HAWAIIAN ELECTRIC CO INC
Form 10-Q
August 07, 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 June 30, 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 ¨

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 ¨

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 July 31, 2009**

Hawaiian Electric Industries, Inc. (Without Par Value)	**91,557,514 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

Hawaiian Electric Company, Inc. and Subsidiaries

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Hawaiian Electric Industries, Inc. and Subsidiaries

Hawaiian Electric Company, Inc. and Subsidiaries

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GLOSSARY OF TERMS

Terms	Definitions
AFUDC	Allowance for funds used during construction
AOCI	Accumulated other comprehensive income
ASB	American Savings Bank, F.S.B., a wholly-owned subsidiary of American Savings Holdings, 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).
ASHI	American Savings Holdings, Inc., formerly HEI Diversified, Inc., a wholly owned subsidiary of Hawaiian Electric Industries, Inc. and the parent company of American Savings Bank, F.S.B.
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); American Savings Holdings, 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

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GLOSSARY OF TERMS, continued

Terms	Definitions
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).
HEI	Hawaiian Electric Industries, Inc., direct parent company of Hawaiian Electric Company, Inc., American Savings Holdings, 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.
HEIII	HEI Investments, Inc. (formerly HEI Investment Corp.) (in dissolution), 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
OTTI	Other-than-temporary impairment
PPA	Power purchase agreement
PRPs	Potentially responsible parties
PUC	Public Utilities Commission of the State of Hawaii
RBA	Revenue balancing account
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. In 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), which could result in higher loan loss provisions and write-offs and material other-than-temporary impairment (OTTI) charges), 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 H1N1 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 (including lines of credit) and to access capital markets to issue common stock (HEI) under volatile and challenging market conditions, and the cost of such financings, if available;

- 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), revenue decoupling and the fulfillment by the utilities of their commitments under the Energy Agreement (given the PUC approvals needed; the PUC s delay in considering HCEI-related costs; reliance on outside parties like the state, independent power producers (IPPs) and developers; potential changes in political support; and uncertainties surrounding wind power, the undersea cable, biofuels, environmental assessments and the impacts of implementation of the HCEI on future costs of electricity);

capacity and supply constraints or difficulties, especially if generating units (utility-owned or IPP-owned) fail or measures such as demand-side management (DSM), distributed generation (DG), combined heat and power (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 impact on customer satisfaction and political and regulatory support resulting from volatility in fuel prices;

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), governmental fees and assessments (such as Federal Deposit Insurance Corporation assessments), potential carbon cap and trade legislation that may fundamentally alter costs to produce electricity and accelerate the move to renewable generation, and the potential elimination of the Office of Thrift Supervision (OTS) and the grandfathering provisions of the Gramm-Leach-Bliley Act of 1998 that have permitted HEI to own ASB);

decisions by the Public Utilities Commission of the State of Hawaii (PUC) in rate cases (including the risks of delays in the timing of decisions, adverse changes in final decisions from interim decisions and the disallowance of project costs);

decisions in 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 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;

the ability of ASB to execute its performance improvement initiatives, including the reduction of expenses through the conversion to the Fiserv Inc. bank platform system;

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

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, SFAS No. 167, Amendments to FASB Interpretation No. 46(R), 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)

(in thousands, except per share amounts and ratio of earnings to fixed charges)	Three months ended June 30 2009	Three months ended June 30 2008	Six months ended June 30 2009	Six months ended June 30 2008
Revenues				
Electric utility	$ 450,417	$ 688,121	$ 912,214	$ 1,312,010
Bank	75,499	85,950	157,531	191,794
Other	(15)	(16)	(47)	(132)
	525,901	**774,055**	**1,069,698**	**1,503,672**
Expenses				
Electric utility	418,254	632,725	848,982	1,205,631
Bank	69,993	116,942	134,904	199,423
Other	2,599	2,786	6,099	6,270
	490,846	**752,453**	**989,985**	**1,411,324**
Operating income (loss)				
Electric utility	32,163	55,396	63,232	106,379
Bank	5,506	(30,992)	22,627	(7,629)
Other	(2,614)	(2,802)	(6,146)	(6,402)
	35,055	**21,602**	**79,713**	**92,348**
Interest expense other than on deposit liabilities and other bank borrowings	(17,910)	(18,186)	(35,743)	(37,435)
Allowance for borrowed funds used during construction	1,727	835	3,349	1,597
Allowance for equity funds used during construction	4,120	2,105	7,725	4,006
Income before income taxes	**22,992**	**6,356**	**55,044**	**60,516**
Income taxes	7,040	747	18,224	20,467
Net income	**15,952**	**5,609**	**36,820**	**40,049**
Less net income attributable to noncontrolling interest - preferred stock of subsidiaries	473	473	946	946
Net income for common stock	**$ 15,479**	**$ 5,136**	**$ 35,874**	**$ 39,103**
Basic earnings per common share	$ 0.17	$ 0.06	$ 0.39	$ 0.47
Diluted earnings per common share	$ 0.17	$ 0.06	$ 0.39	$ 0.47
Dividend per common share	$ 0.31	$ 0.31	$ 0.62	$ 0.62

Weighted-average number of common shares outstanding	91,384	84,052	90,996	83,762
Dilutive effect of stock-based compensation	110	103	92	60
Adjusted weighted-average shares	91,494	84,155	91,088	83,822
Ratio of earnings to fixed charges (SEC method)				
Excluding interest on ASB deposits			2.14	1.75
Including interest on ASB deposits			1.77	1.52

For the three and six months ended June 30, 2009, under the two-class method of computing basic and diluted earnings per share, distributed earnings were $0.31 and $0.62 per share, respectively, and undistributed losses were $0.14 and $0.23 per share, respectively, for both unvested restricted stock awards and unrestricted common stock. For the three and six months ended June 30, 2008, under the two-class method of computing basic and diluted earnings per share, distributed earnings were $0.31 and $0.62 per share, respectively, and undistributed losses were $0.25 and $0.15 per share, respectively, 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)	June 30, 2009	December 31, 2008
Assets		
Cash and equivalents	$ 265,143	$ 182,903
Federal funds sold	788	532
Accounts receivable and unbilled revenues, net	212,358	300,666
Available-for-sale investment and mortgage-related securities	621,740	657,717
Investment in stock of Federal Home Loan Bank of Seattle	97,764	97,764
Loans receivable, net	3,852,605	4,206,492
Property, plant and equipment, net of accumulated depreciation of $1,908,140 and $1,851,813	3,026,621	2,907,376
Regulatory assets	531,708	530,619
Other	317,747	328,823
Goodwill, net	82,190	82,190
	$ 9,008,664	$ 9,295,082
Liabilities and stockholders equity		
Liabilities		
Accounts payable	$ 162,836	$ 183,584
Deposit liabilities	4,168,708	4,180,175
Short-term borrowings other than bank	55,000	
Other bank borrowings	388,858	680,973
Long-term debt, net other than bank	1,214,733	1,211,501
Deferred income taxes	159,069	143,308
Regulatory liabilities	300,450	288,602
Contributions in aid of construction	314,369	311,716
Other	808,602	871,476
	7,572,625	7,871,335
Stockholders equity		
Common stock, no par value, authorized 200,000,000 shares; issued and outstanding: 91,561,514 shares and 90,515,573 shares	1,246,828	1,231,629
Retained earnings	194,018	210,840
Accumulated other comprehensive loss, net of tax benefits	(39,100)	(53,015)
Common stock equity	1,401,746	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
	1,436,039	1,423,747
	$ 9,008,664	$ 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**
Cumulative effect of adoption of FSP FAS 115-2 and FAS 124-2, net of taxes of $2,497			3,781	(3,781)		
Comprehensive income:						
Net income			35,874		946	36,820
Net unrealized gains (losses) on securities:						
Net unrealized gains on securities arising during the period, net of taxes of $14,237				21,561		21,561
Net unrealized losses related to factors other than credit during the period, net of tax benefits of $5,147				(7,794)		(7,794)
Less: reclassification adjustment for net realized losses included in net income, net of tax benefits of $2,202				3,335		3,335
Retirement benefit plans:						
Amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of taxes of $3,718				5,827		5,827
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of tax benefits of $3,333				(5,233)		(5,233)
Comprehensive income			35,874	17,696	946	54,516
Issuance of common stock, net	1,046	15,199				15,199
Common stock dividends ($0.62 per share)			(56,477)			(56,477)
Preferred stock dividends					(946)	(946)
Balance, June 30, 2009	**91,562**	**$ 1,246,828**	**$ 194,018**	**$ (39,100)**	**$ 34,293**	**$ 1,436,039**
Balance, December 31, 2007	**83,432**	**$ 1,072,101**	**$ 225,168**	**$ (21,842)**	**$ 34,293**	**$ 1,309,720**
Comprehensive income:						
Net income			39,103		946	40,049
Net unrealized losses on securities:						
Net unrealized losses on securities arising during the period, net of tax benefits of $2,847				(4,312)		(4,312)
Less: reclassification adjustment for net realized losses included in net income, net of tax benefits of $6,915				10,473		10,473
Retirement benefit plans:						
Amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of taxes of $1,848				2,916		2,916
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of tax benefits of $1,668				(2,618)		(2,618)

Comprehensive income			39,103	6,459	946	46,508
Issuance of common stock, net	1,214	27,847				27,847
Common stock dividends ($0.62 per share)			(51,996)			(51,996)
Preferred stock dividends					(946)	(946)
Balance, June 30, 2008	**84,646**	**$ 1,099,948**	**$ 212,275**	**$ (15,383)**	**$ 34,293**	**$ 1,331,133**

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)

Six months ended June 30 (in thousands)	**2009**	**2008**
Cash flows from operating activities		
Net income	$ 36,820	$ 40,049
Adjustments to reconcile net income to net cash provided by operating activities		
Depreciation of property, plant and equipment	76,999	75,733
Other amortization	2,484	4,203
Provision for loan losses	21,800	2,055
Loans receivable originated and purchased, held for sale	(291,500)	(114,591)
Proceeds from sale of loans receivable, held for sale	322,692	124,526
Net loss (gain) on sale of investment and mortgage-related securities	(44)	17,388
Other-than-temporary impairment of available-for-sale mortgage-related securities	5,581	
Changes in deferred income taxes	3,973	(585)
Changes in excess tax benefits from share-based payment arrangements	318	(613)
Allowance for equity funds used during construction	(7,725)	(4,006)
Changes in assets and liabilities		
Decrease (increase) in accounts receivable and unbilled revenues, net	88,308	(28,564)
Decrease (increase) in fuel oil stock	22,383	(69,254)
Increase (decrease) in accounts payable	(20,748)	45,874
Changes in prepaid and accrued income taxes and utility revenue taxes	(56,397)	(68,490)
Changes in other assets and liabilities	(24,633)	(6,327)
Net cash provided by operating activities	**180,311**	**17,398**
Cash flows from investing activities		
Available-for-sale investment and mortgage-related securities purchased	(190,095)	(376,809)
Principal repayments on available-for-sale investment and mortgage-related securities	248,109	329,669
Proceeds from sale of available-for-sale investment and mortgage-related securities	44	1,291,609
Net decrease (increase) in loans held for investment	305,381	(29,359)
Capital expenditures	(175,092)	(101,976)
Contributions in aid of construction	4,917	7,263
Other	86	750
Net cash provided by investing activities	**193,350**	**1,121,147**
Cash flows from financing activities		
Net decrease in deposit liabilities	(11,467)	(76,790)
Net increase in short-term borrowings with original maturities of three months or less	55,000	130,172
Net decrease in retail repurchase agreements	(24,592)	(20,380)
Proceeds from other bank borrowings	310,000	508,584
Repayments of other bank borrowings	(577,517)	(1,662,119)
Proceeds from issuance of long-term debt	3,168	14,802
Repayment of long-term debt		(50,000)
Changes in excess tax benefits from share-based payment arrangements	(318)	613
Net proceeds from issuance of common stock	8,786	15,473
Common stock dividends	(51,127)	(41,497)
Preferred stock dividends of noncontrolling interest	(946)	(946)
Decrease in cash overdraft	(962)	(8,582)
Other	(1,190)	477

Net cash used in financing activities	**(291,165)**	**(1,190,193)**
Net increase (decrease) in cash and equivalents and federal funds sold	82,496	(51,648)
Cash and equivalents and federal funds sold, beginning of period	183,435	209,855
Cash and equivalents and federal funds sold, end of period	**$ 265,931**	**$ 158,207**

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 filed in HEI Exhibit 99.1 to HEI s Form 8-K dated June 9, 2009 and the unaudited consolidated financial statements and the notes thereto in HEI s Quarterly Report on SEC Form 10-Q for the quarter ended March 31, 2009.

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 June 30, 2009 and December 31, 2008, the results of its operations for the three and six months ended June 30, 2009 and 2008 and cash flows for the six months ended June 30, 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.

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2 Segment financial information

(in thousands)	Electric Utility	Bank	Other	Total
Three months ended June 30, 2009				
Revenues from external customers	$ 450,381	$ 75,499	$ 21	$ 525,901
Intersegment revenues (eliminations)	36		(36)	
Revenues	450,417	75,499	(15)	525,901
Profit (loss)*	24,666	5,482	(7,156)	22,992
Income taxes (benefit)	8,672	1,461	(3,093)	7,040
Net income (loss)	15,994	4,021	(4,063)	15,952
Less net income attributable to noncontrolling interest preferred stock of HECO and its subsidiaries	499		(26)	473
Net income (loss) for common stock	15,495	4,021	(4,037)	15,479
Six months ended June 30, 2009				
Revenues from external customers	912,142	157,531	25	1,069,698
Intersegment revenues (eliminations)	72		(72)	
Revenues	912,214	157,531	(47)	1,069,698
Profit (loss)*	47,749	22,574	(15,279)	55,044
Income taxes (benefit)	17,124	7,671	(6,571)	18,224
Net income (loss)	30,625	14,903	(8,708)	36,820
Less net income attributable to noncontrolling interest preferred stock of HECO and its subsidiaries	998		(52)	946
Net income (loss) for common stock	29,627	14,903	(8,656)	35,874
Assets (at June 30, 2009)	3,876,982	5,120,269	11,413	9,008,664
Three months ended June 30, 2008				
Revenues from external customers	$ 688,087	$ 85,950	$ 18	$ 774,055
Intersegment revenues (eliminations)	34		(34)	
Revenues	688,121	85,950	(16)	774,055
Profit (loss)*	44,828	(31,014)	(7,458)	6,356
Income taxes (benefit)	16,897	(12,921)	(3,229)	747
Net income (loss)	27,931	(18,093)	(4,229)	5,609
Less net income attributable to noncontrolling interest preferred stock of HECO and its subsidiaries	499		(26)	473
Net income (loss) for common stock	27,432	(18,093)	(4,203)	5,136
Six months ended June 30, 2008				
Revenues from external customers	1,311,936	191,794	(58)	1,503,672

Intersegment revenues (eliminations)	74		(74)	
Revenues	1,312,010	191,794	(132)	1,503,672
Profit (loss)*	85,133	(7,673)	(16,944)	60,516
Income taxes (benefit)	32,118	(4,156)	(7,495)	20,467
Net income (loss)	53,015	(3,517)	(9,449)	40,049
Less net income attributable to noncontrolling interest preferred stock of HECO and its subsidiaries	998		(52)	946
Net income (loss) for common stock	52,017	(3,517)	(9,397)	39,103
Assets (at June 30, 2008)	3,586,441	5,585,278	10,477	9,182,196

* 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, contingencies and subsequent events, see pages 23 through 52.

4 Bank subsidiary

Selected financial information

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

Consolidated Statements of Income Data (unaudited)

(in thousands)	Three months ended June 30 2009	2008	Six months ended June 30 2009	2008
Interest and dividend income				
Interest and fees on loans	$ 55,363	$ 61,747	$ 113,455	$ 125,212
Interest and dividends on investment and mortgage-related securities	7,143	22,729	14,819	47,180
	62,506	84,476	128,274	172,392
Interest expense				
Interest on deposit liabilities	9,902	15,619	21,467	33,839
Interest on other borrowings	2,241	16,265	5,505	35,414
	12,143	31,884	26,972	69,253
Net interest income	**50,363**	**52,592**	**101,302**	**103,139**
Provision for loan losses	13,500	1,155	21,800	2,055
Net interest income after provision for loan losses	**36,863**	**51,437**	**79,502**	**101,084**
Noninterest income				
Fees from other financial services	6,443	5,413	12,362	12,236
Fee income on deposit liabilities	7,462	6,767	14,173	13,561
Fee income on other financial products	1,628	1,639	2,672	3,443
Net gains (losses) on available-for-sale securities (includes impairment losses of $5,581, consisting of $18,522 of total other-than-temporary impairment losses, net of $12,941 of non-credit losses recognized in other comprehensive income, for the quarter and six months ended June 30, 2009)	(5,537)	(18,323)	(5,537)	(17,388)
Other income	2,997	5,978	5,587	7,550
	12,993	1,474	29,257	19,402
Noninterest expense				
Compensation and employee benefits	17,991	19,039	37,351	37,279
Occupancy	5,922	5,390	11,051	10,787
Equipment	2,540	3,221	5,330	6,335
Services	3,801	4,170	7,219	9,843
Data processing	3,481	2,609	6,668	5,225
Loss on early extinguishment of debt	60	39,843	101	39,843
Other expense	10,579	9,653	18,465	18,847

	44,374	83,925	86,185	128,159
Income (loss) before income taxes	**5,482**	**(31,014)**	**22,574**	**(7,673)**
Income taxes (benefit)	1,461	(12,921)	7,671	(4,156)
Net income (loss)	**$ 4,021**	**$ (18,093)**	**$ 14,903**	**$ (3,517)**

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

Consolidated Balance Sheets Data (unaudited)

(in thousands)	June 30, 2009	December 31, 2008
Assets		
Cash and equivalents	$ 254,170	$ 168,766
Federal funds sold	788	532
Available-for-sale investment and mortgage-related securities	621,740	657,717
Investment in stock of Federal Home Loan Bank of Seattle	97,764	97,764
Loans receivable, net	3,852,605	4,206,492
Other	211,012	223,659
Goodwill, net	82,190	82,190
	$ 5,120,269	$ 5,437,120
Liabilities and stockholder s equity		
Deposit liabilities noninterest-bearing	$ 750,487	$ 701,090
Deposit liabilities interest-bearing	3,418,221	3,479,085
Other borrowings	388,858	680,973
Other	86,743	98,598
	4,644,309	4,959,746
Common stock	329,130	328,162
Retained earnings	181,135	197,235
Accumulated other comprehensive loss, net of tax benefits	(34,305)	(48,023)
	475,960	477,374
	$ 5,120,269	$ 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 $212 million and $177 million, respectively, as of June 30, 2009 and $241 million and $440 million, respectively, as of December 31, 2008.

As of June 30, 2009, ASB had commitments to borrowers for undisbursed loan funds, loan commitments and unused lines and letters of credit of $1.2 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. The $35.6 million is comprised of: (1) realized losses on the sale of mortgage-related securities and agency notes of $19.3 million included in Noninterest income-Gain (loss) on sale of securities, (2) fees associated with the early retirement of other bank borrowings of $39.8 million included in Noninterest expense-Loss on early extinguishment of debt and (3) income tax benefits of $23.5 million included in Income taxes. 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.

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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 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.

Investment and mortgage-related securities portfolio

Available-for-sale securities

The following table details the amortized cost basis and aggregate fair value by major security type at June 30, 2009:

June 30, 2009 **(in thousands)**	**Cost**	**Gross unrealized gains**	**Gross unrealized losses**	**Fair value**
U.S. Treasury and U.S. agency debentures	$ 33,936	$ 16	$ (101)	$ 33,851
Municipal bonds	6,307	6	(40)	6,273
Mortgage-related securities:				
Federal agencies	339,195	7,441	(35)	346,601
Private-issue	275,018	20	(40,023)	235,015
	$ 654,456	$ 7,483	$ (40,199)	$ 621,740

The following table details the contractual maturities and yields of available-for-sale securities. All positions with variable maturities (e.g. callable debentures and mortgage backed securities) are disclosed based upon the bond s contractual maturity. Actual average maturities may be substantially shorter than those detailed below.

June 30, 2009			**Maturity<1 year**		**Maturity 1-5 years**		**Maturity 5-10 years**		**Maturity>10 years**	
(dollars in thousands)	**Total book value**	**Weighted average Yield (%)**	**Book value**	**Yield (%)**	**Book value**	**Yield (%)**	**Book value**	**Yield (%)**	**Book value**	**Yield (%)**
U.S. Treasury and U.S. agency debentures	$ 33,936	0.80	$		$ 33,936	0.80	$		$	
Municipal bonds	6,307	1.38	5,007	1.15	1,300	2.27				
Mortgage-related securities:										
Federal agencies	339,195	4.14			543	7.00	139,650	3.95	199,002	4.26
Private-issue	275,018	5.15					32,747	4.21	242,271	5.28
	$ 654,456	4.36	$ 5,007	1.15	$ 35,779	0.94	$ 172,397	4.00	$ 441,273	4.82

Gross unrealized losses and fair value

The following table details the gross unrealized losses and fair values for securities held in available for sale by duration of time in which positions have been held in a continuous loss position. Positions for which OTTIs have been identified are categorized based upon the point at which unrealized losses were identified, not the point at which write-downs have occurred.

June 30, 2009	**Less than 12 months**		**12 months or more**		**Total**	
(in thousands)	**Gross unrealized**	**Fair value**	**Gross unrealized**	**Fair value**	**Gross unrealized**	**Fair value**

	losses		losses		losses	
U.S. Treasury and U.S. agency debentures	$ (101)	$ 19,975	$	$	$ (101)	$ 19,975
Municipal bonds	(40)	4,967			(40)	4,967
Mortgage-related securities:						
Federal agencies	(35)	7,697			(35)	7,697
Private-issue	(845)	16,527	(39,178)	217,064	(40,023)	233,591
	$ (1,021)	$ 49,166	$ (39,178)	$ 217,064	$ (40,199)	$ 266,230

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The unrealized losses on ASB s investments in U.S. Treasury and agency debentures and mortgage-related securities issued by federal agencies were caused by interest rate increases. The contractual terms of these investments do not permit the issuer to settle the securities at a price less than the amortized cost bases of the investments. Because ASB does not intend to sell the securities and it is not more likely than not that ASB will be required to sell the investments before recovery of their amortized costs bases, which may be at maturity, ASB does not consider these investments to be other-than-temporarily impaired at June 30, 2009.

The unrealized losses on ASB s investments in municipal bonds are primarily driven by interest rates and not due to the credit of the securities. All municipal obligations held in this portfolio are of investment grade and have been reviewed based on the credit of the underlying issuer. Based upon ASB s initial and ongoing review of these credits, ASB does not consider these investments to be other-than-temporarily impaired at June 30, 2009.

The unrealized losses on ASB s investments in private-issue mortgage-related securities is exemplary of the credit pressures in that sector. Positions are regularly monitored to track delinquency pipelines/trends, prepayment speeds and realized losses. Marginal positions are reviewed using management s expectations of loss severity, constant default rates and prepayment speeds based upon deal performance, collateral characteristics and cohort vintage performance. Exclusive of positions detailed below which have incurred OTTIs, because ASB does not intend to sell the securities and it is not more likely than not that ASB will be required to sell the investments before recovery of their amortized costs bases, which may be at maturity, ASB does not consider these investments to be other-than-temporarily impaired at June 30, 2009.

The fair values of ASB s investment securities could continue to decline if the current economic environment continues to deteriorate. While the performance of ASB s private-issue mortgage-related securities are intrinsically tied to the economy, excess leverage in that sector coupled with weak underwriting of recent vintages could also pressure ASB s positions even if the economy recovers. Despite ASB s best estimate expectation of performance of ASB s positions, economic uncertainty coupled with a very fragile housing market could result in material OTTIs.

Other-than-temporary impaired securities

All securities are reviewed for impairment in accordance with FSP FAS 115-2 and FAS 124-2. Under these standards ASB s intent to sell the security, the probability of more-likely-than-not being forced to sell the position prior to recovery of its cost basis and the probability of more likely-than-not recovering the amortized cost of the position was determined. Because of ASB s intent to hold all positions determined to be other-than-temporarily impaired, credit losses, which are recognized in earnings, were quantified using the position s pre-impairment discount rate and the net present value of these losses. Non-credit related impairments are reflected in other comprehensive income.

The following table reflects cumulative OTTIs of expected losses that have been recognized in earnings. The beginning balance relates to credit losses realized prior to April 1, 2009 on debt securities held by the entity at the end of the period. This initial balance includes the net impact of non-credit losses that were originally reported as losses as of December 31, 2008 and were subsequently recharacterized from retained earnings as a result of the adoption of FSP FAS 115-2 and FAS 124-2. Additions to this balance include new securities in which initial OTTIs have been identified and incremental increases of OTTIs of positions that had already taken similar impairments.

(in thousands)	**June 30, 2009**
Balance, beginning of period	$ 1,486
Additions:	
Initial credit impairments	2,209
Subsequent credit impairments	3,372
Balance, end of period	$ 7,067

Positions which management identified as credit related OTTIs for the first time this quarter include two fixed rate private-issue mortgage-related securities. Both positions are front sequential collateralized mortgage obligations one backed by prime collateral and the other backed by Alt-A collateral. One position which management had previously identified as other-than-temporary impaired at the end of 2008, had its book value increased $6.3 million at the beginning of the second quarter of 2009 upon adoption of FSP FAS 115-2 and FAS 124-2. Subsequent to that change, increasing delinquencies caused the increase in loss estimates and realized losses as a result of credit. Credit related losses for private-issue mortgage-related securities are determined through management s estimation of various inputs which impact the generation of future cash flows. Forward projections of economic activity and national housing market trends impact vectors used in this assessment. All estimates are determined based on specific characteristics of each pool performance and security structure:

Prepayment speeds prepayment speed estimates are based upon historic performance, comparable collateral trends and refinance ability of borrowers. Vector constant prepayment rate (CPR) assumptions within the first 24 months start in a range of 6-9 CPR and average between 13.50 to 14.83 CPR for life speed projections.

Credit support current levels of subordination that absorb credit losses of ASB tranches are considered. Current credit support as a % tranche range from 4.85% to 5.48%.

Gross losses % current balance this ratio provides management s gross expectation of loss divided by the current remaining balance held. Factors which impact these losses include the current/future delinquency pipeline, historical performance, performance of peer collateral and specific collateral characteristics which include geographic concentration, FICO scores, and loan type. Gross loss as a % of current balance ranges from 27.41% to 1.23%. The weighted average of these bonds is 15.99%.

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 delayed the application of SFAS No. 157 to ASB s non-financial assets and non-financial liabilities until the first quarter of 2009. FSP 157-3, Determining the Fair Value of a Financial Asset When the Market for That Asset Is Not Active, and FSP 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, were issued in October 2008 and April 2009, respectively, 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.

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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.

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

		Fair value measurements using		
(in millions)	**June 30, 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	$ 622	$	$ 622	$

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)	**June 30, 2009**	**Quoted prices in active markets for identical assets (Level 1)**	**Significant other observable inputs (Level 2)**	**Significant unobservable inputs (Level 3)**
Loans	$ 10.0	$	$ 3.5	$ 6.5

Specific reserves as of June 30, 2009 were $2.8 million and were included in loans receivable held for investment, net. For the six months ended June 30, 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 income and 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.

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Federal Deposit Insurance Corporation (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. Financial institution failures have significantly increased the DIF s loss provisions, resulting in declines 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 were 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 of deposits. 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 of deposits. 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 assessment rate was 13 basis points of deposits, or $1.3 million, for the quarter ended March 31, 2009 and 14 basis points of deposits, or $1.5 million, for the quarter ended June 30, 2009, compared to an assessment rate of 5 basis points of deposits, or $0.1 million (net of a one-time assessment credit), for the quarter ended March 31, 2008 and 5 basis points of deposits, or $0.2 million (net of a one-time assessment credit), for the quarter ended June 30, 2008. In May 2009, the board of directors of the FDIC voted to levy a special assessment on deposit institutions to build the DIF and restore public confidence in the banking system. The special assessment was 5 basis points on each institution s total assets, minus its Tier 1 core capital, as of June 30, 2009. Based on the FDIC s formula, ASB s special assessment was $2.3 million and ASB recorded the charge in June 2009.

The FDIC may impose additional special assessments in the final two quarters of 2009 if it is deemed necessary to ensure the DIF ratio does not decline to a level that is close to zero or that could otherwise undermine public confidence in federal deposit insurance. The FDIC chairman has commented that, at worst, there may be a similar five basis points assessment in the fourth quarter of 2009, but management cannot predict with certainty the timing or amounts of any additional assessments.

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. In May 2009, the FDIC extended the temporary increase in federal deposit insurance coverage through December 31, 2013. The legislation provides that the basic deposit insurance coverage limit will return to $100,000 after December 31, 2013 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 Transaction Account Guarantee Program, non-interest bearing deposit transaction accounts will be provided unlimited deposit insurance coverage until December 31, 2009.

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5 Retirement benefits

Defined benefit plans. For the first six months of 2009, HECO contributed $15.7 million and HEI contributed $0.7 million to their respective retirement benefit plans, compared to $4.8 million and $0.4 million, respectively, in the first six months of 2008. The Company s current estimate of contributions to its retirement benefit plans in 2009 is $27 million ($26 million to be made by the utilities, nil by ASB and $1 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 six months of 2009, the Company s defined benefit retirement plans assets generated a return, net of investment management fees, of 7.0%. The market value of the defined benefit retirement plans assets as of June 30, 2009 was $761 million compared to $726 million at December 31, 2008, an increase of approximately $35 million.

The components of net periodic benefit cost were as follows:

	Three months ended June 30				Six months ended June 30			
	Pension benefits		Other benefits		Pension benefits		Other benefits	
(in thousands)	2009 (1)	2008 (1)	2009	2008	2009 (1)	2008 (1)	2009	2008
Service cost	$ 6,388	$ 6,989	$ 1,171	$ 1,182	$ 12,729	$ 13,845	$ 2,227	$ 2,347
Interest cost	15,514	14,915	2,838	2,790	31,052	29,791	5,685	5,628
Expected return on plan assets	(14,295)	(18,269)	(2,222)	(2,742)	(28,571)	(36,501)	(4,437)	(5,482)
Amortization of unrecognized transition obligation		1	784	784	1	2	1,569	1,569
Amortization of prior service cost (credit)	(95)	(99)	4	4	(188)	(189)	7	7
Recognized actuarial loss	3,964	1,691	107		7,933	3,381	223	
Net periodic benefit cost	11,476	5,228	2,682	2,018	22,956	10,329	5,274	4,069
Impact of PUC D&Os	(4,107)	1,547	(407)	230	(8,198)	3,204	(732)	423
Net periodic benefit cost (adjusted for impact of PUC D&Os)	$ 7,369	$ 6,775	$ 2,275	$ 2,248	$ 14,758	$ 13,533	$ 4,542	$ 4,492

(1) 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. Thus, there are no amounts for ASB employees for certain components (service cost for benefit accruals, amortization of unrecognized transition obligation and amortization of prior service cost (credit)).

The Company recorded retirement benefits expense of $15 million and $14 million in the first six months of 2009 and 2008, respectively, and charged the remaining amounts primarily to electric utility plant.

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

Defined contribution plan. 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 effective January 1, 2008. On May 7, 2009, the account balances of ASB participants were transferred from HEI s retirement savings plan to account balances in the newly created ASB 401(k) Plan. $41 million in assets was transferred in-kind between plans. On May 15, 2009, ASB contributed $2.1 million to fund the discretionary employer profit sharing (AmeriShare) portion of the plan for the 2008 plan year. This AmeriShare contribution was allocated pro-rata to accounts of eligible participants based on a flat 4% percent of eligible pay. This 4% contribution percentage was determined at year-end based on ASB s performance and achievement of financial goals for 2008. For the first six months of 2009 and 2008, ASB s total expense for its employees participating in the HEI retirement savings plan and the ASB 401(k) Plan combined was $1.3 million and $2.2 million, respectively, and cash contributions were $3.0 million and $0.9 million, respectively.

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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 June 30, 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 awards generally become unrestricted three to five years after the date of grant and are forfeited for terminations of employment during the vesting period, except for terminations by reason of death, disability or termination without cause which allow for pro-rata vesting. Restricted stock awards 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 and are forfeited for terminations of employment during the vesting period, except for terminations due to death, disability and retirement which allow for pro-rata vesting. 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 shares granted under the 2009-2011 Long-Term Incentive Plan (LTIP) are based on the achievement of certain financial goals and vest at the end of the three-year performance period. LTIP is forfeited for terminations of employment during the vesting period, except for terminations due to death, disability and retirement which allow for pro-rata vesting based upon completed months of service after a minimum of 12 months of service in the performance period. Compensation expense for the performance shares portion of the 2009-2011 LTIP award has been recognized in accordance with the fair-value based measurement method of accounting for performance shares.

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 June 30		**Six months ended June 30**	
($ in millions)	**2009**	**2008**	**2009**	**2008**
Share-based compensation expense [1]		(0.1)	0.4	0.2
Income tax benefit			0.1	

[1] The Company has not capitalized any share-based compensation cost. For the second quarter of 2009, the estimated forfeiture rates were 41.0% for restricted stock awards, 5.9% for restricted stock units, and 10.3% for performance shares. In the second quarter of 2009, the cumulative effect of the change in estimated forfeitures was recorded, resulting in nil for the share-based compensation expense in 2009.

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

June 30, 2009			Outstanding & Exercisable	
			Weighted-average	Weighted-average
Year of grant	Range of exercise prices	Number of options	remaining contractual life	exercise price
2000	$ 14.74	46,000	0.8	$ 14.74
2001	17.96	65,000	1.8	17.96
2002	21.68	122,000	2.6	21.68
2003	20.49	141,500	3.2	20.49
	$ 14.74 21.68	374,500	2.5	$ 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 June 30, 2009, all NQSO s outstanding were exercisable and had an aggregate intrinsic value (including dividend equivalents) of $0.9 million.

NQSO activity and statistics are summarized as follows:

	Three months ended June 30		Six months ended June 30	
($ in thousands, except prices)	2009	2008	2009	2008
Shares granted/forfeited/vested				
Aggregate fair value of vested shares				
Shares expired	1,000		1,000	
Shares exercised		200,300		212,300
Weighted-average exercise price		$ 19.56		$ 19.61
Cash received from exercise		$ 3,918		$ 4,164
Intrinsic value of shares exercised [1]		$ 2,101		$ 2,185
Tax benefit realized for the deduction of exercises		$ 818		$ 851
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:

June 30, 2009			Outstanding and Exercisable	
			Weighted-average	Weighted-average
Year of grant	Range of exercise prices	Number of shares underlying SARs	remaining contractual life	exercise price
2004	$ 26.02	150,000	3.8	$ 26.02
2005	26.18	330,000	4.2	26.18
	$ 26.02 26.18	480,000	4.1	$ 26.13

As of December 31, 2008, the shares underlying SARs outstanding totaled 791,000, with a weighted-average exercise price of $26.12. As of June 30, 2009, all SARS outstanding were exercisable and had no intrinsic value.

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SARs activity and statistics are summarized as follows:

($ in thousands, except prices)	Three months ended June 30 2009	Three months ended June 30 2008	Six months ended June 30 2009	Six months ended June 30 2008
Shares granted				
Shares forfeited		30,000	6,000	30,000
Shares expired	305,000		305,000	
Shares vested	228,000	46,000	228,000	61,000
Aggregate fair value of vested shares	$ 1,354	$ 242	$ 1,354	$ 329
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.

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 six months ended June 30, 2009 and 2008 a total of 3,143 and 6,125 dividend equivalent shares, respectively, for NQSO and SAR grants were distributed to SOIP participants. 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 June 30, 2009 and December 31, 2008, restricted stock award shares outstanding totaled 134,000 and 160,500, with a weighted-average grant date fair value of $25.50 and $25.51, respectively. The grant date fair value of a restricted stock award share was the closing or average price of HEI common stock on the date of grant.

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

($ in thousands)	Three months ended June 30 2009	Three months ended June 30 2008	Six months ended June 30 2009	Six months ended June 30 2008
Shares vested	3,257		3,851	
Grant date fair value	$ 80		$ 94	
Shares forfeited	1,243	12,500	22,649	18,500
Grant date fair value	$ 32	$ 323	$ 583	$ 480
Shares granted		42,700		42,700
Grant date fair value		$ 1,055		$ 1,055

The tax benefits realized for the tax deductions related to restricted stock awards were $58,000 and $47,000 for the first six months of 2009 and 2008, respectively.

As of June 30, 2009, there was $1.3 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 2.2 years.

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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 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 June 30, 2009, there were 70,500 restricted stock units outstanding, none were vested and none were forfeited.

As of June 30, 2009, there was $1.0 million of total unrecognized compensation cost related to the nonvested restricted stock units. The cost is expected to be recognized over a period of 3.6 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 (TRS) as a percentile to the Edison Electric Institute Index over the three-year period and return on average common equity (ROACE) targets.

The grant date fair value of the performance shares linked to TRS was $0.5 million. The grant date fair value was determined using a Monte Carlo simulation model utilizing actual information for the common shares of HEI and its peers for the period from January 1, 2009 to the February 20, 2009 grant date and estimated future stock volatility and dividends of HEI and its peers. The expected stock volatility assumptions for HEI and its peer group were based on the three-year historic stock volatility, and the annual dividend yield assumptions were based on dividend yields calculated on the basis of daily stock prices over the same 3-year historical period. The following table summarizes the assumptions used to determine the fair value of the performance shares linked to TRS and the resulting fair value of performance shares granted:

Risk-free interest rate	1.30%
Expected life in years	3
Expected volatility	23.7%
Dividend yield	4.53%
Range of expected volatility for Peer Group	20.8% to 46.9%
Grant date fair value (per share)	$13.08

As of June 30, 2009, there were 36,198 shares underlying the performance share awards with the TRS condition outstanding, based on target performance levels and $0.4 million of total unrecognized compensation cost. The cost is expected to be recognized over a remaining period of 2.5 years.

The grant date fair value of the performance shares linked to ROACE was $0.3 million. The grant date fair value of $13.34 per share was the average price of HEI common stock on grant date less the present value of expected dividends to be paid over the performance period, discounted by the risk-free interest rate based on the U.S. Treasury yield at the date of grant.

As of June 30, 2009, there were 24,131 shares underlying the performance share awards with the ROACE condition outstanding, based on target performance levels and $0.2 million of total unrecognized compensation cost. The cost is expected to be recognized over a period of 2.5 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 six months ended June 30, 2009 and 2008, the Company paid interest (net of amounts capitalized and including bank interest) to non-affiliates amounting to $52 million and $104 million, respectively.

For the six months ended June 30, 2009 and 2008, the Company paid income taxes amounting to $12 million and $91 million, respectively. The significant decrease in taxes paid was due primarily to the differences in the taxes due with the extensions for tax years 2008 and 2007 and in the estimated tax payments due for the first half of 2009 and the first half of 2008. 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

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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. This larger taxable income also resulted in disproportionately higher estimated tax payments for the first two quarters of 2008 versus the first two quarters of 2009.

Supplemental disclosures of noncash activities. Noncash increases in common stock for director and officer compensatory plans of the Company were $1.2 million and $1.3 million for the six months ended June 30, 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 and $10 million for the first six months of 2009 and 2008, respectively. 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. Effective May 7, 2009, HEI began satisfying the requirements of the ASB 401(k) Plan by acquiring for cash its common shares through open market purchases.

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 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 adopted the FSPs in the second quarter of 2009 and provided additional disclosures regarding fair value measurements and OTTIs. 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 reclassified $3.8 million of the previously recognized impairment to accumulated other comprehensive income.

Subsequent events. In May 2009, the FASB issued SFAS No. 165, Subsequent Events, which establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. SFAS No. 165 provides: (1) the period after the balance sheet date during which management of a reporting entity should evaluate events or transactions that may occur for potential recognition or disclosure in the financial statements; (2) the circumstances under which an entity should recognize events or transactions occurring after the balance sheet date in its financial statements; and (3) the disclosures that an entity should make about events or transactions that occurred after the balance sheet date. The Company adopted SFAS No. 165 in the second quarter of 2009. See Note 11.

Variable interest entities. In June 2009, the FASB issued SFAS No. 167, Amendments to FASB Interpretation No. 46(R), which eliminates exceptions to consolidating qualifying special-purpose entities (QSPEs), contains new criteria for determining the primary beneficiary, and increases the frequency of required reassessments to determine whether a company is the primary beneficiary of a variable interest entity (VIE). It also clarifies, but does not significantly change, the characteristics that identify a VIE. The Company will adopt SFAS No. 167 in the first quarter of 2010 and has not yet determined the impact of adoption.

FASB Codification. In June 2009, the FASB issued SFAS No. 168, FASB Accounting Standards Codification™ and the Hierarchy of Generally Accepted Accounting Principles, which establishes the Codification as the single source of authoritative U.S. generally accepted accounting principles (U.S. GAAP) recognized by the FASB to be applied by nongovernmental entities. Rules and interpretive releases of the SEC under authority of federal securities laws are also sources of authoritative U.S. GAAP for SEC registrants. The Company will adopt SFAS No. 168 in the third quarter of 2009 and will change or eliminate citations for previous standards (other than SEC citations) in future financial statements and other documents.

10 Fair value of financial instruments

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

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

Cash and equivalents, federal funds sold and short-term borrowings other than bank. The carrying amount approximated fair value because of the short maturity of these instruments.

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

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

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

The fair value of all loans were adjusted to reflect current assessments of loan collectibility.

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

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

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

Off-balance sheet financial instruments. The fair value of loans serviced for others was calculated by discounting expected net income streams using discount rates that reflect industry pricing for similar assets. Expected net income streams are estimated based on industry assumptions regarding prepayment speeds and income and expenses associated with servicing residential mortgage loans for others. The fair value of commitments to originate loans and unused lines of credit was estimated based on the primary market prices of new commitments and new lines of credit. The change in current primary market prices provided the estimate of the fair value of these commitments and unused lines of credit. The fair values of other off-balance sheet financial instruments (letters of credit) were estimated based on the fees currently charged to enter into similar agreements, taking into account the remaining terms of the agreements. Fair value of HECO-obligated preferred securities of trust subsidiaries was based on quoted market prices.

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

(in thousands)	June 30, 2009 Carrying or notional amount	June 30, 2009 Estimated fair value	December 31, 2008 Carrying or notional amount	December 31, 2008 Estimated fair value
Financial assets				
Cash and equivalents	$ 265,143	$ 265,143	$ 182,903	$ 182,903
Federal funds sold	788	788	532	532
Available-for-sale investment and mortgage-related securities	621,740	621,740	657,717	657,717
Investment in stock of Federal Home Loan Bank of Seattle	97,764	97,764	97,764	97,764
Loans receivable, net	3,852,605	3,928,120	4,206,492	4,322,153
Financial liabilities				
Deposit liabilities	4,168,708	4,180,695	4,180,175	4,197,429
Short-term borrowings other than bank	55,000	55,000		
Other bank borrowings	388,858	402,993	680,973	701,998
Long-term debt	1,214,733	1,077,225	1,211,501	949,170
Off-balance sheet items				
HECO-obligated preferred securities of trust subsidiary	50,000	45,500	50,000	40,420

As of June 30, 2009 and December 31, 2008, loan commitments and unused lines and letters of credit had notional amounts of $1.2 billion and their estimated fair value on such dates was $0.2 million and $0.8 million, respectively. As of June 30, 2009 and December 31, 2008, loans serviced for others had notional amounts of $497.0 million and $307.6 million and the estimated fair value of the servicing rights for such loans was $4.2 million and $2.6 million, respectively.

11 Subsequent events

The Company has evaluated subsequent events through August 7, 2009 (12:01 a.m.), the date the financial statements were issued.

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidated Statements of Income (unaudited)

(in thousands, except ratio of earnings to fixed charges)	Three months ended June 30 2009	Three months ended June 30 2008	Six months ended June 30 2009	Six months ended June 30 2008
Operating revenues	**$ 447,836**	**$ 686,647**	**$ 907,121**	**$ 1,309,141**
Operating expenses				
Fuel oil	131,885	273,755	277,174	523,298
Purchased power	115,189	177,226	229,673	328,021
Other operation	63,181	59,422	125,578	115,001
Maintenance	29,431	23,990	55,594	47,603
Depreciation	36,425	35,401	72,849	70,835
Taxes, other than income taxes	41,975	62,371	87,710	119,857
Income taxes	8,727	17,094	17,271	32,472
	426,813	649,259	865,849	1,237,087
Operating income	**21,023**	**37,388**	**41,272**	**72,054**
Other income				
Allowance for equity funds used during construction	4,120	2,105	7,725	4,006
Other, net	2,468	1,111	4,836	2,207
	6,588	3,216	12,561	6,213
Income before interest and other charges	**27,611**	**40,604**	**53,833**	**78,267**
Interest and other charges				
Interest on long-term debt	11,945	11,810	23,857	23,534
Amortization of net bond premium and expense	682	639	1,357	1,270
Other interest charges	717	1,059	1,343	2,045
Allowance for borrowed funds used during construction	(1,727)	(835)	(3,349)	(1,597)
	11,617	12,673	23,208	25,252
Income before preferred stock dividends of HECO and subsidiaries	**15,994**	**27,931**	**30,625**	**53,015**
Less net income attributable to noncontrolling interest - preferred stock of subsidiaries	229	229	458	458
Income before preferred stock dividends of HECO	**15,765**	**27,702**	**30,167**	**52,557**
Preferred stock dividends of HECO	270	270	540	540
Net income for common stock	**$ 15,495**	**$ 27,432**	**$ 29,627**	**$ 52,017**
Ratio of earnings to fixed charges (SEC method)			2.54	3.90

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)	June 30, 2009	December 31, 2008
Assets		
Utility plant, at cost		
Land	$ 51,408	$ 42,541
Plant and equipment	4,419,824	4,277,499
Less accumulated depreciation	(1,796,263)	(1,741,453)
Construction in progress	293,812	266,628
Net utility plant	2,968,781	2,845,215
Current assets		
Cash and equivalents	3,676	6,901
Customer accounts receivable, net	108,242	166,422
Accrued unbilled revenues, net	78,505	106,544
Other accounts receivable, net	7,716	7,918
Fuel oil stock, at average cost	55,332	77,715
Materials and supplies, at average cost	35,072	34,532
Prepayments and other	14,657	12,626
Total current assets	303,200	412,658
Other long-term assets		
Regulatory assets	531,708	530,619
Unamortized debt expense	13,880	14,503
Other	59,413	53,114
Total other long-term assets	605,001	598,236
	$ 3,876,982	$ 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	299,210	299,214
Retained earnings	811,082	802,590
Accumulated other comprehensive income, net of income taxes	1,768	1,651
Common stock equity	1,197,447	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	1,231,740	1,223,135
Long-term debt, net	907,733	904,501
Total capitalization	2,139,473	2,127,636
Current liabilities		
Short-term borrowings nonaffiliates	55,000	

Short-term borrowings affiliate	45,604	41,550
Accounts payable	110,113	122,994
Interest and preferred dividends payable	16,158	15,397
Taxes accrued	158,565	220,046
Other	56,050	55,268
Total current liabilities	441,490	455,255
Deferred credits and other liabilities		
Deferred income taxes	173,251	166,310
Regulatory liabilities	300,450	288,602
Unamortized tax credits	56,973	58,796
Retirement benefits liability	395,204	392,845
Other	55,772	54,949
Total deferred credits and other liabilities	981,650	961,502
Contributions in aid of construction	314,369	311,716
	$ 3,876,982	$ 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:								
Income before preferred stock dividends of HECO and subsidiaries				29,627		540	458	30,625
Retirement benefit plans:								
Amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of taxes of $3,408					5,350			5,350
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of tax benefits of $3,333					(5,233)			(5,233)
Comprehensive income				29,627	117	540	458	30,742
Capital stock expense			(4)					(4)
Common stock dividends				(21,135)				(21,135)
Preferred stock dividends						(540)	(458)	(998)
Balance, June 30, 2009	**12,806**	**$ 85,387**	**$ 299,210**	**$ 811,082**	**$ 1,768**	**$ 22,293**	**$ 12,000**	**$ 1,231,740**
Balance, December 31, 2007	**12,806**	**$ 85,387**	**$ 299,214**	**$ 724,704**	**$ 1,157**	**$ 22,293**	**$ 12,000**	**$ 1,144,755**
Comprehensive income:								
Income before preferred stock dividends of HECO and subsidiaries				52,017		540	458	53,015
Retirement benefit plans:								
Amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of taxes of $1,741					2,733			2,733
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of tax benefits of $1,668					(2,618)			(2,618)
Comprehensive income				52,017	115	540	458	53,130
Common stock dividends				(14,089)				(14,089)
Preferred stock dividends						(540)	(458)	(998)
Balance, June 30, 2008	**12,806**	**$ 85,387**	**$ 299,214**	**$ 762,632**	**$ 1,272**	**$ 22,293**	**$ 12,000**	**$ 1,182,798**

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)

Six months ended June 30 (in thousands)	2009	2008
Cash flows from operating activities		
Income before preferred stock dividends of HECO and subsidiaries	$ 30,625	$ 53,015
Adjustments to reconcile income before preferred stock dividends of HECO and subsidiaries to net cash provided by operating activities		
Depreciation of property, plant and equipment	72,849	70,835
Other amortization	5,502	4,303
Changes in deferred income taxes	7,264	(3,598)
Changes in tax credits, net	(1,321)	888
Allowance for equity funds used during construction	(7,725)	(4,006)
Changes in assets and liabilities		
Decrease (increase) in accounts receivable	58,382	(26,612)
Decrease (increase) in accrued unbilled revenues	28,039	(8,709)
Decrease (increase) in fuel oil stock	22,383	(69,254)
Increase in materials and supplies	(540)	(2,704)
Increase in regulatory assets	(10,564)	(1,095)
Increase (decrease) in accounts payable	(12,881)	45,634
Change in prepaid and accrued income and utility revenue taxes	(61,259)	(43,085)
Changes in other assets and liabilities	(3,542)	2,211
Net cash provided by operating activities	**127,212**	**17,823**
Cash flows from investing activities		
Capital expenditures	(174,473)	(99,924)
Contributions in aid of construction	4,917	7,263
Other		733
Net cash used in investing activities	**(169,556)**	**(91,928)**
Cash flows from financing activities		
Common stock dividends	(21,135)	(14,089)
Preferred stock dividends	(998)	(998)
Proceeds from issuance of long-term debt	3,168	14,802
Net increase in short-term borrowings from nonaffiliates and affiliate with original maturities of three months or less	59,054	88,636
Decrease in cash overdraft	(962)	(8,582)
Other	(8)	
Net cash provided by financing activities	**39,119**	**79,769**
Net increase (decrease) in cash and equivalents	(3,225)	5,664
Cash and equivalents, beginning of period	6,901	4,678
Cash and equivalents, end of period	**$ 3,676**	**$ 10,342**

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 filed in HECO Exhibit 99.2 to HECO s Form 8-K dated June 9, 2009 and the unaudited consolidated financial statements and the notes thereto in HECO s Quarterly Report on SEC Form 10-Q for the quarter ended March 31, 2009.

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 June 30, 2009 and December 31, 2008 and the results of their operations for the three and six months ended June 30, 2009 and 2008 and their cash flows for the six months ended June 30, 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 June 30, 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 six months ended June 30, 2009 and 2008 each consisted of $1.7 million of interest income received from the 2004 Debentures; $1.6 million of distributions to holders of the Trust Preferred Securities; and $0.1 million 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.

Purchase power agreements. As of June 30, 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 six months ended June 30, 2009 totaled $230 million, with purchases from AES Hawaii, Kalaeloa, HEP and HPOWER totaling $67 million, $72 million, $30 million and $20 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

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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 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. However, HECO and its subsidiaries revenue tax payments to the taxing authorities are based on the prior year s revenues. For the six months ended June 30, 2009 and 2008, HECO and its subsidiaries included approximately $83 million and $115 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 six months of 2009, HECO and its subsidiaries contributed $15.7 million to their retirement benefit plans, compared to $4.8 million in the first six months of 2008. HECO and its subsidiaries current estimate of contributions to their retirement benefit plans in 2009 is $26 million, compared to contributions of $14 million in 2008. In addition, HECO and its subsidiaries expect to pay directly $0.7 million of benefits in 2009, compared to $0.1 million paid in 2008.

For the first six months of 2009, HECO and its subsidiaries defined benefit retirement plans assets generated a return, net of investment management fees, of 7.0%. The market value of the defined benefit retirement plan s assets as of June 30, 2009 was $687 million compared to $655 million at December 31, 2008, an increase of approximately $32 million.

The components of net periodic benefit cost were as follows:

	Three months ended June 30				Six months ended June 30			
	Pension benefits		Other benefits		Pension benefits		Other benefits	
(in thousands)	**2009**	**2008**	**2009**	**2008**	**2009**	**2008**	**2009**	**2008**
Service cost	$ 6,107	$ 6,643	$ 1,137	$ 1,150	$ 12,167	$ 13,176	$ 2,164	$ 2,285
Interest cost	14,034	13,473	2,755	2,709	28,084	26,918	5,520	5,464
Expected return on plan assets	(12,693)	(16,277)	(2,183)	(2,697)	(25,366)	(32,528)	(4,361)	(5,392)
Amortization of unrecognized transition obligation			782	783			1,565	1,565
Amortization of prior service credit	(185)	(190)			(368)	(381)		
Recognized actuarial loss (gain)	3,673	1,644	103		7,344	3,289	217	
Net periodic benefit cost	10,936	5,293	2,594	1,945	21,861	10,474	5,105	3,922
Impact of PUC D&Os	(4,107)	1,547	(407)	230	(8,198)	3,204	(732)	423
Net periodic benefit cost (adjusted for impact of PUC D&Os)	$ 6,829	$ 6,840	$ 2,187	$ 2,175	$ 13,663	$ 13,678	$ 4,373	$ 4,345

HECO and its subsidiaries recorded retirement benefits expense of $14 million in each of the first six months of 2009 and 2008. The electric utilities charged a portion of the net periodic benefit costs to plant.

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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 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.

Many of the actions and programs included in the Energy Agreement require approval of the PUC in proceedings that 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. These changes to the RPS law were subsequently enacted when Act 155 was passed by the Hawaii legislature and signed into law by the Governor in 2009.

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. Such an Energy Efficiency Portfolio Standard was enacted as part of Act 155, which provided that the PUC shall establish the standards designed to achieve a reduction of 4,300 gigawatthours of electricity use statewide by 2030. The law also provides that the PUC shall establish interim goals for electricity use reduction to be achieved by 2015, 2020, and 2025, and may revise the 2030 standard by rule or order to maximize cost-effective, energy-efficiency programs and technologies and may establish incentives and penalties.

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

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(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 Renewable Energy Infrastructure Program (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.

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.

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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, panel hearings were held in April 2009 and opening and reply briefs were filed in June 2009. The procedural schedule calls for a PUC decision on FIT general principles in August 2009 and filing of proposed tariff sheets in September 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 and May 2009. Panel hearings at the PUC were completed on July 1, 2009 and the PUC has requested additional information from the parties, to which HECO is responding. Briefing by the parties is scheduled to be completed in September 2009.

In its 2009 test year rate case, HECO proposed to establish a revenue balancing account (RBA) to be effective upon the issuance of the interim D&O, but the PUC did not approve the proposal, pending the outcome of the decoupling proceeding. 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, however, HELCO and MECO were unable to file 2009 test year rate case applications. On July 17, 2009, MECO filed a Notice of Intent to file an application for a general rate case using a 2010 calendar test year on or after September 30, 2009 (but before January 1, 2010), and HELCO filed a Notice of Intent to file an application for a general rate case using a 2010 test year on or after November 25, 2009 (but before January 1, 2010).

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.

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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 in 2009 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 for approval at the end of April 2009 to the PUC, 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 an annual increase of $24.6 million, or 7.58%, 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 an annual increase of $70 million, a 4.96% increase over rates effective at the time of the interim decision ($78 million 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 an annual increase of $13 million, or a 3.7% increase.

As of June 30, 2009, HECO and its subsidiaries had recognized $198 million of revenues with respect to interim orders ($5 million related to interim orders regarding certain integrated resource planning costs and $193 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.

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 June 30, 2009 noted in parentheses) include HECO s Campbell Industrial Park (CIP) combustion turbine No. 1 (CT-1) and a transmission line ($164 million), HECO s East Oahu Transmission Project ($43 million), HELCO s ST-7 ($83 million) and a customer information system ($23 million).

CIP CT-1 and transmission line. HECO has built a new 110 MW simple cycle combustion turbine (CT) generating unit at CIP and has added 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). The CT completed all utility requirements for system operation on August 3, 2009. Plans are for the CT to be run primarily as a peaking unit and to be fueled by biodiesel at a later date, when a supply of biodiesel fuel becomes available.

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. Construction on the Project began in May 2008. In its 2009 test year rate case, HECO requested inclusion of CIP CT-1 costs in rate base when the unit is placed in service, but the PUC did not grant the request indicating that the record did not yet demonstrate that the unit would be in service by the end of 2009. Subsequently CIP CT-1 completed all utility requirements for system operation on August 3, 2009. HECO contends that the CIP CT-1 costs should be included in rate base in an interim decision and the final decision in the 2009 test year rate case.

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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 June 30, 2009, HECO s cost estimate for the Project (exclusive of the costs of the community benefit measures described above) was $193 million (of which $164 million had been incurred, including $8 million of AFUDC) and outstanding commitments for materials, equipment and outside services totaled $26 million. To the extent actual project costs are higher than the $163 million 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 June 30, 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 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 August 2009, the PUC denied approval of the amended HECO contract with Imperium GH and the related terminalling and trucking agreement, indicating that HECO did not satisfy the burden of proof that the contracts, the costs of which will be passed directly to the ratepayers, were reasonable, prudent and in the public interest. The PUC also stated it remains strongly supportive of biofuels and other renewable energy resources. The commission s decision herein is not intended to reflect a decision as to the prudency of biodiesel or the proposed biodiesel feedstock. HECO intends to solicit new bids from biofuel suppliers for CIP CT-1. Consistent with the plan approved by the PUC in its May 2007 order approving the Project, during the unit s initial period of commercial operation, it is undergoing performance testing using low sulfur diesel fuel in order to comply with the manufacturer s warranties. This will be followed by testing using biofuels to obtain the data necessary for modification of the unit s air permit. Also consistent with the PUC s May 2007 order**,** HECO will be working with the PUC and Consumer Advocate to address contingency plans should there be a delay in securing a biofuel supplier for fuel to be used after the testing phase.

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 second phase is projected to be completed in 2013.

As of June 30, 2009, the accumulated costs recorded for the EOTP amounted to $43 million, including (i) $12 million of planning and permitting costs incurred prior to 2003, (ii) $11 million of planning, permitting and construction costs incurred after 2002 and (iii) $20 million for AFUDC. Management believes no adjustment to project costs is required as of June 30, 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.

On June 22, 2009, ST-7 was placed into service. As of June 30, 2009, HELCO s cost estimate for ST-7 was $92 million (of which $83 million had been incurred and $9 million was estimated for ongoing peripheral work). HELCO intends to seek to recover the costs of ST-7 in HELCO s next rate case application.

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.

Management believes no adjustment to project costs is required at June 30, 2009. However, 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.

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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. 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 into 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 June 30, 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 June 30, 2009, the remaining accrual (amounts expensed less amounts expended) for the Iwilei unit was $1.7 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 develop BART implementation plans and schedules in accordance with the amended regional haze rule by December 2007. If a state does not develop a BART implementation plan, the EPA is required to develop a federal implementation plan (FIP) by 2011. To date, Hawaii has not a developed an implementation plan. After Hawaii adopts its plan or the EPA issues an FIP, 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. On July 2, 2009, the EPA published in the Federal Register a notice of intent to issue an Information Collection Request (ICR) regarding coal-fired and oil-fired utility EGUs. The ICR is the first step in the regulatory process to develop the MACT standards for utility EGUs. The EPA states that the purpose of the ICR is (1) to identify categories of affected sources and (2) to define the emission level being achieved by the average of the top performing 12% of the existing sources. The CAA mandates the average of the top performing 12% of existing sources (i.e., units with the lowest HAP emission rates) as the MACT standard for existing sources. The ICR will be applicable to HECO steam units and will require providing existing fuel and emissions data to the EPA as well as emission testing at each of HECO s steam generating plants on Oahu.

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.

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Hazardous Air Pollutant (HAP) Control Reciprocating Internal Combustion Engines (RICE). 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., 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 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.

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.

In July 2007, the EPA had formally suspended the rule pending the outcome of legal challenges to 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 were subject to permit renewal in mid-2009. HECO timely submitted permit renewal applications for its facilities in 2009. The existing permits remain in force until renewals are issued. Renewable permits may be subject to new permit conditions to address cooling water intake requirements.

Apollo Energy Corporation/Tawhiri Power LLC. HELCO purchases energy generated at the Kamao a wind farm pursuant to the Restated and Amended Power Purchase Contract for As-Available Energy (the RAC) dated October 13, 2004 between HELCO and Apollo Energy Corporation (Apollo), later assigned to Apollo s affiliate, Tawhiri Power LLC (Tawhiri). The maximum ouput of the wind farm is 20 MW. By letter to HELCO dated June 15, 2009, Tawhiri requested binding arbitration as provided for under the provisions of the RAC on the issue of HELCO s curtailment of the wind farm output to 10 MW between October 9, 2007 and July 3, 2008. Tawhiri sought alleged damages for lost production in the amount of $13 million, plus unspecified damages for lost production tax credits, overhead losses, and consultant and legal fees. HELCO responded to Tawhiri s arbitration request on July 2, 2009, stating, among other points, that the curtailment was justified because Tawhiri failed to meet the low voltage ride-through requirements of the RAC and improperly disconnected from the grid on October 9, 2007. Under the dispute resolution provisions of the RAC, a decision in the arbitration could be rendered by or before mid-2010. In addition to the curtailment issue, HELCO and Tawhiri have other disputes relating to costs of

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interconnection facilities, reconciliation of transmission line losses, and transfer of land and title to the switching station. These other disputes have not yet proceeded to arbitration.

Collective bargaining agreements. As of June 30, 2009, approximately 56% 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.

6 Cash flows

Supplemental disclosures of cash flow information. For the six months ended June 30, 2009 and 2008, HECO and its subsidiaries paid interest amounting to $21 million and $24 million, respectively.

For the six months ended June 30, 2009 and 2008, HECO and its subsidiaries paid income taxes amounting to $12 million and $80 million, respectively. The significant change was due primarily to the differences in the taxes refundable or due with the extensions for tax years 2008 and 2007 and in the estimated tax payments due for the first half of 2009 and the first half of 2008. 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. This larger taxable income also resulted in disproportionately higher estimated tax payments for the first two quarters of 2008 versus the first two quarters 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 $7.7 million and $4.0 million for the six months ended June 30, 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 Fair value of financial instruments

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

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

Cash and equivalents and short-term borrowings

The carrying amount approximated fair value because of the short maturity of these instruments.

Long-term debt

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

Off-balance sheet financial instruments

Fair value of HECO-obligated preferred securities of trust subsidiaries was based on quoted market prices.

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

December 31	June 30, 2009		December 31, 2008	
(in thousands)	Carrying amount	Estimated fair value	Carrying amount	Estimated fair value
Financial assets:				
Cash and equivalents	$ 3,676	$ 3,676	$ 6,901	$ 6,901
Financial liabilities:				
Short-term borrowings from affiliate and nonaffiliates	100,604	100,604	41,550	41,550
Long-term debt, net, including amounts due within one year	907,733	759,093	904,501	660,380
Off-balance sheet item:				
HECO-obligated preferred securities of trust subsidiary	50,000	45,500	50,000	40,420

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

	Three months ended June 30		Six months ended June 30	
(in thousands)	2009	2008	2009	2008
Operating income from regulated and nonregulated activities before income taxes (per HEI consolidated statements of income)	$ 32,163	$ 55,396	$ 63,232	$ 106,379
Deduct:				
Income taxes on regulated activities	(8,727)	(17,094)	(17,271)	(32,472)
Revenues from nonregulated activities	(2,581)	(1,474)	(5,093)	(2,869)
Add:				
Expenses from nonregulated activities	168	560	404	1,016
Operating income from regulated activities after income taxes (per HECO consolidated statements of income)	$ 21,023	$ 37,388	$ 41,272	$ 72,054

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10 Subsequent events

HECO and its subsidiaries have evaluated subsequent events through August 7, 2009 (12:01 a.m.), the date the financial statements were issued.

On July 30, 2009, the Department of Budget and Finance of the State of Hawaii closed the sale at par of special purpose revenue bonds (SPRBs) for the benefit of HECO and HELCO in the aggregate principal amount of $150 million, which bonds are uninsured, have a maturity of July 1, 2039 and a fixed coupon rate of 6.50%. Proceeds from the SPRBs were loaned to HECO ($90 million) and HELCO ($60 million), and used to reimburse HECO and HELCO for their previously incurred capital expenditures and, in turn, are expected to be used principally to repay their short-term borrowings.

Effective December 8, 2008, HECO entered into a 9-month revolving unsecured credit agreement establishing a line of credit facility of $75 million with a syndicate of four financial institutions (HECO $75 Million Facility). On August 4, 2009, the second business day following receipt of the proceeds of the Series 2009 SPRBs by HECO and HELCO, the HECO $75 Million Facility terminated in accordance with its terms.

On July 2, 2009, the PUC issued an interim D&O in HECO s 2009 test year rate case granting an annual increase of approximately $61.1 million, or 4.7%, which was implemented on August 3, 2009.

11 Consolidating financial information

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

HECO also unconditionally guarantees HELCO s and MECO s obligations (a) to the State of Hawaii for the repayment of principal and interest on Special Purpose Revenue Bonds issued for the benefit of HELCO and MECO and (b) relating to the trust preferred securities of Trust III. See Note 2 above. HECO is also obligated, after the satisfaction of its obligations on its own preferred stock, to make dividend, redemption and liquidation payments on HELCO s and MECO s preferred stock if the respective subsidiary is unable to make such payments.

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Income (unaudited)

Three months ended June 30, 2009

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassifications and eliminations	HECO consolidated
Operating revenues	$ 300,395	79,674	67,767				$ 447,836
Operating expenses							
Fuel oil	86,808	15,762	29,315				131,885
Purchased power	84,329	26,731	4,129				115,189
Other operation	44,644	8,718	9,819				63,181
Maintenance	17,448	5,696	6,287				29,431
Depreciation	20,798	8,250	7,377				36,425
Taxes, other than income taxes	28,273	7,410	6,292				41,975
Income taxes	5,690	2,290	747				8,727
	287,990	74,857	63,966				426,813
Operating income	12,405	4,817	3,801				21,023
Other income							
Allowance for equity funds used during construction	3,176	767	177				4,120
Equity in earnings of subsidiaries	5,249					(5,249)	
Other, net	2,169	370	116	(1)	(6)	(180)	2,468
	10,594	1,137	293	(1)	(6)	(5,429)	6,588
Income (loss) before interest and other charges	22,999	5,954	4,094	(1)	(6)	(5,429)	27,611
Interest and other charges							
Interest on long-term debt	7,668	2,009	2,268				11,945
Amortization of net bond premium and expense	402	159	121				682
Other interest charges	536	242	119			(180)	717
Allowance for borrowed funds used during construction	(1,372)	(282)	(73)				(1,727)
	7,234	2,128	2,435			(180)	11,617
Income (loss) before preferred stock dividends of HECO and subsidiaries	15,765	3,826	1,659	(1)	(6)	(5,249)	15,994
Less net income attributable to noncontrolling interest preferred stock of subsidiaries		133	96				229
Income (loss) before preferred stock dividends of HECO	15,765	3,693	1,563	(1)	(6)	(5,249)	15,765
Preferred stock dividends of HECO	270						270
Net income (loss) for common stock	$ 15,495	3,693	1,563	(1)	(6)	(5,249)	$ 15,495

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Income (unaudited)

Three months ended June 30, 2008

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassifications and eliminations	HECO consolidated
Operating revenues	$ 469,075	105,429	112,143				$ 686,647
Operating expenses							
Fuel oil	188,374	25,000	60,381				273,755
Purchased power	126,914	40,586	9,726				177,226
Other operation	42,762	7,466	9,194				59,422
Maintenance	16,158	3,595	4,237				23,990
Depreciation	20,552	7,802	7,047				35,401
Taxes, other than income taxes	42,662	9,568	10,141				62,371
Income taxes	9,936	3,716	3,442				17,094
	447,358	97,733	104,168				649,259
Operating income	21,717	7,696	7,975				37,388
Other income							
Allowance for equity funds used during construction	1,633	351	121				2,105
Equity in earnings of subsidiaries	11,464					(11,464)	
Other, net	1,160	330	52	(17)	(68)	(346)	1,111
	14,257	681	173	(17)	(68)	(11,810)	3,216
Income (loss) before interest and other charges	35,974	8,377	8,148	(17)	(68)	(11,810)	40,604
Interest and other charges							
Interest on long-term debt	7,587	1,958	2,265				11,810
Amortization of net bond premium and expense	400	117	122				639
Other interest charges	926	366	113			(346)	1,059
Allowance for borrowed funds used during construction	(641)	(145)	(49)				(835)
	8,272	2,296	2,451			(346)	12,673
Income (loss) before preferred stock dividends of HECO and subsidiaries	27,702	6,081	5,697	(17)	(68)	(11,464)	27,931
Less net income attributable to noncontrolling interest preferred stock of subsidiaries		133	96				229
Income (loss) before preferred stock dividends of HECO	27,702	5,948	5,601	(17)	(68)	(11,464)	27,702
Preferred stock dividends of HECO	270						270
Net income (loss) for common stock	$ 27,432	5,948	5,601	(17)	(68)	(11,464)	$ 27,432

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Income (unaudited)

Six months ended June 30, 2009

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassifications and eliminations	HECO consolidated
Operating revenues	$ 605,856	164,305	136,960				$ 907,121
Operating expenses							
Fuel oil	185,739	31,526	59,909				277,174
Purchased power	160,174	60,138	9,361				229,673
Other operation	87,720	18,712	19,146				125,578
Maintenance	34,106	11,634	9,854				55,594
Depreciation	41,595	16,501	14,753				72,849
Taxes, other than income taxes	58,956	15,656	13,098				87,710
Income taxes	11,919	3,140	2,212				17,271
	580,209	157,307	128,333				865,849
Operating income	25,647	6,998	8,627				41,272
Other income							
Allowance for equity funds used during construction	5,878	1,509	338				7,725
Equity in earnings of subsidiaries	9,209					(9,209)	
Other, net	4,047	939	197	(8)	(13)	(326)	4,836
	19,134	2,448	535	(8)	(13)	(9,535)	12,561
Income (loss) before interest and other charges	44,781	9,446	9,162	(8)	(13)	(9,535)	53,833
Interest and other charges							
Interest on long-term debt	15,336	3,985	4,536				23,857
Amortization of net bond premium and expense	805	310	242				1,357
Other interest charges	1,013	449	207			(326)	1,343
Allowance for borrowed funds used during construction	(2,540)	(670)	(139)				(3,349)
	14,614	4,074	4,846			(326)	23,208
Income (loss) before preferred stock dividends of HECO and subsidiaries	30,167	5,372	4,316	(8)	(13)	(9,209)	30,625
Less net income attributable to noncontrolling interest preferred stock of subsidiaries		267	191				458
Income (loss) before preferred stock dividends of HECO	30,167	5,105	4,125	(8)	(13)	(9,209)	30,167
Preferred stock dividends of HECO	540						540
Net income (loss) for common stock	$ 29,627	5,105	4,125	(8)	(13)	(9,209)	$ 29,627

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Income (unaudited)

Six months ended June 30, 2008

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassifications and eliminations	HECO consolidated
Operating revenues	$ 883,588	210,621	214,932				$ 1,309,141
Operating expenses							
Fuel oil	360,526	49,046	113,726				523,298
Purchased power	226,693	81,945	19,383				328,021
Other operation	80,731	16,360	17,910				115,001
Maintenance	31,434	8,300	7,869				47,603
Depreciation	41,104	15,636	14,095				70,835
Taxes, other than income taxes	81,110	19,187	19,560				119,857
Income taxes	19,430	6,303	6,739				32,472
	841,028	196,777	199,282				1,237,087
Operating income	42,560	13,844	15,650				72,054
Other income							
Allowance for equity funds used during construction	3,135	606	265				4,006
Equity in earnings of subsidiaries	20,765					(20,765)	
Other, net	2,571	597	110	(40)	(322)	(709)	2,207
	26,471	1,203	375	(40)	(322)	(21,474)	6,213
Income (loss) before interest and other charges	69,031	15,047	16,025	(40)	(322)	(21,474)	78,267
Interest and other charges							
Interest on long-term debt	15,112	3,910	4,512				23,534
Amortization of net bond premium and expense	800	224	246				1,270
Other interest charges	1,788	771	195			(709)	2,045
Allowance for borrowed funds used during construction	(1,226)	(262)	(109)				(1,597)
	16,474	4,643	4,844			(709)	25,252
Income (loss) before preferred stock dividends of HECO and subsidiaries	52,557	10,404	11,181	(40)	(322)	(20,765)	53,015
Less net income attributable to noncontrolling interest preferred stock of subsidiaries		267	191				458
Income (loss) before preferred stock dividends of HECO	52,557	10,137	10,990	(40)	(322)	(20,765)	52,557
Preferred stock dividends of HECO	540						540
Net income (loss) for common stock	$ 52,017	10,137	10,990	(40)	(322)	(20,765)	$ 52,017

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Balance Sheet (unaudited)

June 30, 2009

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassifications and Eliminations	HECO consolidated
Assets							
Utility plant, at cost							
Land	$ 42,080	4,982	4,346				$ 51,408
Plant and equipment	2,604,914	966,596	848,314				4,419,824
Less accumulated depreciation	(1,055,479)	(366,200)	(374,584)				(1,796,263)
Construction in progress	265,815	15,167	12,830				293,812
Net utility plant	1,857,330	620,545	490,906				2,968,781
Investment in wholly owned subsidiaries, at equity	442,648					(442,648)	
Current assets							
Cash and equivalents	1,223	1,643	683	101	26		3,676
Advances to affiliates	79,250		19,000			(98,250)	
Customer accounts receivable, net	69,531	22,344	16,367				108,242
Accrued unbilled revenues, net	54,310	12,977	11,218				78,505
Other accounts receivable, net	6,662	2,931	1,277		11	(3,165)	7,716
Fuel oil stock, at average cost	36,903	7,480	10,949				55,332
Materials & supplies, at average cost	17,649	4,579	12,844				35,072
Prepayments and other	9,143	3,757	1,757				14,657
Total current assets	274,671	55,711	74,095	101	37	(101,415)	303,200
Other long-term assets							
Regulatory assets	390,786	76,322	64,600				531,708
Unamortized debt expense	9,399	2,172	2,309				13,880
Other	40,644	10,840	7,810		119		59,413
Total other long-term assets	440,829	89,334	74,719		119		605,001
	$ 3,015,478	765,590	639,720	101	156	(544,063)	$ 3,876,982
Capitalization and liabilities							
Capitalization							
Common stock equity	$ 1,197,447	226,518	215,880	97	153	(442,648)	$ 1,197,447
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	1,219,740	233,518	220,880	97	153	(442,648)	1,231,740

Long-term debt, net	582,166	151,214	174,353				907,733
Total capitalization	1,801,906	384,732	395,233	97	153	(442,648)	2,139,473
Current liabilities							
Short-term borrowings nonaffiliates	55,000						55,000
Short-term borrowings affiliate	64,604	79,250				(98,250)	45,604
Accounts payable	80,190	17,443	12,480				110,113
Interest and preferred dividends payable	10,936	2,416	2,857			(51)	16,158
Taxes accrued	103,102	28,683	26,780				158,565
Other	34,683	12,294	12,180	4	3	(3,114)	56,050
Total current liabilities	348,515	140,086	54,297	4	3	(101,415)	441,490
Deferred credits and other liabilities							
Deferred income taxes	139,211	22,355	11,685				173,251
Regulatory liabilities	211,072	51,625	37,753				300,450
Unamortized tax credits	31,455	13,100	12,418				56,973
Retirement benefits liability	291,177	52,517	51,510				395,204
Other	12,249	35,571	7,952				55,772
Total deferred credits and other liabilities	685,164	175,168	121,318				981,650
Contributions in aid of construction	179,893	65,604	68,872				314,369
	$ 3,015,478	765,590	639,720	101	156	(544,063)	$ 3,876,982

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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)

Six months ended June 30, 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:							
Income before preferred stock dividends of HECO and subsidiaries	30,167	5,372	4,316	(8)	(13)	(9,209)	30,625
Retirement benefit plans:							
Amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of taxes	5,350	813	654			(1,467)	5,350
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of tax benefits	(5,233)	(804)	(641)			1,445	(5,233)
Comprehensive income (loss)	30,284	5,381	4,329	(8)	(13)	(9,231)	30,742
Capital stock expense	(4)	(1)	(1)			2	(4)
Common stock dividends	(21,135)		(3,639)			3,639	(21,135)
Preferred stock dividends	(540)	(267)	(191)				(998)
Issuance of common stock					25	(25)	
Balance, June 30, 2009	$ 1,219,740	233,518	220,880	97	153	(442,648)	$ 1,231,740

Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Changes in Stockholders Equity (unaudited)

Six months ended June 30, 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:							
Income before preferred stock dividends of HECO and subsidiaries	52,557	10,404	11,181	(40)	(322)	(20,765)	53,015
Retirement benefit plans:							
Amortization of net loss, prior service gain and transition obligation included in net periodic benefit cost, net of taxes	2,733	379	307			(686)	2,733
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of tax benefits	(2,618)	(369)	(295)			664	(2,618)

Comprehensive income (loss)	52,672	10,414	11,193	(40)	(322)	(20,787)	53,130
Common stock dividends	(14,089)		(6,764)			6,764	(14,089)
Preferred stock dividends	(540)	(267)	(191)				(998)
Issuance of common stock					100	(100)	
Balance, June 30, 2008	$ 1,170,798	218,967	217,759	142	166	(425,034)	$ 1,182,798

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Cash Flows (unaudited)

Six months ended June 30, 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 and subsidiaries	$ 30,167	5,372	4,316	(8)	(13)	(9,209)	$ 30,625
Adjustments to reconcile income before preferred stock dividends of HECO and subsidiaries to net cash provided by operating activities:							
Equity in earnings	(9,259)					9,209	(50)
Common stock dividends received from subsidiaries	3,689					(3,639)	50
Depreciation of property, plant and equipment	41,595	16,501	14,753				72,849
Other amortization	1,528	1,696	2,278				5,502
Changes in deferred income taxes	5,000	2,754	(490)				7,264
Changes in tax credits, net	(724)	(303)	(294)				(1,321)
Allowance for equity funds used during construction	(5,878)	(1,509)	(338)				(7,725)
Changes in assets and liabilities:							
Decrease in accounts receivable	37,514	9,050	8,089			3,729	58,382
Decrease in accrued unbilled revenues	20,347	4,899	2,793				28,039
Decrease in fuel oil stock	16,643	2,846	2,894				22,383
Decrease (increase) in materials and supplies	(1,066)	(213)	739				(540)
Increase in regulatory assets	(6,787)	(1,420)	(2,357)				(10,564)
Increase (decrease) in accounts payable	(4,048)	(10,352)	1,519				(12,881)
Changes in prepaid and accrued income and utility revenue taxes	(42,552)	(9,376)	(9,331)				(61,259)
Changes in other assets and liabilities	6,387	(3,980)	(2,203)	(14)	(3)	(3,729)	(3,542)
Net cash provided by (used in) operating activities	92,556	15,965	22,368	(22)	(16)	(3,639)	127,212
Cash flows from investing activities							
Capital expenditures	(122,500)	(39,002)	(12,971)				(174,473)
Contributions in aid of construction	2,851	1,382	684				4,917
Advances from (to) affiliates	(17,250)		(7,000)			24,250	
Investment in consolidated subsidiary	(25)					25	
Net cash used in investing activities	(136,924)	(37,620)	(19,287)			24,275	(169,556)
Cash flows from financing activities							
Common stock dividends	(21,135)		(3,639)			3,639	(21,135)
Preferred stock dividends	(540)	(267)	(191)				(998)
Proceeds from issuance of long-term debt		3,168					3,168
Proceeds from issuance of common stock					25	(25)	
Net increase in short-term borrowings from nonaffiliates and affiliate with original maturities of	66,054	17,250				(24,250)	59,054

three months or less							
Increase (decrease) in cash overdraft	(1,046)		84				(962)
Other	(6)	(1)	(1)				(8)
Net cash provided by (used in) financing activities	43,327	20,150	(3,747)		25	(20,636)	39,119
Net increase (decrease) in cash and equivalents	(1,041)	(1,505)	(666)	(22)	9		(3,225)
Cash and equivalents, beginning of period	2,264	3,148	1,349	123	17		6,901
Cash and equivalents, end of period	$ 1,223	1,643	683	101	26		$ 3,676

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Hawaiian Electric Company, Inc. and Subsidiaries

Consolidating Statement of Cash Flows (unaudited)

Six months ended June 30, 2008

(in thousands)	HECO	HELCO	MECO	RHI	UBC	Reclassifications and eliminations	HECO consolidated
Cash flows from operating activities							
Income (loss) before preferred stock dividends of HECO and subsidiaries	$ 52,557	10,404	11,181	(40)	(322)	(20,765)	$ 53,015
Adjustments to reconcile income (loss) before preferred stock dividends of HECO and subsidiaries to net cash provided by (used in) operating activities:							
Equity in earnings	(20,815)					20,765	(50)
Common stock dividends received from subsidiaries	6,814					(6,764)	50
Depreciation of property, plant and equipment	41,104	15,636	14,095				70,835
Other amortization	1,582	390	2,331				4,303
Changes in deferred income taxes	(429)	(503)	(2,666)				(3,598)
Changes in tax credits, net	491	284	113				888
Allowance for equity funds used during construction	(3,135)	(606)	(265)				(4,006)
Changes in assets and liabilities:							
Increase in accounts receivable	(15,224)	(4,751)	(6,917)			280	(26,612)
Increase in accrued unbilled revenues	(4,381)	(1,020)	(3,308)				(8,709)
Decrease (increase) in fuel oil stock	(66,097)	340	(3,497)				(69,254)
Decrease (increase) in materials and supplies	(2,062)	(691)	49				(2,704)
Decrease (increase) in regulatory assets	238	(7)	(1,326)				(1,095)
Increase (decrease) in accounts payable	42,633	3,029	(28)				45,634
Changes in prepaid and accrued income and utility revenue taxes	(30,308)	(4,865)	(7,912)				(43,085)
Changes in other assets and liabilities	1,228	505	805	(4)	(43)	(280)	2,211
Net cash provided by (used in) operating activities	4,196	18,145	2,655	(44)	(365)	(6,764)	17,823
Cash flows from investing activities							
Capital expenditures	(51,684)	(33,202)	(15,038)				(99,924)
Contributions in aid of construction	4,043	2,102	1,118				7,263
Advances from (to) affiliates	(25,100)		2,000			23,100	
Investment in consolidated subsidiary	(100)					100	
Other	862				(129)		733
Net cash used in investing activities	(71,979)	(31,100)	(11,920)		(129)	23,200	(91,928)
Cash flows from financing activities							
Common stock dividends	(14,089)		(6,764)			6,764	(14,089)
Preferred stock dividends	(540)	(267)	(191)				(998)
Proceeds from issuance of long-term debt	10,856	1,266	2,680				14,802

Proceeds from issuance of common stock					100	(100)	
Net increase in short-term borrowings from nonaffiliates and affiliate with original maturities of three months or less	86,636	10,100	15,000			(23,100)	88,636
Decrease in cash overdraft	(8,581)		(1)				(8,582)
Net cash provided by financing activities	74,282	11,099	10,724		100	(16,436)	79,769
Net increase (decrease) in cash and equivalents	6,499	(1,856)	1,459	(44)	(394)		5,664
Cash and equivalents, beginning of period	203	3,069	773	198	435		4,678
Cash and equivalents, end of period	$ 6,702	1,213	2,232	154	41		$ 10,342

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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) included in HEI s and HECO s Form 8-K dated June 9, 2009, and the quarterly (as of and for the three months ended March 31, 2009, and as of and for the three and six months ended June 30, 2009) consolidated financial statements of HEI and HECO and accompanying notes included in the Forms 10-Q for the first and second quarters of 2009.

HEI Consolidated

RESULTS OF OPERATIONS

(in thousands, except per share amounts)	Three months ended June 30, 2009	2008	% change	Primary reason(s) for significant change*
Revenues	$ 525,901	$ 774,055	(32)	Decrease for the electric utility and the bank segments
Operating income	35,055	21,602	62	Increase for the bank segment (resulting from the impact of the June 2008 balance sheet restructuring), partly offset by decrease for the electric utility segment
Net income for common stock	15,479	5,136	201	Higher operating income, higher AFUDC, lower interest expense other than on deposit liabilities and other bank borrowings , partly offset by higher income taxes**
Basic earnings per common share	$ 0.17	$ 0.06	183	Higher net income, partly offset by higher weighted average shares outstanding
Weighted-average number of common shares outstanding	91,384	84,052	9	Issuances of shares through a common stock offering in December 2008 and the HEI Dividend Reinvestment and Stock Purchase Plan and other Company plans

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(in thousands, except per share amounts)	Six months ended June 30 2009	2008	% change	Primary reason(s) for significant change*
Revenues	$ 1,069,698	$ 1,503,672	(29)	Decrease for the electric utility and the bank segments
Operating income	79,713	92,348	(14)	Decrease for the electric utility segment, partly offset by an increase for the bank segment (resulting from the impact of the June 2008 balance sheet restructuring)
Net income for common stock	35,874	39,103	(8)	Lower operating income, partly offset by higher AFUDC and lower interest expense other than on deposit liabilities and other bank borrowings
Basic earnings per common share	$ 0.39	$ 0.47	(17)	Lower net income and higher weighted average shares outstanding
Weighted-average number of common shares outstanding	90,996	83,762	9	Issuances of shares through 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 second quarters of 2009 and 2008 were 31% and 13%, respectively. The effective tax rate for the second quarter of 2008 reflects the effect of utilizing state tax credits against a significantly lower income tax expense base. The Company s effective tax rate for the first six months of 2009 and 2008 were 34%.

Dividends. The payout ratios for 2008 and the first six months of 2009 were 116% and 159%, 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; Kauai Board of Realtors; Realtors Association of Maui; Realty Trac; Blue Chip Financial Forecasts; and local newspapers).

On a national level, improving economic data referred to as green shoots are appearing. The Blue Chip Economic Indicators survey in July 2009 reflects that a majority of the economists polled expect that, in the third quarter of 2009, the National Bureau of Economic Research will declare that the deepest recession since at least World War II is over. The Blue Chip Financial Forecast consensus dated July 1, 2009 reported real gross domestic product (GDP) decreased by 1.8% for the second quarter of 2009 but predicted GDP to increase by 0.7% and 1.8% in the third and fourth quarters of 2009, respectively. Consumer confidence at June 30, 2009 improved from March 31, 2009, but remains at the low level of 49.3 (1985=100) and consumer spending is negatively impacted by the higher savings trend.

Interest rates remained low during the second 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.

While the national economy has signs of green shoots, the Hawaii economy continues to be weak and generally lags the U.S. economy in recovery. For the second quarter of 2009, the Hawaii economy continued to decline although stabilization is expected by the end of the year. Hawaii economic growth as measured by the change in real personal income is predicted to be lower by 2.7% in 2009 and 0.6% in 2010 before a moderate recovery begins in 2011.

The challenging economic environment has resulted in the State revising its estimate for the budget shortfall through June 2011 to $786 million, an increase of $56 million from the prior estimate of $730 million in May 2009. Governor Lingle is currently reviewing remedies to address the budget shortfall that includes layoffs, spending restrictions and/or furloughs.

At 7.4%, seasonally-adjusted Hawaii unemployment at the end of June 2009 remains well below the national average of 9.5%, but remains much higher than the average annual rates of 2.6% for 2007 and 4% for 2008. The Hawaii unemployment rate is expected to be 7.4% in 2009, 8.1% in 2010 and gradually recede beginning in 2011. Declines in tourism-related sectors and construction will result in job losses. The job base is expected to contract by 2.9% in 2009 and by 0.6% in 2010 before recovery begins.

Weakness is most notable in one of the state s largest industries, tourism, which is affected by the health of the U.S. and key international economies, especially Japan. Total visitor arrivals declined 9.8% in the first half of 2009 compared to the same period in 2008. U.S. arrivals appear to have stabilized and Hawaii s largest source of visitor arrivals, the Pacific coast states, experienced consecutive increases of 5.4% and 4.9% in May and June 2009, respectively, compared to the same periods in 2008. However, the H1N1 flu epidemic is expected to further reduce Japanese travel resulting in the outlook for 2009 Japanese visitor arrivals to be nearly 14% lower than their 2008 level. Total visitor arrivals in 2009 are expected to be down approximately 6.8% from 2008 levels, followed by an increase of 3.1% in 2010. The weakness in tourism is expected to impact the neighbor island economies more than Oahu because their economies rely more on tourism. Job losses for 2009 in the accommodation and food service sectors are estimated to be 6% or greater on Maui and Kauai and nearly 9% on the island of Hawaii. This compares to the estimated 2.5% decline for 2009 for Oahu. Visitor expenditures for 2009 were revised downward and are estimated to be down 10% from 2008.

Occupancy rates at Hawaii hotels are expected to average 66% in 2009 and remain below 70% until 2012. Aggressive pricing is expected to continue, resulting in an estimated 12% lower average daily room rate for 2009 compared to 2008.

The Oahu housing market continued to contract during the second quarter of 2009. Home sales for the first half of 2009 decreased 21.7% compared with the same period in 2008 with the median sales price of $570,000, down 9.4% compared with the same period last year. Local authorities note that while the housing market is still weak, there are indications that the worst may be over. Home sales rebounded slightly in June and sales speed of 45 days was the fastest in 2009. The Maui and Kauai housing markets are weaker than Oahu s. For the first half of 2009, Maui and Kauai experienced home sales declines of 41% and 30% and price declines of 14% and 27%, respectively. The finite supply of developable land in Hawaii has been a stabilizing force although the pessimistic outlook for jobs and job growth puts downward pressure on prices and increases the risk for additional foreclosures. Foreclosures in Hawaii continue to rise. For the first half of 2009, the State of Hawaii had a foreclosure rate per housing unit of 1/141, a nearly 300% increase compared to the same period in 2008. The neighbor islands are experiencing a higher foreclosure rate than Oahu. For the first half of 2009, the foreclosure rate per housing unit was 1/81 for Kahului/Wailuku, Maui, 1/88 for Hilo, Hawaii and 1/98 for Kapaa, Kauai. While these rates are close to the U.S. average of 1/84, they are significantly higher than the 1/207 rate experienced in Honolulu.

The global tightening of credit and recession has impacted the Hawaii construction industry. Commercial and resort building are hampered by financing constraints and a weak 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 43% in the first half of 2009 compared with the same period in 2008.

Overall, the Hawaii economy remains weak but is expected to stabilize by the end of the year and there are some signs of modest recovery in the U.S. and Japan economies.

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, including the $150 million of special purpose revenue bonds issued for the benefit of HECO and HELCO on July 30, 2009. This favorable change may influence the utilities decision to participate in issuances of additional 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 six months of 2009, the Company s defined benefit retirement plans assets generated a return, net of investment management fees, of 7.0%. The market value of the defined benefit retirement plans assets as of June 30, 2009 was $761 million compared to $726 million at December 31, 2008, an increase of approximately $35 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 $48 million, respectively, which should fully satisfy the minimum required

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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.

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 June 30, 2009	2008	% change	Primary reason(s) for significant change
Revenues	$ (15)	$ (16)	NM	
Operating loss	(2,614)	(2,802)	NM	Lower expenses, including executive compensation and consulting fees
Net loss	(4,037)	(4,203)	NM	See explanation for operating loss

(in thousands)	Six months ended June 30, 2009	2008	% change	Primary reason(s) for significant change
Revenues	$ (47)	$ (132)	NM	Lower unrealized losses on venture capital investments
Operating loss	(6,146)	(6,402)	NM	See explanation for revenues and lower expenses, including proxy costs
Net loss	(8,656)	(9,397)	NM	See explanation for operating loss and lower interest expense

NM Not meaningful.

The other business segment includes results of operations of HEI and American Savings Holdings, Inc., 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.

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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)	June 30, 2009		December 31, 2008	
Short-term borrowings other than bank	$ 55	2%	$	%
Long-term debt, net other than bank	1,215	45	1,212	46
Noncontrolling interest: cumulative preferred stock of subsidiaries	34	1	34	1
Common stock equity	1,402	52	1,389	53
	$ 2,706	100%	$ 2,635	100%

As of August 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-3	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/Negative/A-3 and S&P s outlook for HEI is negative. HEI s issuer rating by Moody s is Baa2 and Moody s outlook for HEI is negative.

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 May 2009, S&P revised HEI s outlook to negative from stable, and lowered its commercial paper rating to A-3 from A-2 . S&P indicated the rating actions reflected its view that the next two years are likely to be challenging for HEI's electric utilities, which HEI relies on for cash flows to service its own obligations, chiefly debt repayment and common stock distributions. S&P stated that the deterioration in the Hawaii economy is likely to weaken 2009 and 2010 consolidated metrics, which it observed have been only marginally supportive of the BBB corporate credit ratings currently assigned to HEI.

S&P designates business risk profiles as excellent, strong, satisfactory, fair, weak or vulnerable. S&P s financial risk designations are m modest, intermediate, significant, aggressive and highly leveraged. In August 2009, S&P listed HEI s business risk profile as strong and risk profile as significant.

On July 20, Moody s issued a news release in which it indicated it had changed HEI s rating outlook to negative from stable and affirmed HEI s long-term and short-term (commercial paper) ratings. Moody s indicated that the rating affirmation reflects the fact that notwithstanding the issues outlined in the release, HEI s financial metrics are reasonably positioned in its rating category. See discussion below regarding the negative outlook.

Subsequently on August 3, 2009, Moody s issued a credit opinion on HEI. Regarding the negative rating outlook, Moody s indicated that HEI s negative rating outlook reflects the impact of a weakened economy that is affecting electric demand and electric sales resulting in weaker financial performance, which may be influencing the outcome of state regulatory decisions, the high dividend payout ratio, the existence of a negative rating outlook at ASB and the concentration risk that exists at HEI from the very high dependence on the Hawaiian economy. Moody s stated that [t]he rating could be downgraded should weaker than expected economic growth and

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regulatory support emerge at HECO which ultimately causes earnings and sustainable cash flows to suffer over an extended period. Consequently, if Moody s expectations regarding the future sustainable levels of the Company s consolidated financial ratios were to shift such that expectations for FFO (Funds From Operations, defined as net cash flow from operations less net changes in working capital items) to Adjusted Debt were to fall below 16% (15% last twelve months as of March 31, 2009-latest reported by Moody s) or expectations for FFO to Adjusted Interest were less than 3.5x (3.3x last twelve months as of March 31, 2009-latest reported by Moody s) on a sustained basis, the rating could be lowered.

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

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

	Six months ended June 30, 2009		
(in millions)	**Average balance**	**End-of-period balance**	**December 31, 2008**
Short-term borrowings [1]			
HEI commercial paper	$	$	$
HEI line of credit draws			
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 commercial paper issuances and line of credit facilities and draws.

2 At August 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 June 30, 2009, HEI had no short-term borrowings outstanding and had short-term loans to HECO of $46 million. HEI expects that it will require short-term borrowings in the latter half of 2009. Since HEI s commercial paper rating has been downgraded to A-3/P-2, management believes that it will access the commercial paper market at higher prices and shorter maturities, or access may be unreliable. Such limitations could cause HEI to draw on its syndicated credit facility instead. Management believes that if HEI s commercial paper ratings were to be further downgraded, or if credit markets for commercial paper with HEI s ratings or otherwise were to further tighten, it would be even 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.

Starting April 16, 2009, HEI began satisfying the common stock requirements of its Dividend Reinvestment and Stock Purchase Plan and the Hawaiian Electric Industries Retirement Savings Plan through open market purchases of its common stock. Prior to April 16, 2009, issuances of common stock for these plans were a source of capital for HEI and provided new capital of $43 million in 2008 and $41 million in 2007. Management continuously evaluates the company s capital needs in determining how long to continue open market purchases.

For the first six months of 2009, net cash provided by operating activities of consolidated HEI was $180 million. Net cash provided by investing activities for the same period was $193 million, primarily due to net decreases in loans receivable and investment and mortgage-related securities at ASB, partly offset by HECO s consolidated capital expenditures. Net cash used in financing activities during this period was $291 million as a

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result of several factors, including net decreases in other bank borrowings, retail repurchase agreements and deposit liabilities and the payment of common stock dividends, partly offset by a net increase in short-term borrowings, proceeds from the issuance of common stock under HEI plans (before such plans began satisfying their requirements through open market purchases) and funds from the drawdown of SPRB 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, bank borrowings, 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 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 $27 million in 2009 ($26 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 12 to 13, 39 to 44, and 53 to 55 of HEI s MD&A, which is filed in HEI Exhibit 99.1 to HEI s Form 8-K dated June 9, 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 13 to 14, 44 to 45, and 56 of HEI s MD&A, which is filed in HEI Exhibit 99.1 to HEI s Form 8-K dated June 9, 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 June 30, 2009	2008	% change	Primary reason(s) for significant change
Revenues	$ 450,417	$ 688,121	(35)	Lower fuel oil and purchased energy fuel costs, the effects of which are generally passed on to customers ($215 million), lower KWH sales ($21 million) and lower DSM costs recovered through a surcharge ($1 million)
Expenses				
Fuel oil	131,885	273,755	(52)	Lower fuel oil costs and less KWHs generated
Purchased power	115,189	177,226	(35)	Lower fuel costs and less KWHs purchased
Other operation	63,181	59,422	6	See Results three months ended June 30, 2009 below
Maintenance	29,431	23,990	23	See Results three months ended June 30, 2009 below
Depreciation	36,425	35,401	3	Additions to plant in service in 2008
Taxes, other than income taxes	41,975	62,371	(33)	Decrease in revenues
Other	168	560	(70)	
Operating income	32,163	55,396	(42)	Lower sales and higher other operation and maintenance (O&M) and depreciation expenses
Net income for common stock	15,495	27,432	(44)	Lower operating income, partly offset by higher AFUDC
Kilowatthour sales (millions)	2,400	2,476	(3)	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)	1,244	1,295	(4)	
Average fuel oil cost per barrel	$ 50.69	$ 104.78	(52)	

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(dollars in thousands, except per barrel amounts)	Six months ended June 30, 2009	2008	% change	Primary reason(s) for significant change
Revenues	$ 912,214	$ 1,312,010	(30)	Lower fuel oil and purchased energy fuel costs, the effects of which are generally passed on to customers ($337 million), and lower KWH sales ($71 million), partially offset by higher DSM costs recovered through a surcharge ($2 million)
Expenses				
Fuel oil	277,174	523,298	(47)	Lower fuel oil costs and less KWHs generated
Purchased power	229,673	328,021	(30)	Lower fuel costs and less KWHs purchased
Other operation	125,578	115,001	9	See Results six months ended June 30, 2009 below
Maintenance	55,594	47,603	17	See Results six months ended June 30, 2009 below
Depreciation	72,849	70,835	3	Additions to plant in service in 2008
Taxes, other than income taxes	87,710	119,857	(27)	Decrease in revenues
Other	404	1,016	(60)	
Operating income	63,232	106,379	(41)	Lower sales and higher other O&M and depreciation expenses
Net income for common stock	29,627	52,017	(43)	Lower operating income, partly offset by higher AFUDC
Kilowatthour sales (millions)	4,631	4,885	(5)	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)	2,003	2,249	(11)	
Average fuel oil cost per barrel	$ 55.19	$ 99.29	(44)	

Note: The electric utilities had an effective tax rate for the second quarters of 2009 and 2008 of 36% and 38%, respectively. The electric utilities had an effective tax rate for the first six months of 2009 and 2008 of 36% and 38%, respectively.

See Economic conditions in the HEI Consolidated section above.

Results three months ended June 30, 2009. Operating income for the second quarter of 2009 decreased 42% from the same period in 2008 due primarily to lower sales and higher other operation and maintenance (O&M) expenses. For the second quarter of 2009, KWH sales were down 3.1% compared with the same quarter of 2008, primarily due to the soft economy, cooler weather and ongoing customer conservation.

Other operation expenses for the second quarter of 2009 increased by $3.8 million over the same period in 2008, primarily due to $1.6 million higher planned production and transmission and distribution operations expenses to maintain reliable operations and pursue renewable initiatives, higher DSM expenses (see Demand-side management programs below) that are generally passed on to customers through surcharges ($0.9 million) and $0.9 million higher bad debt expense. Maintenance expense increased $5.4 million primarily due to the greater scope of generating unit overhauls and higher expenses for substation maintenance, vegetation management and overhead and underground line maintenance.

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, 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 in July 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, completing all utility requirements for system operation for CIP CT-1 on August 3, 2009 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.

Results six months ended June 30, 2009. Operating income for the first six months of 2009 decreased 41% from the same period in 2008 due primarily to lower sales and higher operation and maintenance (O&M) expenses. For the first six months of 2009, kilowatthour (KWH) sales were down 5.2% compared to the same period in 2008. The decline in sales is attributable to cooler, less humid weather, one less day of sales due to the leap year day in 2008, the soft economy and ongoing customer conservation.

Other operation expenses increased by $10.6 million in the first six months of 2009 compared to the same period in 2008, primarily due to higher DSM expenses (see Demand-side management programs below) that are generally passed on to customers through surcharges ($3.4 million), $3.4 million higher planned production and transmission and distribution operations expense to maintain reliable operations and pursue renewable initiatives; and $1.4 million higher bad debt expense. Maintenance expense increased $8.0 million, primarily due to the greater scope and number of generating unit overhauls and higher expenses for overhead and underground line maintenance, vegetation management and substation maintenance.

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 30, 2009 filing with the PUC, HECO reported a consolidated RPS of 18% in 2008. 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 July 2009, HECO and MECO submitted separate applications with the PUC to approve biodiesel supply contracts for their respective biodiesel demonstration projects, and to include the biodiesel fuel costs and related costs in their respective energy cost adjustment clauses. HECO s application also requested approval of capital project costs, but MECO s estimated capital project costs were below the threshold that required separate PUC approval.

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 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. MECO began negotiating with

BlueEarth Maui for a fuel purchase contract for biodiesel to be used in existing diesel-fired units at MECO s Maalaea plant. However, negotiations for the biodiesel supply contract stalled based on an inability to reach agreement on various financial and risk allocation issues. In October 2008, BlueEarth filed a civil 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 related land agreements. The lawsuit seeks damages and equitable relief. In April 2009, the venue of the action was transferred to Hawaii. A trial date has been scheduled for June 2010. Work on the project was suspended because the litigation was filed. The Memorandum of Understanding (MOU) between HECO, MECO and BlueEarth regarding the project has also expired. Although HECO remains committed to supporting development of renewable fuels production, because of the filing of the litigation, the expiration of the MOU, and other factors, HECO and MECO now consider the project terminated.

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, photovoltaic and wind turbine generating systems). In November 2007, HECO entered into a contract with Hoku Solar, Inc. 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, and Hoku Solar is seeking financing for the project. In October 2008, the PUC approved a power purchase contract between MECO and Lanai Sustainability Research, LLC for the purchase of up to 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, which is now being installed. 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 July 2009, HECO executed a purchase power agreement with Kahuku Wind Power, LLC, subject to PUC approval, to purchase 30 MW of electricity from a wind turbine generating system.

On April 30, 2009, HECO filed an application with the PUC for approval of a Photovoltaic (PV) Host Pilot Program. If approved, this will be a two-year pilot program whereby HECO, HELCO and MECO would lease rooftops or other space from property owners, with a focus on governmental facilities, for third-party owned photovoltaic systems. The PV developer would own, operate and maintain the system and sell the energy to the utilities at a fixed rate under a long term contract.

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. Interconnection requirements studies are underway. 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.

On July 17, 2009, HECO filed an application requesting approval to (1) to defer the costs of outside services incurred in 2009 and 2010 to conduct the studies and analyses necessary (a) to reliably and effectively integrate large amounts of wind-generated renewable energy potentially located on the islands of Molokai and Lanai to the Oahu electric grid, and (b) to assess the potential routes and permitting requirements for the Oahu transmission lines and facilities necessary to interconnect undersea cables delivering power from the Big Wind Projects to Oahu; and (2) to recover the expenses for these Big Wind Implementation Studies through a surcharge mechanism. The specific approvals requested included approvals (1) to defer the costs for outside services (estimated at $6.3 million) for the Big Wind Implementation Studies that are expected to be incurred from January 1, 2009 through 2010, and that would otherwise be expensed; and (2) to recover the revenue requirements of those deferred costs through the Renewable Energy Infrastructure Program/Clean Energy Infrastructure Surcharge (REIP/CEI Surcharge) that is pending approval or, in the alternative, through a Big Wind Project-specific surcharge (Big Wind Surcharge) mechanism that the PUC would approve in this proceeding. If the PUC does not approve recovery of the Big Wind Implementation Studies expenses through a surcharge mechanism, HECO requested PUC approval (1) to defer the Big Wind Implementation Studies costs beginning January 1, 2009 until its next rate case, (2) to amortize the deferred costs over a three-year period beginning when rates established in the next rate case that reflect the amortization become effective, (3) to include the annual amortization expense in determining the revenue requirements in that next rate case, and (4) to include the unamortized balance of the deferred costs in rate base to determine HECO s revenue requirement.

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. Due to the active renewable energy marketplace in Hawaii, RHI is not seeking new projects at this time.

The electric utilities promote research and development in the areas supporting renewable energy such as biofuels, ocean energy, battery storage, smart grids, 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 RFP schedule provides for selection of an Award Group in August 2009 and submittal of PPAs for PUC approval by December 2009. 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 opened a new docket related to MECO s proposed RFP, identified MECO and the Consumer Advocate as parties to the docket and approved MECO s contract with the Independent Observer for the proposed RFP. The schedule for competitive bidding for the first capacity increment (recently targeted for 2015) anticipated the issuance of a draft RFP in 2010. MECO, however, is currently evaluating the projected need date for firm capacity. As a result, the timing for the planned competitive bidding effort is currently also 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, and negotiations to modify that PPA are currently ongoing. 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. In March 2009, HELCO reached agreement on a term sheet with the remaining waivered biomass project. In April 2009, HELCO retained an Independent Engineering consultant to evaluate the suitability of the current generation system conditions for issuing an RFP for acquiring additional renewable resources. In June 2009, the Independent Engineer submitted a preliminary draft of their recommendations, which is currently being reviewed by HELCO.

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. In May 2009, HECO submitted to the PUC an update to the October 2008 filing on the status of negotiations with Honua Power, Kahuku Wind Power and Sea Solar Power International. HECO and Kahuku Wind Power signed a PPA in July 2009, subject to PUC approval. Certain appendices of the PPA will be revised to reflect completion and mutual acceptance of the results of the interconnection requirements study, which is ongoing. Negotiations to reach a PPA with Honua Power and Sea Solar Power International are currently ongoing.

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.

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). The PUC also 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.

By a D&O issued in June 2009, the PUC approved the agreement for the DSG facility at the Honolulu International Airport. The PUC also approved HECO s request to waive the project from the Competitive Bidding Framework and HECO s commitment of funds. However, the PUC denied HECO s proposed accounting and ratemaking treatment for capital and overhaul reimbursement payments to be made by HECO to the Department of Transportation under the terms of the agreement. HECO will work with the Department of Transportation to restructure the agreement to provide HECO with the ability to seek cost recovery for these expenses in accordance with the PUC D&O.

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 DOD. 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 being installed and is planned to be 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.

As required in the Energy Agreement, the utilities conducted a review of the modified DG interconnection tariffs to evaluate whether the tariffs are effective in supporting non-utility DG and distributed energy storage by improving the process and procedure for interconnection. HECO filed its evaluation report to the PUC in June 2009, concluding that the process has been working efficiently. Several minor modifications to clarify portions of the tariff were identified. A request to modify the DG interconnection tariff will 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 distributed energy storage would provide utility system benefits and can be reasonably accommodated.

The utilities also agreed to power utility-owned DG using sustainable biofuels or other renewable technologies and fuels, and to support either customer-owned or utility-owned distributed energy storage.

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

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

The Energy Agreement also provides that to the degree that transmission and distribution automation and other smart grid technology investments are needed to facilitate distributed energy resource utilization, those investments 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 August 3, 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 2009, 2006 and 2007 test years issued in August 2009, April 2007 and December 2007, were 10.5%, 10.7% and 10.7% respectively.

For the 12 months ended June 30, 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 6.40%, 6.77% and 5.22%, respectively. HECO s actual ROACE was 410 basis points lower than its interim D&O ROACE primarily due to lower KWH sales and increased O&M expenses, which are expected to continue. HELCO and MECO s actual ROACEs were 393 and 548 basis points, respectively, lower than their interim D&O ROACEs due in part to lower KWH sales.

As of August 3, 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 2009, 2006 and 2007 test years were 8.45%, 8.33% and 8.67%, respectively. For the 12 months ended June 30, 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 5.61%, 4.87% and 5.21%, respectively.

In 2009, HECO, and in 2007, HELCO and MECO received interim D&Os, 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.

<u>HECO</u>.

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 requested base rates increase was $74 million, or 7.3%.

In September 2005, HECO, the Consumer Advocate and the 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).

On May 1, 2008, the PUC issued the final D&O for HECO s 2005 test year rate case, which was consistent with a 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 another proceeding.

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.

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.

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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.

The requested rate increase was based on anticipated plant additions estimated at the time of filing of $375 million in 2008 and 2009 (including 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. As discussed below, the PUC in its interim D&O did not approve the proposal to establish an RBA to be effective as of the date of the interim D&O, pending the outcome of the decoupling proceeding. Also, the PUC asked for more information on the power purchase adjustment clause and HECO provided additional support for the reasonableness of the surcharge in the supplemental testimonies filed on July 20, 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, 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.

On May 15, 2009, HECO, the Consumer Advocate and the DOD (the parties) executed and filed an agreement on most of the issues in HECO s 2009 test year rate case proceeding. The settlement agreement included an interim increase amounting to $79.8 million annually, or a 6.2% increase. The settlement agreement represented a negotiated compromise of the parties respective positions and was approximately 18% lower than HECO s original request for a $97 million increase in revenues. For purposes of the interim decision only, the parties agreed upon a ROACE of 10.50%. The settlement agreement reflected the average rate base treatment for the CIP CT-1 rather than HECO s proposal for a step increase based on the annualized net cost of CIP CT-1. As part of the settlement, the parties also agreed that the PUC should allow HECO to establish an RBA, which would remove the linkage between electric revenues and KWH sales, to be effective on the date of the interim D&O. If approved, the RBA would have provided a mechanism to adjust revenues (increases/decreases) subsequent to the interim D&O for the differences (shortages/overages) between the actual revenues and the revenues determined in the interim D&O.

The remaining issues among the parties impacting the amount of the increase for the proceeding related to the appropriate test year expense amount for informational advertising, and the appropriate ROACE for the test year. HECO believes its test year estimate for informational advertising and a ROACE of 11%, assuming the approval of a revenue adjustment mechanism, is reasonable. If HECO prevails on the remaining issues, the additional annual revenue increase would be approximately $7 million more than agreed upon in the settlement agreement.

On May 19, 2009, based on the understandings reached in the settlement agreement, HECO submitted its statement of probable entitlement, requesting an interim increase of $79.8 million, based on an 8.45% return on average rate base of $1.253 billion.

On July 2, 2009, the PUC issued an interim D&O in HECO s 2009 test year rate case proceeding. The interim D&O approved a rate increase for interim purposes, but directed that adjustments be made to reduce the increase reflected in HECO s statement of probable entitlement for several items, including certain labor expenses, and the costs related to CIP CT-1. Part of the labor expense reduction relates to new positions established to carry out initiatives included in the HCEI. The PUC removed certain costs related to HCEI, because those initiatives are still the subject of pending PUC proceedings and have not yet been approved. The PUC removed the costs related to CIP CT-1 from rate base indicating that the record did not yet demonstrate that the CIP CT-1 unit would be in service by the end of the 2009 test year. The PUC did not approve the proposal to establish an RBA to be effective as of the date of the interim D&O, pending the outcome of the decoupling proceeding.

Based on the adjustments, HECO calculated the interim increase amount at $61.1 million annually or a 4.7% increase (compared to $79.8 million, or a 6.2% increase, agreed to by the parties under the settlement agreement) and submitted the information to the PUC on July 8, 2009. The interim increase amount is based on a return on average common equity of 10.50% agreed to by the parties for purposes of the interim decision only, and an 8.45% return on average rate base of $1.169 billion (compared to the average rate base of $1.253 billion agreed to by the parties in their settlement agreement).

On July 15, 2009, in responding to HECO s calculations, the Consumer Advocate stated that HECO s proposed adjustments were conservatively prepared, that HECO s revised schedules were in general compliance with the PUC s interim D&O, and that it did not object to HECO s filing. The Consumer Advocate also identified Hawaii Clean Energy Initiative (HCEI)-related costs of $1.5 million that were included in the settlement agreement and HECO s statement of probable entitlement that it believed could be subject to interpretation as to whether they should be included in the interim rate relief under the D&O. HECO filed a response providing an explanation supporting the inclusion of these costs in its original interim increase calculations. The DOD did not file any comments on HECO s interim increase calculations. The interim decision was implemented on August 3, 2009. If the amounts collected pursuant to an interim decision exceed the amount of the increase ultimately approved in the final D&O, then the excess would have to be refunded to HECO s customers, with interest.

In the interim D&O, the PUC indicated the parties are allowed to provide additional testimonies regarding the items excluded from the statement of probable entitlement and requested additional testimonies on certain issues by July 20, 2009. HECO, the Consumer Advocate and the DOD provided testimonies on those issues on July 20, 2009. On July 17, 2009, the PUC rescheduled the evidentiary hearing that was originally scheduled to begin the week of August 10, 2009 to instead begin the week of October 26, 2009. As the PUC did not accept the material terms of the settlement agreement, any (and all) of the parties may withdraw from the agreement and pursue their respective positions at the hearing, but none of the parties have indicated an intention to do so.

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

HELCO.

2006 test year rate case. 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.

2010 test year rate case. On July 17, 2009, HELCO filed a Notice of Intent to file an application for a general rate increase on or after November 25, 2009 (but before January 1, 2010).

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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 July 17, 2009, the parties filed joint 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.

2010 test year rate case. On July 17, 2009, MECO filed a Notice of Intent to file an application for a general rate increase on or after September 30, 2009 but before January 1, 2010.

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 May 11, 2009, the utilities and the Consumer Advocate filed their joint final statement of position and the other parties filed their final 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. Panel hearings at the PUC were completed on July 1, 2009 and the PUC has requested additional information from the parties, to which HECO is responding. Briefing by the parties is scheduled to be completed in September 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 Energy Efficiency Demand-Side Management (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 subsequently 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.

On May 13, 2009, having been unable to negotiate an acceptable agreement to be a subcontractor to SAIC, HECO ended negotiations and began to focus on implementing the transition of the energy efficiency programs to the PBF Administrator. On July 1, 2009, SAIC began administering the energy efficiency DSM programs.

The EE DSM 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. On June 29, 2009, HECO filed with the PUC a request to increase its residential DSM programs budget by a net $1.4 million primarily to pay customer incentives related to DSM program applications that will have been completed and approved through June 30, 2009. The payments to customers of these incentives had been postponed in order for HECO to remain within the monthly program budgets. In June 2009, HECO accrued and expensed the net $1.4 million of incentives. The PUC required that HECO confirm that all required payments of customer incentives (related to undisputed program applications completed and approved through June 30, 2009 for the Residential Efficient Water Heating and Residential New Construction Programs) have been made, and HECO made the required incentive payments and provided the required confirmation in July 2009. HECO is awaiting a determination from the PUC on its request to increase its program budget.

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, 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

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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 (DPP) 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. In its February 18, 2009 Statement of Position (SOP), the Consumer Advocate did not object to the PUC s approval of the proposed pilot program, with certain qualifications. On June 8, 2009, the PUC, in its Order Directing HECO to Modify its Dynamic Pricing Pilot Program, directed HECO to modify the DPP Program to address the recommendations and concerns outlined in the Consumer Advocate s SOP , or alternatively, HECO and the Consumer Advocate may file a stipulated proposed DPP Program. HECO plans to meet with the Consumer Advocate to discuss its recommendations and concerns in order to respond to the PUC s order. The contents of HECO s response and its filing date are dependant on the outcome of discussions with the Consumer Advocate.

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.

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. HECO and the Consumer Advocate filed a proposed CESP framework with the PUC on April 28, 2009. The proposed 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 DSM resources are of higher value. The parties 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. On May 14, 2009, the PUC opened an investigative proceeding to examine the proposed CESP framework. In addition to HECO, HELCO, Kauai Island Utility Cooperative (KIUC) and the Consumer Advocate, eleven parties have been allowed as intervenors in the proceeding.

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, 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, 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 half 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 were not expected to occur prior to startup of CIP CT-1 when reserve capacity conditions were 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.

HECO reported in its 2009 AOS letter that, after the scheduled mid-2009 addition of the CIP CT-1, and in recognition of the uncertainty underlying key forecasts, 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. However, in May 2009, HECO prepared a new sales and peak forecast in which HECO projects peak demand to be lower than previously forecast. The impact of this lower peak demand forecast on HECO s reserve capacity needs is currently being evaluated. As noted under HECO s IRP above, HECO is revisiting its plans to submit an application and waiver request to pursue the installation of a second biofueled CT (100 MW) at its CIP generating station in the 2011-2012 timeframe given its projection of future sales and peak demand. 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.

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 through 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 through 2007, HECO on occasion remotely turned off water heaters for a number of residential customers who participate in its load-control program. No such requests were made or actions taken in 2008 or thus far in 2009.

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.

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. 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. In May 2009, HECO, HELCO and MECO filed a joint position statement recommending that the PUC decline to adopt the four new federal standards, as there are already existing processes and proceedings before the PUC to consider Hawaii-specific standards. Management cannot 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. Act 155, passed by the 2009 Hawaii legislature and signed into law by the Governor, has amended Hawaii s RPS law to require electric utilities to meet an RPS of 10% by December 31, 2010, 15% by December 31, 2015, 25% by December 31, 2020, and 40% by December 31, 2030. The revised RPS law is consistent with the commitment the utilities agreed to in the Energy Agreement signed as part of the HCEI and provides that beginning January 1, 2015, electrical energy savings from renewable energy displacement technologies (such as solar water heating) or from energy efficiency and conservation programs shall not count toward the RPS. The amended RPS law includes a requirement for the PUC to evaluate the standard every five years, beginning in 2013, to determine whether the standards remain effective and achievable and whether the standards should be revised in light of their findings. The standard under the law prior to the amendment (8% of KWH sales by December 31, 2005) was met in 2005 when the electric utilities attained an RPS of 11.7%. The utilities are committed to achieving these goals; however, due to risks such as potential delays in IPPs being able to deliver contracted renewable energy (see risks under Forward-looking Statements), 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. See Hawaii Clean Energy Initiative in Note 5 of HECO s Notes to Consolidated Financial Statements for a further discussion of the penalty.

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 the first quarter of 2009, the parties responded to information requests prepared by the PUC s consultant, and in July 2009, the utilities and the Consumer Advocate submitted separate legal briefs, which responded to the PUC s questions on legal issues.

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

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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 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. The parties are required to file their proposed plans by August 14, 2009. The parties, however, will be allowed to amend their plans based on the decision in the FIT proceeding.

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.

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 proposed endangerment finding was published in the Federal Register on April 24, 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.

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).

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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.

Suspension of Hawaii capital goods excise tax credit. Act 178, which became law on July 15, 2009, temporarily suspended the Hawaii capital goods excise tax credit for property placed in service between May 1 and December 31, 2009. This credit is a 4% investment credit on depreciable tangible personal property placed into service in Hawaii. This suspension of the credit could increase HECO s consolidated current income tax liability by as much as $6 million, depending on the property placed in service during the suspension period. Since these tax credits are deferred and amortized over the expected lives of the properties, the annual net income impact of losing these credits would be significantly lower and is estimated to be $0.2 million per year for the next 30 years.

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.

The AMI project application includes a request to approve a contract between Sensus Meter Systems, Inc. and HECO under which HECO, MECO and HELCO would purchase smart meters and pay Sensus to provide and maintain an AMI system to operate the smart meters. By its terms, either party may declare the contract null and void if it is not approved by a PUC D&O issued by November 30, 2009. Currently, the PUC procedural schedule for review of the application indicates that the PUC may not issue a D&O on the application by November 30, 2009.

HECO continues to operate a Sensus AMI network, currently consisting of 8,000 advanced meters at both residential and commercial customer sites on Oahu, and gathered additional data regarding commercially-available Meter Data Management (MDM) software. The utilities plan to issue an RFP for MDM software by the end of 2009. 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, and integrate with the utilities Customer Information System.

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 are developing a Smart Grid roadmap and are exploring other utility applications such as distribution circuit monitoring and water heater and air conditioning load control for improved residential and commercial customer reliability and renewables support. AMI technology is rapidly evolving and has become an integral part of the utilities Smart Grid planning.

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.

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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)	June 30, 2009		December 31, 2008	
Short-term borrowings	$ 101	5%	$ 42	2%
Long-term debt	908	41	905	42
Cumulative preferred stock	22	1	22	1
Noncontrolling interest cumulative preferred stock of subsidiaries	12		12	
Common stock equity	1,197	53	1,189	55
	$ 2,240	100%	$ 2,170	100%

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

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

The above ratings reflect only the view 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/Negative/A-3. HECO s issuer rating by Moody s is Baa1 and Moody s outlook for HECO is negative.

* 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 name was subsequently changed to National Public Finance Guarantee Corp. (National). The financial strength rating of National by S&P is A. Moody s ratings on securities that are guaranteed or wrapped by a financial guarantor are generally maintained at a level equal to the higher of the rating of the guarantor (if rated at the investment grade level) or the published underlying rating. The insurance financial strength rating of National by Moody s is

Baa1, which is the same as Moody s issuer rating for HECO.

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 May 2009, S&P revised HECO s outlook to negative from stable, and lowered HECO s short-term rating to A-3 from A-2. S&P indicated the rating actions reflected its view that the next two years are likely to be challenging for HEI s electric utilities. S&P stated that the deterioration in the Hawaii economy is likely to weaken 2009 and 2010 consolidated metrics, which it observed have been only marginally supportive of the BBB corporate credit ratings currently assigned to HECO. In July 2009, S&P issued a bulletin which stated the interim ruling July 2 in Hawaiian Electric Co. Inc. s (HECO; BBB/Negative/A-3) rate

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case and a recently announced delay in the company s rate case hearings is adverse for credit quality but is adequately captured in the negative outlook assigned to the ratings last month.

S&P designates business risk profiles as excellent, strong, satisfactory, fair, weak or vulnerable. S&P s financial risk designations are modest, intermediate, significant, aggressive and highly leveraged. In August 2009, S&P listed HECO s business risk profile as strong financial risk profile as significant.

On July 20, 2009, Moody s issued a news release in which it indicated it had changed HECO s rating outlook to negative from stable, affirmed HECO s long-term and short-term (commercial paper) ratings, and assigned a Baa1 rating to the $150 million senior unsecured SPRBs due 2039 that were subsequently issued on July 30, 2009 by the Department of Budget and Finance of the State of Hawaii (DBF) for the benefit of HECO and HELCO. See discussion below regarding the negative outlook and rating affirmation.

Subsequently on August 3, 2009, Moody s issued a credit opinion on HECO. Moody s indicated that the rating affirmation reflects the fact that notwithstanding the issues outlined in the credit opinion, the utilities financial metrics are reasonably positioned in its rating category. Regarding the negative rating outlook, Moody s indicated that HECO s negative rating outlook reflects the impact of a weakened economy that is affecting electric demand and electric sales resulting in weaker financial performance, which may be influencing the outcome of state regulatory decisions, at a time when the company s capital investment program is substantial. Moody s stated that [t]he rating could be downgraded should weaker than expected regulatory support emerge at HECO or if the economy worsens materially more than anticipated causing earnings and sustainable cash flows to suffer. Consequently, if the utilities financial ratios declined on a permanent basis such that FFO (Funds From Operations defined as net cash flow from operations less net changes in working capital items) to Adjusted Debt falls below 17% (17% last twelve months as of March 31, 2009-latest reported by Moody s) or FFO to Adjusted Interest declines to less than 3.5x (3.6x last twelve months as of March 31, 2009-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:

	Six months ended June 30, 2009		
(in millions)	**Average balance**	**End-of-period balance**	**December 31, 2008**
Short-term borrowings			
Commercial paper	$ 1	$	$
Line of credit draws	6	55	
Borrowings from affiliates	31	46	42
Line of credit facilities [1]			
Undrawn capacity under line of credit facility expiring March 31, 2011 [2]		120	175
Undrawn capacity under line of credit facility expiring September 8, 2009 [3]		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[4]	260
HELCO		115[4]	115
MECO		25	25
Total special purpose revenue bonds available for issue		$ 420	$ 420

1 At August 1, 2009, there was no outstanding commercial paper balance and outstanding short-term borrowings under the credit facility expiring on March 31, 2011 totaled $80 million. HECO may seek to modify the credit facility expiring March 31, 2011 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

In April 2009, HECO filed with the PUC a request for expedited approval of Amendment No. 2 (which the Required Lenders, as defined in the agreement, signed) to the $175 million credit facility. Among other things, Amendment No. 2

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eliminates from the credit agreement representations relating to the funded status of HECO s pension plan, which were not correct. On May 26, 2009, the PUC approved the Amendment No. 2.

3 On August 4, 2009, the $75 million credit facility terminated in accordance with its terms based on the completion on July 30, 2009 of the $150 million SPRB offering for the benefit of HECO and HELCO.

4 Authorization amounts for HECO and HELCO are reduced to $170 million and $55 million, respectively, as a result of the issuance of $150 million of Series 2009 SPRBs on July 30, 2009 by the Department of Budget and Finance of the State of Hawaii for the benefit of HECO ($90 million) and HELCO ($60 million).

HECO utilizes short-term debt, typically commercial paper, to support normal operations and for other temporary requirements. In June 2009, HECO began drawing on the credit facility expiring March 31, 2011, rather than issuing commercial paper. 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 June 30, 2009, HECO had $46 million and $19 million of short-term borrowings from HEI and MECO, respectively, and HELCO had $79 million of short-term borrowings from HECO. HECO had an average outstanding balance of commercial paper for the first six months of 2009 of $1 million and had no commercial paper outstanding at June 30, 2009. Due to market conditions since September 2008 which resulted in a tightening of the commercial paper (CP) market, escalating CP rates and limitations on maturity options as well as a result of S&P s recent downgrade of HECO s short-term borrowing rating to A-3 from A-2, HECO began drawing on its $175 million syndicated line of credit facility in June 2009, rather than issuing commercial paper. Management believes that, if HECO s commercial paper ratings were to be further downgraded or if credit markets were to further tighten, it would be even more difficult and expensive to sell commercial paper or make other short-term borrowings.

Revenue bonds are issued by the DBF 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 DBF, including HECO s guarantees of its subsidiaries obligations. The payment of principal and interest due on all revenue bonds outstanding as of June 30, 2009 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 insured 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. The $150 million of SPRBs sold by the DBF for the benefit of HECO and HELCO on July 30, 2009, were sold without bond insurance. Management believes that if HECO s long-term credit ratings were to be downgraded, or if credit markets further tighten, it could be even more difficult and/or expensive to sell bonds in the future.

Operating activities provided $127 million in net cash during the first six months of 2009. Investing activities during the same period used net cash of $170 million for capital expenditures, net of contributions in aid of construction. Financing activities for the same period provided net cash of $39 million, primarily due to a $59 million net increase in short-term borrowings and drawdown of $3 million of SPRB proceeds, partly offset by the payment of $22 million of common and preferred dividends and a $1 million decrease in cash overdraft.

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 an application with the PUC for approval of one or more SPRB financings under the 2007 legislative authorization identified in the table above (up to $260 million for HECO, up to $115 million for HELCO, and up to $25 million for MECO). On June 29, 2009, the PUC granted the approvals necessary to permit the electric utilities to borrow the proceeds from the issuance of the SPRBs in the amounts requested. On July 30, 2009, the DBF issued (pursuant to the 2007 legislative authorization), at par, Series 2009 SPRBs in the aggregate principal amount of $150 million, which bonds are uninsured, with a maturity of July 1, 2039 and a fixed coupon interest rate of 6.50%, and loaned the proceeds to HECO ($90 million) and HELCO ($60 million). As of June 30, 2009, HECO s consolidated current liabilities exceeded current assets by $138 million, but the proceeds from the recently-issued SPRBs were used to reimburse the electric utilities for their previously incurred capital expenditures and, in turn, are expected to be used principally to repay short-term borrowings and thus help to improve HECO s working capital position. 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.

HECO s consolidated 2009 gross capital expenditures are now estimated to be approximately $380 million, reflecting a $37 million increase from the 2009 gross capital expenditures included in the previous five-year (2009-2013) consolidated utility forecast of $1.6 billion. The increase primarily reflects the higher cost estimate for CIP CT-1.

Bank

RESULTS OF OPERATIONS

(in thousands)	Three months ended June 30, 2009	2008	% change	Primary reason(s) for significant change
Revenues	$ 75,499	$ 85,950	(12)	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, partly offset by higher noninterest income due to prior year losses on the sale of investment and mortgage-related securities resulting from the balance sheet restructuring
Operating income	5,506	(30,992)	NM	Higher noninterest income due to losses in 2008 on the sale of investment and mortgage-related securities resulting from the balance sheet restructuring and lower noninterest expense due to the loss on early extinguishment of debt from the balance sheet restructuring, partly offset by higher provision for loan losses and lower net interest income in 2009
Net income	4,021	(18,093)	NM	Higher operating income due to charges for the balance sheet restructure in 2008

(in thousands)	Six months ended June 30, 2009	2008	% change	Primary reason(s) for significant change
Revenues	$ 157,531	$ 191,794	(18)	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, partly offset by higher noninterest income due to prior year losses on the sale of investment and mortgage-related securities resulting from the balance sheet restructuring
Operating income	22,627	(7,629)	NM	Higher noninterest income due to losses in 2008 on the sale of investment and mortgage-related securities resulting from the balance sheet restructuring and lower noninterest expense due to the loss on early extinguishment of debt from the balance sheet restructuring, partly offset by higher provision for loan losses and lower net interest income in 2009
Net income	14,903	(3,517)	NM	Higher operating income due to charges for the balance sheet restructure in 2008

See Economic conditions in the HEI Consolidated section above.

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 and six months ended June 30, 2009 and 2008. The average balances for investment and mortgage-related securities and other borrowings were lower due to the balance sheet restructuring in June 2008. The average rate for other borrowings was also impacted by the balance sheet restructure.

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	Three months ended June 30					
	2009			2008		
($ in thousands)	Average Balance	Interest	Average Rate (%)	Average Balance	Interest	Average Rate (%)
Assets:						
Other investments [1]	$ 228,623	$ 55	0.09	$ 146,822	$ 585	1.59
Investment and mortgage-related securities	643,152	7,088	4.41	1,940,258	22,144	4.57
Loans receivable [2]	3,979,321	55,363	5.57	4,167,696	61,747	5.93
Total interest-earning assets	4,851,096	62,506	5.16	6,254,776	84,476	5.40
Allowance for loan losses	(43,617)			(30,034)		
Non-interest-earning assets	330,398			405,505		
Total assets	$ 5,137,877			$ 6,630,247		
Liabilities and Stockholder s Equity:						
Interest-bearing demand and savings deposits	$ 2,200,413	1,798	0.33	$ 2,110,933	2,810	0.53
Time certificates	1,236,328	8,104	2.63	1,496,224	12,809	3.43
Total interest-bearing deposits	3,436,741	9,902	1.16	3,607,157	15,619	1.74
Other borrowings	404,521	2,241	2.20	1,643,441	16,265	3.96
Total interest-bearing liabilities	3,841,262	12,143	1.27	5,250,598	31,884	2.43
Non-interest bearing liabilities:						
Deposits	737,219			687,168		
Other	88,192			105,268		
Stockholder s equity	471,204			587,213		
Total Liabilities and Stockholder s Equity	$ 5,137,877			$ 6,630,247		
Net interest income		$ 50,363			$ 52,592	
Net interest margin (%) [3]			4.16			3.36

	Six months ended June 30					
	2009			2008		
($ in thousands)	Average Balance	Interest	Average Rate (%)	Average Balance	Interest	Average Rate (%)
Assets:						
Other investments [1]	$ 168,206	$ 55	0.06	$ 142,070	$ 1,146	1.61
Investment and mortgage-related securities	659,449	14,764	4.48	2,041,192	46,034	4.51
Loans receivable [2]	4,077,634	113,455	5.58	4,166,851	125,212	6.01
Total interest-earning assets	4,905,289	128,274	5.24	6,350,113	172,392	5.43
Allowance for loan losses	(39,961)			(30,035)		
Non-interest-earning assets	344,741			416,986		
Total assets	$ 5,210,069			$ 6,737,064		
Liabilities and Stockholder s Equity:						
Interest-bearing demand and savings deposits	$ 2,160,417	4,145	0.39	$ 2,104,271	6,317	0.60
Time certificates	1,281,392	17,322	2.73	1,536,978	27,522	3.59

Total interest-bearing deposits	3,441,809	21,467	1.26	3,641,249	33,839	1.86
Other borrowings	482,411	5,505	2.27	1,724,717	35,414	4.11
Total interest-bearing liabilities	3,924,220	26,972	1.38	5,365,966	69,253	2.59
Non-interest bearing liabilities:						
Deposits	725,922			671,157		
Other	86,783			106,603		
Stockholder s equity	473,144			593,338		
Total Liabilities and Stockholder s Equity	$ 5,210,069			$ 6,737,064		
Net interest income		$ 101,302			$ 103,139	
Net interest margin (%) [3]			4.13			3.25

[1] Includes federal funds sold, interest bearing deposits and stock in the FHLB of Seattle ($98 million as of June 30, 2009).

[2] Includes loan fees of $1.9 million and $1.3 million for the three months ended June 30, 2009 and 2008, respectively, $3.8 million and $2.4 million for the six months ended June 30, 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.

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Earning assets, costing liabilities and other factors. Earnings of ASB depend primarily on net interest income, which is the difference between interest earned on earning assets and interest paid on costing liabilities. The current interest rate environment is 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.

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

	June 30, 2009		December 31, 2008	
(dollars in thousands)	**Balance**	**% of total**	**Balance**	**% of total**
Real estate loans:				
Residential 1-4 family	$ 2,482,820	63.7	$ 2,808,611	66.2
Commercial real estate	261,000	6.7	242,952	5.7
Home equity line of credit	300,966	7.7	272,505	6.4
Residential land	115,638	3.0	126,963	3.0
Commercial construction	54,720	1.4	71,518	1.7
Residential construction	29,164	0.8	34,458	0.8
Total real estate loans, net	3,244,308	83.3	3,557,007	83.8
Commercial	580,478	14.9	594,677	14.0
Consumer	70,341	1.8	90,606	2.2
	3,895,127	100.0	4,242,290	100.0
Less: Allowance for loan losses	42,522		35,798	
Total loans, net	$ 3,852,605		$ 4,206,492	

The decrease in the total loan portfolio during the first six month of 2009 was primarily due to ASB s strategic decision to sell all salable residential loans in the current low interest rate environment.

Loan portfolio risk elements. When a borrower fails to make a required payment on a loan and does not cure the delinquency promptly, the loan is classified as delinquent. If delinquencies are not cured promptly, ASB normally commences a collection action, including foreclosure proceedings in the case of secured loans. In a foreclosure action, the property securing the delinquent debt is sold at a public auction in which ASB may participate as a bidder to protect its interest. If ASB is the successful bidder, the property is classified as real estate owned until it is sold.

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The following table sets forth certain information with respect to nonperforming assets as of the dates indicated:

(dollars in thousands)	June 30, 2009	December 31, 2008
Real estate loans:		
Residential 1-4 family	$ 23,927	$ 7,335
Commercial real estate	284	
Home equity line of credit	2,218	716
Residential land	18,658	7,458
Commercial construction		
Residential construction		189
	45,087	15,698
Commercial	11,957	2,801
Consumer	493	488
Total nonperforming loans	57,537	18,987
Real estate owned:		
Residential 1-4 family	533	
Residential land	2,420	1,492
Total real estate owned loans	2,953	1,492
Total nonperforming assets	$ 60,490	$ 20,479
Nonperforming assets to total loans and REO	1.55%	0.48%

The increase in nonperforming loans was primarily due to higher amounts of residential first mortgage and land loans and commercial loans that are 90 days or more past due.

Allowance for loan losses. The following table sets forth the allocation of ASB s allowance for loan losses and the percentage of loans in each category to total loans as of the dates indicated:

(dollars in thousands)	June 30, 2009 Balance	June 30, 2009 % of total	December 31, 2008 Balance	December 31, 2008 % of total
Real estate loans:				
Residential 1-4 family	$ 8,949	63.7	$ 4,024	66.2
Commercial real estate	3,500	8.1	3,977	7.4
Home equity line of credit	2,680	7.7	548	6.4
Residential land	5,783	3.0	1,953	3.0
Residential construction	269	0.8	88	0.8
Total real estate loans, net	21,181	83.3	10,590	83.8
Commercial	18,188	14.9	22,294	14.0
Consumer	2,525	1.8	2,190	2.2
	41,894	100.0	35,074	100.0
Unallocated	628		724	

Total allowance for loan losses	$ 42,522	$ 35,798

The increase in the allowance for loan losses was primarily due to higher residential first mortgage and land loans and home equity lines of credit delinquencies, offset by the partial charge-off of a commercial credit.

Investment and mortgage-related securities. As of June 30, 2009, the bank s investment portfolio consisted of 52% mortgage-related securities issued by Federal National Mortgage Association (FNMA), Federal Home Loan Mortgage Corporation (FHLMC) or Government National Mortgage Association (GNMA), 42% private-issue mortgage-related securities, 5% federal agency obligations and 1% municipal bonds. 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

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deterioration in the U.S. residential housing market continues to pressure the private-issue mortgage-related securities 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 June 30, 2009, private-issue mortgage-related securities represented 42% of the portfolio. 20% 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.

The table below summarizes the private-issue mortgage-related securities by credit rating and year of issuance.

June 30, 2009

Private-issue mortgage-related securities [1]	AAA/Aaa	AA+/AA/AA-	A+/A/A-	BBB/Baa	Book value BB+/BB/BB-	B/B-	CCC+/CCC	CC/Ca	Total	Net unrealized loss
(in thousands)										
Prime year of issuance:										
2003 and earlier	$ 41,068	$ 261	$ 2,553	$	$ 63	$	$	$	$ 43,945	$ (2,377)
2004	34,925								34,925	(806)
2005	36,600		10,497	8,544	12,955	13,404			82,000	(8,571)
2006				7,328	6,404	11,734	33,398	12,019[2]	70,883	(16,118)
2007							13,374[3]		13,374	(832)
Total prime	112,593	261	13,050	15,872	19,422	25,138	46,772	12,019	245,127	(28,704)
Alt-A year of issuance:										
2005					12,132				12,132	(3,144)
2006							13,775[4]		13,775	(6,047)
Total Alt-A					12,132		13,775		25,907	(9,191)
Sub-prime year of issuance:										
1999 and earlier			1,496		2,488				3,984	(2,108)
Total sub-prime			1,496		2,488				3,984	(2,108)
	$ 112,593	$ 261	$ 14,546	$ 15,872	$ 34,042	$ 25,138	$ 60,547	$ 12,019	$ 275,018	$ (40,003)

1 All issues categorized by lowest available rating by Nationally Recognized Statistical Rating Organizations.

2 Includes one issue rated Ca by Moody s, with a realized OTTI credit loss of $2.1 million.

3 Includes one issue rated CCC by Fitch, with a realized OTTI credit loss of $3.4 million.

4 Includes one issue rated Caa1 by Moody s, with a realized OTTI credit loss of $0.1 million.

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December 31, 2008

Private-issue mortgage-related securities [1] (in thousands)	**Book value** AAA/Aaa	AA/Aa	A	BBB/Baa	BB+/Ba	B	Total	**Net unrealized loss**
Prime year of issuance:								
2003 and earlier	$ 54,062	$ 300[2]	$ 2,732	$ 66	$	$	$ 57,160	$ (3,737)
2004	62,356						62,356	(4,089)
2005	100,061						100,061	(14,950)
2006			22,415	45,334	4,321	15,682	87,752	(25,429)
2007						12,042[3]	12,042	
Total prime	216,479	300	25,147	45,400	4,321	27,724	319,371	(48,205)
Alt-A year of issuance:								
2005			13,722				13,722	(3,315)
2006					14,300		14,300	(5,921)
Total Alt-A			13,722		14,300		28,022	(9,236)
Sub-prime year of issuance:								
1999 and earlier			1,623		2,488		4,111	(1,753)
Total sub-prime			1,623		2,488		4,111	(1,753)
	$ 216,479	$ 300	$ 40,492	$ 45,400	$ 21,109	$ 27,724	$ 351,504	$ (59,194)

1 All issues categorized by lowest available rating by Nationally Recognized Statistical Rating Organizations.

2 Includes one issue rated Aa2 by Moody s, with a realized OTTI loss of $0.2 million.

3 Includes one issue rated B by S&P, with a realized OTTI loss of $7.6 million.

Should market conditions and the performance of mortgage-related assets continue to deteriorate, ASB could incur additional material OTTI charges.

Deposits and other borrowings. Deposits continue to be the largest source of funds for ASB and are affected by market interest rates, competition and management s responses to these factors. Deposit retention and growth will remain challenges in the current environment due to competition for deposits and the level of short-term interest rates. Advances from the FHLB of Seattle and securities sold under agreements to repurchase continue to be additional sources of funds. As of June 30, 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.

Other factors. Interest rate risk is a significant risk of ASB s operations and also represents a market risk factor affecting the fair value of ASB s investment securities. Increases and decreases in prevailing interest rates generally translate into decreases and increases in fair value of those instruments. In addition, changes in credit spreads also impact the fair values of those instruments. Continued deterioration in the housing market has amplified the credit risks in ASB s private-issue mortgage-related securities 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 June 30, 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 $20 million and $33 million, respectively. See Quantitative and qualitative disclosures about market risk.

Results three months ended June 30, 2009. Net interest income before provision for loan losses for the second quarter of 2009 decreased by $2.2 million, or 4%, when compared to the same period in 2008 due to lower balances and yields on earning asset balances, partially offset by lower funding costs. Net interest margin increased from 3.36% in the second quarter of 2008 to 4.16% in the second 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 decrease in the average loan portfolio balance was due to a decrease in the average residential loan portfolio of $350 million as ASB continued to sell all salable residential loan production in the current low interest rate environment. Offsetting the decrease in the residential portfolio was growth in the home equity lines of credit and commercial markets loan portfolios. The decrease in the average investment and mortgage-related securities portfolios was primarily due to the sale of securities in the balance sheet restructure and repayments in the portfolio. See Balance sheet restructure in Note 4 to HEI s Notes to Consolidated Financial Statements. Average deposit balances decreased by $120 million compared to the second quarter of 2008, and increased by $13 million compared to the first quarter of 2009. 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.

During the second quarter of 2009, ASB recorded a provision for losses of $13.5 million due to the partial charge-off of a commercial loan, higher nonperforming residential lot loans and higher delinquencies in residential and consumer loans. Higher levels of delinquencies and loan loss provisions are expected through the economic downturn. During the second quarter of 2008, ASB recorded a provision for losses of $1.2 million due to an increase in the classification of commercial loans.

Second quarter of 2009 noninterest income increased by $11.5 million when compared to the second quarter of 2008, primarily due to the loss on sale of mortgage-related securities and agency notes from the balance sheet restructuring in June 2008, partially offset by a charge for OTTI on three mortgage-related securities in the second quarter of 2009. Noninterest income for the second quarter of 2008 also included insurance recoveries on legal and litigation matters of $4.3 million and a $1.0 million gain on sale of stock in a membership organization.

Noninterest expense for the second quarter of 2009 decreased by $39.6 million when compared to the second quarter of 2008, primarily due to losses on the early extinguishment of certain borrowings from the balance sheet restructuring. Excluding the losses from the balance sheet restructuring in the second quarter of 2008, noninterest expense for the second quarter of 2009 increased by $0.2 million.

In the second quarter of 2009, ASB signed an agreement with Fiserv Inc. to use its technology to consolidate ASB s disparate manual processes using a single, integrated approach. The change to the Fiserv Inc. bank platform system is projected to reduce service bureau expenses by an estimated $6 million annually, beginning in June 2010. To convert its existing systems to the Fiserv Inc. technology, ASB expects to incur conversion costs totaling approximately $3 million (to be incurred in the remainder of 2009 and the first half of 2010).

Results six months ended June 30, 2009. Net interest income before provision for loan losses for the first six months of 2009 decreased by $1.8 million, or 2%, when compared to the same period in 2008 as lower funding costs were more than offset by lower balances and yields on loans and investment and mortgage-related securities. Net interest margin increased from 3.25% in the first six months of 2008 to 4.13% in the first six months 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 decrease in the average loan portfolio balance was due to a decrease in the average residential loan portfolio of $277 million as ASB continued to sell all salable residential loan production in the current low interest rate environment. Offsetting the decrease in the residential portfolio was growth in the home equity lines of credit and commercial markets loan portfolios. The decrease in the average investment and mortgage-related securities portfolios was primarily due to the sale of securities in the balance sheet restructuring and paydowns in the portfolio. See Balance sheet restructure in Note 4 to HEI s Notes to Consolidated Financial Statements. Average deposit balances decreased by $145 million compared to the first six months 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.

During the first six months of 2009, ASB recorded a provision for losses of $21.8 million due to the classification and partial charge-off of a commercial credit, higher nonperforming residential lot loans and higher residential and consumer loan delinquencies. The increase in net charge-offs for the first six months of 2009 compared to the same period in 2008 was primarily due to the partial charge-off of the commercial credit and higher residential, consumer and small business loan charge-offs. Higher levels of delinquencies and loan loss provisions are expected through the economic downturn. During the first six months of 2008, ASB recorded a provision for losses of $2.1 million due to loan growth as well as an increase in the classification of commercial loans.

(in thousands)	Six months ended June 30 2009	Six months ended June 30 2008	Year ended December 31 2008
Allowance for loan losses, January 1	$ 35,798	$ 30,211	$ 30,211
Provision for loan losses	21,800	2,055	10,334
Less: net charge-offs	15,076	1,883	4,747
Allowance for loan losses, end of period	$ 42,522	$ 30,383	$ 35,798
Ratio of allowance for loan losses, end of period, to average loans outstanding	1.04%	0.73%	0.86%
Ratio of net charge-offs during the period to average loans outstanding (annualized)	0.74%	0.09%	0.11%
Nonaccrual loans	$ 60,773	$ 8,232	$ 19,494

The first six months of 2009 noninterest income increased by $9.9 million when compared to the first six months of 2008, primarily due to the loss on sale of mortgage-related securities and agency notes from the balance sheet restructuring in June 2008, partially offset by a charge for OTTI on three mortgage-related securities in the second quarter of 2009. Noninterest income for the first half of 2008 also included insurance recoveries on legal and litigation matters of $4.3 million and a $1.9 million gain on sale of stock in a membership organizations.

Noninterest expense for the six months ended June 30, 2009 decreased by $42.0 million when compared to the same period of 2008, primarily due to losses on the early extinguishment of certain borrowings from the balance sheet restructuring in the second quarter of 2008. Excluding the losses from the balance sheet restructuring, noninterest expense for the first six months of 2009 decreased by $2.1 million primarily due to lower legal and consulting 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.

On June 17, 2009, The Treasury Department released its financial regulatory reform proposal. The proposal, if adopted in its current form would eliminate the Office of Thrift Supervision (OTS) and the thrift charter. The proposal also identifies a number of so-called loopholes in the current regulatory framework that have allowed certain types of companies to control insured depository institutions without being subject to comprehensive holding company regulation by the Federal Reserve. Among these loopholes is the grandfathering treatment for certain companies that owned thrifts prior to 1999. HEI relies on this grandfathering treatment to conduct both electric utility and banking activities. The proposal states: [A]lthough [bank holding companies] generally are

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prohibited from engaging in commercial activities, many thrift holding companies established before the GLB [Gramm-Leach-Bliley] Act in 1999 qualify as unitary thrift holding companies and are permitted to engage freely in commercial activities. Under our plan, all thrift holding companies would become [bank holding companies] and would be fully regulated on a consolidated basis. The proposal indicates that such firms would be given five years to conform to the activity limits of the Bank Holding Company Act, such as by divesting their commercial affiliates. Currently, there is substantial uncertainty on the timing and final contents of regulatory reform, but management will continue to follow the proposal closely.

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. In May 2009, the FHLB of Seattle reported a net loss for the first quarter of 2009 and continued to have a risk-based capital deficiency. 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. ASB evaluated its investment in FHLB stock for OTTI as of June 30, 2009, consistent with its accounting policy. Based on ASB s evaluation of the underlying investment, including the long-term nature of the investment, the liquidity position of the FHLB of Seattle, the actions being taken by the FHLB of Seattle to address its regulatory capital situation and ASB s intent and ability to hold the investment for a period of time sufficient to recover the par value, ASB did not recognize an OTTI loss during the six-months ended June 30, 2009. Continued deterioration in the FHLB of Seattle s financial position may result in future impairment losses.

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.

FINANCIAL CONDITION

Liquidity and capital resources

(in millions)	June 30, 2009	December 31, 2008	% change
Total assets	$ 5,120	$ 5,437	(6)
Available-for-sale investment and mortgage-related securities	622	658	(5)
Investment in stock of FHLB of Seattle	98	98	
Loans receivable, net	3,853	4,206	(8)
Deposit liabilities	4,169	4,180	
Other bank borrowings	389	681	(43)

As of June 30, 2009, ASB was one of Hawaii s largest financial institutions based on assets of $5.1 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 ASB s 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 2009 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 June 30, 2009, ASB s unused FHLB borrowing capacity was approximately $1.6 billion. As of June 30, 2009, ASB had commitments to borrowers for undisbursed loan funds, loan commitments and unused lines and letters of credit of $1.2 billion. Management believes ASB s current sources of funds will enable it to meet these obligations while maintaining liquidity at satisfactory levels.

As of June 30, 2009 and December 31, 2008, ASB had $3.0 million and $1.5 million, respectively, of real estate acquired in settlement of loans.

For the first six months of 2009, net cash provided by ASB s operating activities was $62 million. Net cash provided during the same period by ASB s investing activities was $363 million, primarily due to a net decrease in loans receivable of $305 million and repayments of investment and mortgage-related securities of $248 million, partly offset by purchases of investment and mortgage-related securities of $190 million. Net cash used in financing activities during this period was $340 million, primarily due to net decreases in Federal Home Loan Bank advances, retail repurchase agreements, deposit liabilities and securities sold under agreements to repurchase of $263 million, $25 million, $11 million and $5 million, respectively, and the payment of $35 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 June 30, 2009, ASB was well-capitalized (minimum ratio requirements noted in parentheses) with a leverage ratio of 8.7% (5.0%), a Tier-1 risk-based capital ratio of 11.6% (6.0%) and a total risk-based capital ratio of 12.6% (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.

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 and real estate markets. 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 half of 2009. Further, mortgage-related securities values have fallen, and ASB has taken OTTI charges in December 2008 and June 2009. See Net interest margin and other factors and Results six months ended June 30, 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.

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ASB s interest-rate risk sensitivity measures as of June 30, 2009 and December 31, 2008 constitute forward-looking statements and were as follows:

	June 30, 2009			December 31, 2008		
Change in interest rates (basis points)	Change in NII Gradual change	NPV ratio Instantaneous change	NPV ratio sensitivity *	Change in NII Gradual change	NPV ratio Instantaneous change	NPV ratio sensitivity *
+300	(0.2)	8.55	(313)	1.2%	6.94%	(379)
+200	0.1	9.70	(198)	1.2	8.42	(231)
+100	0.2	10.83	(85)	0.7	9.84	(89)
Base		11.68			10.73	
-100	(1.3)	11.73	5	(1.6)	10.43	(30)
-200	**	**	**	**	**	**
-300	**	**	**	**	**	**

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

** For June 30, 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 is less sensitive in the rising rate scenarios from December 31, 2008 to June 30, 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 June 30, 2009 increased compared to December 31, 2008 primarily due to the decrease in size and change in mix of the balance sheet and changes in the level of interest rates.

ASB s NPV ratio sensitivity measure as of June 30, 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.

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Item 4. Controls and Procedures

HEI:

Changes in Internal Control over Financial Reporting

During the second 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 June 30, 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 June 30, 2009. Based on their evaluations, as of June 30, 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 second 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 June 30, 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 June 30, 2009. Based on their evaluations, as of June 30, 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.

PART II - OTHER INFORMATION

Item 1. Legal Proceedings

The descriptions of legal proceedings (including judicial proceedings and proceedings before the PUC and environmental and other administrative agencies) in HEI s Form 10-K (see Part I. Item 3. Legal Proceedings and proceedings referred to therein) and this 10-Q (see

Management s Discussion and Analysis of Financial Condition and Results of Operations and HECO s Notes to Consolidated Financial Statements) are incorporated by reference in this Item 1. With regard to any pending legal proceeding, alternative dispute resolution, such as mediation or settlement, may be pursued where appropriate, with such efforts typically maintained in confidence unless and until a resolution is achieved. Certain HEI subsidiaries (including HECO and its subsidiaries and ASB) may also be involved in ordinary routine PUC proceedings, environmental proceedings and litigation incidental to their respective businesses.

Item 1A. Risk Factors

For information about Risk Factors, see pages 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 2. Unregistered Sales of Equity Securities and Use of Proceeds

(a) For the six months ended June 30, 2009, HEI issued an aggregate of 28,800 shares of unregistered common stock pursuant to the HEI 1990 Nonemployee Director Stock Plan, as amended and restated effective May 6, 2008 (the HEI Nonemployee Director Stock Plan). Under the HEI Nonemployee Director Stock Plan, each HEI nonemployee director receives, in addition to an annual cash retainer, an annual stock grant of 1,800 shares of HEI common stock (2,000 shares for the first time grant to a new HEI director) and each nonemployee subsidiary director who is not also an HEI nonemployee director receives an annual stock grant of 1,000 shares of HEI common stock (1,000 shares for the first time grant to a new subsidiary director). The HEI Nonemployee Director Stock Plan is currently the only equity plan for nonemployee directors and provides for annual stock grants (described above) and annual cash retainers for nonemployee directors of HEI and its subsidiaries.

HEI did not register the shares issued under the director stock plan since their issuance did not involve a sale as defined under Section 2(3) of the Securities Act of 1933, as amended. Participation by nonemployee directors of HEI and subsidiaries in the director stock plans is mandatory and thus does not involve an investment decision.

Item 4. Submission of matters to a vote of security holders

HEI: The Annual Meeting of Shareholders of HEI was held on May 5, 2009. Proxies for the meeting were solicited pursuant to Regulation 14A under the Securities Exchange Act of 1934. As of February 25, 2009, the record date for the Annual Meeting, there were 90,611,290 shares of common stock issued and outstanding and entitled to vote. There was no solicitation in opposition to the Class I management nominees to the Board of Directors with terms ending at the 2012 Annual Meeting as listed in the proxy statement for the meeting and all such nominees were elected to the Board of Directors. Shareholders also ratified the appointment of KPMG LLP as HEI s independent registered public accounting firm for 2009 and amended and restated HEI s Restated Articles of Incorporation.

The record of the voting of shares at the Annual Meeting is as follows:

	Shares of Common Stock				
	For	**Withheld**	**Against**	**Abstain**	**Broker Nonvotes**
Election of Class I Directors					
Shirley J. Daniel	68,495,123	14,950,646			
Constance H. Lau	70,972,434	12,473,335			
A. Maurice Myers	80,020,907	3,424,862			
James K. Scott	79,801,199	3,644,570			
Ratification of KPMG LLP as independent registered public accounting firm	81,121,103		1,384,416	940,250	
Approval of the HEI Restated Articles of Incorporation, as amended and restated	77,893,704		2,732,457	2,819,608	

Class II Directors Thomas B. Fargo, Diane J. Plotts, Kelvin H. Taketa and Jeffrey N. Watanabe continue in office with terms ending at the 2010 Annual Meeting. Class III Directors Don E. Carroll, Richard W. Gushman, II, Victor Hao Li, Barry K. Taniguchi continue in office with terms ending at the 2011 Annual Meeting.

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HECO: On August 6, 2009, HEI, HECO s sole common shareholder, (1) by written consent in lieu of a special meeting, approved amendment of Article V of HECO s Amended Articles of Incorporation and amendments to HECO s Amended and Restated Bylaws, as described under Item 5 below, and (2) by written consent in lieu of an annual meeting, fixed the number of directors at 12, elected all 11 incumbent HECO directors Constance H. Lau (Chairman), Thomas B. Fargo, Timothy E. Johns, Bert A. Kobayashi, Jr., David M. Nakada, Alan M. Oshima, Richard M. Rosenblum, Anne M. Takabuki, Kelvin H. Taketa, Barry K. Taniguchi and Jeffrey N. Watanabe and two new HECO directors, Peggy Y. Fowler and A. Maurice Myers, and ratified the appointment of KPMG LLP as independent registered public accounting firm of HECO for fiscal year 2009.

Item 5. Other Information

A. Ratio of earnings to fixed charges.

	Six months ended June 30,		Years ended December 31,				
	2009	2008	2008	2007	2006	2005	2004
HEI and Subsidiaries							
Excluding interest on ASB deposits	2.14	1.75	2.06	1.78	2.08	2.31	2.32
Including interest on ASB deposits	1.77	1.52	1.71	1.52	1.73	1.98	2.00
HECO and Subsidiaries	2.54	3.90	3.48	2.43	3.14	3.23	3.49

See HEI Exhibit 12.1 and HECO Exhibit 12.2.

B. Amendments to HECO s Articles of Incorporation and Bylaws.

On August 6, 2009, HEI, as the sole common shareholder of HECO, approved amendment of Article V of HECO s Amended Articles of Incorporation to provide that the board of directors is to consist of a number of directors to be determined in accordance with HECO s Bylaws. HEI also approved amendments of Sections 2 and 12 of Article II and Section 1 of Article III of HECO s Amended and Restated Bylaws. The amendments to the Bylaws provide that the board is to consist of between 1 and 15 members (previously 11) and that, at the annual meeting, the shareholders entitled to vote are to fix the number of directors and elect directors. The amendments also specify that action permitted or required to be taken at an annual meeting may be taken by the unanimous written consent of shareholders entitled to vote. The amendment of Article V of HECO s Amended Articles of Incorporation and HECO s Amended and Restated Bylaws (as last amended August 6, 2009) are included as HECO Exhibits 3(i).4 and 3(ii) to this Report.

These amendments were adopted in connection with the election of two new HECO directors, Peggy Y. Fowler and A. Maurice Myers, to the HECO Board of Directors on August 6, 2009. Ms. Fowler is former Chief Executive Officer and President of Portland General Electric Company. She is also on the Board of Directors of Portland General Electric Company and Umpqua Holdings Corporation. Mr. Myers is former Chairman, President and Chief Executive Officer of Waste Management, Inc. He is also on the Board of Directors of HEI.

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Item 6. Exhibits

HEI	Hawaiian Electric Industries, Inc. and Subsidiaries
Exhibit 12.1	Computation of ratio of earnings to fixed charges, six months ended June 30, 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	Amendment 2009-1 to the Hawaiian Electric Industries Retirement Savings Plan, executed May 5, 2009
HECO Exhibit 3(i).1	HECO s Certificate of Amendment of Articles of Incorporation (Exhibit 3.1 to HECO s Annual Report on Form 10-K for the fiscal year ended December 31, 1988, File No. 1-4955).
HECO Exhibit 3(i).2	Articles of Amendment to HECO s Amended Articles of Incorporation (Exhibit 3.1(b) to HECO s Annual Report on Form 10-K for the fiscal year ended December 31, 1989, File No 1-4955).
HECO Exhibit 3(i).3	Articles of Amendment to HECO s Amended Articles of Incorporation (Exhibit 3(i).4 to HECO s Annual Report on Form 10-K for the fiscal year ended December 31, 1998, File No 1-4955).
HECO Exhibit 3(i).4	Amendment to Article V of HECO s Amended Articles of Incorporation effective August 6, 2009
HECO Exhibit 3(ii)	HECO s Amended and Restated Bylaws (as last amended August 6, 2009)
HECO	Hawaiian Electric Company, Inc. and Subsidiaries
Exhibit 12.2	Computation of ratio of earnings to fixed charges, six months ended June 30, 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)

By /s/ Constance H. Lau
Constance H. Lau
President and Chief Executive Officer
(Principal Executive Officer of HEI)

By /s/ James A. Ajello
James A. Ajello
Senior Financial Vice President,
Treasurer and Chief Financial Officer
(Principal Financial Officer of HEI)

By /s/ Curtis Y. Harada
Curtis Y. Harada
Vice President, Controller
(Principal Accounting Officer of HEI)

Date: August 7, 2009

HAWAIIAN ELECTRIC COMPANY, INC.
(Registrant)

By /s/ Richard M. Rosenblum
Richard M. Rosenblum
President and Chief Executive Officer
(Principal Executive Officer of HECO)

By /s/ Tayne S. Y. Sekimura
Tayne S. Y. Sekimura
Senior Vice President, Finance and
Administration
(Principal Financial Officer of HECO)

By /s/ Patsy H. Nanbu
Patsy H. Nanbu
Controller
(Principal Accounting Officer of HECO)

Date: August 7, 2009