, the PUC found that HELCO s, MECO s and HECO s ECACs comply with Act 162 and should be implemented as agreed by the parties to the respective rate case proceedings.

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Other regulatory matters. In addition to the items below, also see Hawaii Clean Energy Initiative and Major projects in Note 5 of HECO s Notes to Consolidated Financial Statements.

Demand-side management programs.

Energy Efficiency DSM Programs. In February 2007, the PUC required that the administration of all Energy Efficiency (EE) DSM programs be turned over to a non-utility, third-party administrator. The PUC executed a public benefits fund (PBF) administrator contract with Science Applications International Corporation (SAIC) and on July 1, 2009, SAIC began administering the EE DSM programs. A PBF surcharge on electric utility revenues (1% in 2010, 1.5% in 2011 and 2012 and 2% thereafter) is being used to fund EE DSM programs, incentives, program administration, and other related program costs.

EE DSM costs and incentives prior to the PBF were subject to PUC review and approval. Because the utilities were not able to recover the entire amount of 2009 DSM program expenditures, the utilities recorded an expense of $1.3 million in December 2010. HECO began recovering $0.6 million in 2009 DSM incentives in April 2011.

Load management DSM programs. Unlike the EE DSM programs, load management DSM programs continue to be administered by the utilities.

In December 2009, the PUC approved HECO s requests to extend the Commercial and Industrial Direct Load Control (CIDLC) Program and the Residential Direct Load Control (RDLC) Program through 2012. The CIDLC Program provides an incentive on the portion of the demand load that eligible commercial/industrial customers allow HECO to be control or interrupt. The RDLC Program includes a monthly electric bill credit for eligible residential customers who allow HECO to disconnect their electric water heaters or central air conditioning systems from HECO s system to reduce system load when deemed necessary by HECO.

In August 2010, HECO filed an application for a Fast Demand Response Pilot Program a two-year pilot program designed to test commercial and industrial market acceptance of load reductions within 10-minutes of event notification, and demonstrate the technical aspects of semi-automatic and automatic mechanisms to initiate customer reductions in load. A PUC decision is pending.

Renewable Energy Infrastructure Program. The Renewable Energy Infrastructure Program (REIP) proposed by HECO in December 2007 consisted of two components: (1) renewable energy infrastructure projects that facilitate third-party development of renewable energy resources, maintain existing renewable energy resources and/or enhance energy choices for customers and (2) the creation and implementation of a temporary renewable energy infrastructure surcharge to recover the capital costs, deferred costs for software development and licenses, and/or other relevant costs approved by the PUC. These costs would be removed from the surcharge and included in base rates in the utility s next rate case. In December 2009, the PUC issued a D&O approving HECO s proposed REIP, including the REIP surcharge, subject to certain conditions specified in the D&O. The PUC may review the benefits and continued need for the REIP every three years or earlier if necessary.

The PUC approved the use of the REIP surcharge to recover certain interconnection costs for a wind project. In July 2010, the utilities submitted (as directed by the PUC) proposed Standards and Guidelines for Utility Funding of Renewable Infrastructure Projects Associated with Independent Power Producers.

Delinking energy payment rates from oil costs. On April 18, 2008, the PUC initiated a docket to examine the methodology for calculating Schedule Q electricity payment rates in the State of Hawaii. In general, Schedule Q rates are available to customers with cogeneration and/or small power production facilities with a capacity of 100 kW or less who buy power from or sell power to the electric utility. The proceeding was intended to examine new methodologies for calculating Schedule Q payment rates, with the intent of removing or reducing any linkages between the price of fossil fuels and the rate for non-fossil fuel generated electricity. The parties to the Energy Agreement agreed that all new renewable energy contracts are to be delinked from fossil fuel and that the utilities would seek to renegotiate existing PPAs with IPPs that are based on fossil fuel prices to delink their energy payment rates from oil costs. In December 2010, HECO, HELCO and MECO filed updated avoided energy costs rates and Schedule Q rates to be effective for 2011, subject to monthly adjustment of the fuel component of the rates for changes in fuel prices. A Stipulated Procedural Schedule for the Schedule Q proceeding, which calls for the filing of final statements of position in April 2012, was approved by the PUC in January 2011.

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Clean energy scenario planning, integrated resource planning and requirements for additional generating capacity. The PUC issued an order in 1992 requiring the energy utilities in Hawaii to develop integrated resource plans (IRPs), which would then be approved, rejected or modified by the PUC. The goal of integrated resource planning is the identification of demand- and supply-side resources and the integration of these resources for meeting near- and long-term consumer energy needs in an efficient and reliable manner at the lowest reasonable cost.

Under the PUC s IRP framework, the utilities were entitled to recover all appropriate and reasonable IRP costs either through a surcharge or through their base rates. Under procedural schedules for the IRP cost proceedings, the utilities were able to recover their incremental IRP costs in the month following the filing of their actual costs incurred for the year, subject to refund with interest pending the PUC s final D&O approving recovery in the docket for each year s costs. HELCO, HECO and MECO currently recover IRP costs through base rates. Previously they recovered their costs through a surcharge. In January 2011, the PUC issued a D&O that allowed the utilities to recover their 2002-2007 IRP planning costs, but disallowed certain costs, primarily costs incurred during a rate case test year. The utilities had been reserving for a potential refund for portions of the cost previously recovered and related interest, based on final D&Os issued for 1995-2001 IRP planning costs. In December 2010, the utilities recorded additional charges of $0.8 million to fully accrue for this refund, and in the first quarter of 2011 refunded approximately $1.2 million to its customers.

The parties to the Energy Agreement agreed to seek to replace the IRP process with a new Clean Energy Scenario Planning (CESP) process intended to be used to determine future investments in generation and transmission that will be necessary to facilitate high levels of renewable energy production and reductions in electricity use through energy efficiency programs. In the fourth quarter of 2008, the PUC closed the IRP-4 processes and directed the utilities to suspend all activities pursuant to the IRP framework to allow for resources to be diverted to the development of the CESP framework.

HECO and the Consumer Advocate filed a proposed CESP framework with the PUC in April 2009. In May 2009, the PUC opened an investigative proceeding to examine the proposed framework. In March 2011, the PUC filed a D&O modifying, updating and expanding the 1992 IRP framework by incorporating the concept of scenario planning, requiring the use of an independent entity to facilitate the IRP process and maintaining IRP rather than CESP as the title for the process. The IRP planning process will begin upon the issuance by the PUC of an order opening the docket. Thereafter, the independent entity shall be selected and retained by the PUC, the utilities shall file a schedule that they intend to follow in their IRP processes and the advisory group shall be selected by the PUC. The utilities must file their IRP report and associated 5-year Action Plan within one year after the selection of the advisory group.

Adequacy of supply.

HECO. In February 2011, HECO filed its 2011 Adequacy of Supply (AOS) letter, which indicated that based on its May 2010 sales and peak forecast, HECO s generation capacity for 2011 to 2015 is sufficiently large to meet all reasonably expected demands for service and provide reasonable reserves for emergencies. HECO anticipates that it will acquire 8 MW from a distributed standby generation facility at the Honolulu International Airport and 27 MW from an expansion of the existing H-Power waste-to-energy facility within the next two years. Beginning in 2016, HECO anticipates that based on increasing demand it will begin experiencing reserve capacity shortfalls if no more firm generating capacity is added to the system. Also, four existing generating units may be retired within the next 10 years because of their age or more stringent environmental regulations. In February 2011, at HECO s request, the PUC opened a new docket to commence the competitive bidding process to acquire approximately 300 MW of new, firm generating capacity to replace the capacity that would be lost with the retirement of these four units and to accommodate load growth.

HELCO. In January 2011, HELCO filed its 2011 AOS letter, which indicated that HELCO s generation capacity through 2013 is sufficiently large to meet all reasonably expected demands for service and provide reasonable reserves for emergencies. HELCO is currently negotiating with an IPP to supply additional firm renewable generating capacity. Should this additional firm renewable facility come on line within the next three

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years as anticipated, HELCO will not have a need for additional firm capacity in the foreseeable future. HELCO, however, may choose to add additional renewable generating capacity to replace existing nonrenewable generation.

MECO. In January 2011, MECO filed its 2011 AOS letter, which indicated that MECO s generation capacity through 2014 is sufficient to meet the forecasted demands on the islands of Maui, Lanai and Molokai, but also stated that additional increments of firm capacity will be needed on Maui in 2015 and 2018 to accommodate the anticipated loss of capacity from an IPP at the end of 2014 and to accommodate load growth.

December 2008 outage. On December 26, 2008, an island-wide outage occurred on the island of Oahu during a severe lightning storm that resulted in a loss of electric service to HECO customers ranging from approximately 7 to 20 hours. On January 12, 2009, the PUC initiated an investigation of the outage.

In February 2011, the PUC issued a final D&O finding that the activities and performance of HECO prior to and during the power outage were reasonable and in the public interest and that no penalties would be imposed on HECO due to the outage.

Intra-governmental wheeling of electricity. In June 2007, the PUC initiated a docket to examine the feasibility of implementing intra-governmental wheeling of electricity in the State of Hawaii. The PUC subsequently suspended this docket, but reinstated it in November 2010. In January 2011, the PUC adopted the procedural schedule proposed by the Parties and Participants, which includes a panel hearing around the fourth quarter of 2012

Collective bargaining agreements. See Collective bargaining agreements in Note 5 of HECO s Notes to Consolidated Financial Statements.

Legislation and regulation. Congress and the Hawaii legislature periodically consider legislation that could have positive or negative effects on the utilities and their customers. Also see, Hawaii Clean Energy Initiative and Environmental regulation in Note 5 of HECO s Notes to Consolidated Financial Statements and Major tax legislation in 2011 above.

Increase in oil tax. On July 1, 2010, the state tax on petroleum products shipped to Hawaii increased from $0.05 to $1.05 per barrel. The higher tax, which is passed on to consumers, increased the price of gasoline and electricity and is expected to generate funds to reduce the state s budget deficit and support local food production and renewable energy programs.

Renewable energy. In 2008, a Hawaii law was enacted that is intended to facilitate the permitting of larger (200 MW or greater) renewable energy projects.

In 2009, a Hawaii law was enacted that authorizes preferential rates to agricultural energy producers selling electricity to utilities. This will help support the long-term development of locally grown biofuel crops, cultivating potential local renewable fuel sources for the utilities. In addition, pursuant to Act 50 (also adopted in 2009), avoided cost is no longer the primary consideration in determining a just and reasonable rate for non-fossil fuel generated electricity. This will allow the utilities to negotiate purchased power prices for renewable energy that have the potential to be more stable and less costly than current pricing tied to avoided cost.

Biofuels. In 2007, a Hawaii law was enacted with the stated purpose of encouraging further production and use of biofuels in Hawaii. It established that biofuel processing facilities in Hawaii are a permitted use in designated agricultural districts and established a program with the Hawaii Department of Agriculture to encourage the production in Hawaii of energy feedstock (i.e., raw materials for biofuels).

In 2008, a Hawaii law was enacted that encourages the development of biofuels by authorizing the Hawaii Board of Land and Natural Resources to lease public lands to growers or producers of plant and animal material used for the production of biofuels.

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Other developments.

Advanced Metering Infrastructure (AMI). The utilities, PUC and Consumer Advocate support a broad range of smart grid initiatives, including AMI, as important components of a clean energy strategy. The utilities are assessing, testing and deploying various smart grid technologies on their systems. On March 31, 2011, HECO and Sensus Metering Systems, Inc. signed an agreement to continue further testing of AMI and smart grid technologies in Hawaii. The cost of the testing conducted under this agreement will be expensed.

Commitments and contingencies. See Note 5 of HECO s Notes to Consolidated Financial Statements.

Recent accounting pronouncements and interpretations. See Note 7 of HECO s Notes to Consolidated Financial Statements.

FINANCIAL CONDITION

Liquidity and capital resources. Management believes that HECO s ability, and that of its subsidiaries, to generate cash, both internally from operations and externally from issuances of equity and debt securities, commercial paper and lines of credit, is adequate to maintain sufficient liquidity to fund their respective capital expenditures and investments and to cover debt, retirement benefits and other cash requirements for the foreseeable future.

HECO s consolidated capital structure was as follows:

(dollars in millions)		March 31, 2011			December 31, 2010	
Short-term borrowings	$		%	$		%
Long-term debt, net		1,058	44		1,058	44
Preferred stock		34	1		34	1
Common stock equity		1,339	55		1,338	55
	$	2,431	100%	$	2,430	100%

HECO s short-term borrowings (other than from HELCO and MECO) and line of credit facility were as follows:

(in millions)	Average balance Three months ended March 31, 2011	Balance March 31, 2011	Balance December 31, 2010
Short-term borrowings(1)			
Commercial paper	$	$	$
Line of credit draws			
Borrowings from HEI			

Line of credit facilities			
Undrawn capacity under line of credit facility expiring May 7, 2013	N/A	175	175

(1) There were no external short-term borrowings during the first quarter of 2011. At March 31, 2011, HECO had $31 million and $17 million of short-term borrowings from HELCO and MECO, respectively, which borrowings are eliminated in consolidation. At April 29, 2011, HECO had no outstanding commercial paper, its line of credit facility was undrawn, it had no borrowings from HEI and it had borrowings of $33 million and $18 million from HELCO and MECO, respectively.

The principal amount of special purpose revenue bonds (SPRBs) that have been authorized by the Hawaii legislature for future issuance by the State of Hawaii Department of Budget and Finance (DBF) for the benefit of the utilities was as follows:

(in millions)	**March 31, 2011**	**December 31, 2010**
2007 legislative SPRBs authorization (expiring June 30, 2012)		
HECO	$ 170	$ 170
HELCO	55	55
MECO	25	25
Total special purpose revenue bonds available for issue	$ 250	$ 250

HECO utilizes short-term debt, typically commercial paper, to support normal operations, to refinance short-term debt and for other temporary requirements. HECO also borrows short-term from HEI for itself and on behalf of

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HELCO and MECO, and HECO may borrow from or loan to HELCO and MECO short-term. The intercompany borrowings among the utilities, but not the borrowings from HEI, are eliminated in the consolidation of HECO s financial statements. HECO and its subsidiaries periodically utilize long-term debt, historically borrowings of the proceeds of SPRBs issued by the DBF, to finance the utilities capital improvement projects, or to repay short-term borrowings used to finance such projects. The PUC must approve issuances, if any, of equity and long-term debt securities by HECO, HELCO and MECO.

Due to market conditions since September 2008 (which resulted in a tightening of the commercial paper market, higher commercial paper rates and limitations on maturity options) and as a result of an S&P downgrade of HECO s short-term borrowing rating to A-3 from A-2, HECO drew on its previous $175 million syndicated line of credit facility in June and July 2009, rather than issue commercial paper. All such draws/borrowings were repaid in August 2009. HECO re-entered the commercial paper market in March 2010, experiencing higher rates and shorter terms.

Effective May 7, 2010, HECO entered into a revolving noncollateralized credit agreement establishing a line of credit facility of $175 million, with a letter of credit sub-facility, with a syndicate of eight financial institutions. See Note 9 of HECO s Notes to Consolidated Financial Statements.

The credit agreement contains provisions for revised pricing in the event of a ratings change. For example, a ratings downgrade of HECO s Issuer Rating (e.g., from BBB/Baa2 to BBB-/Baa3 by S&P and Moody s, respectively) would result in a commitment fee increase of 5 basis points and an interest rate increase of 25 basis points on any drawn amounts. On the other hand, a ratings upgrade (e.g., from BBB/Baa2 to BBB+/Baa1 by S&P or Moody s, respectively) would result in a commitment fee decrease of 10 basis points and an interest rate decrease of 25 basis points on any drawn amounts. The agreement contains customary conditions that must be met in order to draw on it, including compliance with several covenants (such as covenants preventing its subsidiaries from entering into agreements that restrict the ability of the subsidiaries to pay dividends to, or to repay borrowings from, HECO, and restricting its ability as well as the ability of any of its subsidiaries to guarantee additional indebtedness of the subsidiaries if such additional debt would cause the subsidiary s Consolidated Subsidiary Funded Debt to Capitalization Ratio to exceed 65% (actual ratios of 43% for HELCO and 42% for MECO as of March 31, 2011, as calculated under the agreement)). In addition to customary defaults, HECO s failure to maintain its financial ratios, as defined in its agreement, or meet other requirements may result in an event of default. For example, under its agreement, it is an event of default if HECO fails to maintain a Consolidated Capitalization Ratio (equity) of at least 35% (actual ratio of 55% as of March 31, 2011, as calculated under the agreement).

In addition to their impact on pricing under HECO s credit agreement, the ratings of HECO s commercial paper and debt securities could significantly impact the ability of HECO to sell its commercial paper and issue debt securities and/or the cost of such debt. The rating agencies use a combination of qualitative measures (e.g., assessment of business risk that incorporates an analysis of the qualitative factors such as management, competitive positioning, operations, markets and regulation) as well as quantitative measures (e.g., cash flow, debt, interest coverage and liquidity ratios) in determining the ratings of HECO securities. On July 30, 2010, Moody s changed HECO s rating outlook to stable from negative and affirmed HECO s long-term and short-term (commercial paper) ratings, indicating that the ratings affirmation and outlook change reflects the progress being made to transform the regulatory framework for the utilities to a decoupling structure that will reduce sales volume risk and produce more timely recovery of invested capital and O&M costs. Moody s indicated the rating could be downgraded if the Hawaii PUC does not follow through with the regulatory transformation contemplated under the HCEI, including all elements of the decoupling mechanism, or if the utilities cash flow to debt declined to below 17% on a sustainable basis and its cash flow coverage of interest fell below 3.5 times. On November 15, 2010, S&P issued an update in which it lowered its long-term ratings for HECO, HELCO and MECO to BBB- from BBB, and indicated the outlook as stable. In addition, S&P affirmed its A-3 short-term rating of HECO and revised HECO s financial profile to aggressive from significant. S&P indicated the rating downgrade reflects an aggressive financial profile combined with weak cash flow generation at HEI s electric utilities, delays in implementing new utility rate recovery mechanisms, the growing risks of regulatory disallowances in future rate cases and a protracted recession.

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As of April 29, 2011, the S&P and Moody s ratings of HECO securities were as follows:

	S&P	Moody s
Commercial paper	A-3	P-2
Special purpose revenue bonds-insured (principal amount noted in parentheses, senior unsecured, insured as follows):		
Ambac Assurance Corporation ($0.2 billion)	BBB-*	Baa1*
Financial Guaranty Insurance Company ($0.3 billion)	BBB-*	Baa1*
MBIA Insurance Corporation ($0.3 billion)	BBB**	Baa1**
Syncora Guarantee Inc. (formerly XL Capital Assurance Inc.) ($0.1 billion)	BBB-*	Baa1*
Special purpose revenue bonds uninsured ($150 million)	BBB-	Baa1
HECO-obligated preferred securities of trust subsidiary	BB	Baa2
Cumulative preferred stock (selected series)	Not rated	Baa3

The above ratings reflect only the view, at the time the ratings are issued, of the applicable rating agency, from whom an explanation of the significance of such ratings may be obtained. Such ratings are not recommendations to buy, sell or hold any securities; such ratings may be subject to revision or withdrawal at any time by the rating agencies; and each rating should be evaluated independently of any other rating.

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* Rating corresponds to HECO s rating (senior unsecured debt rating by S&P or issuer rating by Moody s) because, as a result of rating agency actions to lower or withdraw the ratings of these bond insurers after the bonds were issued, HECO s current ratings are either higher than the current rating of the applicable bond insurer or the bond insurer is not rated.

** Following MBIA Insurance Corporation s (MBIA s) announced restructuring in February 2009, the revenue bonds issued for the benefit of HECO and its subsidiaries and insured by MBIA have been reinsured by MBIA Insurance Corp. of Illinois (MBIA Illinois), whose name was subsequently changed to National Public Finance Guarantee Corp. (National). The financial strength rating of National by S&P is BBB. Moody s ratings on securities that are guaranteed or wrapped by a financial guarantor are generally maintained at a level equal to the higher of the rating of the guarantor (if rated at the investment grade level) or the published underlying rating. The insurance financial strength rating of National by Moody s is Baa1, which is the same as Moody s issuer rating for HECO.

Management believes that, if HECO s commercial paper ratings were to be further downgraded or if credit markets were to further tighten, it would be even more difficult and expensive for HECO to sell commercial paper or secure other short-term borrowings or HECO might not be able to sell commercial paper in the future. Similarly, management believes that if HECO s long-term credit ratings were to be further downgraded, or if credit markets further tighten, it could be even more difficult and/or expensive for DBF and/or the Company to sell SPRBs and other debt securities, respectively, for the benefit of the utilities in the future. Such limitations and/or increased costs could materially adversely affect the results of operations and financial condition of HECO and its subsidiaries.

The PUC must approve issuances, if any, of equity and long-term debt securities by HECO, HELCO and MECO. Revenue bonds are issued by the DBF to finance capital improvement projects of HECO and its subsidiaries, but the source of their repayment is the unsecured obligations of HECO and its subsidiaries under loan agreements and notes issued to the DBF, including HECO s guarantees of its subsidiaries obligations. The payment of principal and interest due on SPRBs currently outstanding and issued prior to 2009 are insured either by Ambac Assurance Corporation, Financial Guaranty Insurance Company, MBIA (which bonds have been reinsured by National Public Finance Guarantee Corp.) or Syncora Guarantee Inc. (which bonds have been reinsured by Syncora Capital Assurance Inc.). The insured outstanding SPRBs were initially issued with S&P and Moody s ratings of AAA and Aaa, respectively, based on the ratings at the time of issuance of the applicable bond insurer. Beginning in 2008, however, ratings of the insurers (or their predecessors) were downgraded and/or withdrawn by S&P and Moody s, resulting in a downgrade of the bond ratings of all of the bonds as shown in the ratings table above. The $150 million of SPRBs sold by the DBF for the benefit of HECO and HELCO on July 30, 2009, were sold without bond insurance.

On November 15, 2010, the PUC approved the request of HECO, HELCO and MECO for the sale of each utility s common stock over a five-year period from 2010 through 2014 (HECO s sale to HEI of up to $210 million and HELCO and MECO s sales to HECO of up to $43 million and $15 million, respectively), and the purchase of the HELCO and MECO common stock by HECO. In December 2010, HELCO and MECO sold $23 million and $3 million, respectively, of their common stock to HECO, and HECO sold $4 million of its common stock to HEI. On March 31, 2011, HECO, HELCO and MECO filed with the PUC an application for the authorization to issue up to $250 million in obligations for HECO, up to $25 million for HELCO and up to $25 million for MECO, in one or more registered public offerings or private placements on or before December 31, 2015.

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Operating activities used $28 million in net cash during the first quarter of 2011. Investing activities during the same period used net cash of $32 million for capital expenditures, net of contributions in aid of construction. Financing activities for the same period used net cash of $18 million, primarily due the payment of $18 million of common and preferred dividends.

Management periodically reviews capital expenditure estimates and the timing of construction projects. These estimates may change significantly as a result of many considerations, including changes in economic conditions, changes in forecasts of KWH sales and peak load, the availability of purchased power and changes in expectations concerning the construction and ownership of future generation units, the availability of generating sites and transmission and distribution corridors, the need for fuel infrastructure investments, the ability to obtain adequate and timely rate increases, escalation in construction costs, commitments under the Energy Agreement, the effects of opposition to proposed construction projects and requirements of environmental and other regulatory and permitting authorities.

Bank

RESULTS OF OPERATIONS

(in thousands)	Three months ended March 31 2011	2010	% change	Primary reason(s) for significant change
Revenues	$ 65,313	$ 70,914	(8)	Lower interest income primarily due to lower earning asset balances as a result of the sale of substantially all of the 1-4 family residential loan production in the first nine months of 2010 and lower yields on earning assets due to the lower interest rate environment
Operating income	21,754	21,771		Lower net interest and noninterest income, largely offset by lower noninterest expenses and lower provision for loan losses
Net income	13,851	13,736	1	Lower income tax expense

See Note 4 of HEI s Notes to Consolidated Financial Statements and Economic conditions in the HEI Consolidated section above.

In 2010, ASB successfully completed its multi-year Performance Improvement Project that began in 2008. The many initiatives of this project resulted in substantially improved profitability and reduced risk in 2010, which continued into the first quarter of 2011.

For the three months ended March 31, 2011, ASB reported a strong 1.15% return on assets and 57% efficiency ratio, and ASB s profitability metrics were in line or better than the average of its high performing peers. Key drivers of this improved performance include:

1. ASB s significant reduction of non-interest expense;

2. ASB s reduction of its exposure to riskier non-core assets;

3. ASB s lowering of its funding costs through its free checking product and lower CD balances; and

4. ASB s optimization of its balance sheet and capital efficiency and improvement of its capital ratios by exercising discipline through the downturn on what was selected to put on its balance sheet and holding additional capital to hedge against the downside of the credit cycle.

In addition, as Hawaii s economy started to improve, ASB saw declines in the provision expense year over year. Importantly, ASB s credit quality metrics through the down cycle has been better than the average of its peers due to its historic disciplined and conservative underwriting standards.

Management is now working to grow its bank franchise in Hawaii and remains focused on maintaining ASB as a high performing community bank with a targeted return on assets of 1.2%, net interest margin above 4% and an efficiency ratio in the mid-50s. Despite the revenue pressures across the banking industry, management expects ASB s low-cost funding base, reduced cost structure and lower-risk profile to continue to deliver strong performance compared to industry averages.

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Average balance sheet and net interest margin. The following tables set forth average balances, together with interest and dividend income earned and accrued, and resulting yields and costs for the three months ended March 31, 2011 and 2010.

Three months ended March 31	**2011**			**2010**		
(dollars in thousands)	**Average balance**	**Interest**	**Average rate (%)**	**Average balance**	**Interest**	**Average rate (%)**
Assets:						
Other investments (1)	$ 236,045	$ 86	0.15	$ 394,588	$ 183	0.19
Investment and mortgage-related securities	659,326	3,809	2.31	454,960	3,134	2.75
Loans receivable (2)	3,546,322	46,097	5.22	3,679,380	49,745	5.43
Total interest-earning assets(3)	4,441,693	49,992	4.52	4,528,928	53,062	4.70
Allowance for loan losses	(39,827)			(40,868)		
Non-interest-earning assets	416,309			412,987		
Total assets	$ 4,818,175			$ 4,901,047		
Liabilities and shareholder s equity:						
Interest-bearing demand and savings deposits	$ 2,460,794	$ 704	0.12	$ 2,369,574	1,040	0.18
Time certificates	645,356	1,889	1.19	848,526	3,383	1.62
Total interest-bearing deposits	3,106,150	2,593	0.34	3,218,100	4,423	0.56
Other borrowings	242,385	1,367	2.26	294,869	1,426	1.94
Total interest-bearing liabilities	3,348,535	3,960	0.48	3,512,969	5,849	0.67
Non-interest bearing liabilities:						
Deposits	883,635			796,705		
Other	91,517			92,844		
Shareholder s equity	494,488			498,529		
Total liabilities and shareholder s equity	$ 4,818,175			$ 4,901,047		
Net interest income		$ 46,032			$ 47,213	
Net interest margin (%) (4)			4.16			4.18

(1) Includes federal funds sold, interest bearing deposits and stock in the FHLB of Seattle ($98 million as of March 31, 2011).

(2) Includes loan fees of $1.2 million and $1.4 million for the three months ended March 31, 2011 and 2010, respectively, together with interest accrued prior to suspension of interest accrual on nonaccrual loans, includes nonaccrual loans.

(3) Interest income includes taxable equivalent basis adjustments, based upon a federal statutory tax rate of 35%, of $126,000 and nil for the three months ended March 31, 2011 and 2010, respectively.

(4) Defined as net interest income as a percentage of average earning assets.

Earning assets, costing liabilities and other factors. Earnings of ASB depend primarily on net interest income, which is the difference between interest earned on earning assets and interest paid on costing liabilities. The current interest rate environment is impacted by disruptions in the financial markets and these conditions may have a negative impact on ASB s net interest margin.

Loan originations and mortgage-related securities are ASB s primary sources of earning assets.

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Loan portfolio. ASB s loan volumes and yields are affected by market interest rates, competition, demand for financing, availability of funds and management s responses to these factors. The following table sets forth the composition of ASB s loan portfolio:

	March 31, 2011		December 31, 2010	
(dollars in thousands)	**Balance**	**% of total**	**Balance**	**% of total**
Real estate loans:				
Residential 1-4 family	$ 2,051,945	56.9	$ 2,087,813	58.9
Commercial real estate	300,248	8.3	300,689	8.5
Home equity line of credit	444,684	12.3	416,453	11.7
Residential land	60,671	1.7	65,599	1.8
Commercial construction	39,960	1.1	38,079	1.1
Residential construction	3,568	0.1	5,602	0.2
Total real estate loans, net	2,901,076	80.4	2,914,235	82.2
Commercial loans	617,800	17.2	551,683	15.5
Consumer loans	86,895	2.4	80,138	2.3
	3,605,771	100.0	3,546,056	100.0
Less: Deferred fees and discounts	(15,207)		(15,530)	
Allowance for loan losses	(40,814)		(40,646)	
Total loans, net	$ 3,549,750		$ 3,489,880	

The increase in the total loan portfolio during the first quarter of 2011 was primarily due to an increase in ASB s commercial loan and home equity lines of credit portfolios.

Loan portfolio risk elements. See Note 4 of HEI s Notes to Consolidated Financial Statements.

Investment and mortgage-related securities. As of March 31, 2011, the bank s investment portfolio consisted of 51% mortgage-related securities issued by Federal National Mortgage Association (FNMA), Federal Home Loan Mortgage Corporation (FHLMC) or Government National Mortgage Association (GNMA), 43% federal agency obligations and 6% municipal bonds. As of December 31, 2010, the bank s investment portfolio consisted of 47% mortgage-related securities issued by FNMA, FHLMC or GNMA, 47% federal agency obligations and 6% municipal bonds.

Principal and interest on mortgage-related securities issued by FNMA, FHLMC and GNMA are guaranteed by the issuer, and the securities carry implied AAA ratings.

Deposits and other borrowings. Deposits continue to be the largest source of funds for ASB and are affected by market interest rates, competition and management s responses to these factors. Core deposits continue to be strong, as depositors remain risk adverse. Advances from the FHLB of Seattle and securities sold under agreements to repurchase continue to be additional sources of funds. As of March 31, 2011 and December 31, 2010, ASB s costing liabilities consisted of 94% deposits and 6% other borrowings. The weighted average cost of deposits for the three months ended March 31, 2011 was 0.26%, compared to 0.45% for the three months ended March 31, 2010.

Other factors. Interest rate risk is a significant risk of ASB s operations and also represents a market risk factor affecting the fair value of ASB s investment securities. Increases and decreases in prevailing interest rates generally translate into decreases and increases in fair value of those instruments. In addition, changes in credit spreads also impact the fair values of those instruments.

Although higher long-term interest rates or other conditions in credit markets (such as the effects of the deteriorated subprime market) could reduce the market value of available-for-sale investment and mortgage-related securities and reduce shareholder s equity through a balance sheet charge to AOCI, this reduction in the market value of investments and mortgage-related securities would not result in a charge to net income in the absence of a sale of such securities (such as those that occurred in the fourth quarter of 2009 and in a 2008 balance sheet restructure) or an other-than-temporary impairment in the value of the securities. As of March 31, 2011 and December 31, 2010, the unrealized gains, net of taxes, on available-for-sale investments and mortgage-

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related securities (including securities pledged for repurchase agreements) in AOCI was $3 million and $4 million, respectively. See Item 3. Quantitative and qualitative disclosures about market risk.

Results three months ended March 31, 2011. Net interest income before provision for loan losses for the first quarter of 2011 decreased by $1.3 million, or 3%, when compared to the same quarter in 2010 as lower funding costs were more than offset by lower balances and yields on loans and lower yields on investment and mortgage-related securities. Net interest margin decreased from 4.18% in the first quarter of 2010 to 4.16% in the first quarter of 2011 due to lower yields on the investment and mortgage-related securities portfolio and loans receivable. The decrease in the average loan portfolio balance compared to the first quarter of 2010 was due to a decrease in the average 1-4 family residential loan portfolio of $240 million as a result of the sale of substantial residential loan production in 2010 and lower loan production in 2011. Average residential land balances decreased by $30 million compared to the first quarter of 2010 due to paydowns in the portfolio. The average home equity lines of credit portfolio increased by $101 million compared to the first quarter of 2010 due to promotional campaigns during 2010. The increase in the average investment and mortgage-related securities portfolios was primarily due to the purchase of federal agency securities and obligations with excess liquidity. Average deposit balances decreased by $25 million compared to the first quarter of 2010. The average term certificate balance decreased by $203 million due to the outflow of term certificates throughout 2010 and the first quarter of 2011 as ASB determined not to aggressively price its term certificate products. Offsetting the decrease in the term certificate portfolio was growth in the average core deposit balance of $178 million as ASB introduced new deposit products and attracted core deposits to partially offset the outflow of term certificates. The shift in deposit mix from higher cost certificates to lower cost savings and checking accounts, along with the repricing of deposits as a result of a downward movement in the general level of interest rates, has contributed to decreased funding costs. Average other borrowings decreased by $52 million compared to the first quarter of 2010 primarily due to an outflow of retail repurchase agreements.

During the first quarter of 2011, ASB recorded a provision for loan losses of $4.6 million primarily due to the net charge-offs during the quarter for 1-4 family, residential land, and commercial loans. Continued financial stress on ASB s customers may result in higher levels of delinquencies and losses. During the first quarter of 2010, ASB recorded a provision for loan losses of $5.4 million due to net charge-offs during the quarter for 1-4 family and residential land and consumer loans.

(in thousands)	**Three months ended March 31** **2011**	**2010**	**Year ended December 31** **2010**
Allowance for loan losses, January 1	$ 40,646	$ 41,679	$ 41,679
Provision for loan losses	4,550	5,359	20,894
Less: net charge-offs	4,382	5,738	21,927
Allowance for loan losses, end of period	$ 40,814	$ 41,300	$ 40,646
Ratio of allowance for loan losses, end of period, to end of period loans outstanding	1.14%	1.13%	1.15%
Ratio of net charge-offs during the period to average loans outstanding (annualized)	0.49%	0.62%	0.61%
Nonaccrual loans	$ 61,029	$ 68,469	58,855

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First quarter of 2011 noninterest income decreased by $2.4 million, or 13%, when compared to the first quarter of 2010, primarily due to lower deposit liability fees as a result of new overdraft fee regulations, which took effect in mid-2010.

Three months ended March 31 **(in thousands)**		**2011**		**2010**
Fees from other financial services	$	6,946	$	6,414
Fee income on deposit liabilities		4,449		7,520
Fee income on other financial products		1,673		1,525
Other income				
Gain on sale of loans		658		1,042
Bank-owned life insurance		970		1,006
Other		751		345
Total noninterest income	$	15,447	$	17,852

Noninterest expense for the first quarter of 2011 decreased by $2.9 million, or 8%, when compared to the first quarter of 2010, primarily due to lower data processing expense as a result of ASB s conversion to Fiserv Inc. s bank platform system in May 2010.

Three months ended March 31 **(in thousands)**		**2011**		**2010**
Compensation and benefits	$	17,505	$	17,402
Occupancy		4,240		4,225
Data processing		1,970		4,338
Services		1,771		1,728
Equipment		1,657		1,709
Other				
FDIC insurance premium		1,427		1,659
Marketing		641		954
Office supplies, printing and postage		918		867
Communication		387		497
Other		4,560		4,591
Total noninterest expense	$	35,076	$	37,970

Legislation and regulation. ASB is subject to extensive regulation, principally by the Office of Thrift Supervision (OTS), whose regulatory functions are to be transferred to the Office of the Comptroller of the Currency (OCC) as described below, and the Federal Deposit Insurance Corporation (FDIC). Depending on ASB s level of regulatory capital and other considerations, these regulations could restrict the ability of ASB to compete with other institutions and to pay dividends to its shareholder. See the discussion below under Liquidity and capital resources.

Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act). Regulation of the financial services industry, including regulation of HEI and ASB, will undergo substantial changes as a result of the enactment of the Dodd-Frank Act, which became law in July 2010. The Dodd-Frank Act increases regulation and oversight of the financial services industry and imposes restrictions on the ability of firms within the industry to conduct business consistent with historical practices. Importantly for HEI and ASB, the Dodd-Frank Act will abolish their historical federal financial institution regulator, the OTS, effective one year from the enactment date (subject to extension by not more than an additional six months). Supervision and regulation of HEI, as a thrift holding company, will move to the Federal Reserve, and supervision and regulation of ASB, as a federally chartered savings bank, will move to the OCC. While the laws and regulations applicable to HEI and ASB will not generally change the Home Owners Loan Act and regulations issued thereunder will still apply the applicable laws and regulations will be interpreted, and new and amended regulations will be adopted, by the Federal Reserve and the OCC. HEI will for the first time be subject to minimum consolidated capital requirements, and ASB may be required to be supervised through ASHI, its intermediate holding company. The

Dodd-Frank Act requires regulators, at a minimum, to apply to bank and thrift holding companies leverage and risk-based capital standards that are at least as strict as those in effect at the insured depository institution level on the date the Act became effective, although there will be a phase-in period for meeting these standards. In addition, HEI will continue to be required to serve as

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a source of strength to ASB in the event of its financial distress. The Dodd-Frank Act also imposes new restrictions on the ability of a savings bank to pay dividends should it fail to remain a qualified thrift lender.

More stringent affiliate transaction rules will apply to ASB in the securities lending, repurchase agreement and derivatives areas. Standards are raised with respect to the ability of ASB to merge with or acquire another institution. While the Dodd-Frank Act requires the minimum reserve ratio for the Deposit Insurance Fund to be increased from 1.15% to 1.35% by 2020, the FDIC is required to offset the effect of this increase for depository institutions with total consolidated assets of less than $10 billion. Based on the proposed changes to the assessment base and rates, ASB anticipates a reduction in its annual FDIC assessment by approximately $2 million. ASB may be affected by the provision of the Dodd-Frank Act that repeals, effective in July 2011 (unless extended), the prohibition on payments of interest by banks or savings associations on demand deposit accounts for businesses.

The Dodd-Frank Act establishes a Consumer Financial Protection Bureau (Bureau) to be housed in the Federal Reserve to take sole responsibility (subject to limited oversight by the new Financial Stability Oversight Council) for rulemaking under the principal federal consumer financial protection laws, such as the Truth in Lending Act, Real Estate Settlement Procedures Act, Equal Credit Opportunity Act, Truth in Savings Act, Fair Debt Collection Practices Act and several other consumer protection laws, but enforcement of these laws and rules will be by the OCC in the case of ASB because it has less than $10 billion in assets. The Bureau will have broad power in that it will have authority to prohibit practices it finds to be unfair, deceptive or abusive, and it may also issue rules requiring specified disclosures, including the use of new model forms it may adopt. ASB may also be subject to new state regulation because of a provision in the Dodd-Frank Act that acknowledges that a federal savings bank may be subject to state regulation and only allows federal law to preempt state law on a case by case basis in the consumer financial protection area when (1) the state law would have a discriminatory effect on the bank compared to that on a bank chartered in that state; (2) the state law prevents or significantly interferes with a bank s exercise of its power; or (3) the state law is preempted by another federal law.

The Dodd-Frank Act also adopts a number of provisions that will impact the mortgage industry, including the imposition of new specific duties on the part of mortgage originators (such as ASB) to act in the best interests of consumers and to take steps to ensure that consumers will have the capability to repay loans they may obtain, as well as provisions imposing new disclosure requirements and requiring appraisal reforms. Regulations are required to be adopted under these provisions of the Dodd-Frank Act within 18 months after the date that is to be specified by the Secretary of the Treasury for the transfer of consumer protection power to the Bureau. ASB cannot predict at this time what effect these new rules may ultimately have on its mortgage origination practices, its ability to originate mortgage loans or the costs it will incur in complying with these requirements.

The Dodd-Frank Act will affect financial regulation more generally as well, although many of these regulatory changes may not impact ASB or the Company directly, either because they are limited in application to larger entities or because they relate to activities in which ASB is not substantially engaged. For example, the Dodd-Frank Act establishes a Financial Stability Oversight Council that would, among other things, designate certain nonbank financial companies that it considers to be of systemic risk to be supervised by the Federal Reserve, as well as monitor the financial markets for trends affecting systemic risk and coordinate the regulatory activities of the federal bank regulators. It also would establish a mechanism for the FDIC to resolve systemically important companies that may fail. The ability of companies to engage in derivatives transactions and hedge for their own account likely will be impacted by provisions in the Dodd-Frank Act that require such transactions to be moved to exchanges and for capital and margin to be held against them, as well as by the so-called Volcker rule, which will limit the ability of financial institutions to invest for their own account once the rule becomes effective (but with exceptions important to ASB, such as for purchases of U.S. government or agency obligations).

The Durbin Amendment to the Dodd-Frank Act requires the Federal Reserve to issue rules to ensure that debit card interchange fees are reasonable and proportional to the processing costs incurred. The Federal Reserve has proposed a cap on debit card interchange fees that card issuers can receive to 12 cents per transaction. ASB currently earns an average of 52 cents per transaction. As specified in the Dodd-Frank Act, these regulations will exempt banks with less than $10 billion in assets. However, market pressures could very well push the impact down to all banks.

Many of the provisions of the Dodd-Frank Act, as amended, will not become effective until a year or more after its enactment, when implementing regulations are issued and effective. Thus, management cannot predict the ultimate

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impact of the Dodd-Frank Act, as amended, on the Company or ASB at this time. Nor can management predict the impact or substance of other future federal or state legislation or regulation, or the application thereof.

Credit CARD Act. On May 22, 2009, President Obama signed the Credit Card Accountability Responsibility and Disclosure Act of 2009 into law. Among other things, it requires that consumers receive a reasonable amount of time to make their credit card payments, prohibits payment allocation methods that unfairly maximize interest charges, prohibits issuers from raising the interest rate on an existing credit card balance in certain circumstances, and prohibits issuers from charging over-limit fees unless the cardholder agreed to allow the issuer to complete over-limit transactions and restricts the manner in which the issuer may assess over-limit fees. The major provisions of the Act were effective February 22, 2010.

New overdraft rules. On November 12, 2009, the Board of Governors of the Federal Reserve System announced that it amended Regulation E (which implements the Electronic Fund Transfer Act) to limit the ability of a financial institution to assess an overdraft fee for paying automated teller machine or one-time debit card transactions that overdraw a consumer s account, unless the consumer affirmatively consents, or opts in, to the institution s payment of overdrafts for those transactions. These new rules applied on July 1, 2010 for new accounts and August 15, 2010 for existing accounts. In 2009, these types of overdraft fees totaled approximately $15 million pretax for ASB. The amendment had a negative impact on ASB s noninterest income of approximately $2.8 million pretax for the first quarter of 2011 compared to the first quarter of 2010.

FHLB of Seattle stock. As of March 31, 2011, ASB s investment in stock of the FHLB of Seattle of $98 million was carried at cost because it can only be redeemed at par. There is a minimum required investment based on measurements of ASB s capital, assets and/or borrowing levels. The FHLB of Seattle reported net income of $20.5 million for 2010 compared to a net loss of $161.6 million for 2009. The FHLB of Seattle reported retained earnings of $73.4 million as of December 31, 2010 and was in compliance with all of its regulatory capital requirements. In October 2010, the FHLB of Seattle entered into a Stipulation and Consent to the Issuance of a Consent Order with the Federal Housing Finance Agency, which requires the FHLB of Seattle to take certain actions related to its business and operations. The Consents provide that, following a stabilization period and once the FHLB of Seattle reaches and maintains certain thresholds, it may redeem or repurchase capital stock and begin paying dividends. ASB does not believe that the Consents will affect the FHLB of Seattle s ability to meet ASB s liquidity and funding needs. ASB received no cash dividends on its $98 million of FHLB of Seattle stock in the first quarters of 2011 or 2010

Commitments and contingencies. See Note 4 of HEI s Notes to Consolidated Financial Statements.

Recent accounting pronouncements and interpretations. See Note 12 of HEI s Notes to Consolidated Financial Statements.

FINANCIAL CONDITION

Liquidity and capital resources.

(in millions)	**% change**

	March 31, 2011	December 31, 2010	
Total assets	$ 4,858	$ 4,797	1
Available-for-sale investment and mortgage-related securities	671	678	(1)
Loans receivable, net	3,554	3,498	2
Deposit liabilities	4,035	3,975	2
Other bank borrowings	245	237	3

As of March 31, 2011, ASB was one of Hawaii s largest financial institutions based on assets of $4.9 billion and deposits of $4.0 billion.

As of March 31, 2011, ASB s unused FHLB borrowing capacity was approximately $1.3 billion. As of March 31, 2011, ASB had commitments to borrowers for undisbursed loan funds, loan commitments and unused lines and letters of credit of $1.2 billion. Management believes ASB s current sources of funds will enable it to meet these obligations while maintaining liquidity at satisfactory levels.

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As of March 31, 2011 and December 31, 2010, ASB had $61.0 million and $58.9 million of loans on nonaccrual status, respectively, or 1.7% of net loans outstanding. As of March 31, 2011 and December 31, 2010, ASB had $5.8 million and $4.3 million, respectively, of real estate acquired in settlement of loans.

For the first quarter of 2011, net cash provided by ASB s operating activities was $29 million. Net cash used during the same period by ASB s investing activities was $65 million, primarily due to purchases of investment and mortgage-related securities of $109 million and a net decrease in loans receivable of $70 million, offset by repayments of investment and mortgage-related securities of $115 million. Net cash provided in financing activities during this period was $50 million, primarily due to net increases in deposit liabilities and retail repurchase agreements of $60 million and $7 million, respectively, offset by a decrease in mortgage escrow deposits of $4 million and the payment of $14 million in common stock dividends.

FDIC regulations restrict the ability of financial institutions that are not well-capitalized to compete on the same terms as well-capitalized institutions, such as by offering interest rates on deposits that are significantly higher than the rates offered by competing institutions. As of March 31, 2011, ASB was well-capitalized (minimum ratio requirements noted in parentheses) with a leverage ratio of 9.1% (5.0%), a Tier-1 risk-based capital ratio of 12.5% (6.0%) and a total risk-based capital ratio of 13.5% (10.0%). OTS approval is required before ASB can pay a dividend or otherwise make a capital distribution to HEI (through ASHI).

Item 3. Quantitative and Qualitative Disclosures About Market Risk

The Company considers interest-rate risk (a non-trading market risk) to be a very significant market risk for ASB as it could potentially have a significant effect on the Company s financial condition and results of operations. For additional quantitative and qualitative information about the Company s market risks, see pages 90 to 92, HEI s Quantitative and Qualitative Disclosures About Market Risk, in Part II, Item 7A of HEI s 2010 Form 10-K and HECO s Quantitative and Qualitative Disclosures About Market Risk, which is incorporated into Part II, Item 7A of HECO s 2010 Form 10-K by reference to Exhibit 99.2.

ASB s interest-rate risk sensitivity measures as of March 31, 2011 and December 31, 2010 constitute forward-looking statements and were as follows:

	March 31, 2011			December 31, 2010		
Change in interest rates (basis points)	**Change in NII** Gradual change	**NPV ratio** Instantaneous change	**NPV ratio sensitivity***	**Change in NII** Gradual change	**NPV ratio** Instantaneous change	**NPV ratio sensitivity***
+300	(1.7)%	11.76%	(217)	(1.3)%	12.04%	(196)
+200	(1.5)	12.59	(134)	(1.3)	12.84	(116)
+100	(0.9)	13.33	(60)	(0.8)	13.52	(48)
Base		13.93			14.00	
-100	(0.4)	14.12	19	(0.6)	14.04	4

* Change from base case in basis points (bp).

ASB s net interest income (NII) sensitivity as of March 31, 2011 was more sensitive for rising rates compared to December 31, 2010 as higher rates and changes in asset mix reduced maturing or repricing cash flows within the one-year horizon. ASB s base net present value (NPV) ratio as of March 31, 2011 decreased slightly compared to December 31, 2010. ASB s NPV ratio sensitivity measure as of March 31, 2011 increased compared to December 31, 2010 in the rising interest rate scenarios primarily due to the increase in duration of mortgage-related loans and investments.

The computation of the prospective effects of hypothetical interest rate changes on the NII sensitivity, NPV ratio, and NPV ratio sensitivity analyses is based on numerous assumptions, including relative levels of market interest rates, loan prepayments, balance changes and pricing strategies, and should not be relied upon as indicative of actual results. To the extent market conditions and other factors vary from the assumptions used in the simulation analysis, actual results may differ materially from the simulation results. Furthermore, NII sensitivity analysis measures the change in ASB s twelve-month, pre-tax NII in alternate interest rate scenarios, and is intended to help management identify potential exposures in ASB s current balance sheet and formulate appropriate strategies for managing interest rate risk. The simulation does not contemplate any actions that ASB management might undertake in response to changes in interest rates. Further, the changes in NII vary in the

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twelve-month simulation period and are not necessarily evenly distributed over the period. These analyses are for analytical purposes only and do not represent management s views of future market movements, the level of future earnings, or the timing of any changes in earnings within the twelve month analysis horizon. The actual impact of changes in interest rates on NII will depend on the magnitude and speed with which rates change, actual changes in ASB s balance sheet, and management s responses to the changes in interest rates.

Item 4. Controls and Procedures

HEI:

Changes in Internal Control over Financial Reporting

During the first quarter of 2011, there were no changes in internal control over financial reporting identified in connection with management s evaluation of the effectiveness of the Company s internal control over financial reporting as of March 31, 2011 that has materially affected, or is reasonably likely to materially affect, the Company s internal control over financial reporting.

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

Constance H. Lau, HEI Chief Executive Officer, and James A. Ajello, HEI Chief Financial Officer, have evaluated the disclosure controls and procedures of HEI as of March 31, 2011. Based on their evaluations, as of March 31, 2011, they have concluded that the disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) were effective in ensuring that information required to be disclosed by HEI in reports HEI files or submits under the Securities Exchange Act of 1934:

(1) is recorded, processed, summarized, and reported within the time periods specified in the Securities and Exchange Commission rules and forms, and

(2) is accumulated and communicated to HEI management, including HEI s principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

HECO:

Changes in Internal Control over Financial Reporting

During the first quarter of 2011, there was no change in internal control over financial reporting identified in connection with management s evaluation of the effectiveness of HECO and its subsidiaries internal control over financial reporting as of March 31, 2011 that has materially affected, or is reasonably likely to materially affect, HECO and its subsidiaries internal control over financial reporting.

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

Richard M. Rosenblum, HECO Chief Executive Officer, and Tayne S. Y. Sekimura, HECO Chief Financial Officer, have evaluated the disclosure controls and procedures of HECO as of March 31, 2011. Based on their evaluations, as of March 31, 2011, they have concluded that the disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934) were effective in ensuring that information required to be disclosed by HECO in reports HECO files or submits under the Securities Exchange Act of 1934:

(1) is recorded, processed, summarized, and reported within the time periods specified in the Securities and Exchange Commission rules and forms, and

(2) is accumulated and communicated to HECO management, including HECO s principal executive and principal financial officers, or persons performing similar functions, as appropriate to allow timely decisions regarding required disclosure.

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PART II - OTHER INFORMATION

Item 1. Legal Proceedings

The descriptions of legal proceedings (including judicial proceedings and proceedings before the PUC and environmental and other administrative agencies) in HEI s Form 10-K (see Part I. Item 3. Legal Proceedings and proceedings referred to therein) and this 10-Q (see Management s Discussion and Analysis of Financial Condition and Results of Operations and HECO s Notes to Consolidated Financial Statements) are incorporated by reference in this Item 1. With regard to any pending legal proceeding, alternative dispute resolution, such as mediation or settlement, may be pursued where appropriate, with such efforts typically maintained in confidence unless and until a resolution is achieved. Certain HEI subsidiaries (including HECO and its subsidiaries and ASB) may also be involved in ordinary routine PUC proceedings, environmental proceedings and litigation incidental to their respective businesses.

Item 1A. Risk Factors

For information about Risk Factors, see pages 28 to 37 of HEI s 2010 Form 10-K, and Management s Discussion and Analysis of Financial Condition and Results of Operations, Quantitative and Qualitative Disclosures about Market Risk, HEI s Consolidated Financial Statements and HECO s Consolidated Financial Statements herein. Also, see Forward-Looking Statements on pages v and vi of HEI s 2010 Form 10-K, as updated on pages iv and v herein.

Item 5. Other Information

A. Ratio of earnings to fixed charges.

	Three months ended March 31		Years ended December 31				
	2011	**2010**	**2010**	**2009**	**2008**	**2007**	**2006**
HEI and Subsidiaries							
Excluding interest on ASB deposits	2.89	2.76	2.89	2.29	2.06	1.78	2.08
Including interest on ASB deposits	2.70	2.48	2.64	1.95	1.71	1.52	1.73
HECO and Subsidiaries	2.85	2.72	2.88	2.99	3.48	2.43	3.14

See HEI Exhibit 12.1 and HECO Exhibit 12.2.

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Item 6. Exhibits

HEI Exhibit 4.1	Hawaiian Electric Industries Retirement Savings Plan, restatement effective May 1, 2011
HEI Exhibit 4.2	Letter Amendment effective April 29, 2011, to Trust Agreement (dated as of February 1, 2000) between HEI, ASB and Fidelity Management Trust Company, as Trustee
HEI Exhibit 12.1	Hawaiian Electric Industries, Inc. and Subsidiaries Computation of ratio of earnings to fixed charges, three months ended March 31, 2011 and 2010 and years ended December 31, 2010, 2009, 2008, 2007 and 2006
HEI Exhibit 31.1	Certification Pursuant to Rule 13a-14 promulgated under the Securities Exchange Act of 1934 of Constance H. Lau (HEI Chief Executive Officer)
HEI Exhibit 31.2	Certification Pursuant to Rule 13a-14 promulgated under the Securities Exchange Act of 1934 of James A. Ajello (HEI Chief Financial Officer)
HEI Exhibit 32.1	Written Statement of Constance H. Lau (HEI Chief Executive Officer) Furnished Pursuant to 18 U.S.C. Section 1350, as Adopted by Section 906 of the Sarbanes-Oxley Act of 2002
HEI Exhibit 32.2	Written Statement of James A. Ajello (HEI Chief Financial Officer) Furnished Pursuant to 18 U.S.C. Section 1350, as Adopted by Section 906 of the Sarbanes-Oxley Act of 2002
HEI Exhibit 101.INS	XBRL Instance Document
HEI Exhibit 101.SCH	XBRL Taxonomy Extension Schema Document
HEI Exhibit 101.CAL	XBRL Taxonomy Extension Calculation Linkbase Document
HEI Exhibit 101.DEF	XBRL Taxonomy Extension Definition Linkbase Document
HEI Exhibit 101.LAB	XBRL Taxonomy Extension Label Linkbase Document
HEI Exhibit 101.PRE	XBRL Taxonomy Extension Presentation Linkbase Document
HECO Exhibit 12.2	Hawaiian Electric Company, Inc. and Subsidiaries Computation of ratio of earnings to fixed charges, three months ended March 31, 2011 and 2010 and years ended December 31, 2010, 2009, 2008, 2007 and 2006
HECO Exhibit 31.3	Certification Pursuant to Rule 13a-14 promulgated under the Securities Exchange Act of 1934 of Richard M. Rosenblum (HECO Chief Executive Officer)
HECO Exhibit 31.4	Certification Pursuant to Rule 13a-14 promulgated under the Securities Exchange Act of 1934 of Tayne S. Y. Sekimura (HECO Chief Financial Officer)
HECO Exhibit 32.3	Written Statement of Richard M. Rosenblum (HECO Chief Executive Officer) Furnished Pursuant to 18 U.S.C. Section 1350, as Adopted by Section 906 of the Sarbanes-Oxley Act of 2002
HECO Exhibit 32.4	Written Statement of Tayne S. Y. Sekimura (HECO Chief Financial Officer) Furnished Pursuant to 18 U.S.C. Section 1350, as Adopted by Section 906 of the Sarbanes-Oxley Act of 2002

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrants have duly caused this report to be signed on their behalf by the undersigned, thereunto duly authorized. The signature of the undersigned companies shall be deemed to relate only to matters having reference to such companies and any subsidiaries thereof.

HAWAIIAN ELECTRIC INDUSTRIES, INC.		**HAWAIIAN ELECTRIC COMPANY, INC.**	
(Registrant)		(Registrant)	
By	/s/ Constance H. Lau Constance H. Lau President and Chief Executive Officer (Principal Executive Officer of HEI)	By	/s/ Richard M. Rosenblum Richard M. Rosenblum President and Chief Executive Officer (Principal Executive Officer of HECO)
By	/s/ James A. Ajello James A. Ajello Executive Vice President, Chief Financial Officer and Treasurer (Principal Financial Officer of HEI)	By	/s/ Tayne S. Y. Sekimura Tayne S. Y. Sekimura Senior Vice President and Chief Financial Officer (Principal Financial Officer of HECO)
By	/s/ David M. Kostecki David M. Kostecki Vice President-Finance, Controller and Chief Accounting Officer (Principal Accounting Officer of HEI)	By	/s/ Patsy H. Nanbu Patsy H. Nanbu Controller (Principal Accounting Officer of HECO)
Date: May 9, 2011		Date: May 9, 2011	