HAWAIIAN ELECTRIC CO INC
Form 10-Q
May 05, 2009
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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, 2009

OR

¨ **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 ¨

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 ¨

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 ¨ No x

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 ¨ No x

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 ¨ 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 ¨ 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 30, 2009**

Hawaiian Electric Industries, Inc. (Without Par Value)	**91,533,957 Shares**
Hawaiian Electric Company, Inc. ($6-2/3 Par Value)	**12,805,843 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 ¨
Non-accelerated filer ¨ (Do not check if a smaller reporting company)	Smaller reporting company ¨

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

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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

Form 10-Q Quarter ended March 31, 2009

GLOSSARY OF TERMS

Terms	Definitions
AFUDC	Allowance for funds used during construction
AOCI	Accumulated other comprehensive income
ASB	American Savings Bank, F.S.B., a wholly-owned subsidiary of HEI Diversified, Inc. and parent company of American Savings Investment Services Corp. (and its subsidiary, Bishop Insurance Agency of Hawaii, Inc.). Former subsidiaries include ASB Service Corporation (dissolved in January 2004), ASB Realty Corporation (dissolved in May 2005) and AdCommunications, Inc. (dissolved in May 2007).
CHP	Combined heat and power
CIP CT-1	Campbell Industrial Park 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); HEI Diversified, Inc. and its subsidiary, American Savings Bank, F.S.B. and its subsidiaries (listed under ASB); Pacific Energy Conservation Services, Inc.; HEI Properties, Inc.; HEI Investments, 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.). Former subsidiaries of HEI (other than former subsidiaries of HECO and ASB and former subsidiaries of HEI sold or dissolved prior to 2004) include Hycap Management, Inc. (dissolution completed in 2007); Hawaiian Electric Industries Capital Trust I (dissolved and terminated in 2004)*, HEI Preferred Funding, LP (dissolved and terminated in 2004)*, Malama Pacific Corp. (discontinued operations, dissolved in June 2004), and HEI Power Corp. (discontinued operations, dissolved in 2006) and its dissolved subsidiaries. (*unconsolidated subsidiaries as of January 1, 2004). When used in Hawaiian Electric Company, Inc. sections, the Company refers to Hawaiian Electric Company, Inc. and its direct subsidiaries.
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
D&O	Decision and order
DG	Distributed generation
DOD	Department of Defense federal
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
EITF	Emerging Issues Task Force
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
Exchange Act	Securities Exchange Act of 1934
FASB	Financial Accounting Standards Board
federal	U.S. Government
FHLB	Federal Home Loan Bank
FIN	Financial Accounting Standards Board Interpretation No.
GAAP	U.S. generally accepted accounting principles
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. Former subsidiaries include HECO Capital Trust I (dissolved and terminated in 2004)* and HECO Capital Trust II (dissolved and terminated in 2004)*. (*unconsolidated subsidiaries as of January 1, 2004).

GLOSSARY OF TERMS, continued

Terms	Definitions
HEI	Hawaiian Electric Industries, Inc., direct parent company of Hawaiian Electric Company, Inc., HEI Diversified, Inc., Pacific Energy Conservation Services, Inc., HEI Properties, Inc., HEI Investments, 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.). Former subsidiaries (other than those sold or dissolved prior to 2004) are listed under Company.
HEIDI	HEI Diversified, Inc., a wholly owned subsidiary of Hawaiian Electric Industries, Inc. and the parent company of American Savings Bank, F.S.B.
HEIII	HEI Investments, Inc. (formerly HEI Investment Corp.), a wholly owned subsidiary of Hawaiian Electric Industries, Inc.
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
HREA	Hawaii Renewable Energy Alliance
IPP	Independent power producer
IRP	Integrated resource plan
Kalaeloa	Kalaeloa Partners, L.P.
kV	Kilovolt
kw	Kilowatts
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
OPEB	Postretirement benefits other than pensions
OTS	Office of Thrift Supervision, Department of Treasury
PPA	Power purchase agreement
PRPs	Potentially responsible parties
PUC	Public Utilities Commission of the State of Hawaii
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
SFAS	Statement of Financial Accounting Standards
SOIP	1987 Stock Option and Incentive Plan, as amended
SPRBs	Special Purpose Revenue Bonds
TOOTS	The Old Oahu Tug Service, a wholly owned subsidiary of Hawaiian Electric Industries, Inc.
UBC	Uluwehiokama Biofuels Corp., a newly formed, 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 and 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 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 and mortgage-related securities held by American Savings Bank, F.S.B. (ASB)), decisions concerning the extent of the presence of the federal government and military in Hawaii, and the implications and potential impacts of current capital and credit market conditions and federal and state responses to those conditions, such as the Emergency Economic Stabilization Act of 2008 (plan for a $700 billion bailout of the financial industry) and the American Economic Recovery and Reinvestment Act of 2009 (economic stimulus package);

- weather and natural disasters, such as hurricanes, earthquakes, tsunamis, lightning strikes and the potential effects of global warming;

- global developments, including terrorist acts, the war on terrorism, continuing U.S. presence in Iraq and Afghanistan, potential conflict or crisis with North Korea and in the Middle East, Iran s nuclear activities and potential swine and avian flu pandemics;

- 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 and to access capital markets to issue common stock (HEI) under volatile and challenging market conditions;

- a potentially reduced market for HEI s and HECO s commercial paper as a result of the Investment Company Institute s March 2009 resolution that urges money market funds governed by SEC Rule 2a-7 under the Investment Company Act of 1940, to eliminate investments in second tier securities, such as commercial paper rated A-2 or P-2, by September 18, 2009;

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

- changes in laws, regulations, market conditions and other factors that result in changes in assumptions used to calculate retirement benefits costs and funding requirements and the fair value of ASB used to test goodwill for impairment;

increasing competition in the electric utility and banking industries (e.g., increased self-generation of electricity may have an adverse impact on HECO s revenues and increased price competition for deposits, or an outflow of deposits to alternative investments, 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), the fulfillment by the utilities of their commitments under the Energy Agreement and revenue decoupling;

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

increased risk to generation reliability as generation peak reserve margins on Oahu continue to be 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 risks associated with increasing reliance on renewable energy, as contemplated under the Energy Agreement, including the availability of non-fossil fuel supplies for renewable 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 and its subsidiaries) or their competitors;

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- 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, regulatory changes resulting from the HCEI, environmental laws and regulations, the potential regulation of greenhouse gas emissions (GHG) and governmental fees and assessments); decisions by the Public Utilities Commission of the State of Hawaii (PUC) in rate cases (including decisions on ECACs) and other proceedings and by other agencies and courts on land use, environmental and other permitting issues (such as required corrective actions, restrictions and penalties that may arise, for example with respect to environmental conditions or renewable portfolio standards (RPS)); enforcement actions by the Office of Thrift Supervision (OTS) 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 the Bank Secrecy Act or other regulatory requirements or with respect to capital adequacy);

- increasing operation and maintenance expenses and investment in infrastructure for the electric utilities, resulting in the need for more frequent rate cases, and increasing noninterest expenses at ASB;

- the risks associated with the geographic concentration of HEI s businesses;

- changes in accounting principles applicable to HEI, HECO, ASB and their subsidiaries, including the adoption of International Financial Reporting Standards or new accounting principles, continued regulatory accounting under Statement of Financial Accounting Standards (SFAS) No. 71, Accounting for the Effects of Certain Types of Regulation, and the possible effects of applying Financial Accounting Standards Board (FASB) Interpretation No. (FIN) 46R, Consolidation of Variable Interest Entities, and Emerging Issues Task Force (EITF) Issue No. 01-8, Determining Whether an Arrangement Contains a Lease, to 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;

- 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; 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 and ratio of earnings to fixed charges)	2009	2008
Revenues		
Electric utility	$ 461,797	$ 623,889
Bank	82,032	105,844
Other	(32)	(116)
	543,797	729,617
Expenses		
Electric utility	430,728	572,906
Bank	64,911	82,481
Other	3,500	3,484
	499,139	658,871
Operating income (loss)		
Electric utility	31,069	50,983
Bank	17,121	23,363
Other	(3,532)	(3,600)
	44,658	70,746
Interest expense other than on deposit liabilities and other bank borrowings	(17,833)	(19,249)
Allowance for borrowed funds used during construction	1,622	762
Allowance for equity funds used during construction	3,605	1,901
Income before income taxes	32,052	54,160
Income taxes	11,184	19,720
Net income	20,868	34,440
Less net income attributable to noncontrolling interest - preferred stock of subsidiaries	473	473
Net income for common stock	$ 20,395	$ 33,967
Basic earnings per common share	$ 0.23	$ 0.41
Diluted earnings per common share	$ 0.22	$ 0.41
Dividend per common share	$ 0.31	$ 0.31
Weighted-average number of common shares outstanding	90,604	83,472
Dilutive effect of stock-based compensation	88	142

Adjusted weighted-average shares	90,692	83,614
Ratio of earnings to fixed charges (SEC method)		
Excluding interest on ASB deposits	2.31	2.31
Including interest on ASB deposits	1.87	1.90

For the three months ended March 31, 2009, under the two-class method of computing basic and diluted earnings per share, distributed earnings were $0.31 per share and undistributed losses were $0.09 per share for both unvested restricted stock awards and unrestricted common stock. For the three months ended March 31, 2008, under the two-class method of computing basic and diluted earnings per share, distributed earnings were $0.31 per share and undistributed earnings were $0.10 per share for both unvested restricted stock awards and unrestricted common stock.

See accompanying Notes to Consolidated Financial Statements for HEI.

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Hawaiian Electric Industries, Inc. and Subsidiaries

Consolidated Balance Sheets (unaudited)

(dollars in thousands)	March 31, 2009	December 31, 2008
Assets		
Cash and equivalents	$ 160,222	$ 182,903
Federal funds sold	1,137	532
Accounts receivable and unbilled revenues, net	198,923	300,666
Available-for-sale investment and mortgage-related securities	600,269	657,717
Investment in stock of Federal Home Loan Bank of Seattle (estimated fair value $97,764)	97,764	97,764
Loans receivable, net	4,014,961	4,206,492
Property, plant and equipment, net of accumulated depreciation of $1,879,389 and $1,851,813	2,959,900	2,907,376
Regulatory assets	531,078	530,619
Other	313,512	328,823
Goodwill, net	82,190	82,190
	$ 8,959,956	$ 9,295,082
Liabilities and stockholders equity		
Liabilities		
Accounts payable	$ 158,711	$ 183,584
Deposit liabilities	4,154,124	4,180,175
Other bank borrowings	436,071	680,973
Long-term debt, net other than bank	1,214,681	1,211,501
Deferred income taxes	146,751	143,308
Regulatory liabilities	294,814	288,602
Contributions in aid of construction	312,933	311,716
Other	803,475	871,476
	7,521,560	7,871,335
Stockholders equity		
Common stock, no par value, authorized 200,000,000 shares; issued and outstanding: 91,439,984 shares and 90,515,573 shares	1,245,048	1,231,629
Retained earnings	203,122	210,840
Accumulated other comprehensive loss, net of tax benefits	(44,067)	(53,015)
Common stock equity	1,404,103	1,389,454
Preferred stock, no par value, authorized 10,000,000 shares; issued: none		
Noncontrolling interest: cumulative preferred stock of subsidiaries - not subject to mandatory redemption	34,293	34,293
	1,438,396	1,423,747
	$ 8,959,956	$ 9,295,082

See accompanying Notes to Consolidated Financial Statements for HEI.

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Hawaiian Electric Industries, Inc. and Subsidiaries

Consolidated Statements of Changes in Stockholders Equity (unaudited)

(in thousands, except per share amounts)	Common stock Shares	Common stock Amount	Retained earnings	Accumulated other comprehensive loss	Noncontrolling interest: cumulative preferred stock of subsidiaries	Total
Balance, December 31, 2008	**90,516**	**$ 1,231,629**	**$ 210,840**	**$ (53,015)**	**$ 34,293**	**$ 1,423,747**
Comprehensive income:						
Net income			20,395		473	20,868
Net unrealized gains on securities						
Net unrealized gains on securities arising during the period, net of taxes of $5,711				8,649		8,649
Retirement benefit plans:						
Amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of taxes of $1,862				2,918		2,918
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of tax benefits of $1,668				(2,619)		(2,619)
Comprehensive income			20,395	8,948	473	29,816
Issuance of common stock, net	924	13,419				13,419
Common stock dividends ($0.31 per share)			(28,113)			(28,113)
Preferred stock dividends					(473)	(473)
Balance, March 31, 2009	**91,440**	**$ 1,245,048**	**$ 203,122**	**$ (44,067)**	**$ 34,293**	**$ 1,438,396**
Balance, December 31, 2007	**83,432**	**$ 1,072,101**	**$ 225,168**	**$ (21,842)**	**$ 34,293**	**$ 1,309,720**
Comprehensive income:						
Net income			33,967		473	34,440
Net unrealized gains on securities						
Net unrealized gains on securities arising during the period, net of taxes of $5,808				8,796		8,796
Less: reclassification adjustment for net realized gains included in net income, net of taxes of $372				(563)		(563)
Retirement benefit plans:						
Amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of taxes of $923				1,448		1,448
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of tax benefits of $834				(1,309)		(1,309)
Comprehensive income			33,967	8,372	473	42,812
Issuance of common stock, net	524	12,166				12,166
Common stock dividends ($0.31 per share)			(25,922)			(25,922)
Preferred stock dividends					(473)	(473)

Balance, March 31, 2008	**83,956**	**$ 1,084,267**	**$ 233,213**	**$ (13,470)**	**$ 34,293**	**$ 1,338,303**

See accompanying Notes to Consolidated Financial Statements for HEI.

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Hawaiian Electric Industries, Inc. and Subsidiaries

Consolidated Statements of Cash Flows (unaudited)

Three months ended March 31 **(in thousands)**	**2009**	**2008**
Cash flows from operating activities		
Net income for common stock	$ 20,395	$ 33,967
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation of property, plant and equipment	38,494	37,882
Other amortization	594	2,860
Provision for loan losses	8,300	900
Loans receivable originated and purchased, held for sale	(171,390)	(66,664)
Proceeds from sale of loans receivable, held for sale	192,367	67,223
Deferred income taxes	(2,530)	(5,874)
Excess tax benefits from share-based payment arrangements	(21)	(28)
Allowance for equity funds used during construction	(3,605)	(1,901)
Changes in assets and liabilities		
Decrease (increase) in accounts receivable and unbilled revenues, net	101,743	(3,857)
Decrease (increase) in fuel oil stock	15,028	(9,269)
Increase (decrease) in accounts payable	(24,873)	11,667
Changes in prepaid and accrued income taxes and utility revenue taxes	(48,253)	(41,888)
Changes in other assets and liabilities	(11,045)	950
Net cash provided by operating activities	**115,204**	**25,968**
Cash flows from investing activities		
Available-for-sale investment and mortgage-related securities purchased	(109,364)	(66,145)
Principal repayments on available-for-sale investment and mortgage-related securities	180,918	132,885
Proceeds from sale of available-for-sale investment securities		935
Net decrease (increase) in loans held for investment	163,721	(52,401)
Capital expenditures	(80,510)	(48,882)
Contributions in aid of construction	2,362	3,836
Other	86	(57)
Net cash provided by (used in) investing activities	**157,213**	**(29,829)**
Cash flows from financing activities		
Net decrease in deposit liabilities	(26,051)	(16,904)
Net increase in short-term borrowings with original maturities of three months or less		107,501
Net increase (decrease) in retail repurchase agreements	(2,366)	14,432
Proceeds from other bank borrowings	310,000	152,500
Repayments of other bank borrowings	(552,517)	(188,600)
Proceeds from issuance of long-term debt	3,148	9,897
Repayment of long-term debt		(50,000)
Excess tax benefits from share-based payment arrangements	21	28
Net proceeds from issuance of common stock	7,365	6,314
Common stock dividends	(22,765)	(20,676)
Decrease in cash overdraft	(5,865)	(8,582)
Other	(5,463)	(4,761)
Net cash provided by (used in) financing activities	**(294,493)**	**1,149**
Net decrease in cash and equivalents and federal funds sold	(22,076)	(2,712)

Cash and equivalents and federal funds sold, beginning of period	183,435	209,855
Cash and equivalents and federal funds sold, end of period	**$ 161,359**	**$ 207,143**

See accompanying Notes to Consolidated Financial Statements for HEI.

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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 should be read in conjunction with the audited consolidated financial statements and the notes thereto incorporated by reference in HEI s Form 10-K for the year ended December 31, 2008.

In the opinion of HEI s management, the accompanying unaudited consolidated financial statements contain all material adjustments required by GAAP to present fairly the Company s financial position as of March 31, 2009 and December 31, 2008 and the results of its operations and cash flows for the three months ended March 31, 2009 and 2008. 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 Segment financial information

(in thousands)	Electric Utility	Bank	Other	Total
Three months ended March 31, 2009				
Revenues from external customers	$ 461,761	$ 82,032	$ 4	$ 543,797
Intersegment revenues (eliminations)	36		(36)	
Revenues	461,797	82,032	(32)	543,797
Profit (loss)*	23,083	17,092	(8,123)	32,052
Income taxes (benefit)	8,452	6,210	(3,478)	11,184
Net income (loss)	14,631	10,882	(4,645)	20,868
Less net income attributable to noncontrolling interest preferred stock of HECO and its subsidiaries	499		(26)	473
Net income (loss) for common stock	14,132	10,882	(4,619)	20,395
Assets (at March 31, 2009)	3,793,747	5,159,756	6,453	8,959,956
Three months ended March 31, 2008				
Revenues from external customers	$ 623,849	$ 105,844	$ (76)	$ 729,617
Intersegment revenues (eliminations)	40		(40)	
Revenues	623,889	105,844	(116)	729,617
Profit (loss)*	40,305	23,341	(9,486)	54,160
Income taxes (benefit)	15,221	8,765	(4,266)	19,720

Net income (loss)	25,084	14,576	(5,220)	34,440
Less net income attributable to noncontrolling interest preferred stock of HECO and its subsidiaries	499		(26)	473
Net income (loss) for common stock	24,585	14,576	(5,194)	33,967
Assets (at March 31, 2008)	3,468,599	6,844,494	9,487	10,322,580

* Income (loss) before income taxes.

Intercompany electric sales of consolidated HECO 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.

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.

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3 Electric utility subsidiary

For HECO s consolidated financial information, including its commitments and contingencies, see pages 16 through 41.

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)	2009	2008
Interest and dividend income		
Interest and fees on loans	$ 58,092	$ 63,465
Interest and dividends on investment and mortgage-related securities	7,676	24,451
	65,768	87,916
Interest expense		
Interest on deposit liabilities	11,565	18,220
Interest on other borrowings	3,264	19,149
	14,829	37,369
Net interest income	50,939	50,547
Provision for loan losses	8,300	900
Net interest income after provision for loan losses	42,639	49,647
Noninterest income		
Fees from other financial services	5,919	6,823
Fee income on deposit liabilities	6,711	6,794
Fee income on other financial products	1,044	1,804
Gain on sale of securities		935
Other income	2,590	1,572
	16,264	17,928
Noninterest expense		
Compensation and employee benefits	19,360	18,240
Occupancy	5,129	5,397
Equipment	2,790	3,114
Services	3,418	5,673
Data processing	3,187	2,616
Other expense	7,927	9,194
	41,811	44,234
Income before income taxes	17,092	23,341
Income taxes	6,210	8,765

Net income for common stock	$ 10,882	$ 14,576

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

Consolidated Balance Sheets Data (unaudited)

(in thousands)	March 31, 2009	December 31, 2008
Assets		
Cash and equivalents	$ 151,080	$ 168,766
Federal funds sold	1,137	532
Available-for-sale investment and mortgage-related securities	600,269	657,717
Investment in stock of Federal Home Loan Bank of Seattle	97,764	97,764
Loans receivable, net	4,014,961	4,206,492
Other	212,355	223,659
Goodwill, net	82,190	82,190
	$ 5,159,756	$ 5,437,120
Liabilities and stockholder s equity		
Deposit liabilities noninterest-bearing	$ 721,153	$ 701,090
Deposit liabilities interest-bearing	3,432,971	3,479,085
Other borrowings	436,071	680,973
Other	83,022	98,598
	4,673,217	4,959,746
Common stock	328,567	328,162
Retained earnings	197,333	197,235
Accumulated other comprehensive loss, net of tax benefits	(39,361)	(48,023)
	486,539	477,374
	$ 5,159,756	$ 5,437,120

Other borrowings consisted of securities sold under agreements to repurchase and advances from the Federal Home Loan Bank (FHLB) of Seattle of $234 million and $202 million, respectively, as of March 31, 2009 and $241 million and $440 million, respectively, as of December 31, 2008.

As of March 31, 2009, ASB had commitments to borrowers for undisbursed loan funds, loan commitments and unused lines and letters of credit of $1.3 billion.

Balance sheet restructure. In June 2008, ASB undertook and substantially completed a restructuring of its balance sheet through the sale of mortgage-related securities and agency notes and the early extinguishment of certain borrowings to strengthen future profitability ratios and enhance future net interest margin, while remaining well-capitalized and without significantly impacting future net income and interest rate risk. On June 25, 2008, ASB completed a series of transactions which resulted in the sales to various broker/dealers of available-for-sale agency and private-issue mortgage-related securities and agency notes with a weighted average yield of 4.33% for approximately $1.3 billion. ASB used the proceeds from the sales of these mortgage-related securities and agency notes to retire debt with a weighted average cost of 4.70%, comprised of approximately $0.9 billion of FHLB advances and $0.3 billion of securities sold under agreements to repurchase. These transactions resulted in a charge to net income of $35.6 million in the second quarter of 2008. Although the sales of the mortgage-related securities and agency notes resulted in realized losses in the second quarter of 2008, a portion of the losses on these available-for-sale securities had been previously recognized as unrealized losses in ASB s equity as a result of mark-to-market charges to other comprehensive income in earlier periods.

ASB subsequently purchased approximately $0.3 billion of short-term agency notes and entered into approximately $0.2 billion of FHLB advances to facilitate the timing of the release of certain collateral. These notes and advances had original maturities up to December 31, 2008.

As a result of this balance sheet restructuring, ASB freed up capital and paid a dividend of approximately $55 million to HEI in 2008. HEI used the dividend to repay commercial paper and for other corporate purposes. The OTS has approved ASB s payment of quarterly dividends through the quarter ended June 30, 2009 to the

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extent that payment of the dividend would not cause ASB s Tier I leverage ratio to fall below 8% as of the end of the quarter.

Private-issue mortgage-related securities. As of March 31, 2009, the net unrealized losses on ASB s investment in private-issue mortgage-related securities was due to multiple factors primarily related to continued deterioration in the residential housing market and spread widening for all credit sensitive sectors of the market. Increasing foreclosures coupled with recessionary employment pressures and declining housing prices have depressed the values of all private-issue mortgage collateralized securities as risks for this sector have increased. Changes in credit rating for issues originated in 2006 and 2007 have dramatically depressed valuations in this sector of the portfolio. While risks within this sector have increased, ASB believes that, based on its internal assessment of positions held in the portfolio and its ability and intent to hold these securities until a recovery of fair value, which may be at maturity, it does not consider securities held in this sector to be other-than-temporarily impaired at March 31, 2009.

SFAS No. 157, Fair Value Measurements. SFAS No. 157 (which defines fair value, establishes a framework for measuring fair value under GAAP and expands disclosures about fair value measurements) was adopted by ASB prospectively and only partially applied as of January 1, 2008. In accordance with FASB Staff Position (FSP) FAS 157-2, the Company has delayed the application of SFAS No. 157 to ASB s goodwill until the first quarter of 2009. FSP No. 157-3, Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active, was issued in October 2008, and did not have an impact on fair value measurements for ASB or the Company. Fair value is the price that would be received to sell an asset in an orderly transaction between market participants at the measurement date. ASB grouped its financial assets measured at fair value in three levels outlined in SFAS No.157 as follows:

Level 1: Inputs to the valuation methodology are quoted prices, unadjusted, for identical assets or liabilities in active markets. A quoted price in an active market provides the most reliable evidence of fair value and shall be used to measure fair value whenever available.

Level 2: Inputs to the valuation methodology include quoted prices for similar assets or liabilities in active markets; inputs to the valuation methodology include quoted prices for identical or similar assets or liabilities in markets that are not active; or inputs to the valuation methodology that are derived principally from or can be corroborated by observable market data by correlation or other means.

Level 3: Inputs to the valuation methodology are unobservable and significant to the fair value measurement. Level 3 assets and liabilities include financial instruments whose value is determined using discounted cash flow methodologies, as well as instruments for which the determination of fair value requires significant management judgment or estimation.

Assets measured at fair value on a recurring basis

Available-for-sale investment and mortgage-related securities. 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 current 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.

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The table below presents the balances of assets measured at fair value on a recurring basis:

		Fair value measurements using		
(in millions)	March 31, 2009	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Available-for-sale securities	$ 600	$	$ 600	$

Assets measured at fair value on a nonrecurring basis

Loans. 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 assumption. These adjustments to fair value usually result from the application of lower-of-cost-or-market accounting or write-downs of individual loans. Unobservable assumptions reflect ASB s own estimate of the fair value of collateral used in valuing the loan.

The table below presents the balances of assets measured at fair value on a nonrecurring basis:

		Fair value measurements using		
(in millions)	March 31, 2009	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Loans	$ 23.3	$	$ 3.5	$ 19.8

Specific reserves as of March 31, 2009 were $9.2 million and were included in loans receivable held for investment, net. For the three months ended March 31, 2009, there were no adjustments to fair value for ASB s loans held for sale.

Guarantees. In October 2007, ASB, as a member financial institution of Visa U.S.A. Inc., received restricted shares of Visa, Inc. (Visa) as a result of a restructuring of Visa U.S.A. Inc. in preparation for an initial public offering by Visa. As a part of the restructuring, ASB entered into judgment and loss sharing agreements with Visa in order to apportion financial responsibilities arising from any potential adverse judgment or negotiated settlements related to indemnified litigation involving Visa. In November 2007, Visa announced that it had reached a settlement with American Express regarding part of this litigation. In the fourth quarter of 2007, ASB recorded a charge of $0.3 million for its proportionate share of this settlement and a charge of approximately $0.6 million for potential losses arising from indemnified litigation that has not yet settled, which estimated fair value is highly judgmental. In March 2008, Visa funded an escrow account designed to address potential liabilities arising from litigation covered in the Retrospective Responsibility Plan and, based on the amount funded in the escrow account, ASB recorded a receivable of $0.4 million for its proportionate share of the escrow account. In the fourth quarter of 2008, Visa reached a settlement in a case brought by Discover Financial Services. This case is covered litigation under Visa s Retrospective Responsibility Plan and ASB s proportionate share of this settlement is estimated to be $0.2 million. Because the extent of ASB s obligations under this agreement depends entirely upon the occurrence of future events, ASB s maximum potential future liability under this agreement is not determinable.

FDIC restoration plan. Under the Federal Deposit Insurance Reform Act of 2005 (the Reform Act), the FDIC may set the designated reserve ratio within a range of 1.15% to 1.50%. The Reform Act requires that the FDIC s Board of Directors adopt a restoration plan when the Deposit Insurance Fund (DIF) reserve ratio falls below 1.15% or is expected to within six months. Recent financial institution failures have significantly increased the DIF s loss provisions, resulting in a decline in the reserve ratio. As of June 30, 2008, the reserve ratio had fallen 18 basis points since the previous quarter to 1.01%. To restore the reserve ratio to 1.15%, higher assessment rates are required. The FDIC made changes to the assessment system to ensure that riskier institutions will bear a greater share of the proposed increase in assessments. Under the final rules, financial institutions in Risk Category I, the lowest risk group, will have an initial base assessment rate within the range of 12 to 16 basis points. After applying adjustments for unsecured debt, secured liabilities and brokered deposits, the total base assessment rate for financial institutions in Risk Category I would be within the range of 7 to 24 basis points. The new assessment rates became effective April 1, 2009. The FDIC also raised the current rates uniformly by seven basis points for the assessment for the quarter beginning January 1, 2009. ASB is classified in Risk Category I and its current assessment rate is 12.2 basis points of deposits, or $1.5 million for the quarter ended March 31, 2009. ASB anticipates its assessment rate to be 14 to 15 basis points for the quarter beginning April 1, 2009.

Deposit insurance coverage. The Emergency Economic Stabilization Act of 2008 was signed into law on October 3, 2008 and temporarily raises the basic limit on federal deposit insurance coverage from $100,000 to $250,000 per depositor, effective October 3, 2008 through December 31, 2009. The legislation provides that the basic deposit insurance coverage limit will return to $100,000 after December 31, 2009 for all interest bearing deposit categories except for individual retirement accounts and certain other retirement accounts, which will continue to be insured at $250,000 per owner. Under the FDIC s Temporary Liquidity Guarantee Program, non-interest bearing deposit transaction accounts will be provided unlimited deposit insurance coverage until December 31, 2009.

5 Retirement benefits

Defined benefit plans. For the first quarter of 2009, HECO contributed $9.4 million and HEI contributed $0.4 million to their respective retirement benefit plans, compared to $0.9 million and $0.2 million, respectively, in the first quarter of 2008. The Company s current estimate of contributions to its retirement benefit plans in 2009 is $27 million ($25 million to be made by the utilities, nil by ASB and $2 million by HEI), compared to contributions of $15 million in 2008 ($14 million made by the utilities, nil by ASB and $1 million by HEI). In addition, the Company expects to pay directly $2 million of benefits in 2009, compared to the $1 million paid in 2008.

For the first quarter of 2009, the Company s defined benefit retirement plans assets generated a loss, including investment management fees, of 6.3%. The market value of the defined benefit retirement plans assets as of March 31, 2009 was $676 million compared to $726 million at December 31, 2008, a decline of approximately $50 million.

The components of net periodic benefit cost were as follows:

	Pension benefits		Other benefits	
Three months ended March 31	**2009 (1)**	**2008 (1)**	**2009**	**2008**
(in thousands)				
Service cost	$ 6,341	$ 6,856	$ 1,056	$ 1,165
Interest cost	15,538	14,876	2,847	2,838
Expected return on plan assets	(14,276)	(18,232)	(2,215)	(2,740)
Amortization of unrecognized transition obligation	1	1	785	785
Amortization of prior service cost (gain)	(93)	(90)	3	3
Recognized actuarial loss	3,969	1,690	116	
Net periodic benefit cost	11,480	5,101	2,592	2,051
Impact of PUC D&Os	(4,091)	1,657	(325)	193
Net periodic benefit cost (adjusted for impact of PUC D&Os)	$ 7,389	$ 6,758	$ 2,267	$ 2,244

(1) Due to the freezing of ASB s defined benefit plan as of December 31, 2007 (see below), there are no amounts for ASB employees for certain components (service cost, amortizations and recognized actuarial loss).

The Company recorded retirement benefits expense of $7 million in each of the first quarters of 2009 and 2008, and charged the remaining amounts primarily to electric utility plant.

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

Effective December 31, 2007, ASB ended the accrual of benefits in, and the addition of new participants to, ASB s defined benefit pension plan. The change to the plan did not affect the vested pension benefits of former participants, including ASB retirees, as of December 31, 2007. All active participants who were employed by ASB on December 31, 2007 became fully vested in their accrued pension benefit as of December 31, 2007.

Defined contribution plan. On January 1, 2008, ASB began providing matching contributions of 100% on the first 4% of eligible pay contributed by participants to HEI s retirement savings plan for its eligible employees. In addition, a new ASB 401(k) Plan was created to initially fund a discretionary employer profit sharing contribution for the 2008 plan year, with the intent to transfer over ASB employee accounts from the HEI retirement savings plan to the new ASB 401(k) Plan in the second quarter of 2009. The discretionary employer profit sharing contribution will be allocated pro-rata to accounts of all eligible participants based on a flat percent of eligible pay. This percentage will be determined annually after year-end, based on ASB s performance and achievement of financial goals. For the first quarters of 2009 and 2008, ASB s total expense for its employees participating in the HEI retirement savings plan was $0.8 million and $1.1 million, respectively, and contributions were $0.5 million.

6 Share-based compensation

Under the 1987 Stock Option and Incentive Plan, as amended (SOIP), HEI may issue an aggregate of 7.7 million shares of common stock (4.5 million shares available for issuance under outstanding and future grants and awards as of March 31, 2009) to officers and key employees as incentive stock options, nonqualified stock options (NQSOs), restricted stock awards, restricted stock units, stock appreciation rights (SARs), stock performance awards or dividend equivalents. HEI has issued new shares for NQSOs, restricted stock awards (nonvested stock), restricted stock units, stock performance awards, SARs and dividend equivalents under the SOIP. All information presented has been adjusted for the 2-for-1 stock split in June 2004.

For the NQSOs and SARs, the exercise price of each NQSO or SAR generally equaled the fair market value of HEI s stock on or near the date of grant. NQSOs, SARs and related dividend equivalents issued in the form of stock awarded prior to and through 2004 generally become exercisable in installments of 25% each year for four years, and expire if not exercised ten years from the date of the grant. The 2005 SARs awards, which have a ten year exercise life, generally become exercisable at the end of four years (i.e., cliff vesting) with the related dividend equivalents issued in the form of stock on an annual basis for retirement eligible participants. Accelerated vesting is provided in the event of a change-in-control or upon retirement. NQSOs and SARs compensation expense has been recognized in accordance with the fair value-based measurement method of accounting. The estimated fair value of each NQSO and SAR grant was calculated on the date of grant using a Binomial Option Pricing Model.

Restricted stock grants generally become unrestricted three to five years after the date of grant and restricted stock compensation expense has been recognized in accordance with the fair value-based measurement method of accounting. Dividends on restricted stock awards are paid quarterly in cash.

Restricted stock units generally vest and will be issued as unrestricted stock four years after the date of the grant. Restricted stock units expense has been recognized in accordance with the fair-value based measurement method of accounting. Dividend equivalent rights on restricted stock units are accrued quarterly and are paid in cash at the end of the restriction period when the restricted stock units vest.

Performance awards granted under the 2009-2011 Long-term Incentive Plan (LTIP) provide for payment in cash or shares of HEI common stock based on the achievement of certain financial goals over a three-year performance period. The Company accrues compensation expense based on the price of the Company s common stock and reassesses at each reporting date whether achievement of the performance condition is probable.

The Company s share-based compensation expense and related income tax benefit (including a valuation allowance due to limits on the deductibility of executive compensation) are as follows:

Three months ended March 31 ($ in millions)	**2009**	**2008**
Share-based compensation expense [1]	0.4	0.3
Income tax benefit	0.1	0.1

[1] The Company has not capitalized any share-based compensation cost. The estimated forfeiture rate for SARs was 8.8%, the estimated forfeiture rate for restricted stock was 30.2% and the estimated forfeiture rate for restricted stock units was 5.9%.

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

March 31, 2009			**Outstanding & Exercisable**	
			Weighted-average	**Weighted-average**
Year of grant	**Range of exercise prices**	**Number of options**	**remaining contractual life**	**exercise price**
1999	$ 17.61	1,000	0.1	$ 17.61
2000	14.74	46,000	1.1	14.74
2001	17.96	65,000	2.1	17.96
2002	21.68	122,000	2.9	21.68
2003	20.49	141,500	3.5	20.49
	$ 14.74 21.68	375,500	2.7	$ 19.73

As of December 31, 2008, NQSOs outstanding totaled 375,500 (representing the same number of underlying shares), with a weighted-average exercise price of $19.73. As of March 31, 2009, all NQSO s outstanding were exercisable and had no intrinsic value.

NQSO activity and statistics are summarized as follows:

Three months ended March 31 **($ in thousands, except prices)**	**2009**	**2008**
Shares granted		
Shares forfeited		
Shares expired		
Shares vested		
Aggregate fair value of vested shares		
Shares exercised		12,000
Weighted-average exercise price		$ 20.49
Cash received from exercise		$ 246
Intrinsic value of shares exercised [1]		$ 84
Tax benefit realized for the deduction of exercises		$ 33
Dividend equivalent shares distributed under Section 409A		6,125
Weighted-average Section 409A distribution price		$ 22.38
Intrinsic value of shares distributed under Section 409A		$ 137
Tax benefit realized for Section 409A distributions		$ 53

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, 2009		**Outstanding**			**Exercisable**		
Year of grant	**Range of exercise prices**	**Number of shares underlying SARs**	**Weighted-average remaining contractual life**	**Weighted-average exercise price**	**Number of shares underlying SARs**	**Weighted-average remaining contractual life**	**Weighted-average exercise price**
2004	$ 26.02	295,000	2.1	$ 26.02	295,000	2.1	$ 26.02
2005	26.18	490,000	3.3	26.18	262,000	1.0	26.18

	$ 26.02	26.18	785,000	2.9	$	26.12	557,000	1.6	$	26.10

As of December 31, 2008, the shares underlying SARs outstanding totaled 791,000, with a weighted-average exercise price of $26.12. As of March 31, 2009, the SARs outstanding and exercisable (including dividend equivalents) had no intrinsic value.

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SARs activity and statistics are summarized as follows:

Three months ended March 31 **($ in thousands, except prices)**	**2009**	**2008**
Shares granted		
Shares forfeited	6,000	
Shares expired		
Shares vested		15,000
Aggregate fair value of vested shares		$ 87
Shares exercised		
Weighted-average exercise price		
Cash received from exercise		
Intrinsic value of shares exercised [1]		
Tax benefit realized for the deduction of exercises		
Dividend equivalent shares distributed under Section 409A	3,143	
Weighted-average Section 409A distribution price	$ 13.64	
Intrinsic value of shares distributed under Section 409A	$ 43	
Tax benefit realized for Section 409A distributions	$ 17	

[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 right.

As of March 31, 2009, there was $17,000 of total unrecognized compensation cost related to SARs and that cost is expected to be recognized over a weighted average period of 1 month.

Section 409A modification. As a result of the changes enacted in Section 409A of the Internal Revenue Code of 1986, as amended (Section 409A), for the three months ended March 31, 2009 and 2008 a total of 3,143 and 6,125 dividend equivalent shares for NQSO and SAR grants were distributed to SOIP participants, respectively. Section 409A, which amended the rules on deferred compensation, required the Company to change the way certain affected dividend equivalents are paid in order to avoid significant adverse tax consequences to the SOIP participants. Generally dividend equivalents subject to Section 409A will be paid within 2 1 /2 months after the end of the calendar year. Upon retirement, an SOIP participant may elect to take distributions of dividend equivalents subject to Section 409A at the time of retirement or at the end of the calendar year. The dividend equivalents associated with the 2005 SAR grants are planned to be paid in March 2010. These are the last dividend equivalents intended to be paid in accordance with this Section 409A modified distribution.

Restricted stock awards. As of March 31, 2009 and December 31, 2008, restricted stock award shares outstanding totaled 138,500 and 160,500, with a weighted-average grant date fair value of $25.48 and $25.51, respectively. The grant date fair value of a grant of a restricted stock award share was the closing or average price of HEI common stock on the date of grant.

Information about HEI s grants of restricted stock awards is summarized as follows:

Three months ended March 31 **($ in thousands)**	**2009**	**2008**
Shares vested	594	
Shares forfeited	21,406	6,000
Grant date fair value	$ 551	$ 157
Shares granted		
Grant date fair value		

The tax benefit realized for the tax deductions related to restricted stock awards was immaterial for the first quarters of 2009 and 2008.

As of March 31, 2009, there was $1.7 million of total unrecognized compensation cost related to nonvested restricted stock awards. The cost is expected to be recognized over a weighted-average period of 2.4 years.

Restricted stock units. In February 2009, 70,500 restricted stock units (representing the same number of underlying shares) were granted to officers and key employees with a grant date fair value of $1.2 million and a weighted-average grant date fair value of $16.99 per restricted stock unit. The grant date fair value of the restricted stock units was the average price of HEI common stock on the date of grant. As of March 31, 2009, there were 70,500 restricted stock units outstanding, none were vested and none were forfeited.

As of March 31, 2009, there was $1.1 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 3.9 years.

Performance Shares. Under the 2009-2011 LTIP, performance awards, which provide for payment in shares of HEI common stock or cash based on achievement of certain financial goals and service conditions over a three-year performance period were granted on February 20, 2009 to certain key executives. The payout varies from 0% to 280% of the number of shares depending on achievement of the goals. Performance conditions require the achievement of stated goals for total return to shareholders as a percentile to the Edison Electric Institute Index and return on average common equity targets. The Company accrues compensation expense over the performance period based on the price of the Company s common stock and reassesses at each reporting date whether achievement of the performance condition is probable.

As of March 31, 2009, there were 60,329 shares underlying nonvested performance awards outstanding, based on target performance levels. The performance awards had a weighted average remaining contractual term of 2.75 years.

7 Commitments and contingencies

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

8 Cash flows

Supplemental disclosures of cash flow information. For the three months ended March 31, 2009 and 2008, the Company paid interest (net of amounts capitalized and including bank interest) to non-affiliates amounting to $25 million and $50 million, respectively.

For the three months ended March 31, 2009 and 2008, the Company paid income taxes amounting to $0.7 million and $38 million, respectively. The significant decrease in taxes paid was due primarily to the difference in the taxes due with the extensions for tax years 2008 and 2007. In 2007, taxable income was significantly larger in the fourth quarter when compared to the first three quarters, resulting in a larger portion of the 2007 taxes paid with the extension filed in the first quarter of 2008. Taxable income for 2008 was much larger in the first half versus the second half of the year, resulting in only a nominal amount due in the first quarter of 2009.

Supplemental disclosures of noncash activities. Noncash increases in common stock for director and officer compensatory plans of the Company were $0.5 million and $0.6 million for the three months ended March 31, 2009 and 2008, respectively.

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 $5 million for each of the first quarters of 2009 and 2008. Effective April 16, 2009, HEI began satisfying the requirements of the HEI DRIP and the Hawaiian Electric Industries Retirement Savings Plan by acquiring for cash its common shares through open market purchases rather than issuing additional shares.

9 Recent accounting pronouncements and interpretations

See SFAS No. 157, Fair Value Measurements in Note 4.

Noncontrolling interests. In December 2007, the FASB issued SFAS No. 160, Noncontrolling Interests in Consolidated Financial Statements. SFAS No. 160 requires the recognition of a noncontrolling interest (i.e., a minority interest) as equity in the consolidated financial statements, separate from the parent s equity, and requires the amount of consolidated net income attributable to the parent and to the noncontrolling interest to be clearly identified and presented on the face of the income statement. Under SFAS No. 160, changes in the

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parent s ownership interest that leave control intact are accounted for as capital transactions (i.e., as increases or decreases in ownership), a gain or loss will be recognized when a subsidiary is deconsolidated based on the fair value of the noncontrolling equity investment (not carrying amount), and entities must provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and of the noncontrolling owners. The Company adopted SFAS No. 160 prospectively on January 1, 2009, except for the presentation and disclosure requirements which must be applied retrospectively. Thus, beginning in the first quarter of 2009, Preferred stock of subsidiaries not subject to mandatory redemption is presented as a separate component of Stockholders equity rather than as Minority interests in the mezzanine section between liabilities and equity on the balance sheet, dividends on preferred stock of subsidiaries is deducted from net income to arrive at net income for common stock on the income statement, and a column for Preferred stock of subsidiaries not subject to mandatory redemption has been added to the statement of changes in stockholders equity.

Participating securities. In June 2008, the FASB issued FASB Staff Position (FSP) EITF 03-6-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities, according to which unvested share-based-payment awards that contain non-forfeitable rights to dividends or dividend equivalents are participating securities as defined in EITF 03-6 and therefore should be included in computing earnings per share using the two-class method. The Company adopted FSP EITF 03-6-1 in the first quarter of 2009 retrospectively and determined that restricted stock award grants were participating securities. The impact of adoption of FSP EITF 03-6-1 on the Company s financial statements was not material.

Fair value measurements and impairments. In April 2009, the FASB issued three Staff Positions (FSPs) providing additional application guidance and enhancing disclosures regarding fair value measurements and impairments of securities.

FSP FAS 157-4, Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly, (FSP 157-4) relates to determining fair values when there is no active market or where the price inputs being used represent distressed sales. FSP 157-4 provides guidelines for making fair value measurements more consistent with the principles presented in FASB Statement No. 157, Fair Value Measurements, by reaffirming that the objective of fair value measurement is to reflect how much an asset would be sold for in an orderly transaction (as opposed to a distressed or forced transaction) at the date of the financial statements under current market conditions. Specifically, FSP 157-4 reaffirms the need to use judgment in determining fair values when markets have become inactive.

FSP FAS 107-1 and APB 28-1, Interim Disclosures about Fair Value of Financial Instruments, (FSP 107-1) relates to fair value disclosures for any financial instruments that are not currently reflected on the balance sheet of companies at fair value. Prior to issuance of FSP 107-1, fair values for these assets and liabilities were only disclosed annually. FSP 107-1 now requires these disclosures on a quarterly basis, providing qualitative and quantitative information about fair value estimates for financial instruments not measured on the balance sheet at fair value.

FSP FAS 115-2 and FAS 124-2, Recognition and Presentation of Other-Than-Temporary Impairments, provides greater consistency to the timing of impairment recognition and greater clarity to investors about the credit and noncredit components of impaired debt securities that are not expected to be sold. The measure of impairment in comprehensive income remains fair value. FSP FAS 115-2 and FAS 124-2 also require increased and more timely disclosures regarding expected cash flows, credit losses and an aging of securities with unrealized losses.

The Company will adopt the FSPs in the second quarter of 2009 and will be required to provide additional disclosures regarding fair value measurements and other-than-temporary impairments. In the fourth quarter of 2008 the Company determined the impairment on two private-issue mortgage-related securities to be other- than-temporary, adjusted the carrying values to market value, and recognized a noncash impairment charge of $4.7 million, net of income tax, in the fourth quarter of 2008. Upon adoption of the FSPs, the Company expects a significant portion of the previously recognized impairment to be reclassified to accumulated other comprehensive income.

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidated Statements of Income (unaudited)

Three months ended March 31 **(in thousands, except ratio of earnings to fixed charges)**	**2009**	**2008**
Operating revenues	$ 459,285	$ 622,494
Operating expenses		
Fuel oil	145,289	249,543
Purchased power	114,484	150,795
Other operation	62,397	55,579
Maintenance	26,163	23,613
Depreciation	36,424	35,434
Taxes, other than income taxes	45,735	57,486
Income taxes	8,544	15,378
	439,036	587,828
Operating income	20,249	34,666
Other income		
Allowance for equity funds used during construction	3,605	1,901
Other, net	2,368	1,096
	5,973	2,997
Income before interest and other charges	26,222	37,663
Interest and other charges		
Interest on long-term debt	11,912	11,724
Amortization of net bond premium and expense	675	631
Other interest charges	626	986
Allowance for borrowed funds used during construction	(1,622)	(762)
	11,591	12,579
Income before preferred stock dividends of HECO and subsidiaries	14,631	25,084
Less net income attributable to noncontrolling interest - preferred stock of subsidiaries	229	229
Income before preferred stock dividends of HECO	14,402	24,855
Preferred stock dividends of HECO	270	270
Net income for common stock	$ 14,132	$ 24,585
Ratio of earnings to fixed charges (SEC method)	2.49	3.77

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

See accompanying Notes to Consolidated Financial Statements for HECO.

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidated Balance Sheets (unaudited)

(in thousands, except par value)	March 31, 2009	December 31, 2008
Assets		
Utility plant, at cost		
Land	$ 42,541	$ 42,541
Plant and equipment	4,305,782	4,277,499
Less accumulated depreciation	(1,767,821)	(1,741,453)
Construction in progress	319,362	266,628
Net utility plant	2,899,864	2,845,215
Current assets		
Cash and equivalents	4,227	6,901
Customer accounts receivable, net	93,699	166,422
Accrued unbilled revenues, net	79,170	106,544
Other accounts receivable, net	7,510	7,918
Fuel oil stock, at average cost	62,687	77,715
Materials and supplies, at average cost	35,809	34,532
Prepayments and other	10,796	12,626
Total current assets	293,898	412,658
Other long-term assets		
Regulatory assets	531,078	530,619
Unamortized debt expense	14,194	14,503
Other	54,713	53,114
Total other long-term assets	599,985	598,236
	$ 3,793,747	$ 3,856,109
Capitalization and liabilities		
Capitalization		
Common stock, $6 2/3 par value, authorized 50,000 shares; outstanding 12,806 shares	$ 85,387	$ 85,387
Premium on capital stock	299,214	299,214
Retained earnings	806,186	802,590
Accumulated other comprehensive income, net of income taxes	1,710	1,651
Common stock equity	1,192,497	1,188,842
Cumulative preferred stock not subject to mandatory redemption	22,293	22,293
Noncontrolling interest cumulative preferred stock of subsidiaries not subject to mandatory redemption	12,000	12,000
Stockholders equity	1,226,790	1,223,135
Long-term debt, net	907,681	904,501
Total capitalization	2,134,471	2,127,636
Current liabilities		

Short-term borrowings affiliate	29,339	41,550
Accounts payable	107,146	122,994
Interest and preferred dividends payable	18,552	15,397
Taxes accrued	169,207	220,046
Other	53,874	55,268
Total current liabilities	378,118	455,255
Deferred credits and other liabilities		
Deferred income taxes	164,788	166,310
Regulatory liabilities	294,814	288,602
Unamortized tax credits	61,059	58,796
Retirement benefits liability	392,351	392,845
Other	55,213	54,949
Total deferred credits and other liabilities	968,225	961,502
Contributions in aid of construction	312,933	311,716
	$ 3,793,747	$ 3,856,109

See accompanying Notes to Consolidated Financial Statements for HECO.

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidated Statements of Changes in Stockholders Equity (unaudited)

(in thousands, except per share amounts)	Common stock Shares	Common stock Amount	Premium on capital income (loss)	Retained earnings	Accumulated other comprehensive income (loss)	Cumulative preferred stock	Noncontrolling interest: cumulative preferred stock of subsidiaries	Total
Balance, December 31, 2008	**12,806**	**$ 85,387**	**$ 299,214**	**$ 802,590**	**$ 1,651**	**$ 22,293**	**$ 12,000**	**$ 1,223,135**
Comprehensive income:								
Net income				14,132		270	229	14,631
Retirement benefit plans:								
Amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of taxes of $1,706					2,678			2,678
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of tax benefits of $1,668					(2,619)			(2,619)
Comprehensive income				14,132	59	270	229	14,690
Common stock dividends				(10,536)				(10,536)
Preferred stock dividends						(270)	(229)	(499)
Balance, March 31, 2009	**12,806**	**$ 85,387**	**$ 299,214**	**$ 806,186**	**$ 1,710**	**$ 22,293**	**$ 12,000**	**$ 1,226,790**
Balance, December 31, 2007	**12,806**	**$ 85,387**	**$ 299,214**	**$ 724,704**	**$ 1,157**	**$ 22,293**	**$ 12,000**	**$ 1,144,755**
Comprehensive income:								
Net income				24,585		270	229	25,084
Retirement benefit plans:								
Amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of taxes of $870					1,366			1,366
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of tax benefits of $834					(1,309)			(1,309)
Comprehensive income				24,585	57	270	229	25,141
Common stock dividends				(14,089)				(14,089)
Preferred stock dividends						(270)	(229)	(499)
Balance, March 31, 2008	**12,806**	**$ 85,387**	**$ 299,214**	**$ 735,200**	**$ 1,214**	**$ 22,293**	**$ 12,000**	**$ 1,155,308**

See accompanying Notes to Consolidated Financial Statements for HECO.

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidated Statements of Cash Flows (unaudited)

Three months ended March 31 **(in thousands)**	**2009**	**2008**
Cash flows from operating activities		
Income before preferred stock dividends of HECO	$ 14,402	$ 24,855
Adjustments to reconcile income before preferred stock dividends of HECO to net cash provided by operating activities		
Depreciation of property, plant and equipment	36,424	35,434
Other amortization	2,206	2,163
Deferred income taxes	(1,290)	(5,953)
Tax credits, net	2,514	435
Allowance for equity funds used during construction	(3,605)	(1,901)
Changes in assets and liabilities		
Decrease (increase) in accounts receivable	73,131	(7,902)
Decrease in accrued unbilled revenues	27,374	3,818
Decrease (increase) fuel oil stock	15,028	(9,269)
Increase in materials and supplies	(1,277)	(981)
Increase in regulatory assets	(4,255)	(2,326)
Increase (decrease) in accounts payable	(15,848)	454
Changes in prepaid and accrued income and utility revenue taxes	(49,561)	(41,106)
Changes in other assets and liabilities	5,771	9,528
Net cash provided by operating activities	**101,014**	**7,249**
Cash flows from investing activities		
Capital expenditures	(80,315)	(47,729)
Contributions in aid of construction	2,362	3,836
Other		(57)
Net cash used in investing activities	**(77,953)**	**(43,950)**
Cash flows from financing activities		
Common stock dividends	(10,536)	(14,089)
Preferred stock dividends	(270)	(270)
Proceeds from issuance of long-term debt	3,148	9,897
Net increase (decrease) in short-term borrowings from nonaffiliates and affiliate with original maturities of three months or less	(12,211)	60,317
Decrease in cash overdraft	(5,865)	(8,582)
Other	(1)	
Net cash provided by (used in) financing activities	**(25,735)**	**47,273**
Net increase (decrease) in cash and equivalents	(2,674)	10,572
Cash and equivalents, beginning of period	6,901	4,678
Cash and equivalents, end of period	**$ 4,227**	**$ 15,250**

See accompanying Notes to Consolidated Financial Statements for HECO.

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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 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, 2008.

In the opinion of HECO s management, the accompanying unaudited consolidated financial statements contain all material adjustments required by GAAP to present fairly the financial position of HECO and its subsidiaries as of March 31, 2009 and December 31, 2008 and the results of their operations and cash flows for the three months ended March 31, 2009 and 2008. 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 each of Hawaii Electric Light Company, Inc. (HELCO) and Maui Electric Company, Limited (MECO) in the respective principal amounts of $10 million, (iii) making distributions on the 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 FIN 46R, Consolidation of Variable Interest Entities. Trust III s balance sheets as of March 31, 2009 and December 31, 2008 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 three months ended March 31, 2009 and 2008 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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Purchase power agreements. As of March 31, 2009, HECO and its subsidiaries had six PPAs for a total of 540 megawatts (MW) of firm capacity, and other PPAs with smaller IPPs and Schedule Q providers (i.e., customers with cogeneration and/or small power production facilities with a capacity of 100 KWHs or less who buy power from or sell power to the utilities) that supplied as-available energy. Approximately 91% of the 540 MW of firm capacity is under 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 three months ended March 31, 2009 totaled $114 million, with purchases from AES Hawaii, Kalaeloa, HEP and HPOWER totaling $32 million, $34 million, $15 million and $10 million, respectively. The primary business activities of these IPPs are the generation and sale of power to HECO and its subsidiaries (and municipal waste disposal in the case of HPOWER). Current financial information about the size, including total assets and revenues, for many of these IPPs is not publicly available.

Under FIN 46R, an enterprise with an interest in a variable interest entity (VIE) or potential VIE created before December 31, 2003 (and not thereafter materially modified) is not required to apply FIN 46R to that entity if the enterprise is unable to obtain, after making an exhaustive effort, the necessary information.

HECO reviewed its significant PPAs and determined in 2004 that the IPPs at that time had no contractual obligation to provide such information. In March 2004, HECO and its subsidiaries sent letters to all of their IPPs, except the Schedule Q providers, requesting the information that they need to determine the applicability of FIN 46R to the respective IPP, and subsequently contacted most of the IPPs to explain and repeat its request for information. (HECO and its subsidiaries excluded their Schedule Q providers from the scope of FIN 46R because their variable interest in the provider would not be significant to the utilities and they did not participate significantly in the design of the provider.) Some of the IPPs 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) as defined under FIN 46R, and thus excluded from the scope of FIN 46R. Other IPPs, including the three largest, declined to provide the information necessary for HECO to determine the applicability of FIN 46R, and HECO was unable to apply FIN 46R to these IPPs.

As required under FIN 46R since 2004, HECO has continued its efforts to obtain from the IPPs the information necessary to make the determinations required under FIN 46R. In each year from 2005 to 2009, HECO and its subsidiaries sent letters to the IPPs that were not excluded from the scope of FIN 46R, requesting the information required to determine the applicability of FIN 46R to the respective IPP. All of these IPPs declined to provide necessary information, except that Kalaeloa provided the information pursuant to the amendments to its PPA (see below) and an entity owning a wind farm provided information as required under the PPA. Management has concluded that the consolidation of two entities owning wind farms was not required as HELCO and MECO do not have variable interests in the entities because the PPAs do not require them to absorb any variability of the entities.

If the requested information is ultimately received from the other IPPs, a possible outcome of future analysis is the consolidation of one or more of such IPPs in HECO s consolidated financial statements. The consolidation of any significant IPP could have a material effect on HECO s consolidated financial statements, including the recognition of a significant amount of assets and liabilities and, if such a consolidated IPP were operating at a loss and had insufficient equity, the potential recognition of such 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 FIN 46R in accordance with SFAS No. 154, Accounting Changes and Error Corrections.

Kalaeloa Partners, L.P. In October 1988, HECO entered into a PPA with Kalaeloa, subsequently approved by the PUC, which provided that HECO would purchase 180 MW of firm capacity for a period of 25 years beginning in May 1991. In October 2004, HECO and Kalaeloa entered into amendments to the PPA, subsequently approved by the PUC, which together effectively increased the firm capacity from 180 MW to 208 MW. The energy payments that HECO makes to Kalaeloa include: 1) a fuel component, with a fuel price adjustment based on the cost of low sulfur fuel oil, 2) a fuel additives cost component, and 3) a non-fuel component, with an adjustment based on changes in the Gross National Product Implicit Price Deflator. The capacity payments that

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HECO makes to Kalaeloa are fixed in accordance with the PPA. Kalaeloa also has a steam delivery cogeneration contract with another customer, the term of which coincides with the PPA. The facility has been certified by the Federal Energy Regulatory Commission as a Qualifying Facility under the Public Utility Regulatory Policies Act of 1978.

Pursuant to the provisions of FIN 46R, HECO is deemed to have a variable interest in Kalaeloa by reason of the provisions of HECO s PPA with Kalaeloa. However, management has concluded that HECO is not the primary beneficiary of Kalaeloa because HECO does not absorb the majority of Kalealoa s expected losses nor receive a majority of Kalaeloa s expected residual returns and, thus, HECO has not consolidated Kalaeloa in its consolidated financial statements. A significant factor affecting the level of expected losses HECO would absorb is the fact that HECO s exposure to fuel price variability is limited to the remaining term of the PPA as compared to the facility s remaining useful life. Although HECO absorbs fuel price variability for the remaining term of the PPA, the PPA does not currently expose HECO to losses as the fuel and fuel related energy payments under the PPA have been approved by the PUC for recovery from customers through base electric rates and through HECO s ECAC to the extent the fuel and fuel related energy payments are not included in base energy rates.

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. HECO and its subsidiaries payments to the taxing authorities are based on the prior year s revenues. For the three months ended March 31, 2009 and 2008, HECO and its subsidiaries included approximately $43 million and $55 million, respectively, of revenue taxes in operating revenues and in taxes, other than income taxes expense.

4 Retirement benefits

Defined benefit plans. For the first quarter of 2009, HECO and its subsidiaries contributed $9.4 million to their retirement benefit plans, compared to $0.9 million in the first quarter of 2008. HECO and its subsidiaries current estimate of contributions to their retirement benefit plans in 2009 is $25 million, compared to contributions of $14 million in 2008. In addition, HECO and its subsidiaries expect to pay directly $0.9 million of benefits in 2009, compared to $0.1 million paid in 2008.

For the first quarter of 2009, HECO and its subsidiaries defined benefit retirement plans assets generated a loss, including investment management fees, of 6.3%. The market value of the defined benefit retirement plan s assets as of March 31, 2009 was $610 million compared to $655 million at December 31, 2008, a decline of approximately $45 million.

The components of net periodic benefit cost were as follows:

	Pension benefits		Other benefits	
Three months ended March 31	**2009**	**2008**	**2009**	**2008**
(in thousands)				
Service cost	$ 6,060	$ 6,533	$ 1,027	$ 1,135
Interest cost	14,050	13,445	2,765	2,755
Expected return on plan assets	(12,673)	(16,251)	(2,178)	(2,695)
Amortization of unrecognized transition obligation			783	782
Amortization of prior service gain	(183)	(191)		
Recognized actuarial loss	3,671	1,645	114	
Net periodic benefit cost	10,925	5,181	2,511	1,977
Impact of PUC D&Os	(4,091)	1,657	(325)	193
Net periodic benefit cost (adjusted for impact of PUC D&Os)	$ 6,834	$ 6,838	$ 2,186	$ 2,170

HECO and its subsidiaries recorded retirement benefits expense of $7 million in each of the first quarters of 2009 and 2008. The electric utilities charged a portion of the net periodic benefit costs to plant.

In HELCO s 2006, HECO s 2007 and MECO s 2007 test year rate cases, the utilities and the Consumer Advocate proposed adoption of pension and postretirement benefits other than pensions (OPEB) tracking mechanisms, which are intended to smooth the impact to ratepayers of potential fluctuations in pension and

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OPEB costs. Under the tracking mechanisms, any costs determined under SFAS Nos. 87 and 106, as amended, that are over/under amounts allowed in rates are charged/credited to a regulatory asset/liability. The regulatory asset/liability for each utility will be amortized over 5 years beginning with the respective utility s next rate case.

The pension tracking mechanisms generally require the electric utilities to fund only the minimum level required under the law until the existing pension assets are reduced to zero, at which time the electric utilities would make contributions to the pension trust in the amount of the actuarially calculated net periodic pension costs, except when limited by the ERISA minimum contribution requirements or the maximum contribution limitation on deductible contributions imposed by the Internal Revenue Code. The OPEB tracking mechanisms generally require the electric utilities to make contributions to the OPEB trust in the amount of the actuarially calculated net periodic benefit costs, except when limited by material, adverse consequences imposed by federal regulations.

A pension funding study was filed in the HECO rate case in May 2007. The conclusions in the study were consistent with the funding practice proposed with the pension tracking mechanism.

In its 2007 interim decisions for HELCO s 2006, HECO s 2007 and MECO s 2007 test year rate cases, the PUC approved the adoption of the proposed pension and OPEB tracking mechanisms on an interim basis (subject to the PUC s final decision and orders (D&Os)) and established the amount of net periodic benefit costs to be recovered in rates by each utility. HECO reflected the continuation of the pension and OPEB tracking mechanisms in its rate increase application based on a 2009 test year.

Under HELCO s interim order, a regulatory asset (representing HELCO s $12.8 million prepaid pension asset as of December 31, 2006 prior to the adoption of SFAS No. 158) was allowed to be recovered (and is being amortized) over a period of five years and was allowed to be included in HELCO s rate base, net of deferred income taxes. In the interim PUC decisions in HECO s and MECO s 2007 test year rate cases, their pension assets ($51 million and $1 million, respectively, as of December 31, 2007) were not included in their rate bases and amortization of the pension assets was not included as part of the pension tracking mechanisms adopted in the proceedings on an interim basis. The issue of whether to amortize HECO s prepaid pension asset, if allowed to be included in rate base by the PUC, has been deferred until a subsequent rate case proceeding. However, HECO s pension asset was not included in rate base, and amortization of the pension asset was not included in revenue requirements, in HECO s rate increase application based on a 2009 test year.

5 Commitments and contingencies

Hawaii Clean Energy Initiative. In January 2008, the State of Hawaii and the U.S. Department of Energy (DOE) signed a memorandum of understanding establishing the Hawaii Clean Energy Initiative (HCEI). The stated purpose of the HCEI is to establish a long-term partnership between the State of Hawaii and the DOE that will result in a fundamental and sustained transformation in the way in which energy resources are planned and used in the State. HECO has been working with the State, the DOE and other stakeholders to align the utility s energy plans with the State s plans.

On October 20, 2008, 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 State of Hawaii Department of Commerce and Consumer Affairs, and HECO, on behalf of itself and its subsidiaries, HELCO and MECO (collectively, the parties), signed an Energy Agreement setting forth goals and objectives under the HCEI and the related commitments of the parties (the Energy Agreement). The Energy Agreement provides that the parties pursue a wide range of actions with the purpose of decreasing the State of Hawaii s dependence on imported fossil fuels through substantial increases in the use of renewable energy and implementation of new programs intended to secure greater energy efficiency and conservation.

The parties recognize that the move toward a more renewable and distributed and intermittent power system will pose increased operating challenges to the utilities and that there is a need to assure that Hawaii preserves a stable electric grid to minimize disruption in service quality and reliability. They further recognize that Hawaii needs a system of utility regulation to transform the utilities from traditional sales-based companies to energy services companies while preserving financially sound utilities.

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Many of the actions and programs included in the Energy Agreement will require approval of the PUC in proceedings that will need to be initiated by the PUC or the utilities.

Among the major provisions of the Energy Agreement most directly affecting HECO and its subsidiaries are the following:

The Energy Agreement provides for the parties to pursue an overall goal of providing 70% of Hawaii s electricity and ground transportation energy needs from clean energy sources, including renewable energy and energy efficiency, by 2030. The ground transportation energy needs included in this goal include a contemplated move in Hawaii to electrification of transportation and the use of electric utility capacity in off peak hours to recharge vehicles and batteries. To promote the transportation goals, the Energy Agreement provides for the parties to evaluate and implement incentives to encourage adoption of electric vehicles, and to lead by example by acquiring hybrid or electric-only vehicles for government and utility fleets.

To help achieve the HCEI goals, the Energy Agreement further provides for the parties to seek amendment to the Hawaii Renewable Portfolio Standards (RPS) law (law which establishes renewable energy requirements for electric utilities that sell electricity for consumption in the State) to increase the current requirements from 20% to 25% by the year 2020, and to add a further RPS goal of 40% by the year 2030. The revised RPS law would also require that after 2014 the RPS goal be met solely with renewable energy generation versus including energy savings from energy efficiency measures. However, energy savings from energy efficiency measures would be counted toward the achievement of the overall HCEI 70% goal.

In December 2007, the PUC issued a D&O approving a stipulated RPS framework to govern electric utilities compliance with the RPS law. In a follow up order in December 2008, the PUC approved a penalty of $20 for every MWh that an electric utility is deficient under Hawaii s RPS law. The PUC noted, however, that this penalty may be reduced, in the PUC s discretion, due to events or circumstances that are outside an electric utility s reasonable control, to the extent the event or circumstance could not be reasonably foreseen and ameliorated, as described in the RPS law and in the RPS Framework. In addition, the PUC ordered that: (1) any penalties assessed against HECO and its subsidiaries for failure to meet the RPS will go into the public benefits fund account used to support energy efficiency and DSM programs and services, unless otherwise directed; and (2) the utilities will be prohibited from recovering any RPS penalty costs through rates.

To further encourage the contributions of energy efficiency to the overall HCEI goal, the Energy Agreement provides for the parties to seek establishment of energy efficiency goals through an Energy Efficiency Portfolio Standard.

To help fund energy efficiency programs, incentives, program administration, customer education, and other related program costs, as expended by the third-party administrator for the energy efficiency programs or by program contractors, which may include the utilities, the Energy Agreement provides that the parties will request that the PUC establish a Public Benefits Fund (PBF) that is funded by collecting 1% of the utilities revenues in years one and two after implementation of a PBF; 1.5% in years three and four; and 2% thereafter. In December 2008, the PUC issued an order directing the utilities to collect revenue equal to 1% of the projected total electric revenue of the utilities, of which 60% shall be collected via the DSM surcharge and 40% via the PBF surcharge. Beginning January 1, 2009, the 1% is being assessed on customers of HECO and its subsidiaries.

The Energy Agreement provides for the establishment of a Clean Energy Infrastructure Surcharge (CEIS). The CEIS, which will need to be approved by the PUC, is to be designed to expedite cost recovery for a variety of infrastructure that supports greater use of renewable energy or grid efficiency within the utility systems (such as advanced metering, energy storage, interconnections and interfaces). The Energy Agreement provides that the surcharge should be available to recover costs that would normally be expensed in the year incurred and capital costs (including the allowed return on investment, AFUDC, depreciation, applicable taxes and other approved costs), and could also be used to recover costs stranded by clean energy initiatives. On November 28, 2008, HECO and the Consumer Advocate filed a joint letter informing the PUC that the pending REIP Surcharge satisfies the Energy Agreement provision for an implementation procedure for the CEIS recovery mechanism and that no further regulatory action on the CEIS is necessary, and reaffirming that the REIP Surcharge is ready for PUC decision-making. In the first quarter of 2009, the parties responded to information requests prepared by the PUC s consultant.

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HECO and its subsidiaries will continue to negotiate with developers of currently proposed projects (identified in the Energy Agreement) to integrate 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 of Hawaii, 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 wind farms proposed by developers to be built on the islands of Lanai and/or Molokai. Utilizing technical resources such as the U.S. Department of Energy national laboratories, HECO, along with the other parties, have committed to work together to evaluate, assess and address the operational challenges for integrating such a large increment of wind into its grid system on Oahu. The State and HECO have agreed to work together to ensure the supporting infrastructure needed for the Oahu grid 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 wind farm facilities.

With respect to the undersea transmission cable system, the State has agreed to seek, with HECO and/or developers reasonable assistance, federal grant or loan assistance to pay for the undersea cable system. In the event federal funding is unavailable, the State will employ its best effort to fund the undersea cable system through a prudent combination of taxpayer and ratepayer sources. There is no obligation on the part of HECO to fund any of the cost of the undersea cable. However, in the event HECO funds any part of the cost to develop the undersea cable system and assumes any ownership of the cable system, all reasonably incurred capital costs and expenses are intended to be recoverable through the CEIS.

As another method of accelerating the acquisition of renewable energy by the utilities, the Energy Agreement includes support of the parties for the development of a feed-in tariff (FIT) system with standardized purchase prices for renewable energy. The PUC was requested to conclude an investigative proceeding by March 2009 to determine the best design for an FIT that supports the HCEI goals, considering such factors as categories of renewables, size or locational limits for projects qualifying for the FIT, what annual limits should apply to the amount of renewables allowed to utilize the FIT, what factors to incorporate into the prices set for FIT payments, and other terms and conditions. Based on these understandings, the Energy Agreement required that the parties request the PUC to suspend the pending intra-governmental wheeling and avoided cost (Schedule Q) dockets for a period of 12 months. On October 24, 2008, the PUC opened an investigative proceeding to examine the implementation of FITs. The utilities and Consumer Advocate were named as initial parties to the proceeding and 18 other parties were granted intervener or participant status. On December 11, 2008, the PUC issued a scoping paper prepared by its consultant that specified certain issues and questions for the parties to address and for the utilities and the Consumer Advocate to consider in a joint FIT proposal. On December 23, 2008, the utilities and the Consumer Advocate filed a joint proposal on FITs that called for the establishment of simple, streamlined and broad standard payment rates, which can be offered to as many renewable technologies as feasible. It proposed that the initial FIT be focused on photovoltaics (PV), concentrated solar power (CSP), in-line hydropower and wind, with individual project sizes targeted to provide a greater likelihood of more straightforward interconnection, project implementation and use of standardized energy rates and power purchase contracting. The FIT would be regularly reviewed to update tariff pricing to applicable technologies, project sizes and annual targets. An FIT update would be conducted for all islands in the utilities service territory not later than two years after initial implementation of the FIT and every three years thereafter. The proposed initial target project sizes are:

PV systems up to and including 500 kilowatts (kW) on Oahu, PV systems up to and including 250 kW on Maui and the island of Hawaii and PV systems up to and including 100 kW on Lanai and Molokai.

CSP systems up to and including 500 kW on Oahu, Maui, and the island of Hawaii and up to and including 100 kW on Lanai and Molokai.

In-line hydropower systems up to and including 100 kW on Oahu, Maui, Lanai, Molokai and the island of Hawaii.

Wind power systems up to and including 100 kW on Oahu, Maui, Lanai, Molokai and the island of Hawaii.

The FIT joint proposal also recommended that no applications for new net energy metering contracts be accepted once the FIT is formally made available to customers (although existing net energy metering systems under contract would be grandfathered), and no applications for new Schedule Q contracts would be accepted once an FIT is formally made available for the resource type. Schedule Q would continue as an option for qualifying projects of 100 kW and less for which an FIT is not available. Final position statements in the FIT docket were submitted by the parties at the end of March 2009, and panel hearings were held in April 2009. Remaining procedural steps include opening briefs at the end of May 2009, reply briefs in June 2009 and proposed tariffs on September 1, 2009.

The Energy Agreement also provides that system-wide caps on net energy metering should be removed. Instead, all distributed generation interconnections, including net metered systems, should be limited on a per-circuit basis to no more than 15% of peak circuit demand, to encourage the development of more cost effective distributed resources while still maintaining safe reliable service.

The Energy Agreement includes support of the parties for the development and use of renewable biofuels for electricity generation, including the testing of the technical feasibility of using biofuel or biofuel blends in HECO, HELCO and MECO generating units. The parties agree that use of biofuels in the utilities generating units, particularly biofuels from local sources, can contribute to achieving RPS requirements and decreasing greenhouse gas emissions, while avoiding major capital investment for new, replacement generation.

In recognition of the need to recover the infrastructure and other investments required to support significantly increased levels of renewable energy and to eliminate the potential conflict between encouraging energy efficiency and conservation and lower sales revenues, the parties agree that it is appropriate to adopt a regulatory rate-making model, which is subject to PUC approval, under which HECO, HELCO and MECO revenues would be decoupled from KWH sales. If approved by the PUC, the new regulatory model, which could be similar to the regulatory models currently used in California, would employ a revenue adjustment mechanism to track on an ongoing basis the differences between the amount of revenues allowed in the last rate case and (a) the current costs of providing electric service and (b) a reasonable return on and return of additional capital investment in the electric system. The utilities would also continue to use existing PUC-approved tracking mechanisms for pension and other post-retirement benefits. The utilities would also be allowed an automatic revenue adjustment mechanism to reflect changes in state or federal tax rates.

On October 24, 2008, the PUC opened an investigative proceeding to examine implementing a decoupling mechanism for the utilities. In addition to the utilities and the Consumer Advocate, there are five other parties in the proceeding. The utilities and the Consumer Advocate filed a joint statement of position in March 2009, which was discussed in a technical workshop held in April 2009. The remaining schedule for the proceeding includes final position statements of the parties to be submitted in May 2009 and panel hearings during June 2009.

The PUC has been requested to approve the establishment of a revenue balancing account to be effective upon the issuance of the PUC s interim D&O in HECO s 2009 test year rate case. The Energy Agreement also contemplates that additional rate cases based on a 2009 test year will be filed by HELCO and MECO in order to provide their respective baselines for implementation of the new regulatory model. On March 20, 2009, MECO filed a Notice of Intent to file an application for a general rate increase on or after May 29, 2009 (but before June 30, 2009) and a motion requesting PUC approval to use a 2009 calendar year test period for this upcoming rate case. On April 27, 2009, the PUC issued an order denying MECO s motion and stating that MECO may elect to file its rate case application with either a split 2009/2010 test period or a 2010 calendar test period, pursuant to the PUC s rules. Under the rules, MECO (and HELCO) would be allowed to file rate cases with 2010 test years on or after July 1, 2009.

The Energy Agreement confirms that the existing ECAC will continue, subject to periodic review by the PUC. As part of that review, the parties agree that the PUC will examine whether there are renewable energy projects from which the utilities should have, but did not, purchase energy or whether alternate fuel purchase strategies were appropriately used or not used.

With PUC approval, a separate surcharge would be established to allow HECO and its subsidiaries to pass through all reasonably incurred purchased power costs, including all capacity, operation and maintenance expenses and other non-energy payments approved by the PUC which are currently recovered through base rates, with the surcharge to be adjusted monthly and reconciled quarterly.

The Energy Agreement includes a number of other undertakings intended to accomplish the purposes and goals of the HCEI, subject to PUC approval and including, but not limited to: (a) promoting through specifically proposed steps greater use of solar energy through solar water heating, commercial and residential photovoltaic energy installations and concentrated solar power generation; (b) providing for the retirement or placement on reserve standby status of older and less efficient fossil fuel fired generating units as new, renewable generation is installed; (c) improving and expanding load management and demand response programs that allow the utilities to control customer loads to improve grid reliability and cost management; (d) the filing of PUC applications this year for approval of the installation of Advanced Metering Infrastructure, coupled with time-of-use or dynamic rate options for customers; (e) supporting prudent and cost effective investments in smart grid technologies, which become even more important as wind and solar generation is added to the grid; (f) including 10% of the energy purchased under FITs in each utility s respective rate base through January 2015; (g) delinking prices paid under all new renewable energy contracts from oil prices; and (h) exploring the possibility of establishing lifeline rates designed to provide a cap on rates for those who are unable to pay the full cost of electricity. The utilities proposed Lifeline Rate Program, submitted to the PUC for approval at the end of April 2009, would provide a monthly bill credit to qualified, low-income customers estimated to be in the range of $25 to $35 per month. The utilities and the Consumer Advocate are in discussions as to the appropriate recovery mechanism for the utilities to recover the cost of the credits passed on to program participants.

Interim increases. On April 4, 2007, the PUC issued an interim D&O in HELCO s 2006 test year rate case granting a general rate increase on the island of Hawaii of 7.58%, or $24.6 million, which was implemented on April 5, 2007.

On October 22, 2007, the PUC issued, and HECO immediately implemented, an interim D&O in HECO s 2007 test year rate case, granting HECO an increase of $70 million in annual revenues, a 4.96% increase over rates effective at the time of the interim decision ($78 million in annual revenues over rates granted in the final decision in HECO s 2005 test year rate case).

On December 21, 2007, the PUC issued, and MECO immediately implemented, an interim D&O in MECO s 2007 test year rate case, granting MECO an increase of $13 million in annual revenues, or a 3.7% increase.

As of March 31, 2009, HECO and its subsidiaries had recognized $171 million of revenues with respect to interim orders ($5 million related to interim orders regarding certain integrated resource planning costs and $166 million related to interim orders regarding general rate increase requests). Revenue amounts recorded pursuant to interim orders are subject to refund, with interest, pending a final order.

Energy cost adjustment clauses. Hawaii Act 162 (Act 162) was signed into law in June 2006 and requires that any automatic fuel rate adjustment clause requested by a public utility in an application filed with the PUC be designed, as determined in the PUC s discretion, to (1) fairly share the risk of fuel cost changes between the utility and its customers, (2) provide the utility with incentive to manage or lower its fuel costs and encourage greater use of renewable energy, (3) allow the utility to mitigate the risk of sudden or frequent fuel cost changes that cannot otherwise reasonably be mitigated through commercially reasonable means, such as through fuel hedging contracts, (4) preserve the utility s financial integrity, and (5) minimize the utility s need to apply for frequent general rate increases for fuel cost changes. While the PUC already had reviewed the automatic fuel adjustment clauses in rate cases, Act 162 requires that these five specific factors be addressed in the record.

In May 2008, the PUC issued a final D&O in HECO s 2005 test year rate case in which the PUC agreed with the parties stipulation in the proceeding that it would not require the parties in the proceeding to submit a stipulated procedural schedule to address the Act 162 factors in the 2005 test year rate case proceeding, and stated it expected HECO and HELCO to develop information relating to the Act 162 factors for examination during their next rate case proceedings.

In the HELCO 2006 test year rate case, the filed testimony of the Consumer Advocate s consultant concluded that HELCO s ECAC provides a fair sharing of the risks of fuel cost changes between HELCO and its ratepayers in a manner that preserves the financial integrity of HELCO without the need for frequent rate filings. In April and December 2007, the PUC issued interim D&Os in the HELCO 2006 and MECO 2007 test year rate cases that reflected for purposes of the interim order the continuation of their ECACs, consistent with agreements reached between the Consumer Advocate and HELCO and MECO, respectively. The Consumer Advocate and MECO agreed that no further changes are required to MECO s ECAC in order to comply with the requirements of Act 162.

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In September 2007, HECO, the Consumer Advocate and the federal Department of Defense (DOD) agreed that the ECAC should continue in its present form for purposes of an interim rate increase in the HECO 2007 test year rate case and stated that they are continuing discussions with respect to the final design of the ECAC to be proposed for approval in the final D&O. In October 2007, the PUC issued an interim D&O, which reflected the continuation of HECO s ECAC for purposes of the interim increase.

Management cannot predict the ultimate effect of the required Act 162 analysis on the continuation of the utilities existing ECACs, but the Energy Agreement confirms the intent of the parties that the existing ECACs will continue, subject to periodic review by the PUC. As part of that periodic review, the parties agree that the PUC will examine whether there are renewable energy projects from which the utility should have, but did not, purchase energy or whether alternate fuel purchase strategies were appropriately used or not used.

In December 2008, HECO filed updates to its 2009 test year rate case. The updates proposed the establishment of a purchased power adjustment clause to recover non-energy purchased power costs, pursuant to the Energy Agreement provision stating the utilities will be allowed to pass through reasonably incurred purchase power contract costs, including all capacity, operation and maintenance (O&M) and other non-energy payments approved by the PUC through a separate surcharge. The purchased power adjustment clause will be adjusted monthly and reconciled quarterly.

On December 30, 2008, HECO and the Consumer Advocate filed joint proposed findings of fact and conclusions of law in the HECO 2007 test year rate case, which stated that, given the Energy Agreement, which documents a course of action to make Hawaii energy independent and recognizes the need to maintain HECO s financial health while achieving that objective, as well as the overwhelming support in the record for maintaining the ECAC in its current form, the PUC should determine that HECO s proposed ECAC complies with the requirements of Act 162.

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 the PUC disallows cost recovery for all or part of the 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 (with capitalized and deferred costs accumulated through March 31, 2009 noted in parentheses) include HECO s Campbell Industrial Park (CIP) combustion turbine No. 1 (CIP CT-1) and a transmission line ($129 million), HECO s East Oahu Transmission Project ($39 million), HELCO s ST-7 ($69 million) and a customer information system ($22 million).

CIP CT-1 and transmission line. HECO is building a new 110 MW simple cycle combustion turbine (CT) generating unit at CIP and plans to add an additional 138 kilovolt transmission line to transmit power from generating units at CIP (including the new unit) to the rest of the Oahu electric grid (collectively, the Project). Plans are for the CT to be run primarily as a peaking unit beginning in mid-2009, fueled by biodiesel.

HECO s Final Environmental Impact Statement for the Project was accepted by the Department of Planning & Permitting of the City and County of Honolulu in August 2006. In December 2006, HECO filed with the PUC an agreement with the Consumer Advocate in which HECO committed to use 100% biofuels in its new plant and to take the steps necessary for HECO to reach that goal. In May 2007, the PUC issued a D&O approving the Project and the DOH issued the final air permit, which became effective at the end of June 2007. The D&O further stated that no part of the Project costs may be included in HECO s rate base unless and until the Project is in fact installed, and is used and useful for public utility purposes. HECO s 2009 test year rate case application, filed in July 2008, requests inclusion of the Project investment in rate base when the new unit is placed in service (expected to be at the end of July 2009). Construction on the Project began in May 2008.

In a related application filed with the PUC in June 2005, HECO requested approval of community benefit measures to mitigate the impact of the new generating unit on communities near the proposed generating unit site. In June 2007, the PUC issued a D&O which (1) approved HECO s request to commit funds for HECO s project to use recycled instead of potable water for industrial water consumption at the Kahe power plant,

(2) approved HECO s request to commit funds for the environmental monitoring programs and (3) denied HECO s request to provide a base electric rate discount for HECO s residential customers who live near the proposed generation site. The approved measures are estimated to cost $9 million (through the first 10 years of implementation).

As of March 31, 2009, HECO s cost estimate for the Project (exclusive of the costs of the community benefit measures described above) was $193 million (of which $129 million had been incurred, including $6 million of AFUDC) and outstanding commitments for materials, equipment and outside services totaled $28 million. To the extent actual project costs are higher than the estimate included in the 2009 test year rate case, HECO plans to seek recovery in a future proceeding. Management believes no adjustment to project costs is required as of March 31, 2009. However, if it becomes probable that the PUC will disallow some or all of the incurred costs for rate-making purposes, HECO may be required to write off a material portion or all of the project costs incurred in its efforts to put the project into service whether or not it is completed.

In August 2007, HECO entered into a contract with Imperium Services, LLC (Imperium), to supply biodiesel for the planned generating unit, subject to PUC approval. Imperium agreed to comply with HECO s procurement policy requiring sustainable sources of biofuel feedstocks. In October 2007, HECO filed an application with the PUC for approval of this biodiesel supply contract. An evidentiary hearing on the application was held in October 2008. In January 2009, HECO and Imperium amended the contract, Imperium assigned the contract to Imperium Grays Harbor, LLC (Imperium GH), and HECO filed the amended contract with the PUC. In February 2009, HECO requested PUC approval of a related terminalling and trucking agreement with Aloha Petroleum, Ltd. to support the delivery and storage on Oahu of biodiesel from Imperium GH. In February 2009, the PUC modified the procedural schedule for this proceeding, and re-opened the evidentiary hearing, which re-commenced in March 2009. After the parties file proposed findings of fact and conclusions of law and then their respective comments on the same in May 2009, the application should be ready for PUC decision-making.

East Oahu Transmission Project (EOTP). HECO had planned a project (EOTP) to construct a partially underground 138 kilovolt (kV) line in order to close the gap between the southern and northern transmission corridors on Oahu and provide a third 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.

HECO continued to believe that the proposed reliability project was needed and, in 2003, filed an application with the PUC requesting approval to commit funds (then estimated at $56 million; see costs incurred below) for an EOTP, revised to use a 46 kV system and modified route, none of which is in conservation district lands. The environmental review process for the EOTP, as revised, was completed in 2005.

In written testimony filed in 2005, a consultant for the Consumer Advocate contended that HECO should always have planned for a project using only the 46 kV system and recommended that HECO be required to expense the $12 million incurred prior to the denial of the permit in 2002, and the related allowance for funds used during construction (AFUDC) of $5 million at the time. HECO contested the consultant s recommendation, emphasizing that the originally proposed 138 kV line would have been a more comprehensive and robust solution to the transmission concerns the project addresses. In October 2007, the PUC issued a final D&O approving HECO s request to expend funds for the EOTP, but stating 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.

The project is currently estimated to cost $74 million and HECO plans to construct the EOTP in two phases. The first phase is currently in construction and projected to be completed in 2010. The projected completion date of the second phase is being evaluated.

As of March 31, 2009, the accumulated costs recorded for the EOTP amounted to $39 million, including (i) $12 million of planning and permitting costs incurred prior to 2003, (ii) $8 million of planning, permitting and construction costs incurred after 2002 and (iii) $19 million for AFUDC. Management believes no adjustment to project costs is required as of March 31, 2009. However, if it becomes probable that the PUC will disallow some or all of the incurred costs for rate-making purposes, HECO may be required to write off a material portion or all of the project costs incurred in its efforts to put the project into service whether or not it is completed.

HELCO generating units. In 1991, HELCO began planning to meet increased demand for electricity forecast for 1994. HELCO planned to install at its Keahole power plant two 20 MW combustion turbines (CT-4 and CT-5), followed by an 18 MW heat recovery steam generator (ST-7), at which time the units would be converted to a 56 MW (net) dual-train combined-cycle unit. In January 1994, the PUC approved expenditures for CT-4. In 1995, the PUC allowed HELCO to pursue construction of and commit expenditures for CT-5 and ST-7, but noted that such costs are not to be included in rate base until the project is installed and is used and useful for utility purposes.

There were a number of environmental and other permitting challenges to construction of the units, including several lawsuits, which resulted in significant delays. However, in 2003, all but one of the parties actively opposing the plant expansion project entered into a settlement agreement with HELCO and several Hawaii regulatory agencies (the Settlement Agreement) intended in part to permit HELCO to complete CT-4 and CT-5. The Settlement Agreement required HELCO to undertake a number of actions, which have been completed or are ongoing. As a result of the final resolution of various proceedings due primarily to the Settlement Agreement, there are no pending lawsuits involving the project.

CT-4 and CT-5 became operational in mid-2004 and currently can be operated as required to meet HELCO s system needs, but additional noise mitigation work is ongoing to ensure compliance with the applicable night-time noise standard.

HELCO has completed engineering and design activities and construction work for ST-7 is progressing towards completion in mid-2009. As of March 31, 2009, HELCO s cost estimate for ST-7 was $92 million (of which $69 million had been incurred) and outstanding commitments for materials, equipment and outside services totaled $17 million, a substantial portion of which are subject to cancellation charges.

CT-4 and CT-5 costs incurred and allowed. HELCO s capitalized costs for CT-4 and CT-5 and related supporting infrastructure amounted to $110 million. HELCO sought recovery of these costs as part of its 2006 test year rate case.

In March 2007, HELCO and the Consumer Advocate reached a settlement of the issues in the 2006 rate case proceeding, subject to PUC approval. Under the settlement, HELCO agreed to write-off approximately $12 million of the costs relating to CT-4 and CT-5, resulting in an after-tax charge to net income in the first quarter of 2007 of $7 million (included in Other, net under Other income (loss) on HECO s consolidated statement of income).

In April 2007, the PUC issued an interim D&O granting HELCO a 7.58% increase in rates, which D&O reflected the agreement to write-off $12 million of the CT-4 and CT-5 costs. However, the interim D&O does not commit the PUC to accept any of the amounts in the interim increase in its final D&O.

If it becomes probable that the PUC will disallow for rate-making purposes additional CT-4 and CT-5 costs in its final D&O or disallow any ST-7 costs, HELCO will be required to record an additional write-off.

Customer Information System (CIS) Project. On August 26, 2004, HECO, HELCO and MECO filed a joint application with the PUC for approval of the accounting treatment and recovery of certain costs related to acquiring and implementing a new CIS. The application stated that the new CIS would allow the utilities to (i) more quickly and accurately store, maintain and manage customer-specific information necessary to provide basic customer service functions, such as producing bills, collecting payments, establishing service and fulfilling customer requests in the field, and (ii) have substantially greater capabilities and features than the existing system, enabling the utilities to enhance their operations, including customer service. In a D&O filed on May 3, 2005, the PUC approved the utilities request to (i) expend the then-estimated amount of $20.4 million for the new 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 an allowance for funds used during construction 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.

Following a competitive bidding process, HECO signed a contract with Peace Software US Inc. (Peace) in March 2006 to have Peace develop, deliver and implement the new CIS, with a transition to the new CIS originally scheduled to occur in 2008. The CIS project is currently in the development and implementation phase and has experienced delays, for which HECO considers Peace responsible. In July 2008, HECO notified the PUC that, due to cost overruns and other issues, the total estimated cost of the project had increased to $39.5 million and the transition to the new CIS would be postponed to 2009. In April 2009, HECO notified the PUC that, due to the delays and other issues, a transition to the new CIS was no longer expected to occur in 2009. Because a transition to the new CIS had previously been anticipated in 2009, HECO initially included in its 2009 test year rate case its share of certain costs related to the new CIS being placed into service during 2009. Since the transition to the new CIS is no longer expected to occur in 2009, HECO has subsequently agreed to remove most of those costs from 2009 test year rate case estimates. HECO is considering options under the Peace contract, and HECO has asserted that Peace is in breach of the contract. HECO is evaluating the recovery plan developed with Peace to complete installation of the new CIS using the Peace software, and its options to complete the needed CIS if its contract with Peace is terminated. A new anticipated transition date has not yet been determined. HECO plans to seek recovery in a future proceeding for the new CIS costs in accordance with the May 3, 2005 D&O. However, if it becomes probable that the PUC will disallow some or all of the incurred costs for rate-making purposes, HECO may be required to write off a material portion or all of the project costs incurred in its efforts to put the project into service whether or not it is completed.

HCEI Projects. While much of the renewable energy infrastructure contemplated by the Energy Agreement will be developed by others (e.g., wind plant developments on Molokai and Lanai producing in aggregate up to 400 MW of wind power would be owned by a third-party developer, and the undersea cable system to bring the power generated by the wind plants to Oahu is currently planned to be owned by the State), the utilities may be making substantial investments in related infrastructure.

In the Energy Agreement, the State agrees to support, facilitate and help expedite renewable projects, including expediting permitting processes.

Environmental regulation. HEI 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.

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 Company believes the costs of responding to its subsidiaries releases identified to date will not have a material adverse effect, individually or in the aggregate, on the Company s or consolidated HECO s financial statements.

Additionally, current environmental laws may require HEI and its subsidiaries to investigate whether releases from historical operations may have contributed to environmental impacts, and, where appropriate, respond to such releases, even if they were not inconsistent with law or standard industrial practices prevailing at the time when they occurred. Such releases may involve area-wide impacts contributed to by multiple potentially responsible parties.

Honolulu Harbor investigation. HECO has been involved since 1995 in a work group with several other potentially responsible parties (PRPs) identified by the DOH, including oil companies, in investigating and responding to historical subsurface petroleum contamination in the Honolulu Harbor area. The U.S. Environmental Protection Agency (EPA) became involved in the investigation in June 2000. Some of the PRPs (the Participating Parties) entered into a joint defense agreement and ultimately entered an Enforceable Agreement with the DOH. 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.

Besides subsurface investigation, assessments and preliminary oil removal tasks that have been conducted by the Participating Parties, HECO and others investigated their ongoing operations in the Iwilei Unit in 2003 to evaluate whether their facilities were active sources of petroleum contamination in the area. HECO s investigation concluded that its facilities were not then releasing petroleum. Routine maintenance and inspections of HECO facilities since then confirm that they are not currently releasing petroleum.

For administrative management purposes, the Iwilei Unit has been subdivided into four subunits. The Participating Parties have developed analyses of various remedial alternatives for the four subunits. The DOH uses the analyses to make a final determination of which remedial alternatives the Participating Parties will be required to implement. Once the DOH makes a remedial determination, the Participating Parties are required to develop remedial designs for the various elements of the remedy chosen. The DOH has completed remedial determinations for two subunits to date and the Participating Parties have initiated the remedial design work for those subunits. The Participating Parties anticipate that the DOH will complete the remaining remedial determinations during 2009 and anticipate that all remedial design work will be completed by the end of 2009 or early 2010. The Participating Parties will begin implementation of the remedial design elements as they are approved by the DOH.

Through March 31, 2009, HECO has accrued a total of $3.3 million for estimates of HECO s share of costs for continuing investigative work, remedial activities and monitoring for the Iwilei unit. As of March 31, 2009, the remaining accrual (amounts expensed less amounts expended) for the Iwilei unit was $1.8 million. Because (1) the full scope of work remains to be determined, (2) the final cost allocation method among the PRPs has not yet been established and (3) management cannot estimate the 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 of the Honolulu Harbor site), the cost estimate may be subject to significant change and additional material costs may be incurred.

Regional Haze Rule amendments. In June 2005, the EPA finalized amendments to the July 1999 Regional Haze Rule that require emission controls known as best available retrofit technology (BART) for industrial facilities emitting air pollutants that reduce visibility in National Parks by causing or contributing to regional haze. States were to adopt BART implementation plans and schedules in accordance with the amended regional haze rule by December 2007. After Hawaii adopts its plan, which it has not done to date, HECO, HELCO and MECO will evaluate the plan s impacts, if any. If any of the utilities generating units are ultimately required to install post-combustion control technologies to meet BART emission limits, the resulting capital and operation and maintenance costs could be significant.

Hazardous Air Pollutant (HAP) Control Steam Electric Generating Units. In February 2008, the federal Circuit Court of Appeals for the District of Columbia vacated the EPA s Delisting Rule, which had removed coal- and oil-fired electric generating units (EGUs) from the list of sources requiring control under Section 112 of the Clean Air Act. The EPA s request for a rehearing was denied. In October 2008, the EPA petitioned the U.S. Supreme Court to review the decision of the Circuit Court of Appeals for the District of Columbia vacating the EPA s Delisting Rule. Also, an industry group sought review of the Delisting Rule decision. On February 6, 2009, the EPA filed a motion with the Supreme Court to withdraw its petition for review. In the motion, the EPA indicated that it would begin rulemaking to establish MACT standards for EGUs. On February 23, 2009, the U.S. Supreme Court dismissed the petitions filed by the EPA and industry group requesting review of the decision vacating the EPA s Delisting Rule.

The EPA is thus required to develop Maximum Achievable Control Technology (MACT) standards for oil-fired EGU HAP emissions, including nickel compounds. Depending on the MACT standards developed (and the success of a potential challenge, after the MACT standards are issued, that the EPA inappropriately listed oil-fired EGUs initially), costs to comply with the standards could be significant. Management is currently evaluating its options regarding potential MACT standards for applicable HECO steam units, but will need to review the standards adopted by the EPA before determining its ultimate response and course of action.

Hazardous Air Pollutant (HAP) Control Reciprocating Internal Combustion Engines. On February 25, 2009, the EPA issued proposed MACT standards that would regulate HAPs from certain existing diesel compression ignition engines and gasoline spark ignition engines (i.e., reciprocating internal combustion engines or RICE). As proposed, the RICE MACT rule would require installation of pollution control devices on 80 RICE at the utilities facilities. Eight of the utilities RICE would be required to implement only specified maintenance practices, rather than install pollution control equipment. If adopted, the RICE MACT rule would provide a three-year compliance period after its effective date. Under the terms of a consent decree, the EPA is required to complete the final rule

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by February 10, 2010. Management is evaluating the impacts of the proposed RICE MACT rule, including potential capital expenditures and other compliance costs.

Clean Water Act. Section 316(b) of the federal Clean Water Act requires that the EPA ensure that existing power plant cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts. In 2004, the EPA issued a rule establishing design, construction and capacity standards for existing cooling water intake structures, such as those at HECO s Kahe, Waiau and Honolulu generating stations, and required demonstrated compliance by March 2008. The rule provided a number of compliance options, some of which were far less costly than others. HECO had retained a consultant that was developing a cost effective compliance strategy.

In January 2007, the U.S. Circuit Court of Appeals for the Second Circuit issued a decision that remanded for further consideration and proceedings significant portions of the rule and found other portions to be impermissible, including the EPA s use of a cost-benefit analysis to determine compliance options. In July 2007, the EPA formally suspended the rule and provided guidance to federal and state permit writers that they should use their best professional judgment in determining permit conditions regarding cooling water intake requirements at existing power plants. HECO facilities are subject to permit renewal in mid-2009 and may be subject to new permit conditions to address cooling water intake requirements at that time.

In April 2008, the U.S. Supreme Court agreed to review the Second Circuit Court of Appeal s rejection of a cost-benefit test to determine compliance options. On April 1, 2009, the Supreme Court issued its opinion, ruling that it was permissible, but not required, for the EPA to rely on a cost-benefit analysis in developing cooling water intake standards under the Clean Water Act and to allow variances from the standards based on a cost-benefit comparison. The Supreme Court remanded the case. Because it remains unclear what form the regulations will take and whether the EPA will retain the cost-benefit portions of the rule, management is unable to predict which compliance options, some of which could entail significant capital expenditures to implement, will be applicable to its facilities.

Collective bargaining agreements. As of March 31, 2009, approximately 57% 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 Company. On March 1, 2008, members of the union ratified new collective bargaining and benefit agreements with HECO, HELCO and MECO. The new agreements cover a three-year term, from November 1, 2007 to October 31, 2010, and provide for non-compounded wage increases of 3.5% effective November 1, 2007, 4% effective January 1, 2009 and 4.5% effective January 1, 2010.

Limited insurance. HECO and its subsidiaries purchase insurance to protect themselves against loss or damage to their properties 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 overhead and underground transmission and distribution systems (with the exception of substation buildings and contents) have a replacement value roughly estimated at $4 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 and financial condition could be materially adversely impacted. Also, certain insurance has substantial deductibles , limits on the maximum amounts that may be recovered and exclusions or limitations of coverage for claims related to certain perils. If a series of losses occurred, such as from a series of lawsuits in the ordinary course of business, each of which were subject to the deductible amount, or if the maximum limit of the available insurance were substantially exceeded, HECO, HELCO and MECO could incur losses in amounts that would have a material adverse effect on their results of operations and financial condition.

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6 Cash flows

Supplemental disclosures of cash flow information. For the three months ended March 31, 2009 and 2008, HECO and its subsidiaries paid interest amounting to $8 million and $9 million, respectively.

For the three months ended March 31, 2009, HECO and its subsidiaries received an income tax refund amounting to $2.0 million. For the three months ended March 31, 2008, HECO and its subsidiaries paid income taxes amounting to $33 million. The significant change was due primarily to the difference in the taxes refundable or due with the extensions for tax years 2008 and 2007. In 2007, taxable income was significantly larger in the fourth quarter when compared to the first three quarters, resulting in a larger portion of the 2007 taxes paid with the extension filed in the first quarter of 2008. Taxable income for 2008 was larger in the first half versus the second half of the year, resulting in overpayments being refunded in the first quarter of 2009.

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 $3.6 million and $1.9 million for the three months ended March 31, 2009 and 2008, respectively.

7 Recent accounting pronouncements and interpretations

For a discussion of recent accounting pronouncements and interpretations, see Note 9 of HEI s Notes to Consolidated Financial Statements.

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

Three months ended March 31 **(in thousands)**	**2009**	**2008**
Operating income from regulated and nonregulated activities before income taxes (per HEI consolidated statements of income)	$ 31,069	$ 50,983
Deduct:		
Income taxes on regulated activities	(8,544)	(15,378)
Revenues from nonregulated activities	(2,512)	(1,395)
Add:		
Expenses from nonregulated activities	236	456
Operating income from regulated activities after income taxes (per HECO consolidated statements of income)	$ 20,249	$ 34,666

9 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 (unaudited)

Three months ended March 31, 2009

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassifications and eliminations	HECO consolidated
Operating revenues	$ 305,461	84,631	69,193				$ 459,285
Operating expenses							
Fuel oil	98,931	15,764	30,594				145,289
Purchased power	75,845	33,407	5,232				114,484
Other operation	43,076	9,994	9,327				62,397
Maintenance	16,658	5,938	3,567				26,163
Depreciation	20,797	8,251	7,376				36,424
Taxes, other than income taxes	30,683	8,246	6,806				45,735
Income taxes	6,229	850	1,465				8,544
	292,219	82,450	64,367				439,036
Operating income	13,242	2,181	4,826				20,249
Other income							
Allowance for equity funds used during construction	2,702	742	161				3,605
Equity in earnings of subsidiaries	3,960					(3,960)	
Other, net	1,878	569	81	(7)	(7)	(146)	2,368
	8,540	1,311	242	(7)	(7)	(4,106)	5,973
Income (loss) before interest and other charges	21,782	3,492	5,068	(7)	(7)	(4,106)	26,222
Interest and other charges							
Interest on long-term debt	7,668	1,976	2,268				11,912
Amortization of net bond premium and expense	403	151	121				675
Other interest charges	477	207	88			(146)	626
Allowance for borrowed funds used during construction	(1,168)	(388)	(66)				(1,622)
	7,380	1,946	2,411			(146)	11,591
Income (loss) before preferred stock dividends of HECO and subsidiaries	14,402	1,546	2,657	(7)	(7)	(3,960)	14,631
Less net income attributable to noncontrolling interest preferred stock of subsidiaries		134	95				229
Income (loss) before preferred stock dividends of HECO	14,402	1,412	2,562	(7)	(7)	(3,960)	14,402
Preferred stock dividends of HECO	270						270
Net income (loss) for common stock	$ 14,132	1,412	2,562	(7)	(7)	(3,960)	$ 14,132

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Income (unaudited)

Three months ended March 31, 2008

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassifications and eliminations	HECO consolidated
Operating revenues	$ 414,513	105,192	102,789				$ 622,494
Operating expenses							
Fuel oil	172,152	24,046	53,345				249,543
Purchased power	99,779	41,359	9,657				150,795
Other operation	37,969	8,894	8,716				55,579
Maintenance	15,276	4,705	3,632				23,613
Depreciation	20,552	7,834	7,048				35,434
Taxes, other than income taxes	38,448	9,619	9,419				57,486
Income taxes	9,494	2,587	3,297				15,378
	393,670	99,044	95,114				587,828
Operating income	20,843	6,148	7,675				34,666
Other income							
Allowance for equity funds used during construction	1,502	255	144				1,901
Equity in earnings of subsidiaries	9,301					(9,301)	
Other, net	1,411	267	58	(23)	(254)	(363)	1,096
	12,214	522	202	(23)	(254)	(9,664)	2,997
Income (loss) before interest and other charges	33,057	6,670	7,877	(23)	(254)	(9,664)	37,663
Interest and other charges							
Interest on long-term debt	7,525	1,952	2,247				11,724
Amortization of net bond premium and expense	400	107	124				631
Other interest charges	862	405	82			(363)	986
Allowance for borrowed funds used during construction	(585)	(117)	(60)				(762)
	8,202	2,347	2,393			(363)	12,579
Income (loss) before preferred stock dividends of HECO and subsidiaries	24,855	4,323	5,484	(23)	(254)	(9,301)	25,084
Less net income attributable to noncontrolling interest preferred stock of subsidiaries		134	95				229
Income (loss) before preferred stock dividends of HECO	24,855	4,189	5,389	(23)	(254)	(9,301)	24,855
Preferred stock dividends of HECO	270						270
Net income (loss) for common stock	$ 24,585	4,189	5,389	(23)	(254)	(9,301)	$ 24,585

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Balance Sheet (unaudited)

March 31, 2009

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassifications and Eliminations	HECO Consolidated
Assets							
Utility plant, at cost							
Land	$ 33,213	4,982	4,346				$ 42,541
Plant and equipment	2,583,884	878,477	843,421				4,305,782
Less accumulated depreciation	(1,040,897)	(359,319)	(367,605)				(1,767,821)
Construction in progress	227,693	82,021	9,648				319,362
Net utility plant	1,803,893	606,161	489,810				2,899,864
Investment in wholly owned subsidiaries, at equity	439,286					(439,286)	
Current assets							
Cash and equivalents	477	2,628	1,005	105	12		4,227
Advances to affiliates	66,550		24,500			(91,050)	
Customer accounts receivable, net	58,997	20,753	13,949				93,699
Accrued unbilled revenues, net	53,699	14,406	11,065				79,170
Other accounts receivable, net	4,679	2,662	1,075		11	(917)	7,510
Fuel oil stock, at average cost	42,070	9,314	11,303				62,687
Materials & supplies, at average cost	17,471	4,628	13,710				35,809
Prepayments and other	7,143	2,694	1,143			(184)	10,796
Total current assets	251,086	57,085	77,750	105	23	(92,151)	293,898
Other long-term assets							
Regulatory assets	389,330	76,791	64,957				531,078
Unamortized debt expense	9,602	2,228	2,364				14,194
Other	39,254	7,962	7,378		119		54,713
Total other long-term assets	438,186	86,981	74,699		119		599,985
	$ 2,932,451	750,227	642,259	105	142	(531,437)	$ 3,793,747
Capitalization and liabilities							
Capitalization							
Common stock equity	$ 1,192,497	222,821	216,233	98	134	(439,286)	$ 1,192,497
Cumulative preferred stock not subject to mandatory redemption	22,293						22,293
Noncontrolling interest cumulative preferred stock of subsidiaries not subject to mandatory redemption		7,000	5,000				12,000
Stockholders equity	1,214,790	229,821	221,233	98	134	(439,286)	1,226,790
Long-term debt, net	582,150	151,185	174,346				907,681
Total capitalization	1,796,940	381,006	395,579	98	134	(439,286)	2,134,471

Current liabilities							
Short-term borrowings-affiliate	53,839	66,550				(91,050)	29,339
Accounts payable	74,270	22,363	10,513				107,146
Interest and preferred dividends payable	11,625	3,198	3,778			(49)	18,552
Taxes accrued	111,218	28,352	29,821			(184)	169,207
Other	33,677	8,541	12,509	7	8	(868)	53,874
Total current liabilities	284,629	129,004	56,621	7	8	(92,151)	378,118
Deferred credits and other liabilities							
Deferred income taxes	133,192	20,269	11,327				164,788
Regulatory liabilities	206,630	50,823	37,361				294,814
Unamortized tax credits	34,128	14,184	12,747				61,059
Retirement benefits liability	286,608	53,440	52,303				392,351
Other	11,770	35,868	7,575				55,213
Total deferred credits and other liabilities	672,328	174,584	121,313				968,225
Contributions in aid of construction	178,554	65,633	68,746				312,933
	$ 2,932,451	750,227	642,259	105	142	(531,437)	$ 3,793,747

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Balance Sheet (unaudited)

December 31, 2008

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassifications and Eliminations	HECO Consolidated
Assets							
Utility plant, at cost							
Land	$ 33,213	4,982	4,346				$ 42,541
Plant and equipment	2,567,018	874,322	836,159				4,277,499
Less accumulated depreciation	(1,028,501)	(352,382)	(360,570)				(1,741,453)
Construction in progress	188,754	68,650	9,224				266,628
Net utility plant	1,760,484	595,572	489,159				2,845,215
Investment in wholly owned subsidiaries, at equity	437,033					(437,033)	
Current assets							
Cash and equivalents	2,264	3,148	1,349	123	17		6,901
Advances to affiliates	62,000		12,000			(74,000)	
Customer accounts receivable, net	109,724	32,108	24,590				166,422
Accrued unbilled revenues, net	74,657	17,876	14,011				106,544
Other accounts receivable, net	3,983	2,217	1,143		11	564	7,918
Fuel oil stock, at average cost	53,546	10,326	13,843				77,715
Materials & supplies, at average cost	16,583	4,366	13,583				34,532
Prepayments and other	6,918	2,311	3,664			(267)	12,626
Total current assets	329,675	72,352	84,183	123	28	(73,703)	412,658
Other long-term assets							
Regulatory assets	388,054	77,038	65,527				530,619
Unamortized debt expense	9,802	2,282	2,419				14,503
Other	38,099	7,699	7,197		119		53,114
Total other long-term assets	435,955	87,019	75,143		119		598,236
	$ 2,963,147	754,943	648,485	123	147	(510,736)	$ 3,856,109
Capitalization and liabilities							
Capitalization							
Common stock equity	$ 1,188,842	221,405	215,382	105	141	(437,033)	$ 1,188,842
Cumulative preferred stock not subject to mandatory redemption	22,293						22,293
Noncontrolling interest cumulative preferred stock of subsidiaries not subject to mandatory redemption		7,000	5,000				12,000
Stockholders equity	1,211,135	228,405	220,382	105	141	(437,033)	1,223,135
Long-term debt, net	582,132	148,030	174,339				904,501
Total capitalization	1,793,267	376,435	394,721	105	141	(437,033)	2,127,636

Current liabilities							
Short-term borrowings-affiliate	53,550	62,000				(74,000)	41,550
Accounts payable	84,238	27,795	10,961				122,994
Interest and preferred dividends payable	10,242	2,547	2,819			(211)	15,397
Taxes accrued	144,366	38,117	37,830			(267)	220,046
Other	33,462	9,015	11,992	18	6	775	55,268
Total current liabilities	325,858	139,474	63,602	18	6	(73,703)	455,255
Deferred credits and other liabilities							
Deferred income taxes	134,359	19,621	12,330				166,310
Regulatory liabilities	202,003	49,843	36,756				288,602
Unamortized tax credits	32,501	13,476	12,819				58,796
Retirement benefits liability	284,826	54,664	53,355				392,845
Other	11,576	35,432	7,941				54,949
Total deferred credits and other liabilities	665,265	173,036	123,201				961,502
Contributions in aid of construction	178,757	65,998	66,961				311,716
	$ 2,963,147	754,943	648,485	123	147	(510,736)	$ 3,856,109

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Changes in Stockholders Equity (unaudited)

Three months ended March 31, 2009

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassifications and eliminations	HECO consolidated
Balance, December 31, 2008	$ 1,211,135	228,405	220,382	105	141	(437,033)	$ 1,223,135
Comprehensive income:							
Net income	14,402	1,546	2,657	(7)	(7)	(3,960)	14,631
Retirement benefit plans:							
Amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of taxes	2,678	409	325			(734)	2,678
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of tax benefits	(2,619)	(405)	(319)			724	(2,619)
Comprehensive income (loss)	14,461	1,550	2,663	(7)	(7)	(3,970)	14,690
Common stock dividends	(10,536)		(1,717)			1,717	(10,536)
Preferred stock dividends	(270)	(134)	(95)				(499)
Balance, March 31, 2009	$ 1,214,790	229,821	221,233	98	134	(439,286)	$ 1,226,790

Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Changes in Stockholders Equity (unaudited)

Three months ended March 31, 2008

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassifications and eliminations	HECO consolidated
Balance, December 31, 2007	$ 1,132,755	208,820	213,521	182	388	(410,911)	$ 1,144,755
Comprehensive income:							
Net income	24,855	4,323	5,484	(23)	(254)	(9,301)	25,084
Retirement benefit plans:							
Amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of taxes	1,366	190	153			(343)	1,366
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of tax benefits	(1,309)	(185)	(147)			332	(1,309)
Comprehensive income (loss)	24,912	4,328	5,490	(23)	(254)	(9,312)	25,141
Common stock dividends	(14,089)		(2,722)			2,722	(14,089)
Preferred stock dividends	(270)	(134)	(95)				(499)
Issuance of common stock					50	(50)	

Balance, March 31, 2008	$ 1,143,308	213,014	216,194	159	184	(417,551)	$ 1,155,308

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Cash Flows (unaudited)

Three months ended March 31, 2009

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassifications and eliminations	HECO Consolidated
Cash flows from operating activities							
Income before preferred stock dividends of HECO	$ 14,402	1,546	2,657	(7)	(7)	(4,189)	$ 14,402
Adjustments to reconcile income before preferred stock dividends of HECO to net cash provided by operating activities:							
Equity in earnings	(3,985)					3,960	(25)
Common stock dividends received from subsidiaries	1,742					(1,717)	25
Depreciation of property, plant and equipment	20,797	8,251	7,376				36,424
Other amortization	694	209	1,303				2,206
Deferred income taxes	(989)	672	(973)				(1,290)
Tax credits, net	1,788	744	(18)				2,514
Allowance for equity funds used during construction	(2,702)	(742)	(161)				(3,605)
Changes in assets and liabilities:							
Decrease in accounts receivable	50,031	10,910	10,709			1,481	73,131
Decrease in accrued unbilled revenues	20,958	3,470	2,946				27,374
Decrease in fuel oil stock	11,476	1,012	2,540				15,028
Decrease in materials and supplies	(888)	(262)	(127)				(1,277)
Decrease (increase) in regulatory assets	(3,292)	108	(1,071)				(4,255)
Decrease in accounts payable	(9,968)	(5,432)	(448)				(15,848)
Changes in prepaid and accrued income and utility revenue taxes	(34,394)	(9,605)	(5,562)				(49,561)
Changes in other assets and liabilities	9,256	(1,874)	(121)	(11)	2	(1,481)	5,771
Net cash provided by (used in) operating activities	74,926	9,007	19,050	(18)	(5)	(1,946)	101,014
Cash flows from investing activities							
Capital expenditures	(57,235)	(17,595)	(5,485)				(80,315)
Contributions in aid of construction	1,455	504	403				2,362
Advances from (to) affiliates	(4,550)		(12,500)			17,050	
Net cash used in investing activities	(60,330)	(17,091)	(17,582)			17,050	(77,953)
Cash flows from financing activities							
Common stock dividends	(10,536)		(1,717)			1,717	(10,536)
Preferred stock dividends	(270)	(134)	(95)			229	(270)
Proceeds from issuance of long-term debt		3,148					3,148
Net increase in short-term borrowings from nonaffiliates and affiliate with original maturities of three months or less	289	4,550				(17,050)	(12,211)
Decrease in cash overdraft	(5,865)						(5,865)
Other	(1)						(1)
Net cash provided by (used in) financing activities	(16,383)	7,564	(1,812)			(15,104)	(25,735)

Net decrease in cash and equivalents	(1,787)	(520)	(344)	(18)	(5)		(2,674)
Cash and equivalents, beginning of period	2,264	3,148	1,349	123	17		6,901
Cash and equivalents, end of period	$ 477	2,628	1,005	105	12		$ 4,227

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Cash Flows (unaudited)

Three months ended March 31, 2008

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassifications and eliminations	HECO Consolidated
Cash flows from operating activities							
Income before preferred stock dividends of HECO	$ 24,855	4,323	5,484	(23)	(254)	(9,530)	$ 24,855
Adjustments to reconcile income before preferred stock dividends of HECO to net cash provided by operating activities:							
Equity in earnings	(9,326)					9,301	(25)
Common stock dividends received from subsidiaries	2,747					(2,722)	25
Depreciation of property, plant and equipment	20,552	7,834	7,048				35,434
Other amortization	792	197	1,174				2,163
Deferred income taxes	(4,055)	(154)	(1,744)				(5,953)
Tax credits, net	264	142	29				435
Allowance for equity funds used during construction	(1,502)	(255)	(144)				(1,901)
Changes in assets and liabilities:							
Increase in accounts receivable	(3,402)	(1,099)	(2,874)			(527)	(7,902)
Decrease (increase) in accrued unbilled revenues	5,375	(539)	(1,018)				3,818
Decrease (increase) in fuel oil stock	(16,744)	2,378	5,097				(9,269)
Decrease (increase) in materials and supplies	(1,306)	(305)	630				(981)
Decrease (increase) in regulatory assets	(1,765)	151	(712)				(2,326)
Increase (decrease) in accounts payable	(1,563)	4,253	(2,236)				454
Increase in taxes accrued	(26,896)	(8,670)	(5,540)				(41,106)
Changes in other assets and liabilities	7,286	850	884	(5)	(14)	527	9,528
Net cash provided by (used in) operating activities	(4,688)	9,106	6,078	(28)	(268)	(2,951)	7,249
Cash flows from investing activities							
Capital expenditures	(23,006)	(17,819)	(6,904)				(47,729)
Contributions in aid of construction	1,629	1,406	801				3,836
Advances from (to) affiliates	(6,400)		1,500			4,900	
Investment in consolidated subsidiary	(50)					50	
Other	122				(179)		(57)
Net cash used in investing activities	(27,705)	(16,413)	(4,603)		(179)	4,950	(43,950)
Cash flows from financing activities							
Common stock dividends	(14,089)		(2,722)			2,722	(14,089)
Preferred stock dividends	(270)	(134)	(95)			229	(270)
Proceeds from issuance of long-term debt	6,808	1,015	2,074				9,897
Proceeds from issuance of common stock					50	(50)	
Net increase in short-term borrowings from nonaffiliates and affiliate with original maturities of three months or less	58,817	6,400				(4,900)	60,317
Decrease in cash overdraft	(8,581)		(1)				(8,582)

Net cash provided by (used in) financing activities	42,685	7,281	(744)		50	(1,999)	47,273
Net increase (decrease) in cash and equivalents	10,292	(26)	731	(28)	(397)		10,572
Cash and equivalents, beginning of period	203	3,069	773	198	435		4,678
Cash and equivalents, end of period	$ 10,495	3,043	1,504	170	38		$ 15,250

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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 incorporated by reference in HEI s and HECO s Form 10-K for the year ended December 31, 2008 and should be read in conjunction with the annual (as of and for the year ended December 31, 2008) and the quarterly (as of and for the three months ended March 31, 2009) consolidated financial statements of HEI and HECO and accompanying notes.

HEI Consolidated

RESULTS OF OPERATIONS

(in thousands, except per share amounts)	Three months ended March 31, 2009	2008	% change	Primary reason(s) for significant change*
Revenues	$ 543,797	$ 729,617	(25)	Decrease for the electric utility and the bank segments
Operating income	44,658	70,746	(37)	Decrease for the electric utility and the bank segments
Net income	20,395	33,967	(40)	Lower operating income, partly offset by higher AFUDC, lower interest expense other than on deposit liabilities and other bank borrowings and lower income taxes**
Basic earnings per common share	$ 0.23	$ 0.41	(44)	Lower net income and higher weighted average shares outstanding
Weighted-average number of common shares outstanding	90,604	83,472	9	Issuances of shares under a common stock offering in December 2008 and the HEI Dividend Reinvestment and Stock Purchase Plan and other Company plans

* Also, see segment discussions which follow.

** The Company s effective tax rates (federal and state) for the first quarters of 2009 and 2008 were 35% and 37%, respectively.

Dividends. The payout ratios for 2008 and the first quarter of 2009 were 116% and 135%, respectively. Excluding the $35.6 million net charge related to ASB s balance sheet restructuring (and disregarding other adjustments to net income that would be necessary to more fully reflect the impact on net income if the restructuring had not occurred), the payout ratio for 2008 would have been 83%. 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.

Economic conditions

Note: The statistical data in this section is from public third-party sources (e.g., Department of Business, Economic Development and Tourism; University of Hawaii Economic Research Organization; Hawaii Department of Labor and Industrial Relations; Honolulu Board of Realtors; Blue Chip Financial Forecasts; Bloomberg and local newspapers).

As a consequence of deteriorating financial conditions within the banking industry, a series of events occurred in the last four months of 2008 that resulted in unprecedented global capital market volatility and decline that continues in 2009.

The Hawaii economy continued to decline in the first quarter of 2009 due to the pressures created by volatile capital markets and the depressed national economy. State economists now expect a much deeper and longer Hawaii recession. Hawaii economic growth as measured by the change in real personal income is expected to be lower by 2.5% in 2009 compared to 2008 and by 0.2% in 2010 compared to 2009.

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Weakness is most notable in one of the state s largest industries, tourism. The closure of Aloha and ATA Airlines, departure of two Norwegian Cruise Line cruise ships from Hawaii, record-high oil prices and downturn in the national economy impacted the visitor industry in 2008. The severity of the global downturn and constraints to consumer spending are expected to cause tourism to remain at a low level through 2010, with only a gradual recovery thereafter. Visitor arrivals were down 14% for the first quarter of 2009 compared to the same quarter in 2008. Arrivals in 2009 are expected to be down from 2008 levels by approximately 5% and flat in 2010. Visitor expenditures were down 18% quarter over quarter.

Local tourism authorities continue to increase marketing efforts in Hawaii s base market, the western U.S., to help stimulate travel to the state.

At 7.1%, seasonally-adjusted Hawaii unemployment at the end of March 2009 remains below the national average of 8.5%, but is much higher than the average annual rates of 2.6% for 2007 and 4% for 2008. Declines in tourism and in consumer spending are expected to cause job losses in 2009, with the largest job losses expected in the construction, accommodation and food services sectors. The job base is expected to contract by 2.4% in 2009 and 0.3% in 2010. The Hawaii unemployment rate is expected to be 7.0% in 2009 and 7.6% in 2010.

The Oahu housing market continued to contract in the first quarter of 2009. Home sales for the first quarter were down 35%, and the median sales price for the quarter of $570,000 was down 8.1% compared with the first quarter of 2008. Foreclosures in Hawaii are on the rise, increasing by a record 503% in March 2009 compared to March 2008. However, the State of Hawaii foreclosure ranking fell back to 30th in March 2009, compared to 27th in February 2009 and 30th in January 2009.

The global credit crisis and deepening recession have impacted the Hawaii construction industry. Commercial and resort building are hampered by financing constraints and a bleak national outlook. Residential construction is expected to decline as income and wealth losses undermine housing demand. Government spending initiatives may provide substantial support for the industry in the medium term. Construction activity, as measured by permitting activity (excluding military construction) declined 27% in the first quarter of 2009 compared with the same period in 2008.

On a national level, the Blue Chip economic consensus dated April 1, 2009 predicts real gross domestic product (GDP) to decline by 5.3% and 2.4% for the first and second quarters of 2009 compared to the immediately preceeding quarter, respectively. Recovery is expected to resume in the second half of 2009. Consumer confidence has been adversely affected and credit is tight, which in turn has and will continue to negatively impact consumer spending.

The price of a barrel of crude oil has fallen sharply, with prices dropping from a peak of $145.29 per barrel on July 3, 2008, and closing at $50.97 per barrel on April 29, 2009.

Interest rates remained low during the first quarter of 2009, including relatively low mortgage rates. The low level of interest rates continued to put downward pressure on yields on loans and investments, but also contributed to lower deposit and borrowing costs.

Overall, the Hawaii economy continues to weaken as the U.S. and Japan economies continue to weaken and relief is not expected until late 2010, or possibly late 2009 at the earliest.

Emergency Economic Stabilization Act of 2008 and American Economic Recovery and Reinvestment Act of 2009. The Emergency Economic Stabilization Act of 2008 (the 2008 Act) was signed into law on October 3, 2008. The principal parts of the 2008 Act are: (1) a $700 billion financial markets stabilization plan; and (2) $150 billion in tax benefits, which are partially offset by $40 billion in revenue raisers. As part of its energy and conservation related incentives, the 2008 Act allows public utility property to qualify for the energy credit for periods after February 13, 2008 and extends the credit for solar energy property, fuel cell property and microturbine property through December 31, 2016. In addition, the 2008 Act allows the credit for combined heat and power (CHP) system property as energy property for periods after October 3, 2008. Further, the 2008 Act extends the renewable production credit through December 31, 2009 for qualified wind and refined coal production facilities and through December 31, 2010 for other sources. The 2008 Act also provides for a 10-year accelerated depreciation period for smart electric meters and smart electric grid equipment for property placed in service after October 3, 2008. Finally, the 2008 Act extends the per-gallon incentives for biodiesel and alternative fuels through December 31, 2009. The tax provisions of the 2008 Act did not have a material effect on the Company s results of operations for 2008. These tax provisions, however, may influence the Company s decisions to invest in the various properties entitled to credits and favorable depreciation. The Company will continue to analyze the 2008 Act for its impacts on results of operations, financial condition and liquidity and for the opportunities it presents.

The American Economic Recovery and Reinvestment Act of 2009 (the 2009 Act) was signed into law on February 17, 2009 at a total cost of $787 billion. The 2009 Act, which is intended to provide a stimulus to the U.S. economy in the midst of the global financial crisis, is comprised of tax relief, spending on infrastructure, health care and alternative energy and aid to states and local governments. The 2009 Act includes more than $300 billion in tax relief, which is focused primarily on low and middle income taxpayers and small businesses. The energy provisions set in motion President Obama s campaign promises to implement a green economic recovery.

The extension through 2009 of bonus depreciation, as originally provided in the 2008 Economic Stimulus Act, has the most direct and immediate impact on the Company. Although not quantified, the additional tax depreciation deduction will increase deferred income taxes and provide positive cash flow. The energy related provisions of the 2009 Act may impact utility operations indirectly. Some of the energy incentives are as follows: (1) a 30% tax credit of up to $1,500 for the purchase of highly efficient residential air conditioners, heat pumps or furnaces, (2) $0.3 billion in rebates for purchases of efficient appliances, (3) $20 billion for green jobs to make wind turbines and solar panels and to improve energy efficiency in schools and federal buildings, (4) $6 billion in loan guarantees for renewable energy projects, (5) $5 billion to help low-income homeowners make energy improvements, (6) $11 billion to modernize and expand the U.S. electric power grid, (7) $2 billion for research into batteries for future electric cars and (8) the extension of existing energy incentives and the addition of a few new ones. Finally, the 2009 Act temporarily eliminates the alternative minimum tax preference item for private activity bond interest for bonds (such as special purpose revenue bonds issued by HECO and its subsidiaries) issued in 2009 and 2010. This favorable change may influence the utilities decision to issue such bonds before the end of 2010.

The Company will continue to analyze the 2009 Act for its impacts on results of operations, financial condition and liquidity and for the opportunities it presents.

Retirement benefits. For the first quarter of 2009, the Company s defined benefit retirement plans assets generated a loss, including investment management fees, of 6.3%. The market value of the defined benefit retirement plans assets as of March 31, 2009 was $676 million compared to $726 million at December 31, 2008, a decline of approximately $50 million.

Additional guidance on funding relief for qualified defined benefit pension plans was received in March 2009 including: (1) IRS Notice 2009-22 related to the application of new asset valuation rules included in the Worker, Retiree, and Employer Recovery Act of 2008 and (2) publication of a Special Edition March 2009 employee plans news related to yield curve selection for the target liability calculation. As a result, the Company estimates that the cash funding for the qualified defined benefit pension plans in 2009 and 2010 will be about $16 million and $42 million, respectively, which should fully satisfy the minimum required contribution, including requirements of the utilities pension tracking mechanisms and the Plan s funding policy. Prior to the March 2009 funding relief measures, cash funding to satisfy the minimum required contribution in 2009 and 2010 was estimated to be $21 million and $64 million, respectively.

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.

The credit rating agencies consider many factors when assigning their ratings. The distress in the worldwide financial market has significantly increased the unfunded status of the Company s pension plans, and may be a factor considered by the credit rating agencies in their evaluations. The associated increase in pension plan

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funding requirements will negatively impact certain financial metrics utilized by the credit rating agencies in determining the Company s credit ratings and could result in a reduction of the Company s credit ratings from their current levels.

Commitments and contingencies. See Note 7 of HEI s Notes to Consolidated Financial Statements.

Recent accounting pronouncements and interpretations. See Note 9 of HEI s Notes to Consolidated Financial Statements.

Other segment

(in thousands)	Three months ended March 31, 2009	2008	% change	Primary reason(s) for significant change
Revenues	$ (32)	$ (116)	NM	Lower unrealized losses on venture capital investments
Operating loss	(3,532)	(3,600)	NM	See explanation for revenues and lower proxy costs (expected to be higher in the second quarter), partly offset by higher consulting and other administrative and general expenses
Net loss	(4,619)	(5,194)	NM	See explanation for operating loss and lower interest expense

NM Not meaningful.

The other business segment includes results of operations of HEI and HEI Diversified, Inc. (HEIDI), holding companies; HEI Investments, Inc. (HEIII), a company previously holding investments in leveraged leases; Pacific Energy Conservation Services, Inc., a contract services company primarily providing wind farm operational and maintenance services to an affiliated electric utility; HEI Properties, Inc., a company holding passive, venture capital investments; The Old Oahu Tug Service, Inc., a maritime freight transportation company that ceased operations in 1999; and eliminations of intercompany transactions. Since HEIII sold all of its leveraged lease investments by the end of 2007, HEIII has filed articles of dissolution and is winding up its affairs.

FINANCIAL CONDITION

Liquidity and capital resources

Despite the recent unprecedented deterioration in the capital markets and tightening of credit, 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 in the foreseeable future.

The consolidated capital structure of HEI (excluding ASB s deposit liabilities and other borrowings) was as follows as of the dates indicated:

(in millions)	March 31, 2009		December 31, 2008	
Short-term borrowings other than bank	$	%	$	%
Long-term debt, net other than bank	1,215	46	1,212	46
Preferred stock of subsidiaries	34	1	34	1
Common stock equity	1,404	53	1,389	53
	$ 2,653	100%	$ 2,635	100%

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As of May 1, 2009, 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-2	P-2
Senior unsecured debt	BBB	Baa2

The above ratings reflect only the view of the applicable rating agency at the time the ratings are issued, 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.

HEI s overall S&P corporate credit rating is BBB/Stable/A-2. HEI s issuer rating by Moody s is Baa2 and Moody s outlook for HEI is stable.

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 HEI securities. In November 2008, S&P affirmed its corporate credit ratings and stable outlook for HEI. S&P s ratings outlook indicates the potential direction of a possible rating change in the coming 6 to 24 months. S&P stated:

The stable outlook reflects our expectation that, for now, HECO appears to have reasonable but not certain prospects for maintaining its existing financial profile, which is weak for the rating. Multiple near-term challenges face the company and include the uncertainties of the cost and feasibility impacts of the CEI [Clean Energy Initiative], the potential for a significant reduction in electric sales in 2009 (due to economic contraction, energy efficiency initiatives, and customer response to high prices), and a recent softening in leading economic indicators. These challenges suggest that a negative outlook or downward revision to the ratings could be possible over the outlook horizon, as further weakening in the financial profile will not support ratings, and near-term business risk will be elevated until the particulars of the CEI are in place and prove to be supportive. Consistent, timely rate relief will continue to be key, and could offset or mitigate the effects of a declining economic environment, but decoupling or other measures are not expected to be available to the company before late 2009 or early 2010. Given these challenges, higher ratings are not foreseen during the outlook horizon and would need to be accompanied by sustained and improved financial performance.

S&P designates business risk profiles as excellent, strong, satisfactory, weak or vulnerable. In November 2008, S&P designated HEI s busi profile as strong and noted that it reflects a degree of diversification afforded by ASB s banking business. However, S&P noted that the consolidated profile s strengths are tempered by the reliance of both businesses on Hawaii s economy. S&P further observed that structural shifts in HECO s business contemplated under the Hawaii Clean Energy Initiative is the largest challenge facing HEI s consolidated operations, along with the potential of ASB credit losses as a function of a weakening Hawaii economy.

S&P s financial risk designations are minimal, modest, intermediate, aggressive and highly leveraged. In November 2008, S&P indicated th [t]he consolidated financial profile is aggressive, reflecting in part the very heavy debt imputation we apply to the three utilities for power purchase agreements (PPA).

In September 2008, Moody s affirmed its credit ratings and stable outlook for HEI. Moody s stated, [t]he rating could be downgraded should weaker than expected economic growth and regulatory support emerge at HECO which ultimately causes earnings and sustainable cash flows to suffer over an extended period. Consequently, Moody s indicated that a shift in its expectations regarding the company s future sustainable levels of consolidated financial ratios such as Funds From Operations (net cash flow from operations less net changes in working capital items) to Adjusted Debt below 16% (16% as of June 30, 2008 latest reported by Moody s) or Funds From Operations to Adjusted Interest of less than 3.5x (3.9x as of June 30, 2008 latest reported by Moody s) could result in a lowering of the Company s rating.

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See the electric utilities and bank s respective Liquidity and capital resources sections below for the ratings of HECO and ASB.

Information about the Company s short-term borrowings and HEI s line of credit facility was as follows:

	Three months ended March 31, 2009		
(in millions)	Average balance	End-of-period balance	December 31, 2008
Short-term borrowings			
HEI commercial paper	$	$	$
HEI line of credit draws			
HECO commercial paper	1		
	$ 1	$	$
Line of credit facility (expiring March 31, 2011) [1]		$ 100	$ 100
Undrawn capacity under HEI s line of credit facility [2]		100	100

[1] In the future, the Company may seek to enter into new lines of credit and may also seek to increase the amount of credit available under such lines as management deems appropriate. This table does not include HECO s separate line of credit facilities.

[2] At May 1, 2009, there was no outstanding commercial paper balance and the 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 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. As of March 31, 2009, HEI had no short-term borrowings outstanding and had short-term loans to HECO of $29 million. HEI expects to sell commercial paper in the latter half of 2009. 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 otherwise were to further tighten, it would be more difficult and expensive to sell commercial paper or it might not be able to sell commercial paper in the future.

In November 2008, HEI filed an omnibus registration statement to register an indeterminate amount of debt, equity and hybrid securities. Under Securities and Exchange Commission (SEC) regulations, this registration statement expires on November 4, 2011. On December 2, 2008, HEI offered and priced under the registration a public offering of 5,000,000 shares of its common stock at $23 per share for gross proceeds of $115 million. HEI used the net proceeds of approximately $110 million, after deduction of underwriting discounts and commissions and estimated HEI expenses, to repay its outstanding short-term indebtedness, to make loans to HECO and for working capital and other general corporate purposes. An over-allotment option granted to the underwriters was not exercised.

For the first three months of 2009, net cash provided by operating activities of consolidated HEI was $115 million. Net cash provided by investing activities for the same period was $157 million, primarily due to net decreases in investment and mortgage-related securities and loans receivable at ASB, partly offset by HECO s consolidated capital expenditures. Net cash used in financing activities during this period was $294 million as a result of several factors, including net decreases in deposit liabilities, retail repurchase agreements, other bank borrowings and cash overdrafts and the payment of common stock dividends, partly offset by proceeds from the issuance of common stock under HEI plans and funds from the drawdown of revenue bond proceeds.

Forecasted HEI consolidated net cash used in investing activities (excluding investing cash flows from ASB) for 2009 through 2011 consists primarily of the net capital expenditures of HECO and its subsidiaries. In addition to the funds required for the electric utilities construction program, approximately $150 million will be required in 2011 to repay maturing HEI medium-term notes, which are expected to be repaid with the proceeds from the issuance of commercial paper, common stock issued under Company plans and/or dividends from subsidiaries. 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 uncertain or unanticipated expenditures not included in the 2009 through 2011 forecast, such as increases in the costs of or an acceleration of the construction of capital

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projects of the utilities, 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. In addition, existing debt may be refinanced prior to maturity (potentially at more favorable rates) with additional debt or equity financing (or both).

The Company was not required to make any contributions to the qualified pension plans to meet minimum funding requirements pursuant to ERISA for 2008, but made voluntary contributions in 2008. Contributions to the retirement benefit plans totaled $15 million in 2008 (comprised of $14 million made by the utilities, $1 million by HEI and nil by ASB) and are expected to total $32 million in 2009 ($31 million by the utilities, $1 million by HEI and nil by ASB). Depending on the performance of the assets held in the plans trusts and numerous other factors, additional contributions may be required in the future to meet the minimum funding requirements of ERISA or to pay benefits to plan participants. Although credit markets have tightened and may tighten further, the Company believes it will have adequate access to capital resources to support any necessary funding requirements.

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 15 to 16, 42 to 47, and 56 to 58 of HEI s MD&A which is incorporated into Part II, Item 7 of HEI s 2008 Form 10-K by reference to HEI Exhibit 13 to HEI s Current Report on Form 8-K dated February 19, 2009.

Additional factors that may affect future results and financial condition are described 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 16 to 17, 47 to 48, and 59 of HEI s MD&A which is incorporated into Part II, Item 7 of HEI s 2008 Form 10-K by reference to HEI Exhibit 13 to HEI s Current Report on Form 8-K dated February 19, 2009.

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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, 2009	2008	% change	Primary reason(s) for significant change
Revenues	$ 461,797	$ 623,889	(26)	Lower fuel oil and purchased energy fuel costs, the effects of which are generally passed on to customers ($122 million), and lower KWH sales ($49 million), partially offset by higher DSM costs recovered through a surcharge ($3 million)
Expenses				
Fuel oil	145,289	249,543	(42)	Lower fuel oil costs and less KWHs generated
Purchased power	114,484	150,795	(24)	Lower fuel costs and less KWHs purchased
Other operation	62,397	55,579	12	See Results three months ended March 31, 2009 below
Maintenance	26,163	23,613	11	See Results three months ended March 31, 2009 below
Depreciation	36,424	35,434	3	Additions to plant in service in 2008
Taxes, other than income taxes	45,735	57,486	(20)	Decrease in revenues
Other	236	456	(48)	
Operating income	31,069	50,983	(39)	Lower sales and higher expenses
Net income	14,132	24,585	(43)	Lower operating income, partly offset by higher AFUDC
Kilowatthour sales (millions)	2,231	2,409	(7)	Slowing economy, customer conservation, cooler, less humid weather on Oahu and the effect of an additional leap year day in February 2008
Cooling degree days (Oahu)	759	954	(20)	
Average fuel oil cost per barrel	$ 60.02	$ 93.89	(36)	

Note: The electric utilities had an effective tax rate for the first quarters of 2009 and 2008 of 37% and 38%, respectively.

See Economic conditions in the HEI Consolidated section above.

Results three months ended March 31, 2009. Operating income for the first quarter of 2009 decreased 39% from the same period in 2008 due primarily to lower sales and higher operation and maintenance (O&M) expenses. For the first quarter of 2009, kilowatthour (KWH) sales were down 7.4% compared with the same quarter of 2008. About two-thirds of the decline in sales is attributable to cooler, less humid weather and one less day of sales due to the leap year day in 2008. The soft economy and overall ongoing customer conservation account for the remainder of the first quarter sales decline.

Other operation expenses increased by $7 million in 2009 primarily due to higher DSM expenses (see Demand-side management programs below) that are generally passed on to customers through surcharges ($2.5 million), $1.8 million higher planned production and transmission and distribution operations expense to maintain reliable operations and pursue renewable initiatives; $0.9 million higher employee benefit costs and

$0.5 million higher bad debt expense. Maintenance expense increased $2.6 million primarily due to the greater scope of generating unit overhauls and higher expenses for overhead line maintenance and vegetation management.

The trend of increased O&M expenses is expected to continue as the electric utilities expect higher production expenses (primarily due to increased utilization of HECO s generating assets commensurate with the level of demand that has occurred over the past five years), higher contract services costs, and higher transmission and distribution expenses to maintain system reliability. Also, additional expenses are expected to be incurred for the costs of CIP CT-1 after July 2009 when it is expected to commence commercial operations, for environmental compliance in response to more stringent regulatory requirements, and to execute the provisions of the Energy Agreement. Partly offsetting the anticipated increased costs are lower DSM expenses (that are generally passed on to customers through a surcharge) due to the transition of energy efficiency programs to a third-party administrator during 2009.

As a result of cumulative load growth over the past five years on Oahu and other factors, there remains an increased risk to generation reliability at least until HECO installs its planned new generating unit in the third quarter of 2009. Although peak demand moderated in 2008, generation reserve margins on Oahu continued to be strained. HECO has taken a number of steps to mitigate the risk of outages, including securing additional purchased power, adding DG at some substations and encouraging energy conservation. The costs of supplying energy to meet high demand and the maintenance costs required to sustain high availability of the aging generating units have been increasing and the trend of increased costs is not likely to ease.

Renewable energy strategy. The electric utilities have been taking actions intended to protect Hawaii s island ecology and counter global warming, while continuing to provide reliable power to customers, and recently 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 generation and 3) the acceleration of energy efficiency and load management programs. Major initiatives are being pursued in each category, and additional ones have been committed to in the Energy Agreement.

In its June 27, 2008 filing with the PUC, HECO reported a consolidated RPS of 16.1% in 2007. 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.

The electric utilities are actively exploring the use of biofuels for existing and planned company-owned generating units. HECO has committed to using 100% biofuels for its new 110 MW generating unit planned for 2009. HECO is researching the possibility of switching its steam generating units from fossil fuels to biofuels, and in the Energy Agreement has committed to do so if economically and technically feasible and if adequate biofuels are available.

In January 2007, HECO and MECO agreed to form a venture with BlueEarth Biofuels LLC (BlueEarth) to develop a biodiesel production facility on MECO property in Wa ena on the island of Maui. BlueEarth Maui Biofuels LLC (BlueEarth Maui), a joint venture to pursue biodiesel development, was formed in early 2008 between BlueEarth and Uluwehiokama Biofuels Corp. (UBC), a non-regulated subsidiary of HECO. In February 2008, an Operating Agreement and an Investment Agreement were executed between BlueEarth and UBC, under which UBC invested $400,000 in BlueEarth Maui in exchange for a minority ownership interest. All of UBC s profits from the project were intended to be directed into a biofuels public trust to be created for the purpose of funding biofuels development in Hawaii. MECO intended to lease to BlueEarth Maui a portion of the land owned by MECO for its future Waena generation station as the site for the biodiesel plant, with lease proceeds intended to be credited to MECO ratepayers. MECO had been negotiating with BlueEarth Maui for a fuel purchase contract for biodiesel to be used in existing diesel-fired units at MECO s Maalaea plant. Both the land lease agreement and biodiesel fuel contract would require PUC approval. However, BlueEarth s and MECO s negotiations for the biodiesel supply contract stalled based on inability to reach agreement on various financial and risk allocation issues. In October 2008, BlueEarth filed an action in federal district court in Texas against MECO, HECO and others alleging claims based on the parties failure to have reached agreement on the biodiesel supply and land agreements. The lawsuit seeks damages and equitable relief. In April 2009, the defendants motions to transfer venue of the action to Hawaii were granted.

The electric utilities also support renewable energy through their solar water heating and heat pump programs, and the negotiation and execution of purchased power contracts with non-utility generators using renewable sources (e.g., refuse-fired, geothermal, hydroelectric and wind turbine generating systems). In November 2007, HECO entered into a contract to purchase energy from a photovoltaic system with a generating capacity of up to 300 kilowatts (kW) to be located at HECO s Archer substation. The PUC approved the contract in May 2008. In October 2008, the PUC approved a power purchase contract between MECO and Lanai Sustainability Research, LLC for the purchase of 1.2 MW of electricity from a photovoltaic system owned by Lanai Sustainability Research, LLC, which was placed in service in December 2008. In December 2008, the PUC approved a power purchase contract between HELCO and Keahole Solar Power LLC (a wholly-owned subsidiary of Sopogy, Inc.) for the purchase of energy from a 500 kW concentrated solar power facility. In March 2009, HECO and HELCO filed an executed term sheet with the PUC for a power purchase contract with Hu Honua Bioenergy, LLC, which intends to refurbish a biomass plant located on the island of Hawaii.

In September 2007, HECO issued a Solicitation of Interest for its planned Renewable Energy Request for Proposals (RFP) for combined renewable energy projects up to 100 MW on Oahu. In June 2008, the PUC approved HECO s Oahu Renewable Energy RFP and HECO issued the RFP shortly thereafter. HECO received bids representing a variety of renewable technologies and a short list of bids proceeding to the Interconnection Requirements Study phase has been identified. Included in the bids received were proposals for large scale neighbor island wind projects. In accordance with the Energy Agreement, the proposals for large scale neighbor island wind projects (Big Wind projects) were bifurcated from the Oahu Renewable Energy RFP. The utilities intend to separately negotiate purchase power agreements with two neighbor island wind projects that would produce energy to be imported to Oahu via a yet-to-be-built undersea transmission cable system.

HECO s unregulated subsidiary, Renewable Hawaii, Inc. (RHI), was established to stimulate renewable energy initiatives by prospecting for new projects and sites and taking a passive, minority interest in selected third-party renewable energy projects. Beginning in 2003, RHI actively pursued a number of projects, particularly those utilizing wind, landfill gas, and ocean energy. While RHI has executed some memoranda of understanding and conditional investment agreements with project developers, no investments have been made to date.

The electric utilities promote research and development in the areas supporting renewable energy such as biofuels, ocean energy, battery storage, electronic shock absorber, and integration of non-firm power into the separate island electric grids.

Energy efficiency and DSM programs for commercial and industrial customers, and residential customers, including load control programs, have resulted in reducing system peak load and contribute to the achievement of the RPS. Since the inception of the energy efficiency and DSM programs in 1996 and through the end of 2008, the total system peak load has been reduced by 163 MW (143 MW at HECO, 8 MW at HELCO, and 12 MW at MECO) at the gross generation level and net of estimated reductions from participants who would have installed the DSM measure without the program and rebate.

For a description of some of the major provisions of the Energy Agreement most directly affecting HECO and its subsidiaries and their commitments relating to renewable energy and energy efficiency, see Hawaii Clean Energy Initiative in Note 5 of HECO s Notes to Consolidated Financial Statements.

Also, see Renewable Portfolio Standard under Legislation and regulation below.

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.

In 1996, the PUC issued an order instituting a proceeding to identify and examine the issues surrounding electric competition and to determine the impact of competition on the electric utility infrastructure in Hawaii. In October 2003, the PUC opened investigative proceedings on two specific issues (competitive bidding and DG) to move toward a more competitive electric industry environment under cost-based regulation. For a description of some of the regulatory changes that will be pursued as part of the Energy Agreement, see Hawaii Clean Energy Initiative in Note 5 of HECO s Notes to Consolidated Financial Statements.

Competitive bidding proceeding. The stated purpose of this proceeding, commenced in 2003, was to evaluate competitive bidding as a mechanism for acquiring or building new generating capacity in Hawaii. 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 determination of whether to use competitive bidding for a future generation resource or a block of generation resources will be made by the PUC during its review of the utility s IRP; (3) the framework does not apply to three pending projects, specifically identified offers to sell energy on an as-available basis or to sell firm energy and/or capacity by non-fossil fuel producers and certain other situations identified in the framework; (4) waivers from competitive bidding for certain circumstances will be considered by the PUC; (5) for each project that is subject to competitive bidding, the utility is required to submit a report on the cost of parallel planning upon the PUC s request; (6) the utility is required to consider the effects on competitive bidding of not allowing bidders access to utility-owned or controlled sites, and to present reasons to the PUC for not allowing site access to bidders when the utility has not chosen to offer a site to a third party; (7) 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); (8) the utility may consider its own self-bid proposals in response to generation needs identified in its RFP; (9) the evaluation of the utility s bid should account for the possibility that the capital or running costs actually incurred, and recovered from ratepayers, over the plant s lifetime, will vary from the levels assumed in the utility s bid; and (10) 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.

In 2007, the PUC approved the utilities tariffs containing procedures for interconnection and transmission upgrades, a list of qualified candidates for the Independent Observer position for future competitive bidding processes and a Code of Conduct.

In June 2008, HECO issued a RFP, which seeks proposals for the supply of up to approximately 100 MW of long-term renewable energy for the island of Oahu under a PPA. Bids were received in September 2008 and a short list of bidders was identified in December 2008. Further discussions with the short listed bidders have begun and an interconnection requirements study has commenced. The Energy Agreement recognized that the Oahu Renewable Energy RFP provides an excellent near-term opportunity to add new clean renewable energy sources on Oahu and included the anticipated up to 100 MW of renewable energy from these project proposals in its goals. See Renewable energy strategy above for a discussion on the bifurcation of the large-scale neighbor island wind project proposals from the other proposals received in response to the Oahu Renewable Energy RFP.

In December 2007, in response to MECO s request for approval to proceed with a competitive bidding process to acquire two separate increments of approximately 20 MW to 25 MW of firm generating capacity on the island of Maui in the 2011 and 2015 timeframes, the PUC issued an order opening a new docket to receive filings, review approval requests, and resolve disputes, if necessary, related to MECO s proposed RFP. The order identified MECO and the Consumer Advocate as parties to this new docket and approved MECO s contract with the Independent Observer for the proposed RFP. The schedule for competitive bidding for the first capacity increment (now targeted for 2015) has been revised and is expected to begin in 2009 to support the issuance of a draft RFP in 2010. The schedule for the second increment is under review.

In May 2008, the PUC issued a D&O stating that PGV s proposal to modify its existing PPA with HELCO to provide an additional 8 MW of firm capacity by expanding its existing facility is exempt from the Competitive Bidding Framework. In the third quarter of 2008, the PUC granted requests for waivers from the Competitive Bidding Framework for four projects (at HELCO one biomass, a wind/hydroelectric and a wind/battery energy storage, and at MECO one biomass), subject to the submittal of a fully executed term sheet within four months of the decision granting the waiver, and documentation showing the fairness of the price being included in the application for approval of a PPA. In the fourth quarter 2008, the PUC granted a request for waiver from the Competitive Bidding Framework for another biomass project on the island of Hawaii, subject to the same conditions as the four previous waivers. The waivers granted in the third quarter of 2008 expired in December 2008 and January 2009 due to the inability of the parties to reach agreement on term sheets. As an alternative to submitting fully executed term sheets for the wind/hydroelectric and wind/battery energy storage projects on the Island of Hawaii, HECO and HELCO informed the PUC that they will be proposing a competitive bidding process to acquire renewable generation on the island of Hawaii. In February 2009, HELCO submitted preliminary plans and timeline for the proposed competitive bidding process and advised the PUC that adjustments may be considered to include firm dispatchable and/or schedulable resources depending on the status of the remaining waivered biomass project. The scope of the proposed competitive bidding process is under review. In March 2009, HELCO reached agreement on a term sheet with the remaining waivered biomass project.

In September 2008, HECO submitted fully executed term sheets for the following three renewable energy projects on Oahu that were grandfathered from the competitive bidding process: a Honua Power steam turbine generator, a Kahuku Wind Power wind farm, and a Sea Solar Power International ocean thermal energy conversion project. In October 2008, timelines for the completion and execution of the power purchase contracts and the planned in-service dates for these three projects were submitted to the PUC.

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

DG proceeding. In October 2003, the PUC opened a DG proceeding to determine DG s potential benefits to and impact on Hawaii s electric distribution systems and markets and to develop policies and a framework for DG projects deployed in Hawaii.

In January 2006, the PUC issued its D&O indicating that its policy is to promote the development of a market structure that assures DG is available at the lowest feasible cost, DG that is economical and reliable has an opportunity to come to fruition and DG that is not cost-effective does not enter the system. The D&O affirmed the ability of the utilities to procure and operate DG for utility purposes at utility sites. The PUC also indicated its desire to promote the development of a competitive market for customer-sited DG. The PUC found that the disadvantages outweigh the advantages of allowing a utility to provide DG services on a customer s site. However, the PUC also found that the utility is the most informed potential provider of DG and it would not be in the public interest to exclude the utilities from providing DG services at this early stage of DG market development. Therefore, 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 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.

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The January 2006 D&O also required the utilities to file tariffs and establish standby rates based on unbundled costs associated with providing each service (i.e., generation, distribution, transmission and ancillary services). The utilities filed their proposed modifications to existing DG interconnection tariffs and their proposed unbundled standby rates for PUC approval in the third quarter of 2006. The Consumer Advocate stated that it did not object to implementation of the interconnection and standby rate tariffs at that time, but reserved the right to review the reasonableness of both tariffs in rate proceedings for each of the utilities. See Distributed generation tariff proceeding below.

In April 2006, the PUC provided clarification to the conditions under which the utilities are allowed to provide regulated DG services (e.g., the utilities can use a portfolio perspective a DG project aggregated with other DG systems and other supply-side and demand-side options to support a finding that utility-owned customer-sited DG projects fulfill a legitimate system need, and the economic standard of least cost in the order means lowest reasonable cost consistent with the standard in the IRP framework), and affirmed that the electric utility has the responsibility to demonstrate that it meets all applicable criteria included in the D&O in its application for PUC approval to proceed with a specific DG project.

The utilities are developing or evaluating potential DG projects. In September 2008, HECO executed an agreement with the State of Hawaii Department of Transportation to develop a dispatchable standby generation (DSG) facility at the Honolulu Airport that will be owned by the State and operated by HECO. The D&O encouraged HECO to pursue such DG operating arrangements with customers. HECO filed an application to the PUC for approval of the agreement in December 2008 and the PUC proceeding is in progress.

HECO is also evaluating the potential to develop utility-owned DG at Oahu military bases, in a manner consistent with the D&O, in order to meet utility system needs and the energy objectives of the U.S. Department of Defense. In 2009, HECO will conduct a feasibility review of extending the use of temporary DG units that were installed at various HECO substations in 2005 to 2007 and converting them to run on biodiesel.

In February 2008, MECO received PUC approval of an agreement for the installation of a CHP system at a hotel site on the island of Lanai. The CHP system is planned to be placed in service in the third quarter of 2009.

Distributed generation tariff proceeding. In December 2006, the PUC opened a new proceeding to investigate the utilities proposed DG interconnection tariff modifications and standby rate tariffs. In March 2008, the parties to the proceeding filed a settlement agreement with the PUC proposing that a standby service tariff agreed to by the parties should be approved. The interconnection tariffs, with modifications made in response to the PUC s information requests, were approved in April 2008. In May 2008, the PUC approved the settlement agreement on the standby service tariff.

In September 2008, the PUC requested that the utilities address various inconsistencies in the interconnection tariff sheets. In the fourth quarter of 2008, the utilities filed revised interconnection tariff sheets and the PUC issued an order approving the revised interconnection tariff sheets and closing the DG tariff proceeding.

Under the Energy Agreement, the utilities will conduct a review of the modified DG interconnection tariffs by June 30, 2009, to evaluate whether the tariffs are effective in supporting non-utility DG and distributed energy storage by improving the process and procedure for interconnection. If modifications are deemed necessary, a request to modify the DG interconnection tariff would be filed with the PUC later in 2009.

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 will be developed by December 31, 2009 to identify areas where DG and DES 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 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 (DSG) 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 will be recovered through a Clean Energy Infrastructure Surcharge and later placed in rate base in the next rate case proceeding.

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 the application, but there is no guarantee of such an interim increase or its amount 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.

As of May 1, 2009, the return on average common equity (ROACE) found by the PUC to be reasonable in the most recent final rate decision for each utility was 10.7% for HECO (D&O issued on May 1, 2008, based on a 2005 test year), 11.5% for HELCO (D&O issued on February 8, 2001, based on a 2000 test year) and 10.94% for MECO (amended D&O issued on April 6, 1999, based on a 1999 test year). The ROACEs used by the PUC in the interim rate increases in HECO, HELCO and MECO rate cases based on 2007, 2006 and 2007 test years issued in October, April and December 2007, respectively, were 10.7%.

For the 12 months ended March 31, 2009, the actual ROACEs (calculated under the rate-making method, which excludes the effects of items not included in determining electric utility rates, and reported to the PUC) for HECO, HELCO and MECO were 7.32%, 7.98% and 7.13%, respectively. HECO s actual ROACE was 338 basis points lower than its authorized ROACE primarily due to lower KWH sales and increased O&M expenses, which are expected to continue. HELCO and MECO s actual ROACEs were 272 and 357 basis points, respectively, lower than their interim D&O ROACEs due in part to lower KWH sales.

As of May 1, 2009, the return on rate base (ROR) found by the PUC to be reasonable in the most recent final rate decision for each utility was 8.66% for HECO, 9.14% for HELCO and 8.83% for MECO (D&Os noted above). The RORs used by the PUC for purposes of the interim D&Os in the HECO, HELCO and MECO rate cases based on 2007, 2006 and 2007 test years were 8.62%, 8.33% and 8.67%, respectively. For the 12 months ended March 31, 2009, the actual RORs (calculated under the rate-making method, which excludes the effects of items not included in determining electric utility rates, and reported to the PUC) for HECO, HELCO and MECO were 6.42%, 6.25% and 6.36%, respectively.

In 2007, HECO, HELCO and MECO received interim D&Os in their most recent rate cases, which included the reclassification to a regulatory asset of the charge for retirement benefits that would otherwise be recorded in accumulated other comprehensive income (AOCI).

For a description of some of the rate-making changes that the parties have agreed to pursue under the Energy Agreement, see Hawaii Clean Energy Initiative in Note 5 of HECO s Notes to Consolidated Financial Statements.

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HECO.

2005 test year rate case. In November 2004, HECO filed a request with the PUC to increase base rates, based on a 2005 test year, a 9.11% ROR and an 11.5% ROACE. Disregarding an amount included in the request to transfer the cost of existing DSM programs from a surcharge line item on electric bills into base electricity charges, which issue was bifurcated for consideration in another proceeding (the EE DSM Docket), the requested base rates increase was $74 million, or 7.3%.

In September 2005, HECO, the Consumer Advocate and the federal Department of Defense (DOD) reached agreement (subject to PUC approval) on most of the issues in the rate case proceeding. The significant issue not resolved among the parties was the appropriateness of including in rate base approximately $50 million related to HECO s prepaid pension asset, net of deferred income taxes.

Later in September 2005, the PUC issued its interim D&O, authorizing an increase of $53 million ($41 million net additional revenues). For purposes of the interim D&O, the PUC included HECO s prepaid pension asset in rate base (with an annual rate increase impact of approximately $7 million).

On October 25, 2007, the PUC issued an amended proposed final D&O, authorizing a net increase of 2.7%, or $34 million, in annual revenues, based on a 10.7% ROACE (and an 8.66% ROR on a rate base of $1.060 billion). The amended proposed final D&O, which was issued in final form with certain modifications (as described below), reversed the portion of the interim D&O related to the inclusion of HECO s approximately $50 million pension asset, net of deferred income taxes, in rate base, and required a refund of revenues associated with that reversal, including interest, retroactive to September 28, 2005 (the date the interim increase became effective). In the third quarter of 2007, HECO accrued $15 million for the potential customer refunds, reducing third quarter 2007 net income by $8.3 million. The potential additional refund to customers for the amounts recorded under interim rates in excess of the amount in the amended proposed final D&O from October 1, 2007 through October 21, 2007, with interest through July 19, 2008, was approximately $1.8 million, which amount was reserved for the refund and included an adjustment for the interest synchronization method adopted by the PUC (as proposed by the DOD in its filed exception to the proposed final D&O).

On May 1, 2008, the PUC issued the final D&O for HECO s 2005 test year rate case, which was consistent with the stipulated revised results of operations filed by the parties on March 28, 2008, and authorized an increase of $45 million in annual revenues ($34 million net) based on a 10.7% ROACE (and an 8.66% ROR on a rate base of $1.060 billion). In the final D&O, the PUC accepted the parties position that the review of the ECAC under Act 162 (Hawaii Revised Statutes §269-16(g)) should not be required in this case, but would be made in HECO s 2007 test year rate case. Following the issuance of the final D&O, the required refund, with interest, to customers was completed in August 2008. On October 2, 2008, HECO filed with the PUC its 2005 test year rate case refund reconciliation, which reflected that $1.4 million was over-refunded. On October 28, 2008, the PUC issued a letter stating that HECO was not authorized to collect the over-refunded amount and HECO reduced its revenues for the third quarter of 2008 by $1.4 million.

2007 test year rate case. On December 22, 2006, HECO filed a request with the PUC for a general rate increase of $99.6 million, or 7.1% over the electric rates currently in effect (i.e., over rates that included the interim rate increase discussed above of $53 million ($41 million net additional revenues) granted by the PUC in September 2005), based on a 2007 test year, an 8.92% ROR, an 11.25% ROACE and a $1.214 billion average rate base. This rate case excluded DSM surcharge revenues and associated incremental DSM costs because certain DSM issues, including cost recovery, were being addressed in the EE DSM Docket.

HECO s 2006 application included a proposed new tiered rate structure for residential customers to reward customers who practice energy conservation with lower electric rates for lower monthly usage. The proposed rate increase includes costs incurred to maintain and improve reliability, such as the new Dispatch Center building and associated equipment and the Energy Management System that became operational in 2006, new substations, a new outage management system (added in 2007) and increased O&M expenses.

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The application addressed the energy cost adjustment clause (ECAC) provisions of Act 162 and requested the continuation of HECO s ECAC. On December 29, 2006, the electric utilities Report on Power Cost Adjustments and Hedging Fuel Risks (ECAC Report) prepared by their consultant, National Economic Research Associates, Inc., was filed with the PUC. The testimonies filed in the latest rate cases for HECO, HELCO and MECO included or incorporated the ECAC Report, which concluded that (1) the electric utilities ECACs are well-designed, and benefit the electric utilities and their ratepayers and (2) the ECACs comply with the statutory requirements of Act 162. With respect to hedging, the consultants concluded that (1) hedging of oil prices by HECO would not be expected to reduce fuel and purchased power costs and in fact would be expected to increase the level of such costs and (2) even if rate smoothing is a desired goal, there may be more effective means of meeting the goal, and there is no compelling reason for the electric utilities to use fuel price hedging as the means of achieving the objective of increased rate stability.

HECO s application requested a return on HECO s pension assets (i.e., accumulated contributions in excess of accumulated net periodic pension costs) by including such assets (net of deferred taxes) in rate base. In a separate AOCI proceeding, the electric utilities had earlier requested PUC approval to record as a regulatory asset for financial reporting purposes, the amounts that would otherwise be charged to AOCI in stockholders equity as a result of adopting SFAS No. 158, but that request was denied. HECO thus proposed in the 2007 test year rate case to restore to book equity for ratemaking purposes the amounts charged to AOCI as a result of adopting SFAS No. 158. The authorized ROACE found to be fair in a rate case is applied to the equity balance in determining the utility s weighted cost of capital, which is the rate of return applied to the rate base in determining the utility s revenue requirements. HECO s position was that, if the reduction in equity balance resulting from the AOCI charges is not restored for ratemaking purposes, a higher ROACE will be required.

In March 2007, a public hearing on the rate case was held. In April 2007, the PUC granted the DOD s motion to intervene.

In a June 2007 update to its direct testimonies, HECO proposed pension and OPEB tracking mechanisms, similar to the mechanisms that were agreed to by HELCO and the Consumer Advocate and approved on an interim basis by the PUC in the HELCO 2006 test year rate case (discussed below). A pension funding study (required by the PUC in the AOCI proceeding) was filed in the HECO rate case in May 2007. The conclusions in the study were consistent with the funding practice proposed with the pension tracking mechanism. For a discussion of this mechanism and related pension issues, see Note 4, Retirement Benefits of HECO s Notes to Consolidated Financial Statements.

On September 6, 2007, HECO, the Consumer Advocate and the DOD (the parties) executed and filed an agreement on most of the issues in HECO s 2007 test year rate case and HECO submitted a statement of probable entitlement with the PUC. The agreement was subject to approval by the PUC.

The amount of the revenue increase based on the stipulated agreement was $70 million annually, or a 4.96% increase over current effective rates at the time of the stipulation. The settlement agreement included, as a negotiated compromise of the parties respective positions, an ROACE of 10.7% (and an 8.62% ROR and a $1.158 billion average rate base) to determine revenue requirements in the proceeding. In the settlement agreement, the parties agreed that the final rates set in HECO s 2005 test year rate case may impact revenues at current effective rates and at present rates, and indicated that the amount of the stipulated interim rate increase in this case would be adjusted to take into account any such changes. For purposes of the settlement, the parties agreed to a pension tracking mechanism that does not include amortization of HECO s pension asset (comprised of accumulated contributions to its pension plan in excess of net periodic pension cost and amounting to $68 million at December 31, 2006) as part of the pension tracking mechanism in the proceeding. (This has the effect of deferring the issue of whether the pension asset should be amortized for rate making purposes to HECO s next rate case.)

In accordance with Act 162, the PUC, by an order issued August 24, 2007, had added as an issue to be addressed in the rate case whether HECO s ECAC complies with the requirements of Act 162. In the settlement agreement, the parties agreed that the ECAC should continue in its present form for purposes of an interim rate increase and stated that they are continuing discussions with respect to the final design of the ECAC to be proposed for approval in the final D&O. The parties agreed to file proposed findings of fact and conclusions of law on all issues in this proceeding, including the ECAC. The parties agreed that their resolution of the ECAC issue would not affect their agreement regarding revenue requirements in the proceeding.

On October 22, 2007, the PUC issued, and HECO implemented, an interim D&O granting HECO an increase of $70 million in annual revenues over rates effective at the time of the interim D&O, subject to refund with interest. The interim increase was based on the settlement agreement described above and did not include in rate base the HECO pension asset. The interim D&O also approved, on an interim basis, the adoption of the pension tracking mechanism and a tracking mechanism for OPEB. See Interim increases in Note 5 and Note 4, Retirement benefits, of HECO s Notes to Consolidated Financial Statements.

On May 1, 2008, the PUC issued the final D&O for HECO s 2005 test year rate case, which was consistent with the stipulated revised results of operations filed by the parties on March 28, 2008. Consistent with the previous settlement agreement with the parties in this case, HECO filed a motion with the PUC in May 2008 to adjust the amount of the annual interim increase in this proceeding from $70 million to $77.9 million to take into account the changes in current effective rates as a result of the final decision in the 2005 test year rate case, and to have the change be effective at the same time the tariff sheets reflecting the final decision in the 2005 rate case become effective. In June 2008, the PUC approved HECO s motion. On September 30, 2008, HECO filed a correction with the PUC to adjust the amount of the annual interim increase for the 2007 test year rate case from $77.9 million to $77.5 million and filed tariff sheets to be effective October 1 through 31, 2008 to refund $0.1 million over-collected from June 20 to September 30, 2008.

On December 30, 2008, HECO and the Consumer Advocate filed a joint set of proposed findings of fact and conclusions of law and HECO requested that the PUC approve the final rate increase of $77.5 million.

Management cannot predict the timing, or the ultimate outcome, of a final D&O in HECO s 2007 test year rate case.

2009 test year rate case. On July 3, 2008, HECO filed a request for a general rate increase of $97 million or 5.2% over the electric rates currently in effect (i.e., over rates that included the interim rate increase discussed above granted by the PUC in HECO s 2007 test year rate case, which amount is $77 million based on the effects of the final decision in HECO s 2005 test year rate case), based on a 2009 test year, an 8.81% ROR, an 11.25% ROACE, and a $1.408 billion rate base. HECO s application requested an interim increase of $73 million on or before the statutory deadline for interim rate relief and a step increase of $24 million based on the return on the annualized net investment of the new CIP CT-1 and recovery of associated expenses to be effective at the in-service date of the new unit, scheduled for the end of July 2009.

The requested rate increase was based on anticipated plant additions estimated at the time of filing of $375 million in 2008 and 2009 (including $162 million for the new CIP CT-1 and related transmission line) to maintain and improve system reliability, higher operation and maintenance costs required for HECO s electrical system, and higher depreciation expenses since the last rate case. To the extent actual project costs are higher than the estimate included in the requested rate increase (e.g., higher costs for the CIP CT-1 and transmission line), HECO plans to seek recovery in a future proceeding. As in its 2007 test year rate case, HECO requests continuation of its ECAC in its present form. The request excludes incremental DSM costs from the test year revenue requirement due to the transition of HECO s DSM programs to a third-party program administrator in 2009 as ordered by the PUC.

In August 2008, the PUC granted the DOD s motion to intervene in the rate case proceeding. In September 2008, the PUC held a public hearing on HECO s rate increase application.

In the Energy Agreement, the parties agree to seek approval from the PUC to implement in the interim D&O in the 2009 HECO rate case a decoupling mechanism (see Decoupling proceeding below). HECO filed updates to its 2009 test year rate case in November and December 2008, which proposed to establish a revenue balancing account for a decoupling mechanism and a purchased power adjustment clause.

In January 2009, the PUC issued an amended stipulated procedural order for the proceeding, which includes an interim D&O by July 2, 2009, and evidentiary hearings scheduled for the week of August 10, 2009.

In March 2009, HECO agreed to remove certain costs and expenses from the rate case, including unamortized system development costs related to replacement of its customer information system due to a delay in transitioning to the new system. See Note 5 of HECO s Notes to Consolidated Financial Statements.

In April 2009, the Consumer Advocate and the DOD filed their direct testimonies in this proceeding. The Consumer Advocate recommended a revenue increase of $62.7 million based on its proposed ROR of 7.86%, an ROACE ranging between 9.5% and 10.5% and a proposed average rate base of $1.259 billion. The Consumer Advocate recommended an average rate base treatment for the CIP CT-1, which is scheduled to go into service on July 31, 2009, rather than accept the Company s proposal for a step increase based on the annualized net cost of the CIP CT-1 which would go into effect on the in-service date of the new unit. In its recommendations, the Consumer Advocate also removed the costs and expenses identified by HECO in March 2009 relating to the replacement of HECO s customer information system. The DOD recommended a revenue increase of $45.1 million based on its proposed ROR of 7.85%, an ROACE of 9.50% and a proposed average rate base of $1.309 billion. The DOD also recommended an average rate base treatment for the CIP CT-1 and in its recommendations has removed the costs and expenses identified by HECO in March 2009 relating to the replacement of HECO s customer information system.

Management cannot predict the timing, or the ultimate outcome, of an interim or final D&O in this rate case.

HELCO. In May 2006, HELCO filed a request with the PUC to increase base rates by $29.9 million, or 9.24% in annual base revenues, based on a 2006 test year, an 8.65% ROR, an 11.25% ROACE and a $369 million average rate base. HELCO s application included a proposed new tiered rate structure, which would enable most residential users to see smaller increases in the range of 3% to 8%. The tiered rate structure was designed to minimize the increase for residential customers using less electricity and is expected to encourage customers to take advantage of solar water heating programs and other energy management options. In addition, HELCO s application proposed new time-of-use service rates for residential and commercial customers. The proposed rate increase would pay for improvements made to increase reliability, including transmission and distribution line improvements and the two generating units at the Keahole power plant (CT-4 and CT-5), and increased O&M expenses. The application requested the continuation of HELCO s ECAC.

The PUC held public hearings on HELCO s application in June 2006. In February 2007, the Consumer Advocate submitted its testimony in the proceeding, recommending a revenue increase of $16.6 million based on its proposed ROR of 7.95%, a ROACE ranging between 9.50% and 10.25% and a proposed average rate base of $345 million. The Consumer Advocate recommended adjustments of $21.5 million to HELCO s rate base for a portion of CT-4 and CT-5 costs (primarily relating to HELCO s allowance for funds used during construction (AFUDC), land use permitting costs, and related litigation expenses). In the filing, the Consumer Advocate s consultant concluded that HELCO s ECAC provides a fair sharing of the risks of fuel cost changes between HELCO and its ratepayers in a manner that preserves the financial integrity of HELCO without the need for frequent rate filings.

Keahole Defense Coalition (whose participation in the proceeding is limited) submitted in February 2007 a Position Statement in which it contended that the PUC should exclude from rate base a greater amount of the CT-4 and CT-5 costs than proposed by the Consumer Advocate.

In March 2007, HELCO and the Consumer Advocate reached settlement agreements on all revenue requirement issues in the HELCO 2006 rate case proceeding, which were documented in an April 5, 2007 settlement letter. Under the revenue requirement agreement, HELCO agreed to write-off a portion of CT-4 and CT-5 costs, which resulted in an after-tax charge of approximately $7 million in the first quarter of 2007.

On April 4, 2007, the PUC issued an interim D&O, which was implemented by tariff changes made effective on April 5, 2007, granting HELCO an increase of 7.58%, or $24.6 million in annual revenues, over revenues at present rates for a normalized 2006 test year. The interim increase reflects the settlement of the revenue requirement issues reached between HELCO and the Consumer Advocate and is based on an average rate base of $357 million (which reflects the write-off of a portion of CT-4 and CT-5 costs) and an ROR of 8.33% (incorporating an ROACE of 10.7%). In the interim D&O, the PUC also approved on an interim basis the adoption of pension and OPEB tracking mechanisms (see Note 4 of HECO s Notes to Consolidated Financial Statements).

Pursuant to an agreed upon schedule of proceedings, Keahole Defense Coalition filed a response to HELCO s rebuttal testimony on April 28, 2007, to which HELCO responded on May 11, 2007. On May 15, 2007, HELCO and the Consumer Advocate filed a settlement letter that reflected their agreement on the remaining rate design issues in the proceeding. HELCO and the Consumer Advocate filed their opening briefs in support of their settlement on June 4, 2007 and agreed not to file reply briefs. In April 2008, HELCO and the Consumer Advocate filed a supplement providing additional record cites and supporting information relevant to their April 2007 settlement letter. In July 2008, HELCO submitted responses to information requests from the PUC regarding the impacts of passing changes in fuel and purchased energy costs to customers through the ECAC.

Management cannot predict the timing, or the ultimate outcome, of a final D&O in this rate case.

In order to implement the decoupling mechanism committed to by the parties in the Energy Agreement, the parties agreed that HELCO would file a 2009 test year rate case. In light of a recent PUC action denying MECO s motion for approval to use a 2009 test year (see MECO 2009 test year rate case below), HELCO is evaluating the timing of its rate case filing.

MECO.

2007 test year rate case. In February 2007, MECO filed a request with the PUC to increase base rates by $19.0 million, or 5.3% in annual base revenues, based on a 2007 test year, an 8.98% ROR, an 11.25% ROACE and a $386 million average rate base. MECO s application included a proposed new tiered rate structure for residential customers to reward customers who practice energy conservation with lower electric rates for lower monthly usage. The proposed rate increase would pay for improvements to increase reliability, including two new generating units added since MECO s last rate case (which was based on a 1999 test year) at its Maalaea Power plant (M19, a 20 MW CT placed in service in 2000 and M18, an 18 MW steam turbine placed in service in October 2006 to complete the installation of a second dual-train combined cycle unit), and transmission and distribution infrastructure improvements. The proposed rate structure also included continuation of MECO s ECAC. The application requested a return on MECO s pension assets (i.e., accumulated contributions in excess of accumulated net periodic pension costs) by including such assets (net of deferred income taxes) in rate base. The application also proposed to restore book equity (in determining the equity balance for ratemaking purposes) for the amounts that were charged against equity (i.e., to AOCI) as a result of recording a pension and other postretirement benefits liability after implementing SFAS No. 158.

In an update to its direct testimonies filed in September 2007, MECO proposed a lower increase in annual revenues of $18.3 million, or 5.1%, but its request continued to be based on an 8.98% ROR and an 11.25% ROACE. Also in the update, MECO proposed tracking mechanisms for pension and OPEB, similar to the mechanisms proposed by HECO and HELCO, and approved by the PUC on an interim basis, in their 2007 and 2006 test year rate cases, respectively. In October 2007, the Consumer Advocate filed its direct testimony which recommended a revenue increase of $8.9 million, based on a ROR of 8.29% and a ROACE of 10.0%. $4.75 million of the $9.4 million difference between MECO s and the Consumer Advocate s proposed increase is caused by the Consumer Advocate s lower recommended ROR and ROACE.

On December 7, 2007, MECO and the Consumer Advocate (for purposes of this section, the parties) reached a settlement of all the revenue requirement issues in this rate case proceeding. For purposes of the settlement agreement, the parties agreed that MECO s ECAC provides a fair sharing of the risks of fuel cost changes between MECO and its ratepayers and no further changes are required for MECO s energy adjustment clause to comply with the requirements of Act 162.

On December 21, 2007, the PUC issued an interim D&O granting MECO an increase of $13.2 million in annual revenues, or a 3.7% increase, subject to refund with interest. The interim increase is based on the settlement agreement, which included as a negotiated compromise of the Parties respective positions, an increase of $13.2 million in annual revenue, a 10.7% ROACE, an 8.67% ROR and a rate base of $383 million (which did not include MECO s pension asset, which amounted to $1 million as of December 31, 2007).

In the interim D&O, the PUC also approved on an interim basis the adoption of pension and OPEB tracking mechanisms (see Note 4 of HECO s Notes to Consolidated Financial Statements).

On April 17, 2009, the PUC directed the parties to file by July 17, 2009 stipulated proposed findings of fact and conclusions of law or, if they are unable to stipulate, each party s proposed findings of fact and conclusions of law.

Management cannot predict the timing, or the ultimate outcome, of a final D&O in this rate case.

2009 test year rate case. On March 20, 2009, MECO filed a Notice of Intent to file an application for a general rate increase on or after May 29, 2009 (but before June 30, 2009) and a motion requesting PUC approval to use a 2009 calendar year test period for this upcoming rate case. The filing of this general rate increase application is in accordance with the Energy Agreement, under which the parties agreed that MECO would file a 2009 test year rate case to implement a decoupling mechanism. On April 27, 2009, the PUC issued an order denying MECO s motion and stating that MECO may elect to file its rate case application with either a split 2009/2010 test period or a 2010 calendar test period, pursuant to the PUC s rules. Under the rules, MECO (and HELCO) would be allowed to file rate cases with 2010 test years on or after July 1, 2009.

Decoupling proceeding. In the Energy Agreement, the parties agreed to seek approval from the PUC to implement, beginning with the 2009 HECO rate case interim decision, a decoupling mechanism, similar to that in place for several California utilities, which decouples revenue of the utilities from KWH sales and provides revenue adjustments (increases/decreases) for the differences (shortages/overages) between the amount determined in the last rate case and (a) the current cost of operating the utility as deemed reasonable and approved by the PUC, (b) the return on and return of ongoing capital investment (excluding projects included in a proposed new Clean Energy Infrastructure Surcharge), and (c) changes in tax expense due to changes in State or Federal tax rates. The decoupling mechanism would be subject to review at any time by the PUC or upon request of the utility or Consumer Advocate.

On October 24, 2008, the PUC opened an investigative proceeding to examine implementing a decoupling mechanism for the utilities. In addition to the utilities and the Consumer Advocate, there are five other parties in the proceeding. On March 30, 2009, the utilities and the Consumer Advocate filed their joint proposal and initial statement of position and the other parties filed their initial statements of position. The utilities and Consumer Advocate s joint proposal is for a decoupling mechanism with two components: (1) a sales decoupling component via a revenue balancing account and a revenue escalation component via a revenue adjustment mechanism and (2) an earnings sharing mechanism. (In December 2008, HECO proposed in its 2009 test year rate case to establish a revenue balancing account to decouple sales from revenues to be effective upon the issuance of the interim decision and order in that rate case.) The remaining schedule for the proceeding includes final position statements of the parties to be submitted in May 2009 and panel hearings during June 2009.

Management cannot predict the timing, or the ultimate outcome, of a final D&O in the decoupling proceeding.

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 for a number of actions committed to in the Energy Agreement that will require PUC approval in either pending or new PUC proceedings.

Demand-side management programs. On February 13, 2007, the PUC issued its D&O in the EE DSM Docket that had been opened by the PUC to bifurcate the EE DSM issues originally raised in the HECO 2005 test year rate case. In the D&O, the PUC required that the administration of all EE DSM programs be turned over to a non-utility, third-party administrator, with the transition to the administrator, funded through a public benefits fund

(PBF) surcharge. The PUC opened a new docket to select a third-party administrator and to refine details of the new market structure in an order issued in September 2007. In the order, the PUC stated that [u]pon selection of the PBF Administrator, the PUC intends, in this docket, to determine whether the electric utilities will be allowed to compete for the implementation of the Energy Efficiency DSM programs. In July 2008, the PUC issued an Order to Initiate the Collection of Funds for the PBF Administrator of Energy Efficiency Programs, which authorized the electric utilities to expense $50,000 per quarter beginning July 1, 2008 for the initial start-up costs associated with the PBF Administrator and recover the cost in the DSM surcharge; confirmed that the load management, SolarSaver Pilot (SSP) and Residential Customer Energy Awareness programs shall remain with the electric utilities; and directed the electric utilities to continue to operate the DSM programs through June 30, 2009, after which transition period the electric utilities can compete for implementation of DSM programs as a subcontractor. The PUC issued its RFP for the PBF Administrator and proposals were received.

In December 2008, the PUC notified Science Applications International Corporation (SAIC) that it had been selected to continue negotiations with the PUC to become the PBF Administrator. The utilities had worked with SAIC to develop the PBF Administrator proposal selected by the PUC that included continued delivery of the existing energy efficiency programs by the utilities as subcontractor to SAIC. The PUC executed a PBF Administrator contract with SAIC in March 2009. HECO has since entered into discussions with SAIC on HECO s role as a subcontractor to SAIC.

On December 15, 2008, the PUC ordered that the $50,000 collected by the utilities during the third quarter of 2008 was to be paid to the PUC. In a separate order, Order Setting the Public Benefits Fee Surcharge for 2009 (Order), also dated December 15, 2008, the PUC established a Public Benefits Fund equal to 1% of estimated 2009 total revenues that would be used for the 2009 implementation of energy efficiency programs, of which 40% would be collected through the PBF Surcharge for use by the PBF Administrator, and 60% would be collected through the DSM Surcharge to be used by the utilities for their energy efficiency programs until those programs were transferred to the PBF Administrator. The 2009 budgets for the SSP Program and the two load management programs (Residential Direct Load Control and Commercial and Industrial Direct Load Control Programs) remained unaffected. The Order stated that the 60/40 split roughly equates with the proportionate period of time that the commission expects the HECO Companies and the third-party administrator to provide services in 2009. The utilities issued new PBF Surcharge and revised DSM Surcharge filings effective January 1, 2009.

The utilities filed new DSM program budgets and goals on January 20, 2009.

The Order also ended the expensing and collection of $50,000 per quarter as of January 1, 2009. The $100,000 collected in total during the third and fourth quarters of 2008, plus interest, was delivered to the PUC s PBF fiscal agent, as instructed, on January 2, 2009. The utilities were ordered to transfer the collected PBF Surcharge revenues, less the revenue tax liabilities, to the PUC s PBF fiscal agent beginning on March 1, 2009, and monthly thereafter.

The EE Docket D&O also provides for HECO s recovery of DSM program costs and utility incentives. With respect to cost recovery, the PUC continues to permit recovery of reasonably-incurred DSM implementation costs, under the IRP framework. DSM utility incentives will be derived from a graduated performance-based schedule of net system benefits. In order to qualify for an incentive, the utility must meet cumulative MW and MWh reduction goals for its EE DSM programs in both the commercial and industrial sector, and the residential sector. The amount of the annual incentive is capped at $4 million for HECO, and may not exceed either 5% of the net system benefits, or utility earnings opportunities foregone by implementing DSM programs in lieu of supply-side rate based investments. Negative incentives will not be imposed for underperformance.

In 2007, HECO recorded incentives of $4 million. HELCO and MECO proposed goals for their programs, based on the goals established for HECO s programs, but recorded no incentives in 2007. On May 21, 2007, the PUC clarified the 2007 and 2008 energy efficiency goals and the calculation of the DSM utility incentive, and granted HECO the ability to request program modifications and budget increases by letter request. Since that time, the PUC has approved budget increases and program modifications for various DSM programs. In June 2008, the PUC issued an order approving MECO s proposed cumulative energy and demand savings goals for 2007 and 2008, but set MECO s annual incentive cap at $320,000. Thus, in the second quarter of

2008, MECO recorded an incentive of $320,000 related to 2007. The PUC also issued an order approving HELCO s proposed cumulative energy and demand savings goals for 2007 and 2008, and an annual incentive cap of $200,000. However, HELCO did not achieve those goals and, therefore, no incentives were earned by HELCO. The utilities DSM incentives for 2007 and 2008 were subject to adjustment based on the results of impact evaluation studies.

In December 2008, the results of the impact evaluation studies became available. The impact evaluation reduced actual DSM energy and demand savings for 2005 through 2007. As a result of the reduced savings, the utilities Lost Margin and Shareholder Incentives earned in 2005 and 2006 were reduced. In addition, MECO no longer met its 2007 goals for DSM utility incentives. As a result of these changes, the utilities accrued a refund to its customers of $1.4 million, including interest, in December 2008.

HECO and MECO surpassed their energy and demand savings goals for 2008 and earned their maximum DSM utility incentives of $4 million and $320,000, respectively. In its December 15, 2008 Order, in anticipation of the transfer of the DSM programs to the third-party administrator during 2009, the PUC decreased the maximum DSM utility incentive for HECO to $2 million for 2009 and decreased HELCO s and MECO s maximum incentives to $100,000 and $160,000, respectively, for 2009.

HECO filed its annual DSM Accomplishments and Surcharge Report (A&S Report) on March 31, 2009, which documents HECO s portion of the refund for years 2005 and 2006 and its earned DSM utility incentive of $4 million. MECO filed its A&S Report on April 30, 2009, documenting its portion of the refund and its earned DSM utility incentive of $320,000.

Unlike the EE DSM programs (for which the utilities are eligible to become a subcontractor to the third-party administrator), load management DSM programs will continue to be administered by the utilities. HECO s residential load management program includes a monthly electric bill credit for eligible customers who participate in the program, which allows HECO to disconnect the customer s residential electric water heaters or central air conditioning systems from HECO s system to reduce system load when deemed necessary by HECO. The commercial and industrial load management program provides an incentive on the portion of the demand load that eligible customers allow to be controlled or interrupted by HECO. This program includes small business direct load control and voluntary program elements.

In March and April 2009, HECO filed applications for three-year extensions, from 2010 through 2012, of the Commercial and Industrial Direct Load Control Program and the Residential Direct Load Control Program, respectively.

In April 2008, HECO filed an application for approval of a Dynamic Pricing Pilot Program and for recovery of the incremental costs of the program through the DSM Adjustment component of the IRP Cost Recovery Provision. Dynamic pricing is a type of demand response program that allows prices to change from normal tariff rates as system conditions change and encourages customer curtailment of load through price incentives when there is insufficient generation to meet a projected peak demand period. The proposed pilot program would run for approximately one year and test the effect of a demand response program on a sample of residential customers. The application is still pending at the PUC.

Avoided cost generic docket. In May 1992, the PUC instituted a generic investigation to examine the proxy method and formula used by the electric utilities to calculate their avoided energy costs and Schedule Q rates. 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 parties to the proceeding agreed that avoided fuel costs, except for Lanai and Molokai, would be determined using a computer production simulation model and agreed on certain parameters that would be used to calculate avoided costs. In March 2008, the PUC ordered that the new avoided energy cost rates and Schedule Q rates would go into effect on August 1, 2008. HECO, HELCO and MECO filed new avoided energy costs rates and Schedule Q rates, which were determined using the new differential revenue requirements resource-in / resource-out methodology instead of the proxy method. These rates were effective from August 1 through December 31, 2008, and the fuel component of the rates was adjusted monthly for changes in fuel prices.

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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. 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 independent power producers (IPPs) that are based on fossil fuel prices to delink their energy payment rates from oil costs. Based on this understanding, the parties agreed to request that the PUC suspend the pending Schedule Q proceeding for a period of 12 months with a view to reviewing the necessity of the docket. On November 28, 2008, the PUC granted the request to suspend the Schedule Q proceeding for 12 months. On December 31, 2008, HECO, HELCO and MECO filed avoided energy costs rates and Schedule Q rates to be effective for 2009, subject to monthly adjustment of the fuel component of the rates for changes in fuel prices.

Integrated resource planning, requirements for additional generating capacity and adequacy of supply. The PUC issued an order in 1992 requiring the energy utilities in Hawaii to develop integrated resource plans (IRPs), which may 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. The utilities proposed IRPs are planning strategies, rather than fixed courses of action, and the resources ultimately added to their systems may differ from those included in their 20-year plans. Under the PUC s IRP framework, the utilities are required to submit annual evaluations of their plans (including a revised five-year program implementation schedule) and to submit new plans on a three-year cycle, subject to changes approved by the PUC. Prior to proceeding with the DSM programs, separate PUC approval proceedings must be completed.

The utilities were to be entitled to recover all appropriate and reasonable integrated resource planning and implementation costs, including the costs of DSM programs, 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 (since February 2001), HECO (since September 2005) and MECO (since December 2007) now recover IRP costs (which are included in O&M) through base rates. Previously, HECO, HELCO and MECO recovered their costs through a surcharge. The Consumer Advocate has objected to the recovery of $1.2 million (before interest) of the $4.0 million of incremental IRP costs incurred by the utilities during the 2002-2007 period, and the PUC s decisions on the recovery of these costs are pending. Also, see Note 5 in HECO s Notes to Consolidated Financial Statements and Demand-side management programs above.

The parties to the Energy Agreement agreed to seek to replace the IRP process with a new Clean Energy Scenario Planning (CESP) process, described in the Energy Agreement, intended to be used to determine future investments in transmission, distribution and generation that will be necessary to facilitate high levels of renewable energy production. Requests by the parties to the Energy Agreement to move to the CESP process were filed with the PUC on November 6, 2008, and the PUC acted on those requests by ordering the utilities and the Consumer Advocate to develop a joint proposal for a framework for the CESP process. On April 7, 2009, in conjunction with the Consumer Advocate, HECO, HELCO and MECO conducted public input meetings on a draft of their proposed CESP framework. The draft CESP framework revises the previous IRP framework and proposes a planning process to develop generation and transmission resource plan options for multiple 20-year planning scenarios. From these scenarios, the framework proposes the development of a 5-year Action Plan based on range of resource needs identified through the various scenarios analyzed. Furthermore, the framework proposes that the CESP include the identification of Renewable Energy Zones, or geographic areas of the islands of rich renewable energy resources in which infrastructure improvements should be focused. The framework also proposes that the CESP include the identification of any geographic areas of the distribution system in which distributed generation or demand-side management resources are of higher value. HECO and the Consumer Advocate filed a proposed CESP framework with the PUC on April 28, 2009. The parties

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committed to supporting reasonable and prudent investment in the ongoing maintenance and upgrade of the existing generation, transmission and distribution systems, unless the CESP process determines otherwise.

HECO s IRP. On September 30, 2008, HECO filed its fourth IRP (IRP-4) covering a 20-year (2009-2028) planning horizon, subject to PUC approval. The IRP-4 preferred plan called for all future generation to be renewable. In addition, it called for conversion of a number of existing HECO-owned generating units to utilize biofuels and for continued aggressive implementation of DSM programs. In addition to CIP CT-1 scheduled for installation in mid-2009, HECO had plans to pursue the installation of a 100 MW biofueled CT at the same station in the 2011-2012 timeframe and to submit to the PUC a request for a waiver from the competitive bidding process to install this increment of additional firm capacity. The addition of two simple-cycle CTs would add to the system additional fast starting and ramping capability, which would facilitate integration of as-available generation (such as wind and solar) to the system. HECO also had plans to remove Waiau Unit 3, a 46 MW oil-fired cycling unit, from service after the second CT is in service, and would later determine whether to place the unit in emergency reserve status or to retire the unit. Subsequent to the filing of IRP-4, HECO is revisiting its plans to submit an application and waiver request for the second CT at Campbell Industrial Park given the uncertainty of future sales and peak demand.

When the necessary test biofuels are obtained, HECO plans to conduct a test on Kahe Unit 3 to evaluate the use of Low Sulfur Fuel Oil/biofuel blends in existing oil-fired steam units. Other renewable generation will be acquired via three renewable energy projects grandfathered from competitive bidding and from projects that are selected from proposals submitted in response to HECO s 100 MW RFP for Non-Firm Energy (see Competitive bidding proceeding above).

On November 26, 2008, the PUC closed the HECO IRP-4 process and directed HECO to suspend all activities pursuant to the IRP framework to allow for resources to be diverted to the development of a CESP framework.

HELCO s IRP. In May 2007, HELCO filed its third IRP. The plan included the installation of a nominal 16 MW steam turbine (ST-7) in 2009 at its Keahole Generating Station (see Major projects in Note 5 of HECO s Notes to Consolidated Financial Statements). The plan also followed through on a commitment to have no new fossil-fired generation installed after ST-7. The plan anticipated increasing customer photovoltaic systems plus a 37 gigawatthours per year renewable energy resource in the 2014 to 2020 timeframe, a firm capacity renewable energy resource in 2022, energy efficiency (continuation of existing DSM programs) and CHP. In November 2007, HELCO and the Consumer Advocate filed a stipulated agreement which recommended that the PUC approve HELCO s IRP-3 and in which HELCO agreed to make improvements to the IRP process and to submit evaluation reports. In January 2008, the PUC issued its D&O approving HELCO s IRP-3 and required HELCO to submit annual evaluation reports and file its IRP-4 by May 31, 2010.

On November 26, 2008, the PUC suspended the HELCO IRP-4 process and directed HELCO to suspend all activities pursuant to the IRP Framework to allow for resources to be diverted to the development of a CESP framework.

MECO s IRP. In April 2007, MECO filed its third IRP, which proposes multiple solutions to meet future energy needs on the islands of Maui, Lanai and Molokai, including renewable energy resources (such as photovoltaics, additional wind, biomass and waste-to-energy), energy efficiency (continuation of existing and addition of new DSM programs), technology (such as CHP and DG) and competitive bidding for generation or blocks of generation on Maui for 20 MW in each of 2011 and 2013 and 18 MW in 2024 which, under the utility parallel plan, could be located at its Waena site. In July 2008, the PUC approved MECO s IRP-3 and directed MECO to submit evaluation reports, to make various improvements to the IRP process and to submit its IRP-4 by April 30, 2010.

On December 8, 2008, the PUC suspended the MECO IRP-4 process and directed MECO to suspend all activities pursuant to the IRP Framework to allow for resources to be diverted to the development of a CESP framework.

HECO s 2009 CIP CT-1 and transmission line. See CIP CT-1 and transmission line in Note 5 of HECO s Notes to Consolidated Financial Statements.

Adequacy of supply.

HECO. HECO s 2009 Adequacy of Supply (AOS) letter, filed in February 2009, indicated that HECO s analysis estimates its reserve capacity shortfall to be approximately 30 MW in 2009, even with the addition of the CIP CT-1 scheduled to be installed in mid-2009, primarily because shortfalls are projected to occur before the unit is installed and will not be entirely alleviated once the unit is available for service. Generation shortfalls did not occur during the first quarter of 2009, in part because power demand was consistently less than forecasted primarily due to weather that was cooler than normal. Moreover, sustained maintenance efforts have resulted in a leveling in availability rates that had been declining since 2002, at levels that continue to be better than those for comparable units on the U.S. mainland. Barring unforeseen equipment failures, generation capacity shortfalls are not expected to occur prior to startup of CIP CT-1 later this year when reserve capacity conditions will be substantially improved.

To mitigate the projected reserve capacity shortfalls, HECO has implemented and is continuing to plan and implement mitigation measures, such as installing distributed generators at substations or other sites, implementing additional load management and other demand reduction measures, and pursuing efforts to improve the availability of generating units. HECO will operate at lower than desired reliability levels and take steps to mitigate the reserve capacity shortfall situation until the next generating unit is installed. Until sufficient generating capacity can be added to the system, HECO will experience a higher risk of generation-related customer outages.

After the scheduled mid-2009 addition of the CIP CT-1, and in recognition of the uncertainty underlying key forecasts, HECO reported in its 2009 AOS letter that it anticipates that its reserve capacity situation could range from a shortfall of 10 MW if demand is higher than expected to a surplus of 50 MW in a base case scenario for 2010, with the shortfalls higher and the surpluses lower in future years. HECO may seek, under the guidance of the Competitive Bidding Framework issued by the PUC in December 2006, a firm, dispatchable renewable resource to meet future needs, while continuing contingency planning activities. As noted under HECO s IRP above, to address future needs HECO plans to pursue the installation of a second biofueled CT (100 MW) at its CIP generating station in the 2011-2012 timeframe, at which time it would remove a 46 MW oil-fired cycling unit from service (and later determine whether to place the unit in emergency reserve status or to retire the unit).

HECO s gross peak demand was 1,327 MW in 2004, 1,273 MW in 2005, 1,315 MW in 2006, 1,261 MW in 2007 and 1,227 MW in 2008. Peak demand may vary from year to year, but over time, demand for electricity on Oahu is projected to increase. On occasions in 2004, 2005, 2006 and 2007, HECO issued public requests that its customers voluntarily conserve electricity as generating units were out for scheduled maintenance or were unexpectedly unavailable. In addition to making the requests, in 2005, 2006 and 2007, HECO on occasion remotely turned off water heaters for a number of residential customers who participate in its load-control program.

HELCO. HELCO s 2009 Adequacy of Supply letter filed in January 2009 indicated that HELCO s generation capacity for the next three years, 2009 through 2011, is sufficiently large to meet all reasonably expected demands for service and provide reasonable reserves for emergencies.

MECO. MECO s 2009 Adequacy of Supply letter filed in January 2009 indicated that MECO s generation capacity for the next three years, 2009 through 2011, is sufficient to meet the forecasted demands on the islands of Maui, Lanai and Molokai. MECO s 2009 Adequacy of Supply letter also indicated that the date the next increment of additional firm generating capacity on Maui is needed has changed from 2014 to 2015 due primarily to a reduction in the forecast of peak demand.

The PPA between MECO and Hawaiian Commercial & Sugar Company (HC&S), which provides for 16 MW of firm capacity, continues in effect from year to year, subject to termination on written notice by either party of not less than two years. In July 2007, however, the parties agreed to not issue a notice of termination that would result in the termination of the PPA prior to the end of 2014.

On occasions in 2006 and 2007, MECO experienced lower than normal generation capacity due to the unexpected temporary losses of several of its generating units, and issued public requests that its customers voluntarily conserve electricity. No such requests were issued in 2008.

December 2008 outage. On December 26, 2008, an island-wide outage occurred on the island of Oahu that resulted in a loss of electric service to HECO customers ranging from approximately 7 to 20 hours.

On January 12, 2009, the PUC issued an order initiating an investigation of the outage to address the following preliminary issues: (1) what caused the outage; (2) if lightning strikes during the lightning storm initially caused the power outage, could HECO have reasonably prevented damaging effects of lightning strikes to prevent the power outage from initially occurring; (3) through reasonable measures, could HECO have prevented the power outage or prevented it from becoming island-wide; (4) could HECO have reasonably shortened the duration of the power outage and restored power more quickly to customers; (5) what are the necessary steps to prevent similar power outages in the future, to minimize the scope and duration of similar power outages and to improve HECO s response to such outages in the future; and (6) what penalties, if any, should be imposed on HECO.

On March 31, 2009, HECO submitted its outage report that was prepared by its expert consultant, POWER Engineers, Inc. (POWER). The outage report concluded that the island-wide outage was triggered by lightning strikes on or near HECO s 138 kilovolt (kV) transmission system, one of which resulted in a short-circuit over all three phases of the Kahe-Waiau 138 kV line, setting in motion a series of events that resulted in the necessary loss of customer load, loss of generation and the eventual island-wide shut down of HECO s system. POWER found that: (1) the HECO system was in proper operating condition and was appropriately staffed at the time of the lightning storm, and (2) HECO s restoration efforts were prudent and allowed for the restoration of power as quickly as possible under the circumstances, while also ensuring the safety and protection of HECO s employees and customers and preventing any further or permanent damage to the electric system from attempts to bring the system back too quickly. POWER made a number of recommendations, largely technical in nature, for HECO to consider that may reduce the likelihood of the recurrence of a similar power outage or minimize the duration of an outage should one occur in the future.

The Consumer Advocate and the PUC will review the outage report and conduct their own independent reviews.

Management cannot at this time predict the outcome of the PUC s or Consumer Advocate s investigations or their impact on HECO.

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 issues in the proceeding adopted by the PUC include (1) identifying what impact, if any, wheeling will have on Hawaii s electric industry, (2) addressing interconnection matters, (3) identifying the costs to utilities, (4) identifying any rate design and cost allocation issues, (5) considering the financial cost and impact on non-wheeling customers, (6) identifying any power back-up issues, (7) addressing how rates would be set, (8) identifying the environmental impacts, (9) identifying and evaluating the various forms of intra-governmental wheeling and (10) identifying and evaluating the resulting impact to any and all governmental entities, including but not limited to economic, feasibility and liability impacts. Parties to this proceeding include HECO, HELCO, MECO, Kauai Island Utility Cooperative and the Consumer Advocate, as well as governmental agencies (the DOD, the Department of Business, Economic Development and Tourism, the City and County of Honolulu and the Counties of Hawaii, Maui and Kauai), an environmental group, and two renewable energy developers. Two renewable energy contractors and a renewable energy developer also have been granted more limited participant status.

In the fourth quarter of 2008, the Department of Business, Economic Development and Tourism requested (in accordance with the provisions of the Energy Agreement) that the PUC suspend the pending intra-governmental wheeling docket for a period of 12 months while the parties to the agreement evaluate the necessity of the docket in view of the other agreements of the parties. The PUC approved the request, provided that the PUC, at its option, may re-institute this docket at an earlier date.

Energy Independence and Security Act of 2007. On February 11, 2009, the PUC issued an order initiating an investigation whether to implement any of four new federal standards, as required by the Public Utility Regulatory Policies Act of 1978, as amended by the Energy Independence and Security Act of 2007. In summary, the four standards are as follows: 1) each electric utility shall integrate energy efficiency resources into utility, state and regional plans and adopt policies establishing cost-effective energy efficiency as a priority resource; 2) electric utility rates shall align utility incentives with the delivery of cost-effective energy efficiency and promote energy efficiency investments; 3) each state shall consider requiring that, prior to undertaking investments in non-advanced grid technologies, an electric utility demonstrate to the state that it considered an investment in a qualified smart grid system; and 4) all electricity purchasers shall be provided direct access to pricing, usage and power source information from their electricity provider. The PUC named HECO, HELCO, MECO, Kauai Island Utility Cooperative and the Consumer Advocate as parties in this proceeding. The PUC directed the parties to file within 90 days of the date of the order a position statement on whether the PUC should adopt, modify, or decline to adopt the standards, and procedural comments on how these issues should be considered in this docket or in a separate proceeding. Management can not predict the outcome of this proceeding.

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 Emergency Economic Stabilization Act of 2008 and American Economic Recovery and Reinvestment Act of 2009 above.

Renewable Portfolio Standard. Hawaii has an RPS law requiring electric utilities to meet an RPS of 8% of KWH sales by December 31, 2005, 10% by December 31, 2010, 15% by December 31, 2015, and 20% by December 31, 2020. The RPS law provides that at least 50% of the RPS targets must be met by electrical energy generated using renewable energy sources, such as wind or solar, versus from the electrical energy savings from renewable energy displacement technologies (such as solar water heating) or from energy efficiency and conservation programs. These standards may be met by the electric utilities on an aggregated basis and were met in 2005 when the electric utilities attained an RPS of 11.7%. The utilities are committed to achieving these goals, as well as the higher goals proposed in the Energy Agreement (discussed below); however, due to risks such as potential delays in IPPs being able to deliver contracted renewable energy (see risks under Forward-looking Statements on pages 2 and 3), it is possible the electric utilities may not attain the required renewable percentages in the future, and management cannot predict the future consequences of failure to do so (including potential penalties to be assessed by the PUC).

The RPS law was amended in 2006 to add provisions for penalties if the utility fails to meet its RPS requirements, to require the PUC to conduct a hearing prior to assessing penalties, and to amend the criteria for waiver of the penalties by the PUC. In January 2007, the PUC opened a new docket (RPS Docket) to examine Hawaii s RPS law, to establish the appropriate penalties for failure to meet RPS targets and to determine the circumstances under which penalties should be levied. The issues also included the appropriate utility ratemaking structure to include in the RPS framework to provide incentives that encourage electric utilities to use cost-effective renewable energy resources found in Hawaii to meet the RPS, while allowing for deviation from the standards in the event that the standards cannot be met in a cost-effective manner, or as a result of circumstances beyond the control of the utility that could not have been reasonably anticipated or ameliorated.

In December 2007, the PUC issued a D&O approving a stipulated RPS framework to govern electric utilities compliance with the RPS law. In a follow up order in December 2008, the PUC approved a penalty of $20 for every MWh that an electric utility is deficient under Hawaii s RPS law. The PUC found that a penalty, in a specific dollar per MWh amount, which the PUC may assess against a non-compliant utility, will provide clarity and transparency to the RPS Framework. The PUC noted, however, that this penalty may be reduced, in the

PUC s discretion, due to events or circumstances that are outside an electric utility s reasonable control, to the extent the event or circumstance could not be reasonably foreseen and ameliorated, as described in the RPS law and in the RPS Framework. In addition, the PUC ordered that: (1) any penalties assessed against HECO and its subsidiaries for failure to meet the RPS will go into the public benefits fund account used to support energy efficiency and DSM programs and services, which will be operated by a third-party administrator, unless otherwise directed; and (2) the utilities will be prohibited from recovering any RPS penalty costs through rates.

In its December 2007 D&O, the PUC deferred the RPS incentive framework to a new generic docket (Renewable Energy Infrastructure Program or REIP Docket). The parties to the REIP Docket include the electric utilities, the Consumer Advocate, an environmental organization and Hawaii Renewable Energy Alliance (HREA). Public hearings were held in May 2008.

The Renewable Energy Infrastructure Program proposed by HECO in the RPS docket consists 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 July 2008, statements of position were filed with the PUC, in which the Consumer Advocate recommended approval of, HREA supported, and the environmental organization did not oppose the REIP proposed by HECO. In October 2008, pursuant to the PUC s request, the parties to the docket informed the PUC, among other things, that the parties (1) have reached an agreement on all of the issues in the docket, (2) agree that it is appropriate that the PUC approve the utilities proposed REIP and related REIP surcharge, (3) agree that the record in the proceeding is complete and ready for PUC decision-making, and (4) waive an evidentiary hearing. In February 2009, the PUC issued to the parties information requests prepared by its consultant.

The Energy Agreement includes a provision to seek legislation to revise the RPS law to require electric utilities to meet an RPS of 25% by 2020 and 40% by 2030. In addition, the Energy Agreement includes a provision to eliminate energy efficiency and conservation entirely from consideration as contributors to the RPS targets after 2014. Furthermore, the Energy Agreement includes a provision under which imported biofuel generation could not account for more than 30% of the RPS target through 2015.

In the Energy Agreement, the parties also agreed that the REIP may be modified to incorporate changes for the CEIS mechanism, provided the appropriate notices to the public regarding the changes are made.

On November 28, 2008, HECO and the Consumer Advocate filed a joint letter informing the PUC that the proposed REIP Surcharge is substantially similar to the CEIS and that the REIP Surcharge proposal satisfies the Energy Agreement commitment for the filing of an implementation procedure for the CEIS.

Management cannot predict the outcome of these proceedings and processes.

Net energy metering. Hawaii has a net energy metering law, which requires that electric utilities offer net energy metering to eligible customer generators (i.e., a customer generator may be a net user or supplier of energy and will make payment to or receive credit from the electric utility accordingly).

In 2005, the Legislature amended the net energy metering law by, among other revisions, authorizing the PUC, by rule or order, to increase the maximum size of the eligible net metered systems and to increase the total rated generating capacity available for net energy metering. In April 2006, the PUC initiated an investigative proceeding on whether the PUC should increase (1) the maximum capacity of eligible customer-generators to more than 50 kW and (2) the total rated generating capacity produced by eligible customer-generators to an amount above 0.5% of an electric utility s system peak demand. The parties to the proceeding include HECO, HELCO, MECO, Kauai Island Utility Cooperative (KIUC), the Consumer Advocate, a renewable energy organization and a solar vendor organization. In March 2008, the PUC approved a stipulated agreement filed by the parties (except for KIUC, which has its own stipulated agreement) to increase the maximum size of the eligible customer-generators from 50 kW to 100 kW and the system cap from 0.5% to 1.0% of system peak demand, to reserve a certain percentage of the 1.0% system peak demand for generators 10 kW or less and to

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consider in the IRP process any further increases in the maximum capacity of customer-generators and the system cap. The PUC further required the utilities: (1) to consider specific items relating to net energy metering in their respective IRP processes, (2) to evaluate the economic effects of net energy metering in future rate case proceedings and (3) to design and propose a net energy metering pilot program for the PUC s review and approval that will allow, on a trial basis, the use of a limited number of larger generating units (i.e., at least 100 kW to 500 kW, and may allow for larger units) for net energy metering purposes.

In April 2008, the electric utilities applied for PUC approval of a proposed four-year net energy metering pilot program to evaluate the effects on the grid of units larger than the currently approved maximum size. The program will consist of analytical investigations and field testing and is designed for a limited number of participants that own (or lease from a third party) and operate a solar, wind, biomass, or hydroelectric generator, or a hybrid system. The electric utilities propose to recover program costs through the IRP cost recovery provision.

In 2008, the net energy metering law was again amended to authorize the PUC, by rule or order, to modify the maximum size of the eligible net metered systems and evaluate on an island-by-island basis whether to exempt an island or utility grid system from the total rated generating capacity limits available for net energy metering.

In the Energy Agreement, the parties agreed to seek to remove system-wide caps on net energy metering. Instead, they plan to seek to limit DG interconnections on a per circuit basis and to replace net energy metering with an appropriate feed-in tariff and new net metered installations that incorporate time-of-use metering equipment for future full scale implementation of time-of-use metering and sale of excess energy.

On February 13, 2009, the parties to the Net Energy Metering proceeding filed a joint letter pointing out that the Energy Agreement calls for the development of a feed-in tariff that may eventually replace net energy metering and that the outcome of the feed-in tariff proceeding may influence the future direction of net energy metering. The parties proposed to provide an update on the proposed pilot program within a month after the completion of the feed-in tariff proceeding.

On December 3, 2008, HELCO, MECO and the Consumer Advocate filed stipulations to increase their net energy metering system caps from 1% to 3% of system peak demand (among other changes). On December 26, 2008, the PUC issued an order approving the proposed caps, but directed the parties to file a proposed plan to address the provisions regarding net energy metering in the Energy Agreement within 45 days. In February 2009, the utilities and the Consumer Advocate filed a joint letter requesting an extension until May 22, 2009 to submit the proposed plan and further agreed that any potential increases to the net energy metering limits be reviewed in each of the utilities Clean Energy Scenario Planning process.

DSM programs. See Demand-side management programs above.

Non-fossil fuel purchased power contracts. In 2006, a law was enacted that required that the PUC establish a methodology that removes or significantly reduces any linkage between the price paid for non-fossil-fuel-generated electricity under future power purchase contracts and the price of fossil fuel, in order to allow utility customers to receive the potential cost savings from non-fossil fuel generation (in connection with the PUC s determination of just and reasonable rates in purchased power contracts).

Greenhouse gas emissions reduction. In July 2007, Act 234 became law, which requires a statewide reduction of greenhouse gas (GHG) emissions by January 1, 2020 to levels at or below the statewide GHG emission levels in 1990. It also establishes a task force, comprised of representatives of state government, business (including the electric utilities), the University of Hawaii and environmental groups, which is charged with preparing a work plan and regulatory approach for implementing the maximum practically and technically feasible and cost-effective reductions in greenhouse gas emissions from sources or categories of sources of greenhouse gases to achieve 1990 statewide GHG emission levels. The electric utilities are participating in the Task Force, as well as in initiatives aimed at reducing their GHG emissions, such as those to be undertaken under the Energy Agreement. Because the full scope of the Task Force report remains to be determined and regulations implementing Act 234 have not yet been promulgated, management cannot predict the impact of Act 234 on the electric utilities and the Company.

If the U.S. Environmental Protection Agency (EPA) grants a waiver to California under the Clean Air Act (CAA) to allow state government control of GHG emissions from new motor vehicles sold in California and the Hawaii legislature passes a pending bill adopting the California motor vehicle emission standards, the ability of Hawaii to meet Act 234 s GHG reduction targets should be enhanced. Although several bills addressing GHG emission reductions also have been introduced in Congress, none has yet been adopted.

On April 7, 2007, in Massachusetts v. EPA, the U.S. Supreme Court ruled that the EPA has the authority to regulate GHG emissions from motor vehicles under the Clean Air Act (CAA or the Act). The Court further ruled that the EPA must determine whether or not motor vehicle GHG emissions cause or contribute to air pollution which may be reasonably anticipated to endanger public health or welfare (known as an endangerment finding), or whether the science about GHGs was too uncertain to make a reasoned decision. On July 11, 2008, the EPA issued its advance notice of proposed rulemaking (ANPR) inviting public comment on the benefits and ramifications of regulating GHGs under the CAA.

On March 10, 2009, the EPA issued a proposed rule under the CAA for the monitoring and reporting of GHG emissions. The rule would apply to fossil fuel suppliers and industrial gas suppliers, as well as to direct GHG emitters, including the electric utilities. As proposed, the rule only requires that sources above certain threshold levels monitor and report GHG emissions it would not require control of GHGs. Comments on the proposed GHG monitoring and reporting rule must be received by the EPA on or before July 9, 2009.

In response to Massachusetts v. EPA, the EPA proposed an endangerment finding that current and projected concentrations of six key GHGs in the atmosphere threaten the public health and welfare of current and future generations and that motor vehicle emissions that contain four of the six GHGs identified in the endangerment finding contribute to climate change. The EPA has scheduled two public hearings on the proposed endangerment finding. The proposed endangerment finding was published in the Federal Register on April 24, 2009, and comments are due by June 23, 2009. The proposed finding, if adopted, would not require any specific action by industry and the EPA noted that an endangerment finding under one part of the CAA would not automatically trigger regulation under other parts of the CAA. Since, however, the CAA s language regarding endangerment findings due to motor vehicle emissions is virtually identical to its language regarding stationary source emissions, such as those emitted from the electric utilities facilities, there is little doubt that the EPA will make the same or similar endangerment finding regarding GHG emissions from stationary sources. In the announcement of the proposed endangerment finding, the EPA stressed that the agency and President Obama s administration prefer comprehensive legislation to address climate change due to GHG emissions and to create a framework for a clean energy economy.

Although, the proposed GHG reporting rule and proposed endangerment finding do not require control of GHGs, they are seen as necessary prerequisites for GHG reduction requirements under the CAA. The electric utilities, therefore, are reviewing the proposals and evaluating whether to submit comments to the EPA.

Renewable energy. In 2007, a law was enacted that stated that the PUC may consider the need for increased renewable energy in rendering decisions on utility matters. Due to this measure, it is possible that, if energy from a renewable source were more expensive than energy from fossil fuel, the PUC may still approve the purchase of energy from the renewable source.

In 2008, a law was enacted to promote and encourage the use of solar thermal energy. This measure will require the installation of solar thermal water heaters in residences constructed after January 1, 2010, but allow for limited variances in cases where installation of solar water heating is deemed inappropriate. The measure will establish standards for quality and performance of such systems. Also in 2008, a law was enacted that is intended to facilitate the permitting of larger (200 MW or greater) renewable energy projects. The Energy Agreement includes several undertakings by the utilities to integrate solar energy into the electric grid.

Biofuels. In 2007, a 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 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.

The utilities have agreed in the Energy Agreement to test the use of biofuels in their generating units and, if economically feasible, to connect them to the use of biofuels. For its part, the State agrees to support this testing and conversion by expediting all necessary approvals and permitting. The Energy Agreement recognizes that, if such conversion is possible, HECO s requirements for biofuels would encourage the development of a local biofuels industry.

For a discussion of environmental legislation and regulations, see Environmental regulation in Note 5 of HECO s Notes to Consolidated Financial Statements.

At this time, it is not possible to predict with certainty the impact of the foregoing legislation or legislation that is, or may in the future be, proposed.

Other developments

Advanced Meter Infrastructure (AMI). On December 1, 2008, the utilities filed an AMI project application with the PUC for approval to implement AMI, covering approximately 451,000 meters (293,000 on Oahu, 92,000 on the island of Hawaii and 66,000 on Maui). The application embodies the goals of the HCEI, which is further described in Note 5 of HECO s Notes to Consolidated Financial Statements. The parties to the proceeding filed a proposed stipulated procedural order, which includes hearings in September 2009 and was approved in April 2009.

HECO continues to operate a Sensus Metering Systems AMI network, currently consisting of 8,000 advanced meters at both residential and commercial customer sites and completed the first phase of its investigation of Meter Data Management (MDM) software. The MDM will ultimately capture the increased data volume from advanced meters and will serve as the data warehouse and knowledge store for current and future utility applications.

AMI technology enables automated meter reading, improved field service operations, more accurate meter readings, time-of-use pricing and conservation options for HECO customers. The utilities continue to explore other utility applications such as distribution circuit monitoring and water heater and air conditioning load control for improved residential and commercial customer reliability.

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

Despite the recent unprecedented deterioration in the capital markets and tightening of credit, HECO believes that its 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 capital expenditures and investments and to cover debt, retirement benefits and other cash requirements in the foreseeable future.

HECO s consolidated capital structure was as follows as of the dates indicated:

(in millions)	March 31, 2009		December 31, 2008	
Short-term borrowings	$ 29	1%	$ 42	2%
Long-term debt	908	42	905	42
Preferred stock	34	2	34	1

Common stock equity	1,193	55	1,189	55
	$ 2,164	100%	$ 2,170	100%

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As of May 1, 2009, the S&P and Moody s ratings of HECO securities were as follows:

	S&P	Moody s
Commercial paper	A-2	P-2
Special purpose revenue bonds		
(principal amount noted in parentheses, senior unsecured, insured as follows):		
Ambac Assurance Corporation ($0.2 billion)	A	Baa1*
Financial Guaranty Insurance Company ($0.3 billion)	BBB*	Baa1*
MBIA Insurance Corporation ($0.3 billion)	AA-**	Baa1**
Syncora Guarantee Inc. (formerly XL Capital Assurance Inc.) ($0.1 billion)	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 of the applicable rating agency at the time the ratings are issued, 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. HECO s overall S&P corporate credit rating is BBB/Stable/A-2. HECO s issuer rating by Moody s is Baa1 and Moody s outlook for HECO is stable.

* 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 s announced restructuring in February 2009, the revenue bonds issued for HECO and its subsidiaries and insured by MBIA have been reinsured by MBIA Insurance Corp. of Illinois (MBIA Illinois), whose financial strength rating by S&P is AA-. Moody s has announced it will assign ratings to the reinsured municipal securities based on the higher of its insurance financial strength rating of MBIA Illinois or the published underlying rating. The insurance financial strength rating of MBIA Illinois by Moody s is Baa1, which is the same as Moody s issuer rating for HECO.

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. In November 2008, S&P affirmed its corporate credit ratings and stable outlook for HECO. S&P s rating outlook indicates the potential direction of a possible rating change in the coming 6 to 24 months. In November 2008, S&P stated:

The stable outlook reflects our expectation that, for now, HECO appears to have reasonable but not certain prospects for maintaining its existing financial profile, which is weak for the rating. Multiple near-term challenges face the company and include the uncertainties of the cost and feasibility impacts of the CEI [Hawaii Clean Energy Initiative], the potential for a significant reduction in electric sales in 2009 (due to economic contraction, energy efficiency initiatives, and customer response to high prices), and a recent softening in leading economic indicators. These challenges suggest that a negative outlook or downward revision to the ratings could be possible over the outlook horizon, as further weakening in the financial profile will not support ratings, and near-term business risk will be elevated until the particulars of the CEI are in place and prove to be supportive. Consistent, timely rate relief will continue to be key, and could offset or mitigate the effects of a declining economic environment, but decoupling or other measures are not expected to be available to the company before late 2009 or early 2010. Given these challenges, higher ratings are not foreseen during the outlook horizon and would need to be accompanied by sustained and improved financial performance.

S&P designates business risk profiles as excellent, strong, satisfactory, weak or vulnerable. S&P stated in November 2008 that: HECO s business profile reflects its ownership of regulated utility assets, which serve about 95% of Hawaii s population.

S&P s financial risk designations are minimal, modest, intermediate, aggressive and highly leveraged. In November 2008, S&P indicated th [t]he consolidated financial profile is aggressive, reflecting

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in part the very heavy debt imputation Standard & Poor s Rating Services applies to HECO for its long-term power purchase agreements (PPAs).

In September 2008, Moody s maintained its ratings and stable outlook for HECO. Moody s stated, The rating could be downgraded should weaker than expected regulatory support emerge at HECO, including the continuation of regulatory lag, which ultimately causes earnings and sustainable cash flows to suffer. To that end, if the utilities financial ratios declined on a permanent basis such that the Adjusted Cash Flow (net cash flow from operations less net changes in working capital items) to Adjusted Debt fell below 17% (20% as of June 30, 2008-latest reported by Moody s) or Adjusted Cash Flow to Adjusted Interest declined to less than 3.6x (4.9x as of June 30, 2008-latest reported by Moody s) for an extended period, the rating could be lowered.

Information about HECO s short-term borrowings (other than from MECO), HECO s line of credit facilities and special purpose revenue bonds authorized by the Hawaii legislature for issuance for the benefit of the utilities was as follows:

	Three months ended March 31, 2009		
(in millions)	**Average balance**	**End-of-period balance**	**December 31, 2008**
Short-term borrowings			
Commercial paper	$ 1	$	$
Borrowings from affiliates	23	29	42
Line of credit facilities [1]			
Future capacity under line of credit facility expiring March 31, 2011 [2]		175	175
Undrawn capacity under line of credit facility expiring September 8, 2009		75	75
Special purpose revenue bonds authorized for issue			
2005 legislative authorization (expiring June 30, 2010)-HELCO		$ 20	$ 20
2007 legislative authorization (expiring June 30, 2012)			
HECO		260	260
HELCO		115	115
MECO		25	25
Total special purpose revenue bonds available for issue		$ 420	$ 420

1 At May 1, 2009, there was no outstanding commercial paper balance and the line of credit facilities were undrawn. HECO may seek to modify credit facilities in accordance with the expedited approval process approved by the PUC, including to increase the amount of credit available under an agreement, and/or to enter into new lines of credit, as management deems appropriate.

2 HECO has filed with the PUC a request for expedited approval of Amendment No. 2 (which the Required Lenders, as defined in the agreement, have signed) to a $175 million credit facility expiring March 31, 2011. Among other things, Amendment No. 2 eliminates from the credit agreement representations relating to the funded status of HECO s pension plan, which are not currently correct. HECO does not anticipate needing to draw on this credit facility prior to obtaining PUC approval of the Amendment. However, if HECO needs to draw under, or issue commercial paper against, this credit facility, HECO will seek to obtain from the lenders waivers to the condition to their obligations to lend that this representation be correct at the time of each borrowing.

HECO utilizes short-term debt, principally commercial paper, to support normal operations and for other temporary requirements. HECO also borrows short-term from HEI for itself and on behalf of 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. At March 31, 2009, HECO had $29 million and $25 million of short-term borrowings from HEI and MECO, respectively, and HELCO had $67 million of short-term borrowings from HECO. HECO had an average outstanding balance of commercial paper for the first quarter of 2009 of $1 million and had no commercial paper outstanding at March 31, 2009. Management believes that, if HECO s commercial paper ratings were to be downgraded or if credit markets were to further tighten, it would be more difficult and expensive to sell commercial paper, or HECO might not be able to sell commercial paper.

Revenue bonds are issued by the Department of Budget and Finance of the State of Hawaii to finance capital improvement projects of HECO and its subsidiaries, but the source of their repayment are the unsecured obligations of HECO and its subsidiaries under loan agreements and notes issued to the Department, including HECO s guarantees of its subsidiaries obligations. The payment of principal and interest due on all revenue bonds currently outstanding are insured either by Ambac Assurance Corporation (Ambac), Financial Guaranty Insurance Company (FGIC), MBIA Insurance Corporation (MBIA) or Syncora Guarantee Inc. (Syncora) (formerly XL Capital Assurance Inc.). The currently outstanding revenue bonds 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 Ambac, MBIA, FGIC and XLCA (now Syncora) 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. Management believes that if HECO s ratings were to be downgraded, or if credit markets further tighten, it could be more difficult and/or expensive to sell bonds in the future.

Operating activities provided $101 million in net cash during the first three months of 2009. Investing activities during the same period used net cash of $78 million for capital expenditures, net of contributions in aid of construction. Financing activities for the same period used net cash of $26 million, primarily due to a $12 million net decrease in short-term borrowings, the payment of $11 million of common and preferred dividends and a $6 million decrease in cash overdraft, partly offset by drawdown of $3 million of SPRB proceeds.

The PUC must approve issuances, if any, of equity and long-term debt securities by HECO, HELCO and MECO. In October 2008, HECO, HELCO and MECO filed with the PUC an application for approval of one or more special purpose revenue bond financings under the 2007 legislative authorization identified above, with the first such financing anticipated to be in 2009 if the PUC approves the application and market conditions are satisfactory. On April 20, 2009, HECO, HELCO and MECO filed with the PUC an application for the approval of the sale of each company s common stock (HECO s sale to HEI of up to $120 million and HELCO s and MECO s sales to HECO of up to $30 million and $7 million, respectively), and the purchase of the HELCO and MECO common stock by HECO, all in 2009.

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Bank

RESULTS OF OPERATIONS

(in thousands)	Three months ended March 31, 2009	2008	% change	Primary reason(s) for significant change
Revenues	$ 82,032	$ 105,844	(22)	Lower interest income primarily due to lower earning asset balances as a result of the balance sheet restructuring in June 2008 and lower yields on earning assets due to the lower interest rate environment
Operating income	17,121	23,363	(27)	Higher net interest income and lower noninterest expense, more than offset by higher provision for loan losses and lower noninterest income
Net income	10,882	14,576	(25)	Lower operating income

See Economic conditions in the HEI Consolidated section above.

Net interest margin 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 very volatile due to disruptions in the financial markets and these conditions may have a negative impact on ASB s net interest margin.

Loan originations and purchases of loans and mortgage-related securities are ASB s primary sources of earning assets. 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. As of March 31, 2009, ASB s loan portfolio mix, net, consisted of 70% residential loans, 13% commercial loans, 9% consumer loans and 8% commercial real estate loans. As of December 31, 2008, ASB s loan portfolio mix, net, consisted of 70% residential loans, 14% commercial loans, 9% consumer loans and 7% commercial real estate loans.

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. Competition for deposits and the level of short-term interest rates have made it difficult to retain deposits and control funding costs, and deposit retention and growth will remain challenges in the current environment. Advances from the FHLB of Seattle and securities sold under agreements to repurchase continue to be additional sources of funds. As of March 31, 2009, ASB s costing liabilities consisted of 91% deposits and 9% other borrowings. As of December 31, 2008, ASB s costing liabilities consisted of 86% deposits and 14% other borrowings.

As of March 31, 2009, the bank s investment portfolio consisted of 50% mortgage-related securities issued by Federal National Mortgage Association (FNMA), Federal Home Loan Mortgage Corporation (FHLMC) or Government National Mortgage Association (GNMA), and 50% private-issue mortgage-related securities. As of December 31, 2008, the bank s investment portfolio consisted of 9% federal agency obligations, 46% mortgage-related securities issued by FNMA, FHLMC or GNMA and 45% private-issue mortgage-related securities.

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. Private-issue mortgage-related securities carry a risk of loss due to delinquencies, foreclosures, and losses in the mortgage loans collateralizing the securities. Further deterioration in the U.S. residential housing market continues to pressure non-agency Residential Mortgage-Backed Securities (RMBS) held in the investment portfolio. The velocity of economic decline has exacerbated already weak home sales, which are impacted by borrowers unable to secure financing but also by those defaulting on current loans as a result of unemployment trends or payment shocks. The flood of inventory as a result of foreclosures has pressured prices and thus the credit of securities held in the portfolio. Those originated within the last 2-3 years have experienced the greatest pressure as borrowers purchasing homes at the peak of the market have experienced price declines that have eroded any remaining equity in their properties. As of March 31, 2009, non-agency RMBS represented 50% of the portfolio. 9% of the portfolio was rated non-investment grade by at least one of the major rating agencies. While the majority of those securities are backed by prime, fixed rate, 30 year mortgages, price declines coupled with increased economic pressure have impacted all sectors of the housing market which has impacted credit ratings of securities backed by loans issued within the last couple of years.

In the first quarter of 2009, rating agencies downgraded three securities with a combined face value of $42 million as of March 31, 2009. The first bond, backed by prime, fixed rate, 30 year mortgages, was downgraded to CC from BBB by one rating agency and to CCC from BB by another rating agency. The second bond, backed by Alt-A, fixed rate, 30 year mortgages, was downgraded to CCC from AAA by one rating agency while another rating agency maintained a BB rating. The third bond, backed by Alt-A, fixed rate, 30 year mortgages, was downgraded to BB from AAA by one rating agency while another rating agency maintained an A rating. From April 1 to 24, 2009, various rating agencies issued ratings downgrades on several securities nine bonds with a combined face value of $88 million were downgraded (downgrades to AA, BBB, BB, Ba3, B1, B3 and CCC). While risks related to private-issue mortgage-related securities have increased, ASB believes that, based on its internal assessment of positions held in the portfolio and its ability and intent to hold these securities until a recovery of fair value, which may be at maturity, it does not consider these securities to be other-than-temporarily impaired at March 31, 2009. ASB will continue to analyze and monitor these securities.

Should market conditions and the performance of mortgage-related assets continue to deteriorate, ASB could incur a material other-than-temporary impairment on additional securities.

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. Continued deterioration in the housing market has amplified the credit risks in ASB s RMBS holdings. Although most of the bonds are senior securities which were underwritten to be the shortest duration instruments in the deal structure, further deterioration in the housing market may negatively impact the outstanding credit enhancement of these positions. Continued deterioration in pools supporting ASB s securities will adversely impact their value. While current AOCI deficits are considered temporary, greater declines in the housing market may negatively impact their valuation and result in other-than-temporary losses that are material.

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 stockholder 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 balance sheet restructure) or an other-than-temporary impairment in the value of the securities. As of March 31, 2009 and December 31, 2008, the unrealized losses, net of tax benefits, on available-for-sale investments and mortgage-related securities (including securities pledged for repurchase agreements) in AOCI was $24 million and $33 million, respectively. See Quantitative and qualitative disclosures about market risk.

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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, 2009 and 2008.

	Three months ended March 31					
	2009			2008		
($ in thousands)	Average Balance	Interest	Average Rate (%)	Average Balance	Interest	Average Rate (%)
Assets:						
Other investments [1]	$ 107,118	$		$ 137,319	$ 561	1.62
Investment and mortgage-related securities	675,927	7,676	4.54	2,142,126	23,890	4.46
Loans receivable [2]	4,177,039	58,092	5.58	4,166,005	63,465	6.10
Total interest-earning assets	4,960,084	65,768	5.32	6,445,450	87,916	5.46
Allowance for loan losses	(36,265)			(30,035)		
Non-interest-earning assets	359,244			428,467		
Total assets	$ 5,283,063			$ 6,843,882		
Liabilities and Stockholder s Equity:						
Interest-bearing demand and savings deposits	$ 2,119,976	2,347	0.45	$ 2,097,608	3,507	0.67
Time certificates	1,326,957	9,218	2.82	1,577,733	14,713	3.74
Total interest-bearing deposits	3,446,933	11,565	1.36	3,675,341	18,220	1.99
Other borrowings	561,166	3,264	2.33	1,805,994	19,149	4.25
Total interest-bearing liabilities	4,008,099	14,829	1.50	5,481,335	37,369	2.73
Non-interest bearing liabilities:						
Deposits	714,499			655,146		
Other	85,360			107,938		
Stockholder s equity	475,105			599,463		
Total Liabilities and Stockholder s Equity	$ 5,283,063			$ 6,843,882		
Net interest income		$ 50,939			$ 50,547	
Net interest margin (%) [3]			4.11			3.13

1 Includes federal funds sold, interest bearing deposits and stock in the FHLB of Seattle ($98 million as of March 31, 2009).

2 Includes loan fees of $1.9 million and $1.1 million for the three months ended March 31, 2009 and 2008, respectively, together with interest accrued prior to suspension of interest accrual on nonaccrual loans. Includes nonaccrual loans.

3 Defined as net interest income as a percentage of average earning assets.

Results three months ended March 31, 2009. Net interest income before provision for loan losses for the three months ended March 31, 2009 increased by $0.4 million, or 1%, when compared to the same period in 2008 as lower funding costs and higher balances on loans were partially offset by lower yields on loans and lower balances of investment and mortgage-related securities. Net interest margin increased from 3.13% in the first quarter of 2008 to 4.11% in the first quarter of 2009 due to the restructuring of the balance sheet, which removed lower spread net assets (investment and mortgage-related securities and other borrowings). The increase in the average loan portfolio balance was due, in part, to growth in the home equity lines of credit and continued growth in the commercial markets loan portfolio. The decrease in average residential loan balances was due to lower demand for residential loans in 2008 and ASB s strategic decision to sell all salable residential loan production in the current low interest rate environment. The decrease in the average investment and mortgage-related securities portfolios was primarily due to the sale of securities in the balance sheet restructure. See Balance sheet restructure in Note 4 to HEI s Notes to Consolidated Financial Statements. Average deposit balances decreased by $169 million compared to the first quarter of 2008, and decreased by $32 million compared to the last quarter of 2008. ASB experienced outflows throughout 2008 as the downward trend in interest rates made it difficult to retain deposits. 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 $1.2 billion primarily due to the early extinguishment of other borrowings in the balance sheet restructure.

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During the first quarter of 2009, ASB recorded a provision for losses of $8.3 million due to an increase in nonperforming residential lot loans and residential mortgages and the reclassification of one commercial loan. Higher levels of delinquencies and loan loss provisions are expected through the economic downturn. During the first quarter of 2008, ASB recorded a provision for losses of $0.9 million due to loan growth as well as an increase in the classification of commercial loans.

(in thousands)	Three months ended March 31 2009	Three months ended March 31 2008	Year ended December 31 2008
Allowance for loan losses, January 1	$ 35,798	$ 30,211	$ 30,211
Provision for loan losses	8,300	900	10,334
Less: net charge-offs	2,047	483	4,747
Allowance for loan losses, end of period	$ 42,051	$ 30,628	$ 35,798
Ratio of allowance for loan losses, end of period, to average loans outstanding	1.01%	0.74%	0.86%
Ratio of net charge-offs during the period to average loans outstanding	0.20%	0.05%	0.11%
Nonaccrual loans	54,627	7,451	19,494

First quarter of 2009 noninterest income decreased by $1.7 million, or 9%, when compared to the first quarter of 2008, primarily due to a gain on sale of stock in a membership organization in 2008.

Noninterest expense for the first quarter of 2009 decreased by $2.4 million, or 5%, when compared to the first quarter of 2008, primarily due to lower legal and consulting expenses, partially offset by higher compensation and employee benefits expenses.

Legislation and regulation**.** ASB is subject to extensive regulation, principally by the Office of Thrift Supervision (OTS) and the Federal Deposit Insurance Corporation (FDIC). Depending on its 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 shareholders. See the discussion below under Liquidity and capital resources. Also see FDIC restoration plan and Deposit insurance coverage in Note 4 of HEI s Notes to Consolidated Financial Statements.

FHLB of Seattle dividends**.** In December 2008, the FHLB of Seattle announced that it would not pay a dividend on its stock in the fourth quarter of 2008 due to a net loss reported by the FHLB of Seattle for the third quarter of 2008. The FHLB of Seattle also announced that it had a risk-based capital deficiency at December 31, 2008 and would not be able to repurchase capital stock or declare a dividend while a risk-based capital deficiency exists. ASB does not believe that the FHLB of Seattle s risk-based capital deficiency will affect the FHLB of Seattle s ability to meet ASB s liquidity and funding needs. ASB received cash dividends on its $98 million of FHLB of Seattle stock of $0.1 million in 2006, $0.6 million in 2007 and $0.9 million in 2008. Periodically and as conditions warrant, ASB reviews its investment in the stock of FHLB of Seattle for impairment and adjusts the carrying value if the investment is determined to be impaired.

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

Recent accounting pronouncements and interpretations. See Note 9 of HEI s Notes to Consolidated Financial Statements.

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FINANCIAL CONDITION

Liquidity and capital resources

(in millions)	March 31, 2009	December 31, 2008	% change
Total assets	$ 5,160	$ 5,437	(5)
Available-for-sale investment and mortgage-related securities	600	658	(9)
Investment in stock of FHLB of Seattle	98	98	
Loans receivable, net	4,015	4,206	(5)
Deposit liabilities	4,154	4,180	(1)
Other bank borrowings	436	681	(36)

As of March 31, 2009, ASB was one of Hawaii s largest financial institutions based on assets of $5.2 billion and deposits of $4.2 billion.

In March 2007, Moody s raised ASB s counterparty credit rating to A3 from Baa3 and, in March 2009, changed the outlook to negative from stable. In April 2007, S&P raised ASB s long-term/short-term counterparty credit ratings to BBB/A-2 from BBB-/A-3 and in May 2008 maintained the rating following its annual review of ASB. These 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.

As of March 31, 2009, ASB s unused FHLB borrowing capacity was approximately $1.7 billion. As of March 31, 2009, ASB had commitments to borrowers for undisbursed loan funds, loan commitments and unused lines and letters of credit of $1.3 billion. Management believes ASB s current sources of funds will enable it to meet these obligations while maintaining liquidity at satisfactory levels.

As of March 31, 2009 and December 31, 2008, ASB had $2.7 million and $1.5 million, respectively, of real estate acquired in settlement of loans.

For the first quarter of 2009, net cash provided by ASB s operating activities was $35 million. Net cash provided during the same period by ASB s investing activities was $235 million, primarily due to a net decrease in loans receivable of $164 million and repayments of investment and mortgage-related securities of $181 million, partly offset by purchases of investment and mortgage-related securities of $109 million. Net cash used in financing activities during this period was $287 million, primarily due to net decreases in Federal Home Loan Bank advances, deposit liabilities, securities sold under agreements to repurchase, escrow deposits and retail repurchase agreements of $238 million, $26 million, $5 million, $5 million and $2 million, respectively, and the payment of $11 million in common stock dividends.

ASB believes that a satisfactory regulatory capital position provides a basis for public confidence, affords protection to depositors, helps to ensure continued access to capital markets on favorable terms and provides a foundation for growth. 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, 2009, ASB was well-capitalized (minimum ratio requirements noted in parentheses) with a leverage ratio of 9.0% (5.0%), a Tier-1 risk-based capital ratio of 12.0% (6.0%) and a total risk-based capital ratio of 13.1% (10.0%). The OTS has approved ASB s payment of quarterly dividends through the quarter ended June 30, 2009 to the extent that payment of the dividend would not cause ASB s Tier I leverage ratio to fall below 8% as of the end of the quarter.

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Item 3. Quantitative and Qualitative Disclosures About Market Risk

Credit risk for ASB is the risk that borrowers or issuers of securities will not be able to repay their obligations to the bank. Credit risk associated with ASB s lending portfolios is controlled through its underwriting standards, loan rating of commercial and commercial real estate loans, on-going monitoring by loan officers, credit review and quality control functions in these lending areas and adequate allowance for loan losses. Credit risk associated with the securities portfolio is mitigated through investment portfolio limits, experienced staff working with analytical tools, monthly fair value analysis and on-going monitoring and reporting such as investment watch reports and loss sensitivity analysis. Credit risk for ASB has risen as a result of the pronounced slowdown in the national and Hawaii economies. In Hawaii, the unemployment rate has increased, residential loan delinquencies have trended upward and bankruptcy filings have increased, resulting in the increased provision for loan losses in 2008 and the first quarter of 2009. Further, the value of mortgage-related securities became impaired resulting in the write-down of two securities in December 2008. See Net interest margin and other factors and Results three months ended March 31, 2009 above.

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 59 to 62, HEI s Quantitative and qualitative disclosures about market risk, which is incorporated into Part II, Item 7A of HEI s 2008 Form 10-K by reference to HEI Exhibit 13 to HEI s Current Report on Form 8-K dated February 19, 2009.

ASB s interest-rate risk sensitivity measures as of March 31, 2009 and December 31, 2008 constitute forward-looking statements and were as follows:

	March 31, 2009			December 31, 2008		
	Change in NII	NPV ratio	NPV ratio sensitivity *	Change in NII	NPV ratio	NPV ratio sensitivity *
Change in interest rates (basis points)	Gradual change	Instantaneous change		Gradual change	Instantaneous change	
+300	(1.6)	8.67	(313)	1.2%	6.94%	(379)
+200	(0.7)	9.97	(183)	1.2	8.42	(231)
+100	(0.2)	11.12	(68)	0.7	9.84	(89)
Base		11.80			10.73	
-100	(1.2)	11.47	(33)	(1.6)	10.43	(30)
-200	**	**	**	**	**	**
-300	**	**	**	**	**	**

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

** For March 31, 2009 and December 31, 2008, the -200 and -300 bp scenarios were not performed because they would have resulted in negative Treasury interest rates.

ASB s net interest income (NII) sensitivity shifted from asset to liability sensitive in the rising rate scenarios from December 31, 2008 to March 31, 2009 primarily due to the decrease in size and change in mix of the balance sheet and changes in assumptions about sensitivity to changes in rates.

ASB s base net present value (NPV) ratio as of March 31, 2009 increased compared to December 31, 2008 primarily due to the decrease in size of the balance sheet, change in mix of the balance sheet and changes in market valuations.

ASB s NPV ratio sensitivity measure as of March 31, 2009 is less sensitive in rising rate scenarios when compared to December 31, 2008 primarily due to changes in balance sheet mix.

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 (see page 60 of HEI Exhibit 13 to HEI s Current Report on Form 8-K dated February 19, 2009 for a more detailed description of key modeling assumptions used in the NII sensitivity analysis). 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 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 2009, there was no change 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, 2009 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, 2009. Based on their evaluations, as of March 31, 2009, 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 2009, 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, 2009 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, 2009. Based on their evaluations, as of March 31, 2009, 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 II. Item 1. Legal Proceedings) 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 31 to 41 of HEI s 2008 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 2008 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,**				
	2009	**2008**	**2008**	**2007**	**2006**	**2005**	**2004**
HEI and Subsidiaries							
Excluding interest on ASB deposits	2.31	2.31	2.06	1.78	2.08	2.31	2.32
Including interest on ASB deposits	1.87	1.90	1.71	1.52	1.73	1.98	2.00
HECO and Subsidiaries	2.49	3.77	3.48	2.43	3.14	3.23	3.49

See HEI Exhibit 12.1 and HECO Exhibit 12.2.

B. News release.

On May 4, 2009, HEI issued a news release, HEI Earns $20 Million in First Quarter; Utility and Bank Pursue Initiatives to Offset Lower Sales and Higher Costs. See HEI Exhibit 99.1.

C. Compensatory arrangement.

ASB has determined that it is in its best interest to ensure that Timothy Schools, President of ASB, remains employed at ASB in order for him to continue leading the organization in its performance improvement initiatives through the end of 2010. Mr. Schools joined ASB in July 2007 after being recruited from South Carolina and subsequently relocated his family to Hawaii. Accordingly, in order to incent Mr. Schools to remain at ASB through 2010, and to protect him with respect to the purchase price of the residence he acquired in order to relocate his family to Hawaii, ASB has agreed to purchase his residence under certain conditions. Effective May 1, 2009, ASB has entered into an agreement with Mr. Schools to purchase his residence in Honolulu on or before the earlier of June 30, 2011 or his termination as an employee of ASB, provided that he is not terminated for cause. If such purchase were to occur, ASB would pay Mr. Schools his original purchase price of $3.635 million for the residence less normal selling costs borne by the seller (including brokers commissions). The purchase is conditioned upon Mr. Schools both (i) remaining with ASB through December 31, 2010 or such earlier date as ASB may determine in its sole discretion, and (ii) thereafter relocating to the mainland. See HEI Exhibit 10.

Item 6. Exhibits

HEI Exhibit 10	Letter agreement between ASB and Timothy Schools, effective May 1, 2009, regarding the purchase of his residence in Honolulu
HEI	Hawaiian Electric Industries, Inc. and Subsidiaries
Exhibit 12.1	Computation of ratio of earnings to fixed charges, three months ended March 31, 2009 and 2008 and years ended December 31, 2008, 2007, 2006, 2005 and 2004
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 99.1	News release, dated May 4, 2009, HEI Earns $20 Million in First Quarter; Utility and Bank Pursue Initiatives to Offset Lower Sales and Higher Costs
HECO	Hawaiian Electric Company, Inc. and Subsidiaries
Exhibit 12.2	Computation of ratio of earnings to fixed charges, three months ended March 31, 2009 and 2008 and years ended December 31, 2008, 2007, 2006, 2005 and 2004
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. (Registrant)	HAWAIIAN ELECTRIC COMPANY, INC. (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 Senior Financial Vice President, Treasurer and Chief Financial Officer (Principal Financial Officer of HEI)	By /s/ Tayne S. Y. Sekimura Tayne S. Y. Sekimura Senior Vice President, Finance and Administration (Principal Financial Officer of HECO)
By /s/ Curtis Y. Harada Curtis Y. Harada Vice President, Controller (Principal Accounting Officer of HEI)	By /s/ Patsy H. Nanbu Patsy H. Nanbu Controller (Principal Accounting Officer of HECO)
Date: May 5, 2009	Date: May 5, 2009