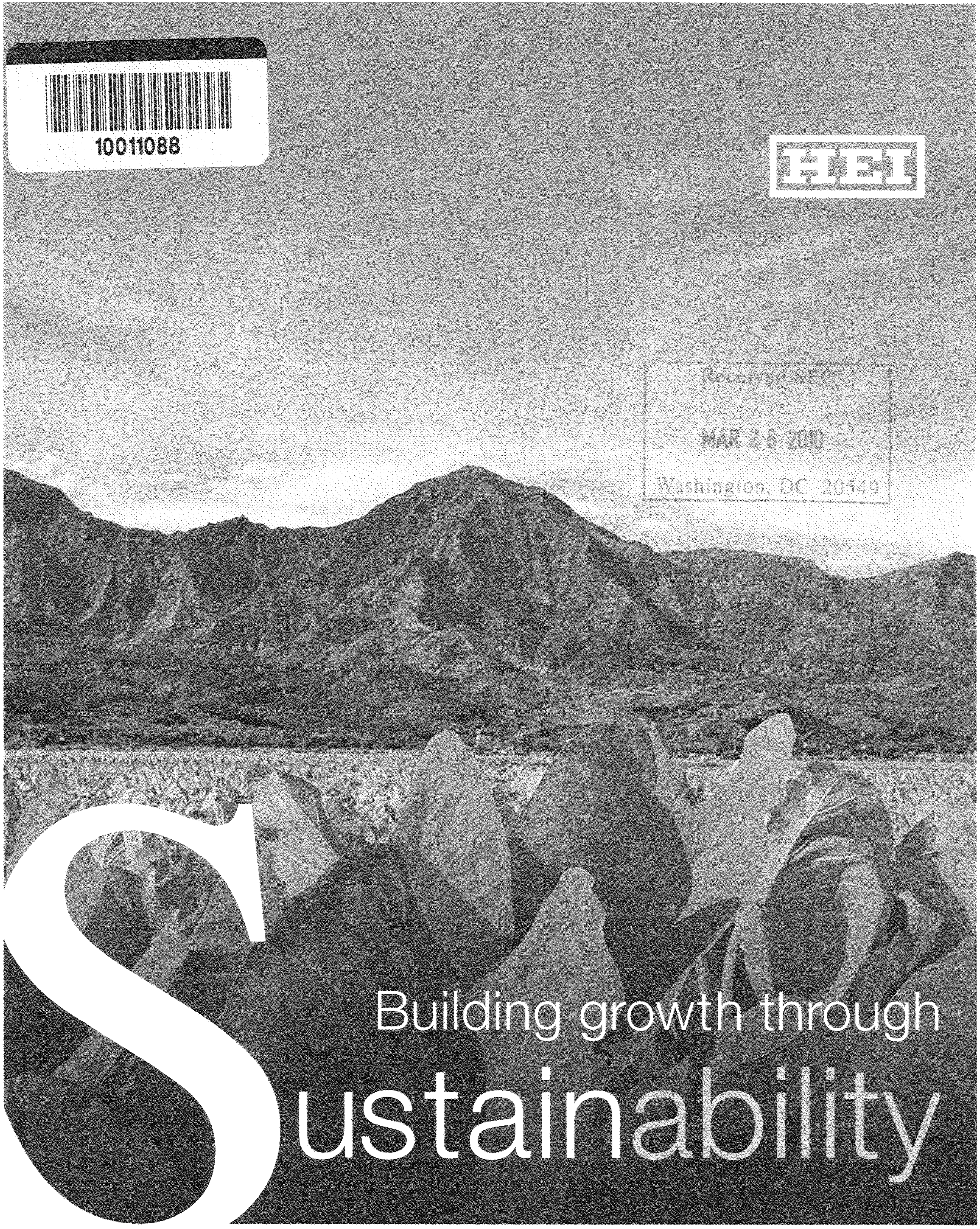
HEI



Building growth through Sustainability

2009 ANNUAL REPORT TO SHAREHOLDERS

Hawaiian Electric Industries (HEI), through its subsidiaries, Hawaiian Electric Company (HECO) and American Savings Bank (ASB), provides essential electric and financial services ensuring a brighter future for the communities it serves.

HEI

Hawaiian Electric Company

AMERICAN Savings Bank

Environmental Benefits Statement

This report is printed partially on Neenah Environment Papers – PC 100, made of 100 percent post-consumer waste material. It is processed chlorine free, and alkaline pH, and meets the American National Standards Institute standards for longevity.

By using Neenah Environment PC 100, Hawaiian Electric Industries, Inc. estimates that it has saved the following resources:

Trees	Water	Energy	Solid waste	Greenhouse gases
142 fully grown	65,112 gallons	46 million BTU	3,953 pounds	3,399 pounds

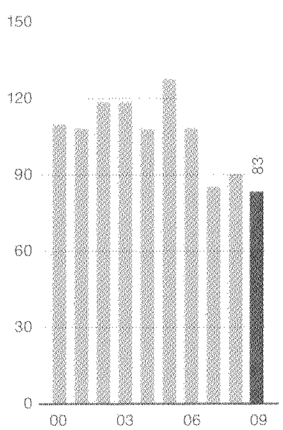
Environmental impact estimates were made using the Environmental Defense Fund Paper Calculator.
For more information visit http://www.edf.org/papercalculator.

Received SEC
MAR 26 2010
Washington, DC 20549

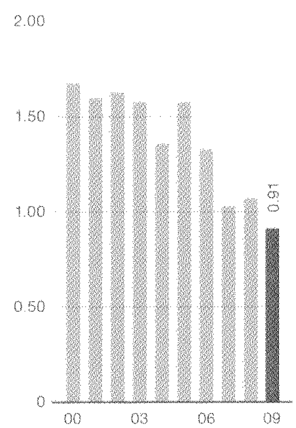
Financial Highlights

Years ended December 31	2009 [1]	2008 [2]	2007
(dollars in millions, except per share amounts)			
Operating income	$ 188	$ 204	$ 204
Net income (loss) by segment			
Electric utility	79	92	52
Bank	22	18	53
Other	(18)	(20)	(20)
Net income	83	90	85
Basic earnings per common share	0.91	1.07	1.03
Dividends per common share	1.24	1.24	1.24
Book value per common share [3]	15.58	15.35	15.29
Market price per common share			
High	22.73	29.75	27.49
Low	12.09	20.95	20.25
December 31	20.90	22.14	22.77
Return on average common equity	5.9%	6.8%	7.2%
Indicated annual yield [3]	5.9%	5.6%	5.4%
Price earnings ratio [4]	23.0x	20.7x	22.1x
Common shares (millions)			
December 31	92.5	90.5	83.4
Weighted-average	91.4	84.6	82.2

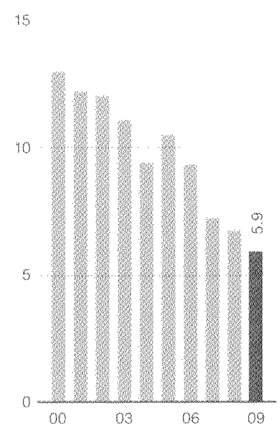
INCOME FROM CONTINUING OPERATIONS [1, 2]
(millions of dollars)



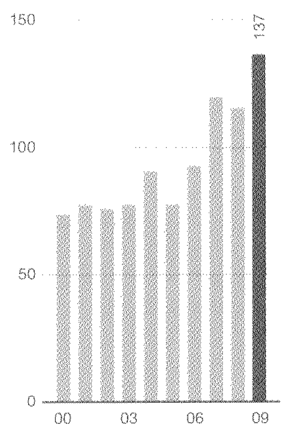
BASIC EARNINGS PER SHARE – CONTINUING OPERATIONS [1, 2, 5]
(dollars)



RETURN ON AVERAGE COMMON EQUITY – CONTINUING OPERATIONS [1, 2]
(percent)



DIVIDENDS PAYOUT RATIO – CONTINUING OPERATIONS [1, 2]
(percent)



[1] 2009 consolidated and bank net income and income from continuing operations included a $19 million after-tax charge ($0.21 per share) resulting from ASB's sale of its private-issue mortgage-related securities portfolio. Return on average common equity (and return on average common equity – continuing operations), adjusted to exclude the $19 million after-tax charge, was 7.2 percent.

[2] 2008 consolidated and bank net income and income from continuing operations included a $36 million after-tax charge ($0.42 per share) resulting from ASB's balance sheet restructuring. The balance sheet restructuring reduced the size of the bank's balance sheet by approximately $1 billion, while enabling ASB to maintain its earnings power on a lower capital base and to dividend excess capital to HEI. Return on average common equity (and return on average common equity – continuing operations), adjusted to exclude the $36 million after-tax balance sheet restructuring charge, was 9.3 percent.

[3] At December 31

[4] Calculated using the December 31 closing market price per common share divided by basic earnings per common share

[5] Adjusted for a 2-for-1 stock split in June 2004

Letter to Shareholders

Building growth through Sustainability

Constance H. Lau
President and Chief Executive Officer
Hawaiian Electric Industries, Inc.

Dear Shareholders:

During a year of unprecedented financial and economic crisis, your board and management made tough decisions to curb spending and reduce risk while continuing to make strategic and fundamental changes necessary to ensure sustainable earnings to support your dividend and build shareholder value for the future.

We are pleased that your company made significant progress on executing our long-term strategies while navigating through the near-term challenges posed by the financial and economic crisis. We were able to preserve earnings and maintain our commitment to your dividend in a year when many other companies could not.

In the face of lower kilowatthour sales and lower and later-than-expected rate relief at our utility, management took action to contain and defer spending, modestly reducing service levels to customers but maintaining a very high level of safety for our employees and the public. As a result, we were able to substantially offset the negative impact of lower-than-expected revenues. Simultaneously, we executed the first steps in carrying out our role in the Hawaii Clean Energy Initiative, a landmark 20-year agreement with the State of Hawaii aimed at achieving among the most aggressive clean energy goals in the nation and a sustainable, clean energy economy for Hawaii. These steps included significant efforts to establish the business and regulatory model needed to align our company and the community under an aggressive clean energy paradigm. The regulatory model we have proposed, with support from the State Consumer Advocate and others, is expected to improve rates of return and consistency of earnings over the next two years. With a full reset of our regulatory model by the end of 2011, we are targeting to earn much closer to our allowed rates of return in the future.

At the bank, despite historically high credit costs driven by the economic recession and losses from proactively opting to liquidate our private-issue mortgage-related securities, the bank remained profitable and is on track to exceed our expectations of its multi-year Performance Improvement Project aimed at improving net income and profitability. With the bank's significant progress to date, expected completion of the project at the end of 2010, and economists' expectations for a gradual improvement in the Hawaii economy in 2010, the bank should be well positioned to perform in line with high performing peers by 2011.

FINANCIAL RESULTS

Although earnings for 2009 were depressed due to lower revenues at the utility and historically high credit costs at the bank, HEI earned net income of $83 million or $0.91 per share. In 2008, net income was $90 million or $1.07 per share.

Utility net income was $79 million in 2009 compared to $92 million in 2008. This decline was primarily driven by 2.5% lower kilowatthour sales and the need for rate relief, which was delayed until the latter part of 2009.

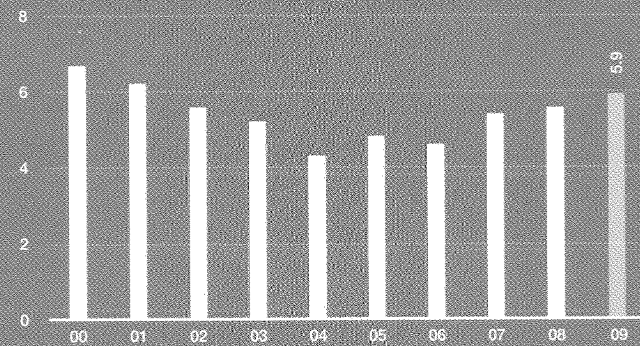
Going into 2009, we expected to under-earn in the first half of the year as we awaited rate relief in our Oahu 2009 rate case; then once rate relief was received mid-year, we expected earnings for our Oahu utility to recover in the second half. While the second half of the year was better, we also experienced significantly lower sales and lower and later-than-expected rate relief. In response to these financially challenging circumstances, the utility significantly reduced and deferred costs in order to maintain its financial strength.

TOTAL RETURN
(percent)

	HEI	S&P 500 Index	EEI Index	KBW Regional Banking Index
2009	1.6	26.5	10.7	(22.1)
2-Year	3.6	(20.3)	(18.0)	(36.6)
3-Year	(8.4)	(16.0)	(4.4)	(50.5)
5-Year	(6.4)	2.1	34.0	(52.4)
10-Year	155.1	(9.1)	133.9	Not Available

Sources: Capital IQ and Bloomberg
HEI NYSE symbol: HE

DIVIDEND YIELD
(percent)



Going forward, timely rate relief and delinking revenues from sales will be key to improving our earnings. We are fortunate that we have an opportunity to address these issues under the Hawaii Clean Energy Initiative.

Turning to our bank, net income was $22 million compared to $18 million in 2008. In both years, earnings were affected by losses related to specific strategic transactions that management elected to execute for long-term performance benefits. In the fourth quarter of 2009, when we saw an attractive market opportunity, we made a strategic decision to sell our portfolio of private-issue mortgage-related securities, resulting in an after-tax loss of $19 million, but eliminating the risk of future charges from these securities, and improving our prospects for more stable earnings from the bank to support your dividend. In 2008, the bank's balance sheet restructuring was executed as part of the Performance Improvement Project. This resulted in a $36 million after-tax charge, but allowed the bank to improve its long-term profitability, increase its capital ratios by retaining additional capital freed up by this transaction and, at the same time, return $55 million in underutilized capital to HEI. Excluding the private-issue mortgage-related securities sales and balance sheet restructuring charges, the bank earned $41 million in 2009 and $53 million in 2008.

Like many banks across the country, our bank was impacted by the economic pressures of 2009. The Hawaii economic decline which began in 2008 worsened in 2009. This resulted in significant credit costs which were partially offset with cost savings from the Performance Improvement Project.

Management's prompt and deliberate execution of the efficiency initiatives under the Performance Improvement Project provided cost savings at the right time. The bottom line efficiency savings realized in 2009 compared to 2008 was $6 million. These cost savings will continue to help offset elevated credit costs in 2010 and should permanently increase the bank's earnings prospects.

As we have done throughout the economic crisis, we kept the bank's capital at healthy levels and depositors' money safe. We continued to maintain a low-risk profile in our loan portfolio. Although we increased our reserve for loan losses and recorded $19 million in after-tax provision expense for the year, our credit issues have been isolated to three small areas of our portfolio: vacant lot loans, purchased mainland mortgages, and one large commercial loan. Delinquencies in our home mortgage portfolio have also contributed to provision expense; however, it is largely driven by the sheer size of this portfolio. On an overall basis, our net loan charge-offs remained very low compared to the industry. In addition, the bank increased its capital ratios throughout 2009 to further strengthen its financial soundness.

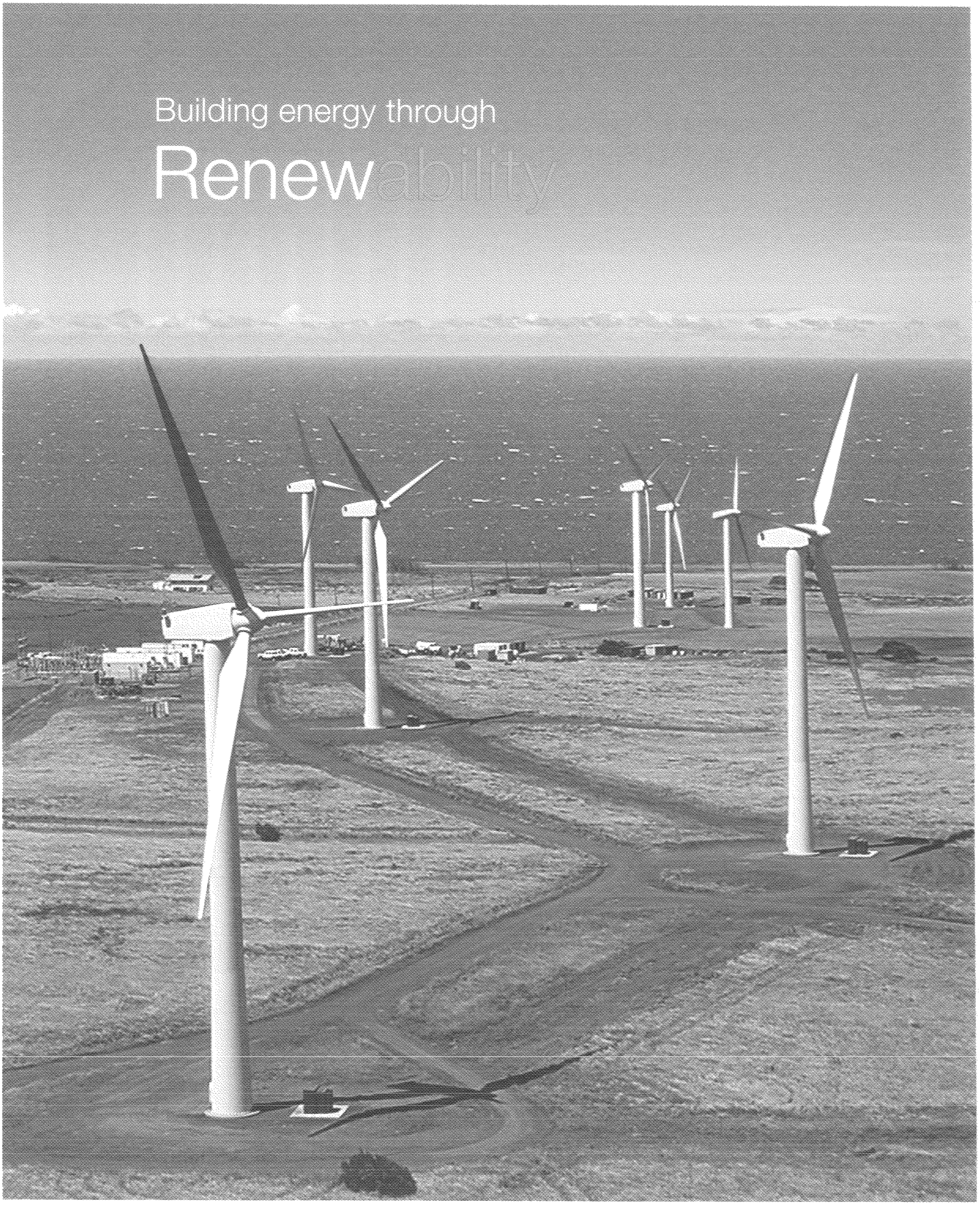
TOTAL SHAREHOLDER RETURN

For 2009, our total shareholder return was 1.6%, the second year in a row of positive total returns. During the last two years, we have experienced the most tumultuous equity markets in recent history and we are pleased that we have outperformed during that time with a positive two-year total return of 3.6% compared to the negative returns of the S&P 500 of (20.3%), EEI index of (18.0%) and the KBW Regional Banking index of (36.6%) – no small achievement during these challenging times.

Long-term value for our investors is our goal and we continue to target stronger total shareholder returns in the future as we implement our clean energy strategies at the utility and solidify improved profitability at the bank.

DIVIDEND

Again in 2009, we demonstrated our commitment to the dividend. In a volatile market and in the face of unprecedented challenges, the board maintained your dividend based on our continuing execution of our multi-year strategies to improve the fundamental operating and financial performance of our businesses.


Building energy through
Renewability

UTILITY

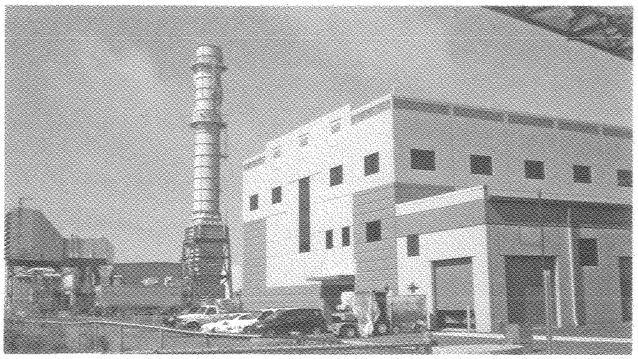
HAWAII CLEAN ENERGY INITIATIVE – AN HISTORIC AGREEMENT

As I shared with you last year, on October 20, 2008, we joined the Governor of Hawaii, the Hawaii Department of Business, Economic Development and Tourism, and the Office of Consumer Advocacy in an historic agreement which aims to transform and protect the economic and environmental future of our home state of Hawaii. The clean energy agreement puts Hawaii on a path to supply 70 percent of overall energy needs (including transportation) using renewable sources by 2030, a substantial change for a state now over 90 percent dependent on imported fossil fuels. We supported placing this goal into law and, in 2009, the Hawaii State Legislature established an increased renewable portfolio standard (RPS) of 40 percent of electric sales by 2030 and a new energy efficiency portfolio standard.

The clean energy agreement recognizes that our collective achievement of these nation-leading goals calls for fundamental changes in our utility regulatory model, operational systems and business practices. These changes will align our company and the community in pursuing greater energy efficiency and renewable sources. They also enable us to take a leadership role in achieving the state's clean energy goals, benefiting our environment, our state economy and our customers, while allowing the utility to remain financially sound and competitive in the equity and debt markets. We have undertaken an enormous effort to effect these regulatory changes; it was a top priority for 2009 and will continue to be in 2010.

HAWAII ISLAND WIND FARM

Located on the northern coast of the island of Hawaii, the 10.6-megawatt Hawi Renewable Development wind farm is one of many renewable energy sources for the island. Energy from wind, geothermal, biomass, hydro and the sun provided more than 30% of the island's energy needs in 2009.



GREENING UTILITY ASSETS
Construction of Hawaiian Electric's Campbell Industrial Park generating station was completed in 2009. The new 110-megawatt power plant will run using sustainably-sourced biodiesel, and is believed to be the first utility combustion turbine to run on biodiesel in the world.

ENERGY-EFFICIENCY MILESTONE
The Case family of Honolulu became the 50,000th customer of our highly successful residential solar water heating rebate program. Combined with previously installed systems, an estimated one out of three single-family homes in Hawaii heats its water from the power of the sun. The program transitioned to a third party administrator in the summer of 2009.

ACCOMPLISHMENTS

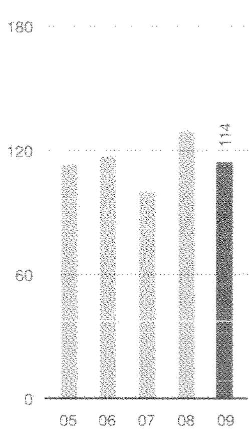
RENEWABLE ENERGY INFRASTRUCTURE SURCHARGE, FEED-IN TARIFFS AND LOAD MANAGEMENT

In 2009, we received favorable regulatory decisions on several key clean energy initiatives. We received a positive decision for the renewable energy infrastructure surcharge which supports more timely recovery of certain renewable-related projects. The Hawaii Public Utilities Commission (Commission) also approved the guidelines for new feed-in tariffs, which will provide standardized prices for various types of renewable energy. These actions are crucial to building the renewable energy market in Hawaii. In 2009, the Commission also allowed us to continue our load management programs, which provide incentives for customers who let us control a portion of their load when needed in emergencies.

DECOUPLING

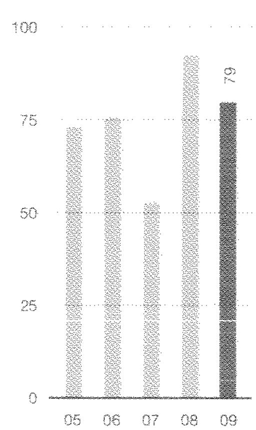
On February 19, 2010, we received Commission approval of the decoupling mechanisms that are fundamental to implementing the new utility business model, subject to a final decision and order detailing the implementation. These mechanisms essentially: 1) delink revenues from electricity usage, thus eliminating revenue volatility related to kilowatthour sales and the financial disincentive to advance energy efficiency; 2) annually adjust rates for indexed increases or decreases in expenses to account for such changes between rate cases; and 3) annually adjust rates for capital additions to allow us to earn a return on those investments between rate cases. This is an important step in helping to carry out our state's energy policy and is key to ensuring that our utility can provide sustainable value for our shareholders.

UTILITY OPERATING INCOME*
(millions of dollars)

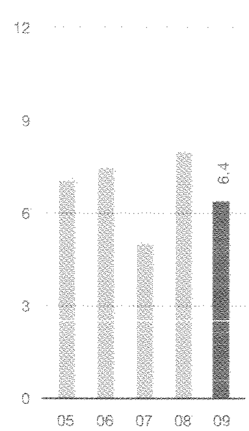


* Includes income taxes and excludes net other income

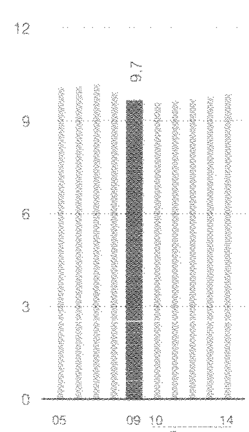
NET INCOME
(millions of dollars)



RETURN ON AVERAGE COMMON EQUITY
(percent)



KILOWATTHOUR SALES
(billions)



RATE CASES

We have also been very focused on rate cases at each of the three utility subsidiaries. These rate cases are not only vital to ensuring recovery and return on investments that have already been made, but they also set the base revenue requirements to implement decoupling.

In August 2009, we received Commission approval in our Oahu 2009 rate case to implement a partial interim increase in annualized revenues of $61 million. In February 2010, the Commission provided a second interim decision and order allowing an additional $13 million of annualized revenues to be put into rates for our new CT-1 peaking unit. Additionally, CT-1 represents one of the more important elements in our early steps toward a clean energy future as the 110-megawatt unit is to be run on biofuels.

In 2009, we filed 2010 rate cases for our Maui and Hawaii island utilities requesting increases in annualized revenues of $28 million and $21 million, respectively. Through these rate cases, we are also requesting implementation of decoupling mechanisms for these smaller neighbor island utilities.

RENEWABLE PORTFOLIO

Hawaii ranks third in the nation in the use of renewable energy (excluding large-scale hydro) relative to the state's total electricity production. Significant initiatives continue our progress toward meeting the state's aggressive renewable portfolio goals, culminating in a 40% requirement by 2030.

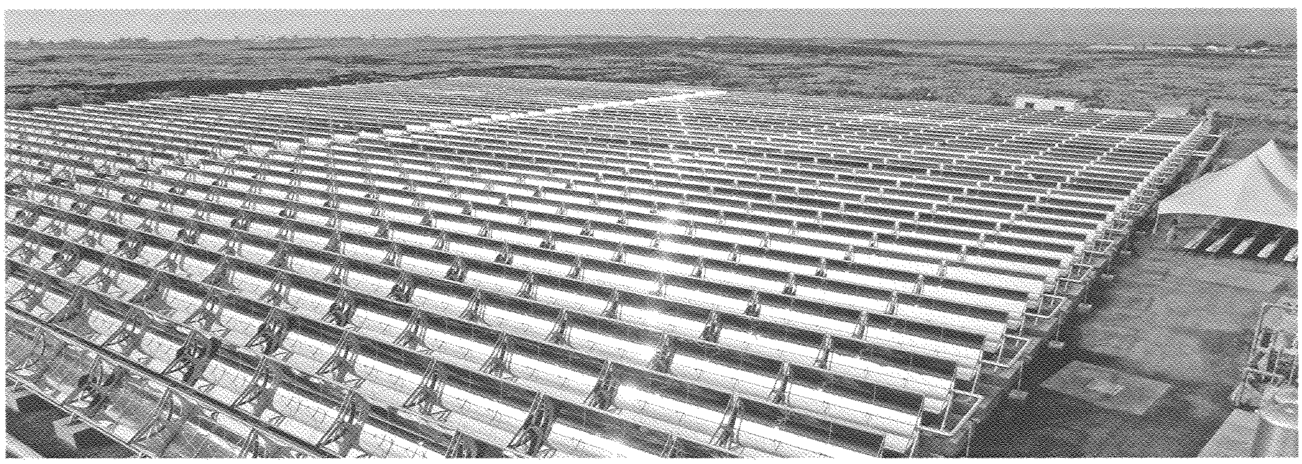


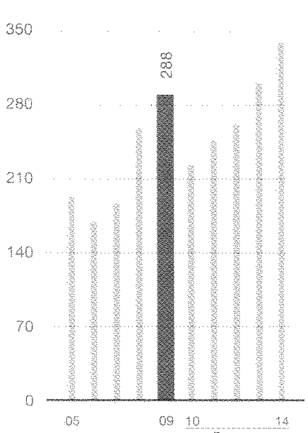
Photo courtesy of Sopogy

SOLAR INNOVATION

Sopogy and Keahole Solar Power Development inaugurated the world's first MicroCSP (Micro-Concentrating solar power) solar thermal farm in December 2009 at the Natural Energy Laboratory of Hawaii. Our Hawaii Island utility is buying the energy from the 500-kilowatthour concentrating solar project, which utilizes 1,000 solar panels, mirrors and optics, an integrated sun tracker, and a unique thermal energy storage buffer that allows energy to be produced even during cloudy periods.

NET CAPITAL EXPENDITURES*

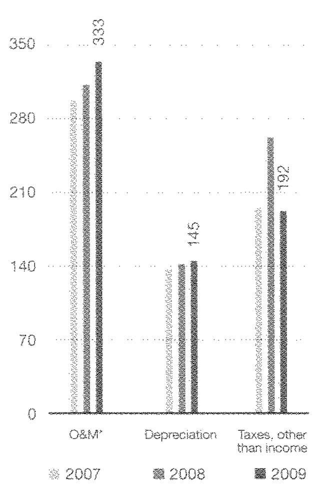
(millions of dollars)



* Net of allowance for funds used during construction and contributions in aid of construction

MAJOR EXPENSES

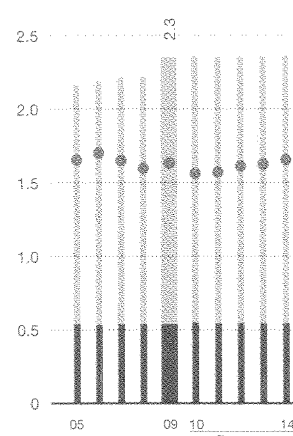
(millions of dollars)



* Other than fuel, purchased power and demand-side management costs

PEAK DEMAND AND CAPABILITY

(megawatts x 1000)



Building strength through

Profitability

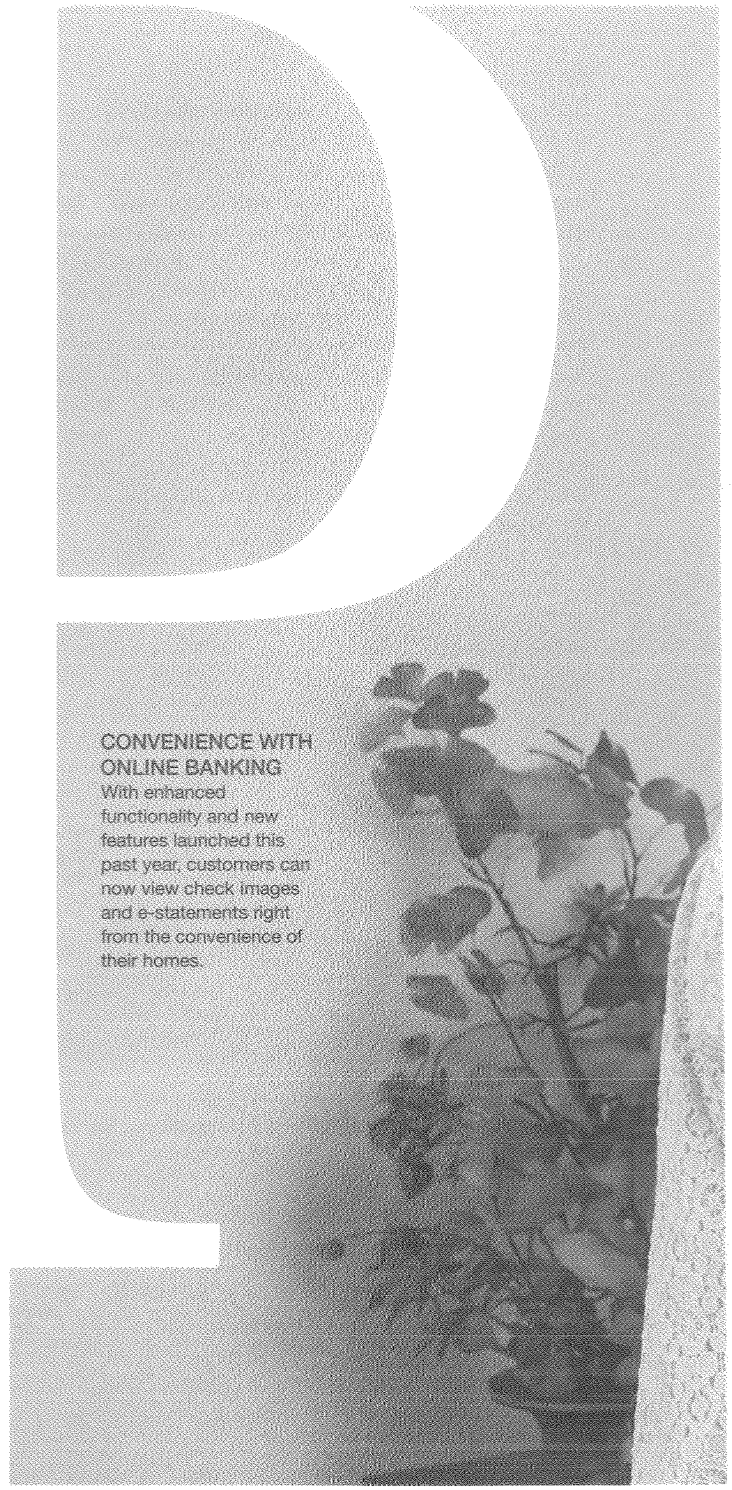
BANK

PERFORMANCE IMPROVEMENT PROJECT

In June of 2008, we announced the start of the bank's Performance Improvement Project aimed at improving the bank's net income and profitability over a multi-year period. Since then, we have exceeded our original expectations.

In the early stages of this project, we announced our profitability targets. As you can see, we have exceeded our original expectations in just a little over a year. Our fourth quarter 2009 performance met or beat our targets and shows significant improvement over the first quarter of 2008, the last quarter before the bank's balance sheet restructuring.

	1st Quarter 2008	Original Performance Improvement Project Targets	4th Quarter 2009
Return on assets	0.81%[1]	1.20%	1.27%[1]
Net interest margin	3.13%	>3.75%	4.27%
Efficiency ratio	66%[1]	55%-60%	56%[1]
Noninterest expense	$177 million[1]	$150-$155 million	$152 million[1]



CONVENIENCE WITH ONLINE BANKING

With enhanced functionality and new features launched this past year, customers can now view check images and e-statements right from the convenience of their homes.

BALANCE SHEET RESTRUCTURING

Our success is the result of several strategic initiatives over the last two years. Last year, I shared with you the positive effects of the 2008 balance sheet restructuring, which reduced the size of the bank's wholesale assets and liabilities and allowed the bank to increase its capital ratios by retaining additional capital freed up in this transaction in addition to returning $55 million of capital to HEI in 2008. With a negligible impact to future net income, the bank's net interest margin, return on assets, and return on equity were significantly enhanced.

OPERATIONAL EFFICIENCY

One of the key initiatives that enabled us to achieve those results started in 2008, when we made operational efficiency a top priority. As a result of our focus on improved processes and procedures, reduced administrative space, and the consolidation of branches, we began to see substantial cost reductions taking hold in 2009. Over the course of less than two years, the bank reduced its adjusted annualized noninterest expense rate by $25 million, or 14%, from $177 million in the first quarter of 2008 to $152 million in the fourth quarter of 2009.[1] In 2010, additional efficiencies are expected from a major system conversion initiative which is expected to be completed during the year.

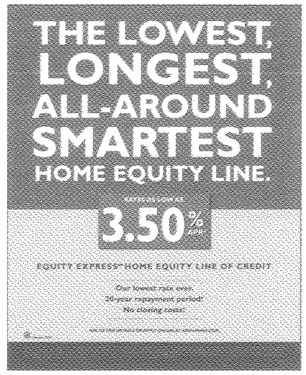
[1] We use adjusted annualized measures to analyze on a consistent basis the performance of the bank's core operating activities and its progress on the execution of the Performance Improvement Project. These measures exclude certain noninterest expense items incurred in order to implement the Performance Improvement Project and management believes it will not recur on a regular basis subsequent to the completion of the project in 2010. It also excludes certain noninterest income and expense items that management believes to be unusual and it is unlikely that it will recur on a regular basis. See the explanation and reconciliation of non-GAAP measures on page 16.

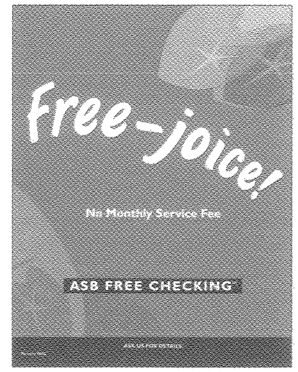
CUSTOMER FOCUS

Market leading products, the most convenient banking hours and second largest branch network in the state, and a focus on best-in-class customer service yielded $393 million or 14% growth in core deposits in 2009 and supported growth in fee income. ASB Free Checking, the first and most comprehensive free checking account in Hawaii, was launched in the spring of 2008. The momentum from the product launch continued in 2009 and resulted in stellar net account growth of 10% and balance growth of over 12%. Related to checking, debit card activity grew 14% resulting in double-digit growth in interchange income, a component of noninterest income. In spite of a challenging credit environment, Equity Express, along with our legacy home equity credit line products, saw balance growth of 20%. In addition, ASB maintained its conservative underwriting posture lowering the maximum loan to value ratio from 80% to 70%.

EMPLOYEE FOCUS

In line with the financial targets established at the outset of the Performance Improvement Project, ASB set a goal to become the employer of choice in Hawaii. Since then, employee feedback and suggestions have been actively





ASB ADVERTISING CAMPAIGNS

Bright, bold colors and clean crisp messaging are the order of the day for creating compelling messaging. This translated into ads for our convenience campaign touting "our longest hours in more locations and on weekends" and "bank where you shop" convenience. In-branch posters featured Equity Express, the smartest home equity credit line product around with the longest repayment period and no closing costs, and our ASB Free Checking acquisition campaign showcasing some of the terrific benefits of ASB Free Checking, including free online bill payment and no monthly service fee.

solicited and management has dedicated significant time studying known employee-friendly companies to determine how to enhance the overall employee experience.

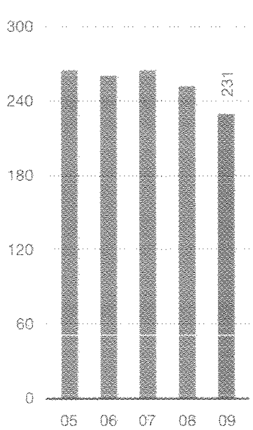
Our progress was recently recognized when American Savings Bank was named as one of Hawaii's Best Places to Work in a survey published by Hawaii Business Magazine. This survey is independently administered and is based 100% on confidential employee feedback. This is the first year for American Savings Bank to be recognized and of the companies selected from the large company category, American Savings Bank is the only bank to achieve this designation.

RESULTS TO DATE

Our success in executing these Performance Improvement Project initiatives is allowing us to build substantially more earnings potential into our core operations on a much smaller asset base. In a little less than two years, we increased annualized adjusted pretax preprovision income by $28 million from the first quarter of 2008 compared to the fourth quarter 2009.[1] In the short-term, this improvement has been offset by rising credit provisions and the costs associated with implementing the Performance Improvement Project. In the long-term, we expect the economic environment to improve and net income and profitability at the bank to benefit.

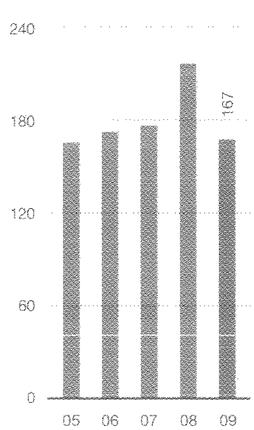
[1] We use adjusted annualized measures to analyze on a consistent basis the performance of the bank's core operating activities and its progress on the execution of the Performance Improvement Project. These measures exclude certain noninterest expense items incurred in order to implement the Performance Improvement Project and management believes it will not recur on a regular basis subsequent to the completion of the project in 2010. It also excludes certain noninterest income and expense items that management believes to be unusual and it is unlikely that it will recur on a regular basis. See the explanation and reconciliation of non-GAAP measures on page 16.

BANK REVENUE *[2, 3]
(millions of dollars)

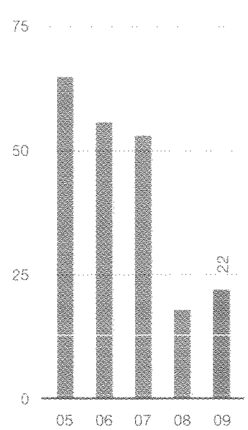


* Consists of net interest income and noninterest income

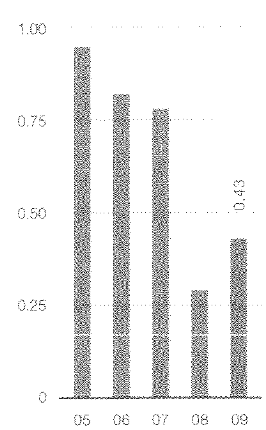
NONINTEREST EXPENSE [3]
(millions of dollars)



NET INCOME [2, 3]
(millions of dollars)

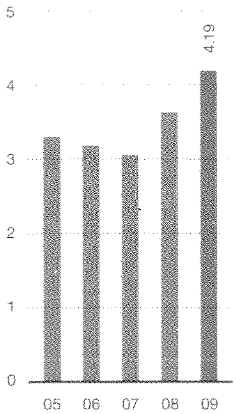


RETURN ON ASSETS* [2, 3]
(percent)

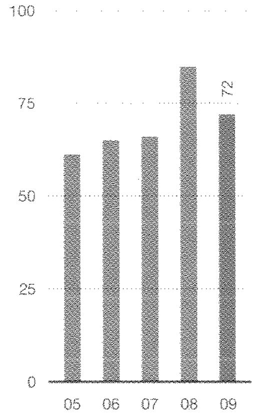


* Net income for common stock divided by average total assets

NET INTEREST MARGIN
(percent)

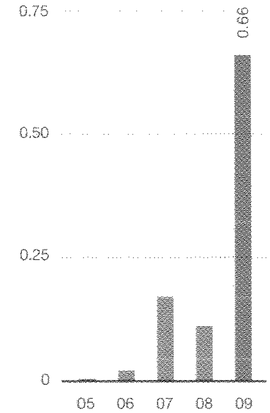


TANGIBLE EFFICIENCY RATIO* [2, 3]
(percent)

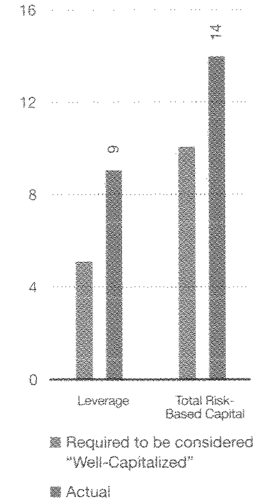


* Represents the cost of earning a dollar of revenue

NET CHARGE-OFFS TO AVERAGE LOANS OUTSTANDING RATIO
(percent)



REGULATORY CAPITAL AT 12/31/09
(percent)



[2] 2009 net income included a $19 million after-tax charge from ASB's sale of its private-issue mortgage-related securities (PMRS) portfolio to reduce its credit risk and improve the prospects for consistent future earnings. Net income, bank revenues, return on assets and the tangible efficiency ratio, adjusted to exclude the PMRS losses were $41 million, $263 million, 0.80 percent and 64 percent, respectively.

[3] 2008 net income included a $36 million after-tax charge resulting from ASB's balance sheet restructuring. The balance sheet restructuring reduced the size of the bank's balance sheet by approximately $1 billion, while enabling the bank to maintain its earnings power on a lower capital base and dividend excess capital to HEI. Net income, bank revenues, noninterest expense, return on assets and tangible efficiency ratio, adjusted to exclude the balance sheet restructuring charge, was $53 million, $272 million, $176 million, 0.88 percent and 65 percent, respectively.

OUTLOOK

We expect and have prepared for the economic challenges to continue, but we are cautiously optimistic for a gradual improvement in the Hawaii economy in 2010, consistent with the forecasts of local economists. Our utility will remain focused on building a clean energy future for Hawaii, and we expect that our earned return will improve as we implement the new regulatory model described in the Hawaii Clean Energy Initiative. Our bank will remain focused on careful execution of its Performance Improvement Project, and with the completion of the project at the end of 2010, we expect that the bank will perform in line with high performing peers by 2011. Overall, we believe our strategies will create significant value for you, our shareholders.

OUR DIRECTORS

A special thank you is in order for our very dedicated directors at each of our companies' boards for their experienced and insightful counsel during these difficult times.

In addition, we are very pleased to welcome Peggy Fowler to our utility board of directors. She joined us in August 2009 and comes with a wealth of utility industry experience, most recently serving as the President and Chief Executive Officer of Portland General Electric until her retirement in March 2009 after 35 years with the company. She is a great addition to the accomplished, diverse and committed leaders on our boards of directors.

One such leader is Diane Plotts who has served on our board since 1987. In February 2010, Diane announced her retirement and the 2010 Annual Meeting will be her last act of business as a director and the chairman of the audit committees for Hawaiian Electric Industries and American Savings Bank. During her 23 years of dedicated service, our companies have benefited from her exemplary leadership, business acumen and wealth of experience. I would like to express my warmest thanks and aloha to Diane for her invaluable contributions. I am privileged to have worked with her for so many years and I wish her all the best in her future endeavors.

OUR EMPLOYEES

I would also like to recognize and thank our employees who are really stepping up to the plate in these difficult times. It is through the tireless and dedicated efforts of the men and women of Hawaiian Electric Industries and our operating companies, Hawaiian Electric, Maui Electric, Hawaii Electric Light Company and American Savings Bank that we are able to continue to move forward with strength, commitment and a strong sense of our responsibility and privilege to navigate your company safely through these challenging times and to emerge as a stronger company, helping to drive sustainable growth for Hawaii and for you, our shareholders.

Thank you for your continued interest and investment in Hawaiian Electric Industries, and aloha.

Constance H. Lau

Constance H. Lau
President and Chief Executive Officer
Hawaiian Electric Industries, Inc.
February 19, 2010

Building community through Dependability

ALOHA UNITED WAY

HEI and its subsidiaries are proud to have been active supporters of the 2009 Aloha United Way campaign. Pictured here along with Connie Lau are HECO and ASB employee coordinators who took the lead and made this campaign a phenomenal success. Fundraising activities included sales of baked goods, t-shirts, cookbooks and more. Along with proceeds from these special events, employee pledges, corporate, and in-kind donations, we collectively raised close to $800,000.

WAYS TO WORK

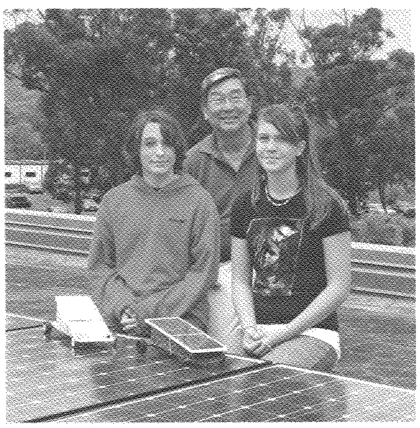
American Savings Bank has provided exclusive loan servicing and funding of the YWCA of Oahu's Ways to Work family loan program since 2001. This innovative loan program provides loans, ranging from $500 to $4,000, to help qualifying families who do not meet traditional lending standards purchase a used car or make a deposit on rental housing. Single mothers account for 80% of loan recipients, and over 50% of borrowers report household incomes of $30,000 or less. American Savings Bank employees volunteer on the loan review committee and assist the organization in an advisory capacity.

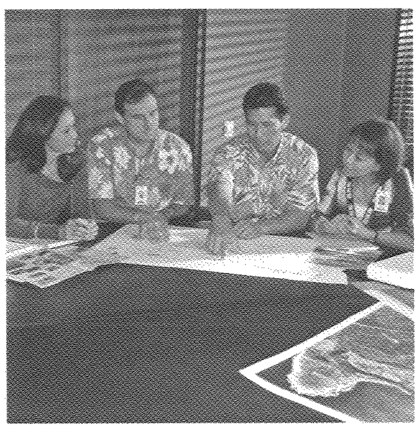
ASB KOKUA CLUB

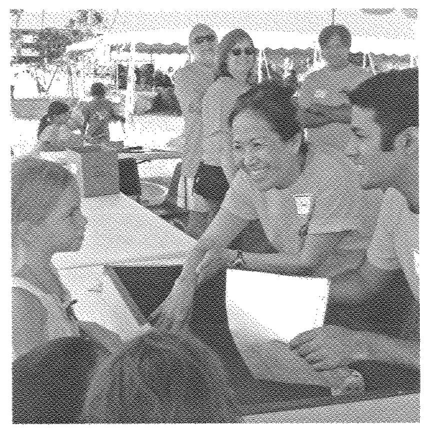
American Savings Bank employees founded the ASB Kokua Club as a way for employees and their family and friends to volunteer together in the community. Employees organize and participate in various community service projects throughout the year, volunteering with many different organizations. This past year, in honor of Earth Day, ASB Kokua Club volunteers, along with students from Iolani and Lutheran high schools, helped the Makiki WAI (Makiki Watershed Awareness Initiative) project transform a portion of the Makiki Valley Trail by clearing the land of weeds and tall grasses, then planting native shrubs and trees.

Over the years, Hawaiian Electric Industries and its family of companies have remained a vital part of the Hawaii community by contributing valuable time and resources.

In 2009, the HEI Charitable Foundation was able to reach out to various organizations by contributing $1.4 million to assist them in sustaining their missions to support communities throughout Hawaii.







POWERED BY THE SUN
Wheeler Middle School is an active participant in the "Solar Sprint" and the "Sun Power for Schools" programs. Here, students and their teacher compare their model solar-powered cars with the photovoltaic panels which power the small solar-electric system installed at the school. Both programs are cosponsored by the Hawaii State Department of Education and the Hawaiian Electric utilities to teach children about renewable energy and demonstrate the use of solar technology.

NATIVE HAWAIIAN PARTNERSHIP
The Department of Hawaiian Home Lands and the Hawaiian Electric utilities signed a formal energy partnership charter that will benefit native Hawaiian homesteaders and support achievement of Hawaii's clean energy goals through the development of affordable, energy self-sufficient, and sustainable communities.

HECO IN YOUR COMMUNITY
Eager participants learned about energy conservation and won prizes at the Hawaiian Electric Company booth at Waianae Sunset on the Beach. This was one of the many "HECO In Your Community" events which promote energy efficiency and electrical safety at community neighborhood programs.

HEI DIRECTORS

Jeffrey N. Watanabe [1]
Retired Founder, Watanabe Ing LLP
Chairman, Hawaiian Electric Industries, Inc.

Constance H. Lau [1]
President and Chief Executive Officer, Hawaiian Electric Industries, Inc.
Chairman, Hawaiian Electric Company, Inc.
Chairman and Chief Executive Officer, American Savings Bank, F.S.B.

Don E. Carroll
Retired Chairman, Oceanic Time Warner Cable Advisory Board

Shirley J. Daniel, Ph.D. [2]
Professor of Accountancy, Shidler College of Business, University of Hawaii-Manoa

Admiral Thomas B. Fargo, USN (Retired) [2, 3]
Former Commander of the U.S. Pacific Command

Richard W. Gushman, II [4]
President and Owner, DGM Group

Victor H. Li, S.J.D. [3]
Co-chairman, Asia Pacific Consulting Group

A. Maurice Myers [3]
Retired Chairman, President and Chief Executive Officer, Waste Management, Inc.

Diane J. Plotts [1, 2, 3]
Business Advisor

James K. Scott, Ed.D. [2, 4]
President, Punahou School

Kelvin H. Taketa [4]
President and Chief Executive Officer, Hawaii Community Foundation

Barry K. Taniguchi [2]
President and Chief Executive Officer, KTA Super Stores

Committees of the board of directors:

(1) Executive
Jeffrey N. Watanabe, Chairman

(2) Audit
Diane J. Plotts, Chairman

(3) Compensation
Thomas B. Fargo, Chairman

(4) Nominating & Corporate Governance
Kelvin H. Taketa, Chairman

Information as of February 19, 2010

HAWAIIAN ELECTRIC COMPANY DIRECTORS

Richard M. Rosenblum
President and Chief Executive Officer, Hawaiian Electric Company, Inc.

Peggy Y. Fowler
Retired President and Chief 0Executive Officer, Portland General Electric Company

Timothy E. Johns
President and Chief Executive Officer, Bishop Museum

Bert A. Kobayashi, Jr.
President and Chief Executive Officer, Kobayashi Group, LLC

David M. Nakada
Executive Director, Boys & Girls Club of Hawaii

Alan M. Oshima
Owner and Principal, AMO Consulting, LLC

Anne M. Takabuki
President, Wailea Golf LLC

The following HEI directors are also directors of Hawaiian Electric Company, Inc.:

Constance H. Lau, Chairman
Thomas B. Fargo
A. Maurice Myers
Kelvin H. Taketa
Barry K. Taniguchi
Jeffrey N. Watanabe

AMERICAN SAVINGS BANK DIRECTORS

Jorge G. Camara, M.D.
Ophthalmologist, Camara Eye Clinic

Kenton T. Eldridge
Co-founder and Partner, Sennet Capital

Louise K.Y. Ing
Partner, Alston Hunt Floyd & Ing, A Law Corporation

Bert A. Kobayashi, Sr.
Chairman and Chief Executive Officer, Kobayashi Development Group LLC

The following HEI directors are also directors of American Savings Bank, F.S.B.:

Constance H. Lau, Chairman
Don E. Carroll
Shirley J. Daniel
Richard W. Gushman, II
Victor H. Li
Diane J. Plotts
James K. Scott
Barry K. Taniguchi
Jeffrey N. Watanabe

Information as of February 19, 2010

HEI EXECUTIVE MANAGEMENT

Hawaiian Electric Industries, Inc.

Constance H. Lau
President and Chief Executive Officer
Hawaiian Electric Industries, Inc.

Chairman
Hawaiian Electric Company, Inc.

Chairman and Chief Executive Officer
American Savings Bank, F.S.B.

James A. Ajello
Senior Financial Vice President,
Treasurer and Chief Financial Officer

Chester A. Richardson
Senior Vice President-General Counsel,
Secretary and Chief Administrative Officer

Hawaiian Electric Company, Inc.

Richard M. Rosenblum
President and Chief Executive Officer

Jay M. Ignacio
President
Hawaii Electric Light Company, Inc.

Edward L. Reinhardt
President
Maui Electric Company, Limited

Robert A. Alm
Executive Vice President

Stephen M. McMenamin
Senior Vice President and
Chief Information Officer

Tayne S.Y. Sekimura
Senior Vice President and
Chief Financial Officer

Patricia U. Wong
Senior Vice President-Corporate
Services

American Savings Bank, F.S.B.

Timothy K. Schools
President

Gabriel S.H. Lee
Executive Vice President,
Commercial Markets

Richard C. Robel
Executive Vice President,
Operations and Technology

Alvin N. Sakamoto
Executive Vice President,
Finance

Ray G. Skinner
Executive Vice President,
Consumer Banking

Natalie M.H. Taniguchi
Executive Vice President,
Enterprise Risk and Regulatory Relations

K. Elizabeth Whitehead
Executive Vice President,
General Counsel, Chief Administrative Officer
and Assistant Secretary

Terence C.Y. Yeh
Executive Vice President,
Chief Credit Officer

Information as of February 19, 2010

CORPORATE GOVERNANCE AT HEI

Hawaiian Electric Industries, Inc. is committed to the highest standards of corporate governance. Since the enactment of the Sarbanes-Oxley Act of 2002, HEI has reviewed and maintained its corporate governance guidelines and charters to meet the spirit and intent of the law and the rules promulgated by the Securities and Exchange Commission as well as by the New York Stock Exchange (NYSE).

The HEI board:

- Is a 12-member board that includes 11 independent nonemployee directors as defined by the NYSE rules.
- Meets in executive session (nonemployee directors only) at each board meeting.
- Conducts annual board evaluations.
- Conducts evaluations of board members up for reelection.
- Has mandatory stock ownership guidelines for Company directors and officers.
- Is diverse with three women, one part native Hawaiian and five Asian American members.
- Has audit, compensation and nominating/corporate governance committees comprised of independent directors. The audit committee has three financial experts.
- Is accessible to shareholders.

The HEI Code of Conduct:

- Covers all employees plus the directors of HEI and its subsidiary companies.
- Is reviewed annually with all employees and directors.
- Contains whistleblower provisions.
- Includes a special code for the CEO and senior financial officers.
- Is monitored by an HEI Code of Conduct committee.

Please visit the HEI website at http://www.hei.com for a review of the Company's corporate governance documents.

EXPLANATION OF HEI'S USE OF CERTAIN UNAUDITED NON-GAAP FINANCIAL MEASURES

HEI and bank management use certain non-GAAP measures in their evaluation of the bank's performance and believe the presentations of such financial measures on this basis provide useful supplemental information and a clearer picture of the bank's operating performance, and are a better indicator of the bank's ongoing core operating activities. Management also uses such measures to assist investors/ analysts in better understanding the bank's progress on the execution of its Performance Improvement Project. These measures are also useful in understanding performance trends and in facilitating comparisons with the performance of others in the financial services industry.

Management utilizes non-GAAP financial measures of noninterest income and expense in the calculation of certain of the bank's metrics/ratios, such as (i) efficiency, (ii) pretax, preprovision income, and (iii) return on average assets, in order to analyze on a consistent basis and over a longer period of time the performance of the bank's core operating activities and its progress on the execution of the Performance Improvement Project. Management also annualizes the non-GAAP measure of noninterest expense by multiplying such measure by 4 to develop an estimate of adjusted noninterest expense for a year-long period. This annualized adjusted noninterest expense metric (non-GAAP measure) is a forward-looking statement based on only a quarter's results and may not reflect actual results. See schedule to the right for a tabular reconciliation between the bank's GAAP and non-GAAP measures.

Certain reconciling items—real estate transactions, FISERV conversion costs, severance, technology write-offs, prepayment penalty on early extinguishment of debt, and a loss on sale of Bishop Insurance Agency—are being incurred pursuant to the bank management's Performance Improvement Project which was announced in June 2008 and is expected to conclude by the end of 2010. These costs are being incurred with the objective of increasing the bank's operating efficiency and profitability in the long-term. Accordingly, bank management believes that these costs will remain temporarily elevated while the Performance Improvement Project is being executed and will be reduced or eliminated once the project has ended.

Reported noninterest income is being adjusted by gains on sales of other assets and other nonrecurring income items. Bank management believes that it would not be appropriate to assume that the bank would realize material gains of this type on a quarterly basis.

Likewise, bank management also adds back to noninterest income charges related to the other-than-temporary impairment (OTTI) of private-issue mortgage-related securities because of the material nature of the charge and the inconsistency of when those charges occurred. The bank incurred material OTTI in the fourth quarter of 2008, impacting the comparability of noninterest income for this quarter. Management believes that adjusting noninterest income to exclude the effects of OTTI helps the comparability of noninterest income quarter to quarter and quarter over quarter.

In addition, management adjusts noninterest income for net gains (losses) on sales of certain securities which includes the fourth quarter 2009 loss on the liquidation of the private-issue mortgage-related securities (PMRS) portfolio and the first quarter 2008 sale of stock in VISA, Inc., because management believes that such transactions are unlikely to recur on a regular basis and impacts the comparability of noninterest income between periods.

Limitations associated with utilizing non-GAAP measures are the risks of disagreement over the appropriateness of adjustments comprising these measures and the risk that other companies might calculate these measures differently. Management addresses these limitations by providing detailed reconciliations between GAAP information and non-GAAP measures. See reconciliation to the right.

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

RECONCILIATION OF GAAP TO NON-GAAP MEASURES

(Unaudited)

(in thousands)	1Q08	4Q08	4Q09
Noninterest income			
Per income statement - GAAP	$ 17,928	$ 10,056	$ (11,277)
Other-than-temporary impairment of private-issue mortgage-related securities	-	7,764	-
Net (gains) losses on sale of securities	(935)	-	32,078
Gain on sale of other assets	-	-	(1,772)
Other nonrecurring income	(384)	-	(500)
Adjusted noninterest income	$ 16,609	$ 17,820	$ 18,529
Noninterest expense			
Per income statement - GAAP	$ 44,234	$ 45,442	$ 41,695
Real estate transactions	-	-	(1,633)
FISERV conversion costs	-	-	(972)
Severance	-	(1,560)	(390)
Technology write-offs	-	-	(35)
Prepayment penalty on early extinguishment of debt	-	-	(659)
Bishop Insurance Agency sale	-	(890)	-
Adjusted noninterest expense	$ 44,234	$ 42,992	$ 38,006
Other bank information			
Noninterest expense (annualized)			
Reported	$ 176,936	$ 181,768	$ 166,780
Adjusted	176,936	171,968	152,024
Efficiency ratio			
Reported	65%	74%	109%
Adjusted	66%	62%	56%
Pretax, preprovision income (annualized)			
Reported	$ 96,964	$ 64,628	$ (14,136)
Adjusted	91,688	105,484	119,844
Return on average assets			
Reported	0.85%	0.44%	(0.36%)
Adjusted	0.81%	0.92%	1.27%

Hawaiian Electric Industries, Inc.

2009 Annual Report to Shareholders
Financial and Other Information

Hawaiian Electric Industries, Inc.
2009 Annual Report to Shareholders (Selected Sections)

Contents

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 held by American Savings Bank, F.S.B. (ASB), which could result in higher loan loss provisions and write-offs), decisions concerning the extent of the presence of the federal government and military in Hawaii, and the implications and potential impacts of current capital and credit market conditions and federal and state responses to those conditions, such as the Emergency Economic Stabilization Act of 2008 and the American Economic Recovery and Reinvestment Act of 2009;
- weather and natural disasters, such as hurricanes, earthquakes, tsunamis, lightning strikes and the potential effects of global warming (such as more severe storms and rising sea levels);
- 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 HEI common stock under volatile and challenging market conditions, and the cost of such financings, if available;
- the risks inherent in changes in the value of 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;
- the impact of potential legislative and regulatory changes increasing oversight of and reporting by banks in response to the recent financial crisis and federal bailout of financial institutions;
- 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 Public Utilities Commission of the State of Hawaii (PUC) approvals needed; the PUC's potential delay in considering HCEI-related costs; reliance by the Company on outside parties like the state, independent power producers (IPPs) and developers; potential changes in political support for the HCEI; and uncertainties surrounding wind power, the proposed undersea cable, 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;
- the risk to generation reliability when generation peak reserve margins on Oahu are strained;
- fuel oil price changes, performance by suppliers of their fuel oil delivery obligations and the continued availability to the electric utilities of their energy cost adjustment clauses (ECACs);
- the impact of fuel price volatility on customer satisfaction and political and regulatory support for the utilities;
- the risks associated with increasing reliance on renewable energy, as contemplated under the Energy Agreement, including the availability and cost of non-fossil fuel supplies for renewable 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;

- 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 regulation of greenhouse gas emissions (GHG), healthcare reform, 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 1999 that have permitted HEI to own ASB);
- decisions by the 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 by the PUC 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 banking regulations 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 project, 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, ASB's concentration in a single product type (first mortgages) and ASB's significant credit relationships (i.e., concentrations of large loans and/or credit lines with certain customers);
- changes in accounting principles applicable to HEI, HECO, ASB and their subsidiaries, including the adoption of International Financial Reporting Standards (IFRS) or new U.S. accounting standards, the potential discontinuance of regulatory accounting and the effects of potentially required consolidation of variable interest entities or required capital lease accounting for PPAs with IPPs;
- changes by securities rating agencies in their ratings of the securities of HEI and HECO and the results of financing efforts;
- faster than expected loan prepayments that can cause an acceleration of the amortization of premiums on loans and investments and the impairment of mortgage servicing assets of ASB;
- changes in ASB's loan portfolio credit profile and asset quality which may increase or decrease the required level of allowance for loan losses and charge-offs;
- changes in ASB's deposit cost or mix which may have an adverse impact on ASB's cost of funds;
- the final outcome of tax positions taken by HEI, HECO, ASB and their subsidiaries;
- the risks of suffering losses and incurring liabilities that are uninsured; 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.

Selected Financial Data

Hawaiian Electric Industries, Inc. and Subsidiaries Years ended December 31	2009	2008	2007	2006	2005
(dollars in thousands, except per share amounts)					
Results of operations					
Revenues	$ 2,309,590	$ 3,218,920	$ 2,536,418	$ 2,460,904	$ 2,215,564
Net income (loss) for common stock					
Continuing operations	$ 83,011	$ 90,278	$ 84,779	$ 108,001	$ 127,444
Discontinued operations	–	–	–	–	(755)
	$ 83,011	$ 90,278	$ 84,779	$ 108,001	$ 126,689
Basic earnings (loss) per common share					
Continuing operations	$ 0.91	$ 1.07	$ 1.03	$ 1.33	$ 1.58
Discontinued operations	–	–	–	–	(0.01)
	$ 0.91	$ 1.07	$ 1.03	$ 1.33	$ 1.57
Diluted earnings per common share	$ 0.91	$ 1.07	$ 1.03	$ 1.33	$ 1.56
Return on average common equity-continuing operations *	5.9%	6.8%	7.2%	9.3%	10.5%
Return on average common equity	5.9%	6.8%	7.2%	9.3%	10.4%
Financial position **					
Total assets	$ 8,925,002	$ 9,295,082	$ 10,293,916	$ 9,891,209	$ 9,951,577
Deposit liabilities	4,058,760	4,180,175	4,347,260	4,575,548	4,557,419
Other bank borrowings	297,628	680,973	1,810,669	1,568,585	1,622,294
Long-term debt, net	1,364,815	1,211,501	1,242,099	1,133,185	1,142,993
Noncontrolling interest: cumulative preferred stock of subsidiaries - not subject to mandatory redemption	34,293	34,293	34,293	34,293	34,293
Common stock equity	1,441,648	1,389,454	1,275,427	1,095,240	1,216,630
Common stock					
Book value per common share **	$ 15.58	$ 15.35	$ 15.29	$ 13.44	$ 15.02
Market price per common share					
High	22.73	29.75	27.49	28.94	29.79
Low	12.09	20.95	20.25	25.69	24.60
December 31	20.90	22.14	22.77	27.15	25.90
Dividends per common share	1.24	1.24	1.24	1.24	1.24
Dividend payout ratio	137%	116%	120%	93%	79%
Dividend payout ratio-continuing operations	137%	116%	120%	93%	78%
Market price to book value per common share **	134%	144%	149%	202%	172%
Price earnings ratio ***	23.0x	20.7x	22.1x	20.4x	16.4x
Common shares outstanding (thousands) **	92,521	90,516	83,432	81,461	80,983
Weighted-average	91,396	84,631	82,215	81,145	80,828
Shareholders ****	33,302	33,588	34,281	35,021	35,645
Employees **	3,453	3,560	3,520	3,447	3,383

* Net income for common stock from continuing operations divided by average common equity.

** At December 31. (Note: Stockholders' equity and book value per common share since December 31, 2006 includes a charge to accumulated other comprehensive income (AOCI) relating to retirement benefits pursuant to FASB Accounting Standards Codification™ (ASC) Topic 715, as adjusted by the impact of decisions of the PUC. See Note 8, "Retirement benefits," of HEI's "Notes to Consolidated Financial Statements.")

*** Calculated using December 31 market price per common share divided by basic earnings per common share from continuing operations. The principal trading market for HEI's common stock is the New York Stock Exchange (NYSE).

**** At December 31. Registered shareholders plus participants in the HEI Dividend Reinvestment and Stock Purchase Plan who are not registered shareholders. As of February 15, 2010, HEI had 33,229 registered shareholders and participants.

See "Commitments and contingencies" in Note 3 and "Balance sheet restructure" and "Private-issue mortgage-related securities" in Note 4 of HEI's "Notes to Consolidated Financial Statements" and "Management's Discussion and Analysis of Financial Condition and Results of Operations" for discussions of certain contingencies that could adversely affect future results of operations and factors that affected reported results of operations.

On December 8, 2008, HEI completed the issuance and sale of 5 million shares of HEI's common stock (without par value) under an omnibus shelf registration statement. The net proceeds from the sale amounted to approximately $110 million and were primarily used to repay HEI's outstanding short-term debt and to make loans to HECO (principally to permit HECO to repay its short-term debt).

For 2009, 2008, 2007, 2006 and 2005, under the two-class method of computing basic and diluted earnings per share, distributed earnings were $1.24 per share each year and undistributed earnings (loss) were $(0.33), $(0.17), $(0.21), $0.09 and $0.33 per share, respectively, for both unvested restricted stock awards and unrestricted common stock.

Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion should be read in conjunction with Hawaiian Electric Industries, Inc.'s (HEI's) consolidated financial statements and accompanying notes. The general discussion of HEI's consolidated results should be read in conjunction with the segment discussions of the electric utilities and the bank that follow.

HEI Consolidated

Executive overview and strategy. HEI is a holding company that operates subsidiaries (collectively, the Company), principally in Hawaii's electric utility and banking sectors. HEI's strategy is to build fundamental earnings and profitability of its operating companies (the electric utilities and the bank) in a controlled risk manner to support its current dividend and improve operating and capital efficiency in order to build shareholder value.

HEI, through its electric utility subsidiary, Hawaiian Electric Company, Inc. (HECO), and HECO's electric utility subsidiaries, Hawaii Electric Light Company, Inc. (HELCO) and Maui Electric Company, Limited (MECO), provides the only electric public utility service to approximately 95% of Hawaii's population. HEI also provides a wide array of banking and other financial services to consumers and businesses through its bank subsidiary, American Savings Bank, F.S.B. (ASB), one of Hawaii's largest financial institutions based on total assets as of December 31, 2009.

In 2009, net income for HEI common stock was $83 million, compared to $90 million in 2008. Basic earnings per share were $0.91 per share in 2009, down 15% from $1.07 per share in 2008 due to lower earnings for the electric utility segment and the effects of the higher weighted average number of shares outstanding, partly offset by slightly lower losses for the "other" segment and higher earnings for the bank segment.

Electric utility net income for common stock in 2009 of $79 million decreased 14% from the prior year due primarily to lower KWH sales and higher other operation and maintenance (O&M) and depreciation expenses. Key to results for 2010 will be additional rate relief and the impacts of actions taken under the Hawaii Clean Energy Initiative (HCEI), including the steps taken toward the integration of approximately 1,100 megawatts (MW) of new generation from a variety of renewable energy sources into the utility systems and adopting a new regulatory rate-making model that decouples revenues from kilowatthour (KWH) sales.

The bank's earnings in 2009 of $21.8 million were a $3.9 million increase over prior year net income. Net income for 2009 reflected a $19.3 million net charge related to the sale of ASB's private issue mortgage-related securities portfolio, a $9.3 million net charge for other-than-temporary impairment (OTTI) of securities and a $19.3 million net charge for provision for loan losses. 2008 earnings included a $35.6 million net charge related to ASB's balance sheet restructuring, a $4.7 million net charge for OTTI of securities and a $6.2 million net charge for provision for loan losses. Management has been focused on increasing revenues and reducing costs through ASB's performance improvement project. ASB's future financial results will continue to be impacted by the interest rate environment, the quality of ASB's loan portfolio, and its success in implementing its performance improvement project.

HEI's "other" segment had a net loss in 2009 of $18 million, compared to a net loss of $20 million in 2008. The lower net loss in 2009 was due to lower interest expense, charitable contributions and consulting fees, partly offset by an accrual to dismantle a windfarm in 2010.

Shareholder dividends are declared and paid quarterly by HEI at the discretion of HEI's Board of Directors. HEI and its predecessor company, HECO, have paid dividends continuously since 1901. The dividend has been stable at $1.24 per share annually since 1998. The indicated dividend yield as of December 31, 2009 was 5.9%. The dividend payout ratios based on net income for common stock for 2009, 2008 and 2007 were 137%, 116% and 120%, respectively. The HEI Board of Directors considers many factors in determining the dividend quarterly, 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.

HEI's subsidiaries from time to time consider various strategies designed to enhance their competitive positions and to maximize shareholder value. These strategies may include the formation of new subsidiaries or the acquisition or disposition of businesses. The Company may from time to time be engaged in preliminary discussions, either internally or with third parties, regarding potential transactions. Management cannot predict whether any of these strategies or transactions will be carried out or, if so, whether they will be successfully implemented.

See the discussions below of the Electric Utility and Bank segments for their respective executive overviews and strategies.

Economic conditions.

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

The U.S. gross domestic product (GDP) grew by 2.2% in the third quarter of 2009 following four straight quarters of contraction. The "advance" estimate of fourth quarter 2009 growth is 5.7%, which was much stronger than expected, although on an annual basis GDP declined 2.4% in 2009. While the GDP report does not mark an official end of the recession, two straight quarters of economic growth is typically a sign of a recovery and many economists agree that the recession ended at some point in the middle of 2009. The February 2010 Blue Chip consensus estimate is for GDP growth of 3.0% and 3.1% in 2010 and 2011, respectively.

Meanwhile, jobs, considered to be a lagging indicator, are not anticipated to be added until the economic recovery is well underway. The national unemployment rate in December 2009 was 10.0%, the third consecutive month in double digits, a level not reached since 1983. After 22 straight months of job losses, non-farm payroll jobs rose 64,000 in November 2009 only to be followed by a preliminary loss of 150,000 jobs in December 2009. In total, 8.4 million jobs were lost nationwide since the recession began in December 2007. While the economy is expected to improve in 2010, job growth is expected to be slow.

Japan's economy returned to GDP growth in the second quarter of 2009, after four quarters of contraction. Export-led growth was also experienced in other Asian countries, including China and Korea.

Hawaii's economy also experienced rapid declines in 2008, followed by additional contraction in 2009. Weakness was most notable in one of the State's largest industries, tourism, which was affected by the health of the U.S. and key international economies, especially Japan. Following a 10.4% decline in total visitor arrivals in 2008, 2009 arrivals were down 4.5%, with domestic arrivals down 4.7% and international arrivals down 3.5%. The neighbor islands have been hardest hit by the visitor downturn, with 2009 visitor arrivals down 7.4% and 8.8% on the islands of Hawaii and Maui, respectively, compared to a 3.9% decline on the island of Oahu. The weakness in tourism impacts the neighbor island economies more than Oahu because their economies are more dependent on the visitor industry.

On a positive note, total visitor arrivals by air in the last half of 2009 are up 1.7% over 2008, partially due to discounting of hotel room rates. Despite lower room rates, occupancy rates at Hawaii hotels were a low 66.5% in 2009, with December alone at 64.9%. Annual visitor expenditures in 2009 were down 11.7% from 2008. The decline in spending is also decreasing expenditures in areas other than hotel rooms such as food, entertainment and shopping. The impact is felt beyond those businesses catering directly to tourists, as lower spending trickles down through suppliers and other companies, including state and city governments receiving reduced tax revenues. Local economists project improvement in the tourism industry with visitor arrivals growing by 3.7% in both 2010 and 2011. Hotel occupancy, however, is expected to remain below 70% in 2010. The Department of Business, Economic Development and Tourism (DBEDT) projects visitor expenditures will be flat in 2010, with growth returning in 2011.

In 2009, residential construction permits and commercial and industrial permits were down 42.2% and 33.3%, respectively, compared to 2008. It is expected that the construction cycle will bottom out in late 2010. Local economists predict that it may take time before any recovery in the housing market translates to increases in construction activity and jobs. Federal and state infrastructure programs provided some support for the construction industry in 2009 and are expected to provide significant support in 2010. In December 2009, single-family home sales on Oahu were up 36.6% compared to December 2008, spurred in part by low interest rates and an $8,000 federal tax credit for first-time buyers that was extended to April 30, 2010, which could support sales through spring. Local economists say it is still too early to tell if this positive trend will be self-sustaining when the credit is discontinued. Overall for 2009, the total number of single-family home sales on Oahu declined 5.7% compared to 2008. Oahu home values also declined 7.9% with the median price paid in 2009 of $575,000, compared to $624,000 in 2008. The Maui and Kauai housing markets were weaker than Oahu, with home sales declines of 23.8% and 8.5% and price declines of 13.8% and 23.5%, respectively. The only exception was the single-family home sales on the Big Island, which increased 7.7%, but the median price declined 19.1% in 2009 compared to 2008. For 2009, Hawaii foreclosures rose 183% to 9,002 compared to foreclosures in 2008, or one per every 56 households. The neighbor islands were the hardest hit.

The declines in tourism-related sectors and construction have resulted, and are expected to continue to result, in job losses. The job base in Hawaii is expected to contract by 3.6% and 1.0% in 2009 and 2010, respectively, before projected recovery of 1.3% begins in 2011. Also reflecting the economic downturn, real personal income in Hawaii was lower in 2008 and 2009, despite lower inflation in 2009. Real personal income is projected to be lower in Hawaii by 0.2% and 0.3% in 2009 and 2010, respectively, before returning to growth in 2011. Various proposals to raise taxes in one form or another are expected to be considered in the 2010 Hawaii legislative session.

The uncertainty over state and local governments' budgets and public employee furloughs may further negatively impact the outlook for personal income. In December 2009, the Hawaii Council on Revenues projected that fiscal year 2010 tax revenues will be 2.5% lower than fiscal year 2009. In September 2009, this decline was projected to be 1.5%. The fiscal year 2010 deficit is now projected to be $720 million, with a $510 million deficit projected for fiscal year 2011. In response to the budget shortfall projections, there have been unprecedented state government job furloughs and pay cuts. Two of the State's largest public employee unions, the Hawaii Government Employees Association and the Hawaii State Teachers Association, which combined represent nearly 45,000 employees, both ratified two year contracts that include 17 to 21 furlough days per year, resulting in pay reductions of nearly 8%. The University of Hawaii Professional Assembly, representing 3,700 faculty members, ratified a contract in January 2010 that includes a 6.7% pay cut over the next 18 months. These reductions have not been enough to eliminate the budget deficit and the State will need to address the possibilities of further spending cuts, tax increases and the use of special funds in order to close the budget gap.

At 6.9%, seasonally-adjusted Hawaii unemployment in December 2009 remains below the national average of 10.0%, but is much higher than the statewide averages of 2.6% for 2007 and 4.0% for 2008. The Hawaii unemployment rate is projected to be 7.0% in 2009, rising to 7.3% in 2010, before gradually receding back to 6.7% in 2011. Hawaii's relatively high unemployment rate is anticipated to further stress businesses as unemployment insurance taxes are expected to be raised beginning in April 2010 as the unemployment insurance trust fund balance is expected to fall below an adequate level.

However, prospects for the Hawaii economy are improving with the return of growth to the global economy. After the deepest recession since the 1930s, the signs of recovery in the U.S. and Japan are positive indicators for the Hawaii economy. Assuming national and international economic conditions continue to improve. Hawaii is expected to see a very gradual recovery beginning in 2010, with jobs and personal income returning to growth in 2011.

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 extended 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 extended 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 2009. These tax provisions, however, may influence the Company's decisions to invest in the various properties entitled to credits and favorable depreciation. The Company evaluates investments by considering the opportunities the 2008 Act presents. For example, in 2009, MECO made investments in CHP equipment for which tax credits of $0.5 million were earned and will be amortized into income over 20 years.

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 was 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, originally provided for in the 2008 Act, has had the most direct and immediate impact on the Company. The additional tax depreciation deduction of approximately $68 million will increase deferred income taxes by about $26 million 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.

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.

Results of operations.

(dollars in millions, except per share amounts)	2009	% change	2008	% change	2007
Revenues	$ 2,310	(28)	$ 3,219	27	$ 2,536
Operating income	188	(8)	204	–	204
Net income for common stock	83	(8)	90	6	85
Electric utility	$ 79	(14)	$ 92	76	$ 52
Bank	22	22	18	(66)	53
Other	(18)	NM	(20)	NM	(20)
Net income for common stock	$ 83	(8)	$ 90	6	$ 85
Basic earnings per share	$ 0.91	(15)	$ 1.07	4	$ 1.03
Dividends per share	$ 1.24	–	$ 1.24	–	$ 1.24
Weighted-average number of common shares outstanding (millions)	91.4	8	84.6	3	82.2
Dividend payout ratio	137%		116%		120%

NM Not meaningful.

See "Executive overview and strategy" above for a discussion of the HEI consolidated results of operations. Also, see "Other segment," "Electric utility" and "Bank" sections below for discussions of those segments.

Retirement benefits. The Company's reported costs of providing retirement benefits are dependent upon numerous factors resulting from actual plan experience and assumptions about future experience. For example, retirement benefits costs are impacted by actual employee demographics (including age and compensation levels), the level of contributions to the plans, plus earnings and realized and unrealized gains and losses on plan assets, and changes made to the provisions of the plans. (See Note 8 of HEI's "Notes to Consolidated Financial Statements" for a listing of plans that have been frozen. No other changes were made to the retirement benefit plans' provisions in 2009, 2008 and 2007 that have had a significant impact on costs.) Costs may also be significantly affected by changes in key actuarial assumptions, including the expected return on plan assets and the discount rate. The Company's accounting for retirement benefits is adjusted to account for the impact of decisions by the Public Utilities Commission of the State of Hawaii (PUC). Changes in obligations associated with the factors noted above may not be immediately recognized as costs on the income statement, but generally are recognized in future years over the remaining average service period of plan participants.

The assumptions used by management in making benefit and funding calculations are based on current economic conditions. Changes in economic conditions will impact the underlying assumptions in determining retirement benefits costs on a prospective basis.

For 2009, the Company's retirement benefit plans' assets generated a gain, net of investment management fees, of 26.1%, resulting in net earnings and unrealized gains of $186 million, compared to net losses and unrealized losses of $287 million for 2008 and net earnings and unrealized gains of $87 million for 2007. The market value of the retirement benefit plans' assets as of December 31, 2009 was $874 million. See "Liquidity and Capital Resources" below for the Company's cash contributions to the retirement benefit plans.

Taking into account the partial recovery in the value of plan assets in 2009, the Company expects that the minimum required contribution to the qualified retirement plans (after consideration of a $26 million credit balance) calculated in accordance with the Pension Protection Act of 2006 and the expected timing of the cash requirement based on the value of plan assets as of December 31, 2009 will be as set forth below for plan years 2010 and 2011. The minimum required contribution may differ from the cash funding for each plan year because the rules under the Internal Revenue Code allow the Company to make its last installment contribution as late as September of the following year. In addition, the Company is allowed to elect to apply any credit balance against the minimum required contribution. Further, 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 Employee Retirement Income Security Act of 1974, as amended (ERISA), minimum contribution requirements or the maximum contribution limitation on deductible contributions imposed by the Internal Revenue Code. The "Cash funding requirement" in the following table considers the utilities' funding commitment (based on various assumptions described in Note 8 of HEI's "Notes to Consolidated Financial Statements").

(in millions)	2010	2011
Pension Protection Act minimum required contribution:		
(net of applied credit balances)		
Based on plan assets as of December 31, 2009		
Consolidated HECO	$27	$70
Consolidated HEI	$27	$71
Cash funding to satisfy the Pension Protection Act minimum required contribution:		
Based on plan assets as of December 31, 2009		
Consolidated HECO	$25	$45
Consolidated HEI	$25	$46

See Note 8 of HEI's "Notes to Consolidated Financial Statements" for factors which could cause changes to the required contribution levels.

Based on various assumptions in Note 8 of HEI's "Notes to Consolidated Financial Statements" and assuming no further changes in retirement benefit plan provisions, consolidated HEI's, consolidated HECO's and ASB's (i) accumulated other comprehensive income (AOCI) balance, net of tax benefits, related to the liability for retirement benefits, (ii) retirement benefits expense, net of income tax benefits and (iii) retirement benefits paid and plan expenses were, or are estimated to be, as follows as of the dates or for the periods indicated:

	AOCI balance, net of tax benefits, related to retirement benefits liability		Retirement benefits expense, net of tax benefits				Retirement benefits paid and plan expenses		
	December 31		Years ended December 31				Years ended December 31		
(in millions)	2009 [1]	2008 [1]	(Estimated) 2010 [1,2]	2009 [1]	2008 [1]	2007 [1]	2009	2008	2007
Consolidated HEI	$(12)	$(20)	$24	$21	$17	$20	$61	$59	$57
Consolidated HECO	2	2	23	19	17	16	57	55	53
ASB	(10)	(15)	(1)	–	(1)	2	3	2	2

1 Includes impact of 2007 decisions by the PUC.

2 Forward-looking statements subject to risks and uncertainties, including the impact of plan changes during the year, if any, and the impact of actual information when received (e.g., actual participant demographics as of January 1, 2010).

The following table reflects the sensitivities of the projected benefit obligation (PBO) and accumulated postretirement benefit obligation (APBO) as of December 31, 2009, associated with a change in certain actuarial assumptions by the indicated basis points and constitute "forward-looking statements." Each sensitivity below reflects the impact of a change in that assumption.

Actuarial assumption	Change in assumption in basis points	Impact on PBO or APBO
(dollars in millions)		
Pension benefits		
Discount rate	+/– 50	$(59)/$65
Other benefits		
Discount rate	+/– 50	(9)/10
Health care cost trend rate	+/– 100	2/(2)

Baseline assumptions: 6.50% discount rate; 8.25% asset return rate; 10% medical trend rate for 2010, grading down to 5% for 2015 and thereafter; 5% dental trend rate; and 4% vision trend rate.

The impact on 2010 net income for common stock for changes in actuarial assumptions should be immaterial based on the adoption by the electric utilities of pension and postretirement benefits other than pensions (OPEB) tracking mechanisms approved by the PUC on an interim basis. See Note 8 of HEI's "Notes to Consolidated Financial Statements" for further retirement benefits information.

Other segment.

(dollars in millions)	2009	% change	2008	% change	2007
Revenues [1]	$ –	NM	$ –	(100)	$ 5
Operating income (loss)	(14)	NM	(14)	NM	(11)
Net loss	(18)	NM	(20)	NM	(20)

1 Including writedowns of and net gains and losses from investments.

NM Not meaningful.

The "other" business segment includes results of the stand-alone corporate operations of HEI and American Savings Holdings, Inc. (ASHI), formerly known as HEI Diversified, Inc., both holding companies; HEI Investments, Inc. (HEIII), a company previously holding investments in leveraged leases but whose wind-down was substantially completed during 2009; Pacific Energy Conservation Services, Inc. (PECS), a contract services company primarily providing windfarm operational and maintenance services to an affiliated electric utility that will cease such services when the windfarm is dismantled in 2010; HEI Properties, Inc. (HEIPI), a company holding passive, venture capital investments; and The Old Oahu Tug Service, Inc. (TOOTS), a maritime freight transportation company that ceased operations in 1999; as well as eliminations of intercompany transactions.

HEIII had a de minimis net loss in 2009. HEIII recorded net income of $0.6 million in 2008, primarily for intercompany interest income, which is eliminated in consolidation. HEIII recorded net income of $4.8 million in 2007, including intercompany interest income, income from leveraged lease investments and a net after-tax gain of $1.3 million on the sale of leveraged lease investments (the last of which was sold in November 2007). HEIII filed articles of dissolution in 2008 and substantially completed winding up its affairs during 2009.

HEIPI recorded net losses of $0.1 million in each of 2009 and 2008 and net income of $1.0 million in 2007, which amounts include income and losses from, and/or writedowns of, venture capital investments. In January 2007, HEIPI sold its remaining investment in Hoku Scientific, Inc., a materials science company focused on clean energy technologies, for a net after-tax gain of $0.9 million. As of December 31, 2009, HEIPI's venture capital investments amounted to $1.3 million.

HEI corporate-level operating, general and administrative expenses (including labor, employee benefits, incentive compensation, charitable contributions, legal fees, consulting, rent, supplies and insurance) were $12.7 million in 2009, compared to $12.7 million in 2008 and $14.0 million in 2007. In 2009, expenses decreased slightly from 2008 due to not funding the HEI Charitable Foundation and lower consulting fees, partly offset by an accrual to dismantle a windfarm in 2010. In 2008 compared to 2007, consulting expenses were lower than the prior year, but labor expenses and funding for the HEI Charitable Foundation were higher. HEI, ASHI, PECS and TOOTS' total net loss was $18.1 million in 2009, $20.0 million in 2008 and $26.2 million in 2007, the majority of which is comprised of financing costs.

The "other" segment's interest expenses were $18.4 million in 2009, $21.4 million in 2008 and $25.3 million in 2007. In 2009, financing costs were lower than in 2008 due to lower levels of short-term borrowings after HEI's common stock sale in December 2008. In 2008, financing costs were lower than 2007, primarily due to lower interest rates, including the use of lower-costing short-term commercial paper borrowings to replace maturing medium-term notes.

Effects of inflation. U.S. inflation, as measured by the U.S. Consumer Price Index (CPI), averaged (0.4%) in 2009, 3.8% in 2008 and 2.8% in 2007. Hawaii inflation, as measured by the Honolulu CPI, was 4.3% in 2008 and 4.9% in 2007. The Department of Business, Economic Development and Tourism estimates average Honolulu CPI to have been 0.1% in 2009 and forecasts it to be 1.5% for 2010.

Inflation continues to have an impact on HEI's operations. Inflation increases operating costs and the replacement cost of assets. Subsidiaries with significant physical assets, such as the electric utilities, replace assets at much higher costs and must request and obtain rate increases to maintain adequate earnings. In the past, the PUC has granted rate increases in part to cover increases in construction costs and operating expenses due to inflation.

Recent accounting pronouncements. See "Recent accounting pronouncements and interpretations" in Note 1 of HEI's "Notes to Consolidated Financial Statements."

Legislation. National health care reform is currently being considered by the U.S. Congress. The Company provides health insurance benefits to their employees under the provisions of the Hawaii Prepaid Health Care Act, which is exempted under current versions of both the Senate and House health reform bills. As such, the impact to costs may not be significant. Because of the many uncertainties remaining in the proposed legislation, however, it is difficult to assess the potential impact to costs resulting from final national health care reform legislation at this time.

Liquidity and capital resources.

Selected contractual obligations and commitments. The following tables present information about total payments due during the indicated periods under the specified contractual obligations and commercial commitments:

December 31, 2009		Payments due by period			
(in millions)	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Contractual obligations					
Deposit liabilities[1]	$ 4,059	$3,803	$ 186	$ 52	$ 18
Other bank borrowings	298	183	15	–	100
Long-term debt, net	1,365	–	215	161	989
Interest on certificates of deposit, other bank borrowings and long-term debt	1,177	91	161	138	787
Operating leases, service bureau contract and maintenance agreements	109	22	32	22	33
Open purchase order obligations [2]	77	54	23	–	–
Fuel oil purchase obligations (estimate based on January 1, 2010 fuel oil prices)	3,279	775	1,565	939	–
Power purchase obligations–minimum fixed capacity charges	1,368	118	234	237	779
Liabilities for uncertain tax positions	8	6	2	–	–
Total (estimated)	$11,740	$5,052	$2,433	$1,549	$2,706

1 Deposits that have no maturity are included in the "Less than 1 year" column, however, they may have a duration longer than one year.

2 Includes contractual obligations and commitments for capital expenditures and expense amounts.

December 31, 2009 (in millions)	
Other commercial commitments to ASB customers	
Loan commitments (primarily expiring in 2010)	$ 7
Loans in process	44
Unused lines and letters of credit	1,136
Total	$ 1,187

The tables above do not include other categories of obligations and commitments, such as deferred taxes, trade payables, amounts that will become payable in future periods under collective bargaining and other employment agreements and employee benefit plans, obligations that may arise under indemnities provided to purchasers of discontinued operations and potential refunds of amounts collected under interim decision and orders (D&Os) of the PUC. As of December 31, 2009, the fair value of the assets held in trusts to satisfy the obligations of the Company's qualified pension plans did not exceed the pension plans' benefit obligation. Minimum funding requirements for retirement benefit plans have not been included in the tables above; however, see "Retirement benefits" above for estimated minimum required contributions for 2010 and 2011.

See Note 3 of HEI's "Notes to Consolidated Financial Statements" for a discussion of fuel and power purchase commitments.

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 Company's total assets were $9.0 billion as of December 31, 2009 and $9.3 billion as of December 31, 2008. The decline in assets was primarily due to ASB's strategic sales of its private-issue mortgage-related securities and residential loan production.

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

December 31	2009		2008	
(dollars in millions)				
Short-term borrowings—other than bank	$ 42	2%	$ –	– %
Long-term debt, net—other than bank	1,365	47	1,212	46
Noncontrolling interest: cumulative preferred stock of subsidiaries	34	1	34	1
Common stock equity	1,442	50	1,389	53
	$2,883	100%	$2,635	100%

As of February 17, 2010, the Standard & Poor's (S&P) and Moody's Investors Service's (Moody's) ratings of HEI securities were as follows:

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

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

HEI's overall S&P corporate credit rating is BBB/Negative/A-3. 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 (i.e., assessment of business risk that incorporates an analysis of the qualitative factors such as management, competitive positioning, operations, markets and regulation) as well as quantitative measures (e.g., cash flow, debt, interest coverage and liquidity ratios) in determining the ratings of HEI securities. 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 HEI's 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 designates financial risk profiles as "minimal," "modest," "intermediate," "significant," "aggressive" or "highly leveraged." As of February 2010, S&P lists HEI's business risk profile as "strong" and financial risk profile as "significant."

On July 20, 2009, 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. Subsequently on August 3, 2009, Moody's issued a credit opinion on HEI. 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 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 Funds From Operations (FFO) (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 HEI's line of credit facility was as follows:

(in millions)	Year ended December 31, 2009 Average balance	End-of-period balance	December 31, 2008
Short-term borrowings			
HEI commercial paper	$ 2	$ 42	$ –
HEI line of credit draws	–	–	–
	$ 2	$ 42	$ –
Line of credit facility (expiring March 31, 2011) [1]		$100	$100
Undrawn capacity under HEI's line of credit facility [2]		100	100

1 See Note 6 in HEI's "Notes to Consolidated Financial Statements" for a description of the line of credit facility. 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 February 17, 2010, 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, to pay dividends and for other temporary requirements. HEI also periodically makes short-term loans to HECO to meet HECO's cash requirements, including the funding of loans by HECO to HELCO and MECO. HEI contributed $93 million of equity to HECO on December 29, 2009 and, as of December 31, 2009, HEI had no short-term loans to HECO.

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

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 net proceeds of approximately $110 million, which were used in part to repay its outstanding short-term indebtedness and to make loans to HECO.

Issuances of common stock through the Hawaiian Electric Industries, Inc. Dividend Reinvestment and Stock Purchase Plan (DRIP) and the Hawaiian Electric Industries Retirement Savings Plan (HEIRS) have been important sources of capital for HEI. Issuances of common stock through DRIP and HEIRS provided new capital of $43 million (approximately 1.8 million shares) in 2008 and $41 million (approximately 1.7 million shares) in 2007. From January 1, 2009 through April 15, 2009, issuances of common stock through these plans increased significantly. During this period, HEI raised $14 million of new capital through the issuance of approximately 1.0 million shares for these plans. HEI ceased such issuances of stock through DRIP and HEIRS effective April 16, 2009 and began satisfying the HEI common stock requirements of DRIP and HEIRS through open market purchases. Also, upon its inception on May 7, 2009, the ASB 401(k) Plan satisfied its HEI common stock requirements through open market purchases. On September 4, 2009, HEI resumed satisfying the HEI common stock requirements of DRIP, HEIRS and the ASB 401(k) Plan through issuances of new common stock and raised $18 million of new capital through the issuance of approximately 1.0 million shares to these plans from September 4 to December 31, 2009.

Operating activities provided net cash of $284 million in 2009, $260 million in 2008 and $219 million in 2007. Investing activities provided (used) net cash of $442 million in 2009, $1.1 billion in 2008 and ($222) million in 2007. In 2009, net cash provided by investing activities was primarily due to proceeds from the sale of and repayments of investment and mortgage-related securities and a net decrease in loans held for investment, partly offset by purchases of investment and mortgage-related securities and HECO's consolidated capital expenditures (net of contributions in aid of construction). Financing activities used net cash of $406 million in 2009, $1.4 billion in 2008 and $45 million in 2007. In 2009, net cash used in financing activities was affected by several factors, including net decreases in other bank borrowings and deposits and the payment of common and preferred stock dividends, partly offset by proceeds from the issuance of common stock under HEI plans and net increases in short-term borrowings and long-term debt.

A portion of the net assets of HECO and ASB is not available for transfer to HEI in the form of dividends, loans or advances without regulatory approval. One of the conditions to the PUC's approval of the merger and corporate restructuring of HECO and HEI requires that HECO maintain a consolidated common equity to total capitalization ratio of not less than 35% (54% at December 31, 2009), and restricts HECO from making distributions to HEI to the extent it would result in that ratio being less than 35%. In the absence of an unexpected material adverse change in the financial condition of the electric utilities or ASB, such restrictions are not expected to significantly affect the operations of HEI, its ability to pay dividends on its common stock or its ability to meet its debt or other cash obligations. See Note 12 of HEI's "Notes to Consolidated Financial Statements."

Forecasted HEI consolidated "net cash used in investing activities" (excluding "investing" cash flows from ASB) for 2010 through 2012 consists primarily of the net capital expenditures of HECO and its subsidiaries. In addition to the funds required for the electric utilities' construction programs (see "Electric utility—Liquidity and capital resources"), approximately $157 million will be required during 2011 through 2012 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. In addition, approximately $57.5 million of HECO special purpose revenue bonds will be maturing in 2012, which bonds are expected to be repaid with proceeds from issuances of long-term debt. Additional debt and/or equity financing may be utilized to pay down commercial paper or other short-term borrowings or may be required to fund unanticipated expenditures not included in the 2010 through 2012 forecast, such as increases in the costs of or an acceleration of the construction of capital projects of the utilities, unanticipated utility capital expenditures that may be required by the HCEI or new environmental laws and regulations, unbudgeted acquisitions or investments in new businesses, significant increases in retirement benefit funding requirements and higher tax payments that would result if certain tax positions taken by the Company do not prevail. In addition, existing debt may be refinanced prior to maturity (potentially at more favorable rates) with additional debt or equity financing (or both).

As further explained in "Retirement benefits" above and Notes 1 and 8 of HEI's "Notes to Consolidated Financial Statements," the Company maintains pension and other postretirement benefit plans. The Company was not required to make any contributions to the qualified pension plans for 2009, 2008 and 2007 to meet minimum funding requirements pursuant to ERISA, including changes promulgated by the Pension Protection Act of 2006, but the Company made voluntary contributions in those years. Contributions to the retirement benefit plans totaled $25 million in 2009 (comprised of $24 million by the utilities, $1 million by HEI and nil by ASB), $15 million in 2008 and $13 million in 2007 and are expected to total $34 million in 2010 ($33 million by the utilities, $1 million by HEI and nil by ASB). In addition, the Company paid directly $1 million of benefits in each of 2009, 2008 and 2007 and expects to pay $2 million of benefits in 2010. 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. The Company believes it will have adequate access to capital resources to support any necessary funding requirements.

Off-balance sheet arrangements. Although the Company has off-balance sheet arrangements, management has determined that it has no off-balance sheet arrangements that either have, or are reasonably likely to have, a current or future effect on the Company's financial condition, changes in financial condition, revenues or expenses, results of operations, liquidity, capital expenditures or capital resources that are material to investors, including the following types of off-balance sheet arrangements:

(1) obligations under guarantee contracts,
(2) retained or contingent interests in assets transferred to an unconsolidated entity or similar arrangements that serves as credit, liquidity or market risk support to that entity for such assets,
(3) obligations under derivative instruments, and
(4) obligations under a material variable interest held by the Company in an unconsolidated entity that provides financing, liquidity, market risk or credit risk support to the Company, or engages in leasing, hedging or research and development services with the Company.

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 its control and could cause future results of operations to differ materially from historical results. The following is a discussion of certain of these factors. Also see "Forward-Looking Statements" above and "Certain factors that may affect future results and financial condition" in each of the electric utility and bank segment discussions below.

Economic conditions, U.S. capital markets and credit and interest rate environment. Because the core businesses of HEI's subsidiaries are providing local electric public utility services and banking services in Hawaii, the Company's operating results are significantly influenced by Hawaii's economy, which in turn is influenced by economic conditions in the mainland U.S. (particularly California) and Asia (particularly Japan) as a result of the impact of those conditions on tourism, by the impact of interest rates, particularly on the construction and real estate industries, and by the impact of world conditions (e.g., Iraq and Afghanistan wars) on federal government spending in Hawaii. The two largest components of Hawaii's economy are tourism and the federal government (including the military).

Declines in the Hawaii, U.S. and Asian economies, led to declines in KWH sales in 2009, higher delinquencies in ASB's loan portfolio, OTTI charges at ASB and other adverse effects on HEI's businesses. GDP declined by 2.4% in 2009, but there is evidence that the U.S. recession has ended as supported by the positive economic growth in the third quarter of 2009 and the expectation of 5.7% growth in the fourth quarter of 2009 and 3.0% growth in 2010. If S&P or Moody's were to downgrade HEI's or HECO's debt ratings, or if future events were to adversely affect the availability of capital to the Company, HEI's and HECO's ability to borrow and raise capital could be constrained and their future borrowing costs would likely increase.

Changes in the U.S. capital markets can also have significant effects on the Company. For example, pension funding requirements, as further explained in "Retirement benefits" above and Notes 1 and 8 of HEI's "Notes to Consolidated Financial Statements," are affected by the market performance of the assets in the master pension trust maintained for pension plans, and by the discount rate used to estimate the service and interest cost components of net periodic pension cost and value obligations. The electric utilities' pension tracking mechanisms help moderate pension expense; however, a decline in the value of the Company's defined benefit pension plan assets may increase the unfunded status of the Company's pension plans and result in increases in expected future funding requirements.

Because the earnings of ASB depend primarily on net interest income, interest rate risk is a significant risk of ASB's operations. HEI and its electric utility subsidiaries are also exposed to interest rate risk primarily due to their periodic borrowing requirements, the discount rate used to determine pension funding requirements and the possible effect of interest rates on the electric utilities' rates of return and overall economic activity. Interest rates are sensitive to many factors, including general economic conditions and the policies of government and regulatory authorities. HEI cannot predict future changes in interest rates, nor be certain that interest rate risk management strategies it or its subsidiaries have implemented will be successful in managing interest rate risk.

Changes in interest rates and credit spreads also affect the fair value of ASB's investment securities. In 2009, the credit markets experienced significant disruptions, liquidity on many financial instruments declined and residential mortgage delinquencies and defaults increased. These disruptions negatively impacted the fair value of ASB's investment portfolio in 2009 and continued volatility in the financial markets could further impact the fair value of this portfolio, which will have an adverse impact on ASB's and HEI's financial condition. However, with the sales of ASB's private-issue mortgage-related securities portfolio and residential loan production in 2009, the Company's exposure to credit and interest rate risks have been reduced.

Limited insurance In the ordinary course of business, the Company purchases insurance coverages (e.g., property and liability coverages) to protect itself against loss of or damage to its properties and against claims made by third-parties and employees for property damage or personal injuries. However, the protection provided by such insurance is limited in significant respects and, in some instances, the Company has no coverage. For electric utility examples, see "Limited insurance" in Note 3 of HEI's "Notes to Consolidated Financial Statements." ASB also has no insurance coverage for business interruption or credit card fraud. Certain of the Company's insurance has substantial "deductibles" or has limits on the maximum amounts that may be recovered. Insurers also have exclusions or limitations of coverage for claims related to certain perils including, but not limited to, mold and terrorism. 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, the Company could incur uninsured losses in amounts that would have a material adverse effect on the Company's results of operations and financial condition.

Environmental matters 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. These laws and regulations, among other things, may require that certain environmental permits be obtained and maintained as a condition to constructing or operating certain facilities. Obtaining such permits can entail significant expense and cause substantial construction delays. Also, these laws and regulations may be amended from time to time, including amendments that increase the burden and expense of compliance.

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.

Material estimates that are particularly susceptible to significant change include the amounts reported for investment and mortgage-related securities; property, plant and equipment; pension and other postretirement benefit obligations; contingencies and litigation; income taxes; regulatory assets and liabilities; electric utility revenues; variable interest entities (VIEs); and allowance for loan losses. Management considers an accounting estimate to be material if it requires assumptions to be made that were uncertain at the time the estimate was made and changes in the assumptions selected could have a material impact on the estimate and on the Company's results of operations or financial condition.

In accordance with SEC Release No. 33-8040, "Cautionary Advice Regarding Disclosure About Critical Accounting Policies," management has identified accounting policies it believes to be the most critical to the Company's financial statements—that is, management believes that the policies discussed below 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. The policies affecting both of the Company's two principal segments are discussed below and the policies affecting just one segment are discussed in the respective segment's section of "Material estimates and critical accounting policies." Management has reviewed the material estimates and critical accounting policies with the HEI Audit Committee and, as applicable, the HECO Audit Committee.

For additional discussion of the Company's accounting policies, see Note 1 of HEI's "Notes to Consolidated Financial Statements" and for additional discussion of material estimates and critical accounting policies, see the electric utility and bank segment discussions below under the same heading.

Pension and other postretirement benefits obligations For a discussion of material estimates related to pension and other postretirement benefits (collectively, retirement benefits), including costs, major assumptions, plan assets, other factors affecting costs, AOCI charges and sensitivity analyses, see "Retirement benefits" in "Consolidated—Results of operations" above and Notes 1 and 8 of HEI's "Notes to Consolidated Financial Statements."

Contingencies and litigation The Company is subject to proceedings, lawsuits and other claims, including proceedings under laws and government regulations, which are subject to change, related to environmental matters. Management assesses the likelihood of any adverse judgments in or outcomes of these matters as well as potential ranges of probable losses, including costs of investigation. A determination of the amount of reserves required, if any, for these contingencies is based on an analysis of each individual case or proceeding often with the assistance of outside counsel. The required reserves may change in the future due to new developments in each matter or changes in approach in dealing with these matters, such as a change in settlement strategy.

In general, environmental contamination treatment costs are charged to expense, unless it is probable that the PUC would allow such costs to be recovered through future rates, in which case such costs would be capitalized as regulatory assets. Also, environmental costs are capitalized if the costs extend the life, increase the capacity, or improve the safety or efficiency of property; the costs mitigate or prevent future environmental contamination; or the costs are incurred in preparing the property for sale. See "Environmental regulation" in Note 3 of HEI's "Notes to Consolidated Financial Statements" for a description of the Honolulu Harbor investigation.

Income taxes Deferred income tax assets and liabilities are established for the temporary differences between the financial reporting bases and the tax bases of the Company's assets and liabilities using tax rates expected to be in effect when such deferred tax assets or liabilities are realized or settled. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible.

Management evaluates its potential exposures from tax positions taken that have or could be challenged by taxing authorities. These potential exposures result because taxing authorities may take positions that differ from those taken by management in the interpretation and application of statutes, regulations and rules. Management considers the possibility of alternative outcomes based upon past experience, previous actions by taxing authorities (e.g., actions taken in other jurisdictions) and advice from its tax advisors. Management believes that the Company's provision for tax contingencies is reasonable. However, the ultimate resolution of tax treatments disputed by governmental authorities may adversely affect the Company's current and deferred income tax amounts. See disclosure in Note 1 of HEI's "Notes to Consolidated Financial Statements" regarding the impact of changes made to estimating the impact of uncertain tax positions. Also, see Note 10, "Income taxes," of HEI's "Notes to Consolidated Financial Statements."

Following are discussions of the electric utility and bank segments. Additional segment information is shown in Note 2 of HEI's "Notes to Consolidated Financial Statements." The discussion concerning Hawaiian Electric Company, Inc. should be read in conjunction with its consolidated financial statements and accompanying notes.

Electric utility

Executive overview and strategy. The electric utilities are vertically integrated and regulated by the PUC. The separate island utility systems are not currently interconnected, which requires that additional reliability be built into each system, but also means that the utilities are not exposed to the risks of inter-ties. The electric utilities' strategic focus has been to meet Hawaii's growing energy needs through a combination of diverse activities—modernizing and adding needed infrastructure through capital investment, placing emphasis on energy efficiency and conservation, pursuing renewable energy generation and taking the necessary steps to secure regulatory support for their plans.

Reliability projects, including projects to increase generation reserves, remain a priority for HECO and its subsidiaries. On Oahu, HECO has completed construction of a new generating unit designed to operate using biodiesel fuel, and in January 2010 confirmed to the PUC that testing of the unit confirms that biodiesel is a viable fuel for the unit, and is making progress in constructing the East Oahu Transmission Project (EOTP), a needed alternative route to move power from the west side of the island. HECO is also working with the State and U.S.

Department of Energy on an undersea cable system to interconnect IPP wind farms proposed on the islands of Lanai and Molokai with the Oahu grid. On the island of Hawaii, after years of delay, the two 20 MW combustion turbines (CTs) at Keahole are operating and an 18 MW heat recovery steam generator was added in 2009 to complete a dual-train combined-cycle unit.

Major infrastructure projects can have a pronounced impact on the communities in which they are located. The electric utilities continue to expand their community outreach and consultation process so they can better understand, evaluate and address community concerns early in the process.

With large power users in the electric utilities' service territories, such as the U.S. military, hotels and state and local government, management believes that retaining customers by maintaining customer satisfaction is critical. The electric utilities have established programs that offer these customers specialized services and energy efficiency audits to help them save on energy costs.

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 the goals and objectives of the HCEI and the related commitments of the parties (the Energy Agreement). The Energy Agreement provides that the parties shall pursue a wide range of actions, many of which will require PUC approval, 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. A few of the major provisions of the Energy Agreement directly affecting HECO and its subsidiaries, which may affect their future results and financial condition and require various PUC approvals, are: (1) pursuing an overall goal of providing 70% of Hawaii's electricity and ground transportation energy needs from clean energy sources; (2) establishing a Clean Energy Infrastructure Surcharge (CEIS) designed to expedite cost recovery for infrastructure that supports greater use of renewable energy or grid efficiency within the utility systems; (3) pursuing the integration of approximately 1,100 MW from a variety of renewable energy sources into the utility systems, including the integration of 400 MW of wind power into the Oahu grid through a yet-to-be constructed undersea transmission cable system from wind farms proposed by developers to be built on the islands of Lanai and/or Molokai; (4) developing a feed-in tariff system with standardized purchase prices for renewable energy; and (5) adopting a new regulatory rate-making model (see "Decoupling proceeding" below). During 2009, the electric utilities actively pursued their commitments under the Energy Agreement. In December 2009, the PUC approved the Renewable Energy Infrastructure Program Surcharge, which replaces the CEIS and establishes the mechanism for more expedited cost recovery of renewable energy infrastructure projects. The utilities need to file for cost inclusion in the surcharge on a project-by-project basis. See "Hawaii Clean Energy Initiative (HCEI)" in Note 3 of HEI's "Notes to Consolidated Financial Statements" for a more detailed discussion of the Energy Agreement and other recent developments.

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 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 achieving 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 nearly 100% biofuels for its new 110 MW generating unit and its testing of the unit has confirmed that biodiesel is a viable fuel for the unit. 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.

The electric utilities also support renewable energy through a heat pump program, 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 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, a portion of which was placed in service in December 2008. The full output of the system will be allowed once Lanai Sustainability Research completes installation of a battery energy storage system. In November 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 concentrated solar power facility of up to 500 kW, which was brought on line in December 2009. In March 2009, HECO and HELCO filed with the PUC an executed term sheet 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 power purchase agreement with Kahuku Wind Power, LLC, subject to PUC approval, to purchase 30 MW of electricity from a wind turbine generating system. HECO filed an application for approval of the PPA and a PPA amendment with the PUC in August 2009 and February 2010, respectively. In December 2009, HECO and Honua Power, LLC signed a purchase power agreement, subject to PUC approval, to purchase approximately 6.6 MW of electricity from a steam turbine generator on Oahu that is fueled with waste materials. HECO filed an application for approval of the PPA with the PUC in January 2010.

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 the installation of 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. The procedural schedule calls for the filing of HECO's Reply Statement of Position in June 2010.

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. An Award Group of bidders was selected in October 2009. HECO is currently negotiating PPAs with the bidders in the Award Group. Included in the bids received were proposals for two large scale neighbor island wind projects. In accordance with the Energy Agreement, the proposals for two large scale neighbor island wind projects (Big Wind projects) were bifurcated from the Oahu Renewable Energy RFP. The utilities intend to separately negotiate purchase power agreements with two neighbor island wind projects that would produce energy to be imported to Oahu via a yet-to-be-built undersea transmission cable system. HECO has requested a ruling from the PUC to confirm that the bifurcation was proper. In December 2009, the PUC issued a modified procedural order for determination of issues related to bifurcation of the Big Wind projects and applicability to them of the competitive bidding framework.

On July 17, 2009, HECO filed an application requesting approval (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) 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 did 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. On December 11, 2009, the PUC issued a D&O that allows HECO to defer costs for the Big Wind Implementation Studies for later review for prudence and reasonableness. The PUC stated that a decision on a specific amount of costs to be recovered from ratepayers would be deferred until a detailed review is conducted at a later date on the actual incurred costs in a rate case or other proceeding. The PUC deferred a decision as to the specific recovery mechanism or the terms of any recovery mechanism (e.g. amortization period or carrying treatment).

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 pursued a number of projects, particularly those utilizing wind, landfill gas, and ocean energy, but 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.

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 3 of HEI's "Notes to Consolidated Financial Statements."

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

Results of operations.

(dollars in millions, except per barrel amounts)	2009	% change	2008	% change	2007
Revenues [1]	$ 2,035	(29)	$ 2,860	36	$ 2,106
Expenses					
Fuel oil	672	(45)	1,229	59	774
Purchased power	500	(28)	690	28	537
Other	694	(8)	750	13	664
Operating income	170	(11)	191	47	131
Allowance for funds used during construction	17	33	13	69	8
Net income for common stock	79	(14)	92	76	52
Return on average common equity	6.4%		8.0%		5.0%
Average fuel oil cost per barrel [1]	$ 63.91	(44)	$ 114.50	66	$ 69.08
Kilowatthour sales (millions)	9,690	(2)	9,936	(2)	10,118
Cooling degree days (Oahu)	4,815	(3)	4,943	2	4,835
Number of employees (at December 31)	2,297	4	2,203	3	2,145

1 The rate schedules of the electric utilities currently contain ECACs through which changes in fuel oil prices and certain components of purchased energy costs are passed on to customers.

- Net income for common stock for HECO and its subsidiaries was $79 million in 2009 compared to $92 million in 2008. The decrease in 2009 compared to 2008 was primarily due to lower KWH sales and certain higher expenses (other O&M, depreciation and interest), partly offset by higher allowance for funds used during construction (AFUDC).

In 2009, the electric utilities' revenues decreased by 29%, or $825 million, from 2008 primarily due to lower fuel prices ($766 million), lower KWH sales ($77 million) and lower DSM program recovery revenues ($13 million) (see "Demand-side management programs" below), partly offset by interim rate relief granted by the PUC to HECO for its 2009 test year ($26 million) (see "Most recent rate requests" below). KWH sales were 2.5% lower when compared to 2008, due largely to customer conservation efforts and the impact of cooler weather, partially offset by new load growth (i.e., increase in number of customers) and the impact of a drop in the average electricity price. Cooling degree days for Oahu were 2.6% lower in 2009 compared to 2008. The electric utilities are currently estimating KWH sales for 2010 to decrease from the prior year by 0.9% and increase by 0.3% in 2011, primarily due to the impact of continued slow economic activity and customer conservation efforts in 2010, offset partly by gradual improvement in the economy beginning in 2010 that is expected to continue strengthening into 2011.

Operating income in 2009 was $22 million lower than in 2008 due primarily to lower KWH sales, higher other expenses, including higher operation and maintenance expenses and higher depreciation expense, partly offset by the interim rate relief for HECO granted by the PUC.

Fuel oil expense in 2009 decreased by 45% due primarily to lower fuel costs and lower KWHs generated. Purchased power expenses in 2009 decreased by 28% due primarily to lower purchased energy costs and lower KWHs purchased. Lower fuel costs are generally passed on to customers.

Other expenses decreased 8% in 2009 due to a 27% (or $70 million) decrease in taxes, other than income taxes, primarily due to the decrease in revenues, partly offset by a 3% (or $11 million) increase in other O&M expenses. "Other operation" expenses increased by $5 million in 2009 when compared to 2008 due primarily to higher administrative and general expense ($9 million), including higher employee benefit expense due to higher retirement benefit expense ($5 million) and a retrospective medical plan premium adjustment ($2 million) and higher production and transmission and distribution expense to maintain reliable operations ($6 million), including more employees for CIP CT-1, offset in part by lower DSM expense ($11 million). Maintenance expense increased $6 million from 2008 due primarily to higher transmission and distribution expense for substation maintenance, overhead and underground line maintenance and vegetation management.

- Net income for common stock for HECO and its subsidiaries was $92 million in 2008 compared to $52 million in 2007. The increase in 2008 compared to 2007 was primarily due to interim rate relief and the effects on 2007 earnings of a write-off of plant at Keahole and a reserve for a refund at the utilities in 2007, partly offset by lower sales.

In 2008, the electric utilities' revenues increased by 36%, or $754 million, from 2007 primarily due to higher fuel prices ($695 million); interim rate relief granted by the PUC to HECO (2007 test year), HELCO (2006 test year) and MECO (2007 test year) in October 2007, April 2007 and December 2007, respectively ($73 million) (see "Most recent rate requests" below); 2007 accrual of a reserve for a refund of a portion of HECO's 2005 test year rate increase ($16 million), and higher DSM program recovery revenues ($12 million); partly offset by lower KWH sales ($44 million). KWH sales for 2008 were 1.8% lower when compared to 2007, due largely to customer conservation efforts, partially offset by new load growth (i.e., increase in number of customers) and the impact of warmer weather. Cooling degree days for Oahu were 2.3% higher in 2008 compared to 2007.

Operating income in 2008 was $61 million higher than in 2007 due primarily to the impact of interim rate increases for HECO, HELCO and MECO, a 2007 accrual of a reserve for a refund of a portion of HECO's 2005 test year rate increase and 2007 write-off of plant-in-service costs related to HELCO's CT-4 and CT-5, partly offset by higher other expenses, including higher operation and retirement benefit expenses, a gain on sale of non-electric utility property in 2007 and higher depreciation expense.

Fuel oil expense in 2008 increased by 59% due primarily to higher fuel costs, partly offset by lower KWHs generated. Purchased power expenses in 2008 increased by 28% due primarily to higher KWHs purchased, higher purchased energy costs, and higher capacity and non-fuel charges. Higher fuel costs are generally passed on to customers.

Other expenses increased 13% in 2008 due to a 14% (or $29 million) increase in "other operation" expense; a 3% (or $5 million) increase in depreciation expense; and a 35% (or $67 million) increase in taxes, other than income taxes, primarily due to the increase in revenues; partly offset by a 4% (or $4 million) decrease in maintenance expense. "Other operation" expenses increased by $29 million in 2008 when compared to 2007 due primarily to higher DSM expenses that are generally passed on to customers through a surcharge ($11 million), higher bad debt expense ($4 million), higher production operation expenses ($6 million) including higher staffing levels at generating plants and work to support the acquisition of renewable resources, and higher transmission and distribution operation expenses ($3 million) resulting primarily from higher expenses for support and maintenance of grid control and operation infrastructure and work to support the development of the advanced metering infrastructure program. Maintenance expenses decreased 4%, or $4 million from 2007, due to $5 million lower production maintenance expense (primarily due to lower generating plant maintenance and the lower scope of generating unit overhauls). Higher depreciation expense was attributable to $174 million of additions to plant in service in 2007.

- Increased O&M expenses are expected to continue as the electric utilities expect higher production expenses (primarily due to the operating duty imposed on HECO's generating assets over the past five years), higher contract services costs, and higher transmission and distribution expenses to maintain system reliability. Also, additional expenses have been incurred for the costs of Campbell Industrial Park (CIP) combustion turbine No. 1 (CT-1), and are expected to be incurred 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 and the impact of cost containment measures. Due to the current economic challenges and management's efforts to prudently manage costs, the utilities are deferring HCEI expenditures that are not time-critical. However, the utilities continue to fund time-critical initiatives in order to maintain momentum in achieving the state's clean energy goals under the HCEI.

The costs of supplying energy to meet demand and the maintenance costs required to sustain high availability of the aging generating units have been increasing and such increased costs are likely to continue.

Most recent rate requests. The electric utilities initiate PUC proceedings from time to time to request electric rate increases to cover rising operating costs and the cost of plant and equipment, including the cost of new capital projects to maintain and improve service reliability. The PUC may grant an interim increase within 10 to 11 months following the filing of an application, but there is no guarantee of such an interim increase 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 February 17, 2010, the 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 2009, the actual ROACEs (calculated under the rate-making method, which excludes the effects of items not included in determining electric utility rates, and reported to the PUC) for HECO, HELCO and MECO were 7.02%, 6.89% and 4.76%, respectively. HECO's actual ROACE was 348 basis points lower than its interim D&O ROACE primarily due to lower KWH sales and increased O&M expenses, both of which are expected to continue through 2010. HELCO and MECO's actual ROACEs were 381 and 594 basis points, respectively, lower than their interim D&O ROACEs primarily due to increased O&M expenses and lower KWH sales.

As of February 17, 2010, the 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 2009, the actual RORs (calculated under the rate-making method, which excludes the effects of items not included in determining electric utility rates, and reported to the PUC) for HECO, HELCO and MECO were 6.12%, 5.70% and 4.99%, 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 AOCI. See Note 3 of HEI's "Notes to Consolidated Financial Statements."

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 3 of HEI's "Notes to Consolidated Financial Statements."

HECO.

2005 test year rate case. On May 1, 2008, the PUC issued the final D&O for HECO's 2005 test year rate case, which authorized an increase of $45 million in annual revenues ($34 million net) based on a 10.7% ROACE (and an 8.66% ROR on an average rate base of $1.060 billion).

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 11.25% ROACE and an 8.92% ROR on 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 included 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 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 proceeding brought in 2005, 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 under a new accounting standard at the time, but that request was denied by the PUC in January 2007. HECO thus proposed in the 2007 test year rate case to restore to book equity for rate-making purposes the amounts charged to AOCI as a result of adopting that new accounting standard. 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 rate-making 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 federal Department of Defense's (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 8, "Retirement Benefits" of HEI's "Notes to Consolidated Financial Statements."

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

The amount of the revenue increase based on the stipulated agreement was $70 million annually, or a 4.96% increase over current effective rates at the time of the stipulation. The settlement agreement included, as a negotiated compromise of the parties' respective positions, an ROACE of 10.7% (and an 8.62% ROR and a $1.158 billion average rate base) to determine revenue requirements in the proceeding. In the settlement agreement, the parties agreed that the final rates set in HECO's 2005 test year rate case may impact revenues at current effective rates and at present rates, and indicated that the amount of the stipulated interim rate increase in this case would be adjusted to take into account any such changes. For purposes of the settlement, the parties agreed to a pension tracking mechanism that does not include amortization of HECO's pension asset (comprised of accumulated contributions to its pension plan in excess of net periodic pension cost and amounting to $68 million at December 31, 2006) as part of the pension tracking mechanism in the proceeding. (This had 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 were 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 3 and Note 8, "Retirement benefits," of HEI'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 then 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 requested continuation of its ECAC in its present form. The request excluded 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 agreed 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 updates proposed to establish a revenue balancing account (RBA) 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. The PUC asked for more information on the power purchase adjustment clause; 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 the replacement of its customer information system due to a delay in transitioning to the new system. See Note 3 of HEI'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 the removal of 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 (the Settlement 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 an 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 an ROACE of 11%, assuming the approval of a joint decoupling proposal, is reasonable.

On May 18, 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 (approximately $13 million of revenue requirements). 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 deferred decision on the proposal to establish an RBA, 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 an ROACE of 10.50% agreed to by the parties for purposes of the interim decision only, and an 8.45% ROR on a rate base of $1.169 billion (compared to the average rate base of $1.253 billion agreed to by the parties in the 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 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 that 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. In hearings that began on October 26, 2009, HECO requested an updated ROACE of 10.75%, assuming the approval of a joint decoupling proposal (see Decoupling proceeding below).

In November 2009, HECO filed a motion with the PUC requesting a second interim increase of $12.7 million to recover CIP CT-1 costs, by allowing HECO to include the costs for the test year in rate base or by allowing HECO to continue to accrue AFUDC on the costs.

On December 22, 2009, HECO filed an application requesting PUC approval of a two-year contract with Renewable Energy Group Marketing and Logistics, LLC to supply biodiesel for use primarily in CIP CT-1. On January 5, 2010, HECO notified the PUC that testing of CIP CT-1 had confirmed that it can operate on biofuels and that it had submitted the emissions data derived from that testing to the DOH in seeking necessary permit modifications.

In January 2010, HECO, the Consumer Advocate and the DOD filed their briefs for this rate case. In its reply brief, HECO indicated its final position was to request a revenue increase for the 2009 test year of $80.2 million over revenues at current rates, based on an ROACE of 10.75% and an ROR of 8.58% on an average rate base of $1.251 billion, which assumes approval of the utilities' decoupling proposal and other rate rider mechanisms. Without these mechanisms, revenue requirements would be based on an ROACE of 11% and an ROR of 8.72%.

As the PUC did not accept all of the material terms of the Settlement Agreement, any of the parties may withdraw from the agreement, 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%, an 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 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 8 of HEI'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 December 9, 2009, HELCO filed a request with the PUC to increase base rates by $20.9 million, or 6.0% in annual base revenues, over the electric rates currently in effect (i.e., over rates that include the $24.6 million interim rate increase discussed above granted in HELCO's 2006 test year rate case), based on a 2010 test year, an 8.73% ROR, a 10.75% ROACE and a $487 million average rate base. The proposed rate increase would cover investments for system upgrade projects, including an 18 MW heat recovery steam generator (ST-7) at Keahole and two major West Hawaii transmission line upgrades, as well as increasing O&M costs for the island's electrical system. HELCO's proposed ROR and ROACE assume (1) the establishment of an RBA and a revenue adjustment mechanism, based on the Joint Decoupling Proposal (see "Decoupling Proceeding" below) between the utilities and the Consumer Advocate, (2) the implementation of the REIP/CEIS, which the PUC has approved in a separate proceeding, and (3) a purchased power adjustment clause to recover non-energy purchased power agreement costs proposed in the proceeding. If the proposals are not approved, the test year revenue requirements would be based on an ROR of 8.87% and an ROACE of 11.0%.

HELCO's general rate increase is based on proposed revised depreciation rates for which PUC approval was requested in an application filed on November 9, 2009. If a decision on the depreciation rates change has not been rendered by the time an interim D&O is to be issued in this proceeding, HELCO's application requests that the interim rate relief be based on the existing depreciation rates, and that upon issuance of the D&O on the proposed depreciation rates change, the PUC approve an adjustment (i.e., depreciation step down) that would effectively implement the difference between HELCO's revenue increase based on its existing depreciation rates and the new depreciation rates approved.

HELCO's filing also asks for adoption of inverted tiered rates and an optional residential time-of-use service rate to enable customers to manage their energy usage. The proposed rate structure also includes the continuation of HELCO's ECAC. Pursuant to the Energy Agreement, HELCO proposes the establishment of a purchased power adjustment clause to recover non-energy purchased power agreement costs to be effective upon issuance of the final D&O. The adoption of pension and OPEB tracking mechanisms is included in the test year estimates that were approved on an interim basis by the PUC in HELCO's 2006 test year interim D&O.

Public hearings have been scheduled for later in February 2010.

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

<u>MECO</u>.

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 rate-making 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 a new accounting standard at that time.

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 an ROACE of 10.0% and an ROR of 8.29% on an average rate base of $378 million. $4.75 million of the $9.4 million difference between MECO's and the Consumer Advocate's proposed increase was due to 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, the parties agreed that MECO's ECAC provided a fair sharing of the risks of fuel cost changes between MECO and its ratepayers and no further changes were 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 was 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 included estimated costs of $64.8 million for the generating unit M18, which is $19.4 million higher than the PUC approved amount, but 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 8 of HEI'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 September 30, 2009, MECO filed a request with the PUC to increase base rates by 9.7%, or $28.2 million in annual base revenues, over the electric rates currently in effect (i.e., over rates that include the $13.2 million interim rate increase discussed above granted in MECO's 2007 test year rate case), based on a 2010 test year, an 8.57% ROR, a 10.75% ROACE and a $390 million average rate base. The proposed rate increase would cover investments to improve service reliability, including the replacement and upgrade of the Maalaea generating units' (M17 & M19) power plant control systems, installation of a new 150-kw photovoltaic system at MECO's Kahului Baseyard to incorporate solar energy into MECO's facilities, replacement and upgrade of underground lines, new or expanded substations to support past and future growth and improve service, and higher O&M expenses due to MECO's aging infrastructure. MECO's proposed ROR and ROACE assume the establishment of an RBA and a revenue adjustment mechanism, based on the Joint Decoupling Proposal between the utilities (HECO, HELCO and MECO) and the Consumer Advocate. If the Joint Decoupling Proposal is not approved, the test year revenue requirements would have to be recalculated according to an ROR of 8.72% and an ROACE of 11%.

MECO's general rate increase is based on proposed revised depreciation rates for which PUC approval was requested in an application filed on September 10, 2009. If a decision on the depreciation rates change has not been rendered by the time an interim D&O is to be issued in the 2010 test-year rate case proceeding, MECO's filing requests that the interim rate relief be based on the existing depreciation rates, and that upon issuance of the D&O on the proposed depreciation rates change, the PUC approve an adjustment (i.e., depreciation step down) that would effectively implement the difference between MECO's revenue increase based on its existing depreciation rates and the new depreciation rates approved.

MECO's filing proposes an inclining rate block structure for residential customers (similar to the structure MECO proposed in its 2007 test year rate case) and an optional residential and commercial time-of-use service rate to enable customers to manage their energy usage. The proposed rate structure also includes the continuation of MECO's ECAC. Pursuant to the Energy Agreement, MECO proposes the establishment of a purchased power adjustment clause to recover non-energy purchased power agreement costs to be effective upon issuance of the final D&O. The adoption of pension and OPEB tracking mechanisms is included in the test year estimates that were approved on an interim basis by the PUC in MECO's 2007 test year interim D&O.

In December 2009, the PUC held public hearings on MECO's 2010 test year rate case. Evidentiary hearings are scheduled for July 2010.

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

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 any utility or the 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 (Joint Decoupling Proposal) is for a decoupling mechanism with two components: (1) a sales decoupling component via an RBA and a revenue escalation component via a revenue adjustment mechanism and (2) an earnings sharing mechanism. In November 2009, the utilities filed a motion for interim approval of their decoupling mechanism. The Consumer Advocate objected to the request asserting that the record in the docket is complete and that a final order should be issued.

Management cannot predict the timing, or the ultimate outcome, of an interim or 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 3 of HEI'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.

Energy Efficiency DSM Programs. On February 13, 2007, the PUC issued its D&O in the EE DSM Docket that had been opened by the PUC to bifurcate the EE DSM issues originally raised in the HECO 2005 test year rate case. In the D&O, the PUC required that the administration of all EE DSM programs be turned over to a non-utility, third-party administrator, with the transition to the administrator, to be funded through a public benefits fund (PBF) surcharge. See "Public benefits fund" in Note 3 of HEI's "Notes to Consolidated Financial Statements."

In July 2008, the PUC issued an Order to initiate the collection of funds for the PBF Administrator; confirmed that the load management, SolarSaver Pilot and Residential Customer Energy Awareness programs shall remain with the electrical utilities; and directed the electric utilities to continue to operate the DSM programs through June 30, 2009.

The PUC executed a PBF Administrator contract with Science Applications International Corporation (SAIC) in March 2009. On July 1, 2009, SAIC began administering the energy efficiency DSM programs.

The EE DSM Docket D&O also provided 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 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 HECO to 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. 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, however, on August 13, 2009 the PUC issued an Order suspending the 45-day approval process for this request.

DSM utility incentives are 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 has been subject to caps determined separately for each utility. In addition, the utilities' DSM incentives for 2007 and 2008 were also 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 showed 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 and 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. The refund was included in the DSM surcharge adjustments effective on April 1, 2009 for HECO, and on May 1, 2009, for HELCO and MECO.

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. On September 17, 2009, the PUC requested a final summary explaining all adjustments and revisions made as a result of the impact evaluation. On October 19, 2009 the utilities filed this summary. HECO, HELCO, and MECO did not earn DSM Utility Incentives in 2009.

Load Management DSM Programs. 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 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 (CIDLC) Program and the Residential Direct Load Control (RDLC) Program, respectively. The CIDLC Program application included an action plan for a load aggregator pilot program. An RFP for the load aggregator was issued and bid proposals were received in September 2009. HECO is currently evaluating the bid proposals. In December 2009, the PUC approved HECO's requests to extend the CIDLC and RDLC programs through 2012, but denied HECO's request to expand the enrollment of customers in both programs pending submission of a program evaluation report by HECO.

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. In June 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 met with the Consumer Advocate in September 2009 and presented a revised DPP Program design for the Consumer Advocate's consideration. HECO's response to the PUC's order and its filing date are dependent 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 requested 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, and in November 2008, the PUC granted the request. In December 2009, HECO, HELCO and MECO filed updated avoided energy costs rates and Schedule Q rates to be effective for 2010, subject to monthly adjustment of the fuel component of the rates for changes in fuel prices.

Clean energy scenario planning, 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 would then be approved, rejected or modified by the PUC. The goal of integrated resource planning is the identification of demand- and supply-side resources and the integration of these resources for meeting near- and long-term consumer energy needs in an efficient and reliable manner at the lowest reasonable cost. The utilities' proposed IRPs have been 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 these costs through a surcharge. Also, see Note 3 in HEI's "Notes to Consolidated Financial Statements," "Demand-side management programs" above and "Certain factors that may affect future results and financial condition--Regulation of electric utility rates" below.

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 a 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, MECO, Kauai Island Utility Cooperative (KIUC) and the Consumer Advocate, ten parties have been allowed as intervenors and two parties have been allowed as participants in the proceeding. The PUC held panel hearings in February 2010.

The utilities' latest IRPs are described below. In the fourth quarter of 2008, however, the PUC closed the IRP-4 processes and directed the utilities to suspend all activities pursuant to the IRP framework to allow for resources to be diverted to the development of the CESP framework.

HECO'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 placing in service of the second CT, and to later determine whether to place the unit in emergency reserve status or to retire the unit.

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 is expected to 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" below).

HELCO's IRP. In May 2007, HELCO filed its third IRP (IRP-3). 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 3 of HEI'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, 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.

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.

HECO's 2009 CIP CT-1 and transmission line. See "CIP CT-1 and transmission line" in Note 3 in HEI'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 estimated its reserve capacity shortfall to be approximately 30 MW in 2009, even with the addition of the CIP CT-1, primarily because shortfalls were projected to occur before the unit was installed and were not expected to be entirely alleviated once the unit was 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. Generation capacity shortfalls did not occur prior to or after the 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 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 anticipated that its reserve capacity situation could range from a shortfall of 10 MW if demand was 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. In May 2009, HECO prepared a new sales and peak forecast in which HECO projected peak demand to be lower than previously forecast in September 2008. However, actual recorded peaks since May 2009 have been more closely tracking the September 2008 forecast. Therefore, the analyses and conclusions in the 2009 AOS letter (that used the September 2008 forecast) continue to be valid. 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 1,273 MW in 2005, 1,315 MW in 2006, 1,261 MW in 2007, 1,227 MW in 2008 and 1,260 MW in 2009. 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 and in 2009, HECO on occasion remotely turned off water heaters for a number of residential customers who participate in its load-control program. In October 2009, a process was established with PUC approval to allow HECO to use CIP CT-1 for critical load purposes, which HECO has done on one occasion.

HELCO. HELCO's 2010 Adequacy of Supply letter filed in January 2010 indicated that HELCO's generation capacity for the period 2010 through 2012 is sufficiently large to meet all reasonably expected demands for service and provide reasonable reserves for emergencies.

MECO. MECO's 2010 Adequacy of Supply letter filed in January 2010 indicated that MECO's generation capacity for the period 2010 through 2012 is sufficient to meet the forecasted demands on the islands of Maui, Lanai and Molokai. The letter affirmed the conclusions stated in the September 2009 update which indicated that the estimated need date for the next increment of firm capacity on the island of Maui is 2021 but that if peak demand is higher than forecast then the need date for the next increment of firm generating capacity could be as soon as 2015.

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.

On March 31, 2009, HECO submitted an outage report prepared by its expert consultant, 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.

In January 2010, the Consumer Advocate submitted its Statement of Position that HECO could not have anticipated or prevented the outage through reasonable measures, given the design and configuration of the equipment and systems in place at the time, and that HECO could not have reasonably shortened the outage and restored power more quickly to customers. The Consumer Advocate further stated that penalties should not be assessed for the outage, but recommended that numerous studies be performed with the objective of preventing or minimizing the scope and duration of future power outages.

Management cannot at this time predict the outcome of the PUC's investigation of the 2008 outage or their impact on HECO.

Intra-governmental wheeling of electricity. In June 2007, the PUC initiated a docket to examine the feasibility of implementing intra-governmental wheeling of electricity in the State of Hawaii. The PUC subsequently suspended this docket until December 1, 2010 so the parties to the Energy Agreement could evaluate the necessity of the docket in view of the other agreements of the parties. The PUC may, at its option, re-institute this docket at an earlier date.

Collective bargaining agreements. See "Collective bargaining agreements" in Note 3 of HEI'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 3 of HEI'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 (RPS). Hawaii has an RPS law, which was amended in 2006 to add provisions for penalties. In December 2008, the PUC approved a potential penalty of $20 for every MWh that an electric utility is deficient under the RPS law. See "Hawaii Clean Energy Initiative" in Note 3 of HEI's "Notes to Consolidated Financial Statements" for a further discussion of the penalty.

In January 2007, the PUC opened a docket (RPS Docket) to examine Hawaii's RPS law. In December 2007, the PUC issued a D&O approving a stipulated RPS framework to govern electric utilities' compliance with the RPS law. In the D&O, the PUC deferred an RPS incentive framework to a new generic docket (Renewable Energy Infrastructure Program (REIP) Docket).

In 2009, Hawaii's RPS law was amended to require electric utilities to meet an RPS of 10%, 15%, 25% and 40% by December 31, 2010, 2015, 2020 and 2030, respectively. The amended RPS law is consistent with the commitment in the Energy Agreement that the utilities signed as part of the HCEI. The PUC must evaluate the standards every five years, beginning in 2013, to determine whether the standards remain effective and achievable or should be revised.

In June 2009, HECO reported the utilities had attained an RPS of 18% for 2008, noting that DSM programs contributed significantly to achieving this RPS level, and indicating that, without including the energy savings, the RPS would have been 9.3% instead of 18%. Under current RPS law, energy savings resulting from energy efficiency programs will not count toward the RPS from January 1, 2015.The utilities are committed to achieving the RPS goals; however, due to risks such as potential delays in IPPs being able to deliver contracted renewable energy (see risks under Forward-looking Statements above), it is possible the electric utilities may not attain the required renewable percentages in the future.

Renewable Energy Infrastructure Program (REIP). The REIP proposed by HECO in the generic RPS Docket opened by the PUC in December 2007 consisted of two components: (1) renewable energy infrastructure projects that facilitate third-party development of renewable energy resources, maintain existing renewable energy resources and/or enhance energy choices for customers, and (2) the creation and implementation of a temporary renewable energy infrastructure surcharge to recover the capital costs, deferred costs for software development and licenses, and/or other relevant costs approved by the PUC. These costs would be removed from the surcharge and included in base rates in the utility's next rate case. In October 2008, the parties to the docket informed the PUC, among other things, that they agreed that it is appropriate that the PUC approve the utilities' proposed REIP and related REIP surcharge. In November 2008, HECO and the Consumer Advocate also 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. In December 2009, the PUC issued a D&O approving HECO's proposed REIP, including the REIP surcharge, subject to certain conditions specified in the D&O. The PUC may review the benefits and continued need for the REIP every three years or earlier if necessary.

Net energy metering (NEM). Hawaii has a NEM law, amended in 2005 and 2008, which requires that electric utilities offer NEM 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), subject to PUC-approved caps on the maximum capacity of customer generators and on the total rated generating capacity available for NEM.

In March 2008, the PUC approved a stipulated agreement filed by the utilities and Consumer Advocate 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, and to reserve a certain percentage of the 1.0% system peak demand for generators 10 kW or less.

In the Energy Agreement, the parties agreed to seek to remove system-wide caps on NEM. Instead, they planned to seek to limit DG interconnections on a per-circuit basis and to replace NEM 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.

In December 2008, HELCO, MECO and the Consumer Advocate filed stipulations to increase their NEM system caps from 1% to 3% of system peak demand (among other changes) and the PUC approved the proposed caps. The PUC directed the utilities and Consumer Advocate to file a proposed plan to address the provisions regarding NEM in the Energy Agreement, which plans were filed in August 2009. In January 2010, a stipulated agreement between the utilities and the Consumer Advocate was filed with the PUC that proposed the removal of the present system-wide cap with the adoption of revised interconnection standards to ensure ongoing reliability and safety, as well as the establishment of Reliability Standards. The proposal included adoption of a 15% per-circuit distribution generation trigger for conducting further circuit-level impact studies; removal of individual NEM program caps in favor of more overall system-wide assessments, and use of Locational Value Maps, a component of a formal Clean Energy Scenario Planning framework as an indicator of circuit penetration levels.

DSM programs. See "Demand-side management programs" above.

Non-fossil fuel purchased power contracts. In 2006, a Hawaii 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).

Renewable energy. In 2007, a Hawaii 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 Hawaii 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 Hawaii 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.

In 2009, a bill became Hawaii law (Act 185) that authorizes preferential rates to agricultural energy producers selling electricity to utilities. This will help support the long-term development of locally grown biofuel crops, cultivating potential local renewable fuel sources for the utilities. In addition, pursuant to Act 50 (also adopted in 2009), avoided cost is no longer a consideration in determining a just and reasonable rate for non-fossil fuel generated electricity. This will allow the utilities to negotiate purchased power prices for renewable energy that have the potential to be more stable and less costly than current pricing tied to avoided cost.

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

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

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. HECO and MECO have applied to the PUC for authority to enter into and recover the costs of biodiesel fuel contracts under which they will purchase biofuels to operate HECO's CIP CT-1 and to test their use in other HECO and MECO generating units.

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 additional discussion of environmental legislation and regulations, see "Environmental regulation" in Note 3 of HEI'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.

Air quality regulation. On January 25, 2010, the EPA published in the Federal Register a final new one hour primary National Ambient Air Quality Standard (NAAQS) for nitrogen dioxide (NO_2), as well as the determination to retain the existing annual average standard for NO_2. The EPA also proposed in the December 9, 2009 Federal Register a new one hour primary standard for sulfur dioxide (SO_2), and proposed to revoke the existing 24-hour and annual SO_2 standards. Both NO_2 and SO_2 are emissions from combustion equipment such as the utilities' electrical generation units. Management is currently evaluating the potential impact of these final and proposed changes to the NAAQS on the utilities.

Other developments.

Advanced Metering 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). Hearings were initially scheduled for July 2009, but have been rescheduled for July 2010. The delay will allow the utilities to provide information on their Smart Grid roadmaps, and how the proposed AMI project will facilitate the roadmaps. The additional time will also allow the utilities to assess the impact, if any, of ongoing developments with respect to their new Customer Information System (CIS) and Cyber-Security. In the fourth quarter of 2009, HECO awarded a contract to a consultant with experience in developing Smart Grid roadmaps.

The AMI project application includes a request to approve a contract between Sensus Meter Systems, Inc. and HECO under which the utilities would purchase smart meters and pay Sensus to provide and maintain an AMI system to operate the smart meters. Either party may declare the contract null and void if it is not approved by the PUC by March 31, 2010.

HECO continues to operate a Sensus AMI network, currently consisting of 8,700 advanced meters at both residential and commercial customer sites on Oahu, and started the RFP development process for the selection of commercially-available Meter Data Management (MDM) software in the fourth quarter of 2009. This effort is being closely coordinated with the utilities' plan to procure a new CIS. 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' CIS.

AMI technology enables automated meter reading, improved field service operations, improved meter accuracy, time-of-use pricing and conservation options for utility customers. The utilities plan to utilize the Smart Grid roadmaps to help explore 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 "Commitments and contingencies" in Note 3 of HEI's "Notes to Consolidated Financial Statements."

Recent accounting pronouncements. See "Recent accounting pronouncements and interpretations" in Note 1 of HEI's "Notes to Consolidated Financial Statements."

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

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

December 31	2009		2008	
(dollars in millions)				
Short-term borrowings	$ –	–%	$ 42	2%
Long-term debt, net	1,058	44	905	42
Cumulative preferred stock	22	1	22	1
Noncontrolling interest – cumulative preferred stock of subsidiaries	12	–	12	–
Common stock equity	1,306	55	1,189	55
	$2,398	100%	$2,170	100%

As of February 17, 2010, 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, 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.

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

** Following MBIA Insurance Corporation's 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.

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."

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 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." In November 2009, S&P further noted that "[r]esolution of the negative outlook will also significantly consider regulatory outcomes next year, including whether the company can demonstrate progress in moving toward a more credit-supportive regulatory model that is being contemplated as part of the Clean Energy Initiative."

S&P designates business risk profiles as "excellent," "strong," "satisfactory," "fair," "weak" or "vulnerable." S&P designates financial risk profiles as "minimal," "modest," "intermediate," "significant," "aggressive" or "highly leveraged." As of February 2010, S&P lists HECO's business risk profile as "strong" and 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 special purpose revenue bonds (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.

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 Funds From Operations (FFO) (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:

(in millions)	Year ended December 31, 2009 Average balance	End-of-period balance	December 31, 2008
Short-term borrowings			
Commercial paper	$ 0.3	$ –	$ –
Line of credit draws	11.1	–	–
Borrowings from affiliates	20.9	–	42
Line of credit facilities			
Undrawn capacity under line of credit facility expiring March 31, 2011 [1,2]		175	175
Undrawn capacity under line of credit facility expiring September 8, 2009 [3]		–	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		170	260
HELCO		55	115
MECO		25	25
Total special purpose revenue bonds available for issue		$270	$420

1 See Note 6 in HEI's "Notes to Consolidated Financial Statements" for a description of the line of credit facility. At February 17, 2010, there was no outstanding commercial paper balance and the credit facility expiring on March 31, 2011 was undrawn. 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 the agreement or extend its term, 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 eliminates from the credit agreement representations relating to the funded status of HECO's pension plan, which no longer were correct. On May 26, 2009, the PUC approved 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.

HECO utilizes short-term debt, typically commercial paper, to support normal operations and for other temporary requirements. In June 2009, HECO began drawing on its 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 December 31, 2009, HECO had $11.0 million of short-term borrowings from MECO, and HELCO had $20.1 million of short-term borrowings from HECO. HECO had average outstanding balances of commercial paper and credit facility draws for 2009 of $0.3 million and $11.1 million, respectively, and had no commercial paper or credit facility draws outstanding at December 31, 2009. Due to market conditions since September 2008 which resulted in a tightening of the commercial paper market, higher commercial paper rates and limitations on maturity options as well as a result of S&P's 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 secure 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 is the unsecured obligations of HECO and its subsidiaries under loan agreements and notes issued to the DBF, including HECO's guarantees of its subsidiaries' obligations. The payment of principal and interest due on SPRBs currently outstanding and issued prior to 2009 are insured either by Ambac Assurance Corporation, Financial Guaranty Insurance Company, MBIA Insurance Corporation (MBIA) (which bonds have been reinsured by National Public Finance Guarantee Corp.) or Syncora Guarantee 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 the insurers (or their predecessors) were downgraded and/or withdrawn by S&P and Moody's, resulting in a downgrade of the bond ratings of all of the bonds as shown in the ratings table above. The $150 million of SPRBs sold by the DBF for the benefit of HECO and HELCO on July 30, 2009, were sold without bond insurance. 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 $217 million in net cash during 2009. Investing activities used net cash of $288 million, primarily for capital expenditures, net of contributions in aid of construction. Financing activities provided net cash of $137 million, including a $153 million net increase in long-term debt, $62 million net proceeds from issuance of common stock, partly offset by $10 million net decrease in short-term borrowings and $56 million for the payment of common and preferred stock dividends.

For the five-year period 2010 through 2014, the utilities forecast $1.6 billion of gross capital expenditures, approximately 53% of which is for transmission and distribution projects and 22% for generation projects, with the remaining 25% for general plant and other projects. These estimates do not include expenditures, which could be material, that would be required to comply with final cooling water intake structure regulations that the EPA will be required to develop in response to a U.S. Supreme Court decision that is currently pending, the July 1999 Regional Haze Rule amendments or pending Maximum Achievable Control Technology or other new environmental laws or regulations that might become effective during this period, (see "Environmental regulation" in Note 3 of HEI's "Notes to Consolidated Financial Statements") or expenditures for significant renewable energy infrastructure projects not currently contemplated for that period. The electric utilities' net capital expenditures (which exclude AFUDC and capital expenditures funded by third-party contributions in aid of construction) for 2010 through 2014 are currently estimated to total approximately $1.4 billion. HECO's consolidated cash flows from operating activities (net income for common stock, adjusted for non-cash income and expense items such as depreciation, amortization and deferred taxes), after the payment of common stock and preferred stock dividends, are currently not expected to provide sufficient cash to cover the forecast net capital expenditures. Debt and equity financing are expected to be required to fund this estimated shortfall as well as to refinance maturing revenue bonds and to fund any unanticipated expenditures not included in the 2010 through 2014 forecast, such as increases in the costs or acceleration of the construction of capital projects, capital expenditures that may be required by 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 tax positions taken by the utilities do not prevail.

Proceeds from the issuances of equity, cash flows from operating activities and temporary increases in short-term borrowings are expected to provide the forecast $223 million needed for the net capital expenditures in 2010. For 2010, gross capital expenditures are estimated to be $268 million, including approximately $156 million for transmission and distribution projects, approximately $57 million for generation projects and approximately $55 million for general plant and other projects. Consolidated net capital expenditures for HECO and subsidiaries for 2009, 2008 and 2007 were $288 million, $257 million and $186 million, respectively.

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). Shortly thereafter, HECO and HELCO had drawn the full amount of the proceeds from the issuance of the SPRBs as reimbursement for previously incurred capital expenditures and had used the proceeds principally to repay short-term borrowings.

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. In October 2009, the PUC approved the utilities' sale of common stock up to the amounts requested by each utility, but subject to the limitation that the issuance not result in the utility exceeding the percentage of common stock used to calculate the capital structure approved for rate-making purposes in the utility's most recent rate case. In accordance with the limitations in the PUC authorization, HECO and HELCO sold $93 million and $3 million, respectively, of their common stock to HEI and HECO, respectively, in December 2009. For HECO's $93 million of common stock, HECO received $62 million of cash from HEI and reduced its intercompany note payable to HEI by $31 million in a noncash transaction.

For a discussion of funding for the electric utilities' retirement benefits plans, see Note 1 and Note 8 of HEI's "Notes to Consolidated Financial Statements" and "Retirement benefits" above. The electric utilities were not required to make any contributions to the qualified pension plans for 2009, 2008 and 2007 to meet minimum funding requirements pursuant to ERISA, including changes promulgated by the Pension Protection Act of 2006, but they made voluntary contributions in those years. Contributions by the electric utilities to the retirement benefit plans for 2009, 2008 and 2007 totaled $24 million, $14 million, $12 million, respectively, and are expected to total $33 million in 2010. In addition, the electric utilities paid directly less than $1 million of benefits in each of 2009, 2008 and 2007 and expect to pay less than $1 million of benefits in 2010. 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. The electric utilities believe they will have adequate access to capital resources to support any necessary funding requirements.

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

Certain factors that may affect future results and financial condition. Also see "Forward-Looking Statements" and "Certain factors that may affect future results and financial condition" for Consolidated HEI above.

HCEI Energy Agreement. HECO, for itself and its subsidiaries, entered into the Energy Agreement on October 20, 2008. For a detailed discussion of certain of the electric utilities' commitments contained in the Energy Agreement, see "Hawaii Clean Energy Initiative" in Note 3 of HEI's "Notes to Consolidated Financial Statements."

The far-reaching nature of the Energy Agreement, including the extent of renewable energy commitments and the proposal to implement a new regulatory model which would decouple revenues from sales, present new increased risks to the Company. Among such risks are: (1) the dependence on third-party suppliers of renewable purchased energy, which if the utilities are unsuccessful in negotiating purchased power agreements with such IPPs or if a major IPP fails to deliver the anticipated capacity in its purchased power agreement, could impact the utilities' achievement of their commitments under the Energy Agreement and/or the utilities' ability to deliver reliable service; (2) delays in acquiring or unavailability of non-fossil fuel supplies for renewable generation; (3) the impact of intermittent power to the electrical grid and reliability of service if appropriate supporting infrastructure is not installed or does not operate effectively; (4) the likelihood that the utilities may need to make substantial investments in related infrastructure, which could result in increased borrowings and materially impact the financial condition and liquidity of the utilities; and (5) the commitment to support a variety of initiatives, which, if approved by the PUC, may have a material impact on the results of operations and financial condition of the utilities depending on their design and implementation. These programs include, but are not limited to, decoupling revenues from sales; implementing feed-in tariffs to encourage development of renewable energy; removing the system-wide caps on net energy metering (but limiting DG interconnections on a per-circuit basis to no more than 15% of peak circuit demand); and developing an Energy Efficiency Portfolio Standard. Management cannot predict the ultimate impact or outcome of the implementation of these or other HCEI programs on the results of operations, financial condition and liquidity of the electric utilities.

Regulation of electric utility rates. The rates the electric utilities are allowed to charge for their services, and the timeliness of permitted rate increases, are among the most important items influencing their financial condition, results of operations and liquidity. The PUC has broad discretion over the rates the electric utilities charge and other matters. Any adverse decision by the PUC concerning the level or method of determining electric utility rates, the items and amounts permitted to be included in rate base, the authorized returns on equity or rate base found to be reasonable, the potential consequences of exceeding or not meeting such returns, or any prolonged delay in rendering a decision in a rate or other proceeding could have a material adverse affect on the Company's and HECO's consolidated results of operations, financial condition and liquidity. Upon a showing of probable entitlement, the PUC is required to issue an interim D&O in a rate case within 10 months from the date of filing a completed application if the evidentiary hearing is completed (subject to extension for 30 days if the evidentiary hearing is not completed). There is no time limit for rendering a final D&O. Interim rate increases are subject to refund with interest, pending the final outcome of the case. Through December 31, 2009, HECO and its subsidiaries had recognized $281 million of revenues with respect to interim orders ($5 million related to interim orders regarding certain integrated resource planning costs and $276 million related to interim orders regarding general rate increase requests), which revenues are subject to refund, with interest, if and to the extent they exceed the amounts allowed in final orders. 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 decision is pending on these costs.

Management cannot predict when the final D&Os in pending or future rate cases will be rendered or the amount of any interim or final rate increase that may be granted. Further, the increasing levels of O&M expenses (including increased retirement benefit costs), increased plant-in-service, and other factors have and are likely to continue to result in the electric utilities seeking rate relief more often than in the past.

The rate schedules of each of HEI's electric utilities include ECACs under which electric rates charged to customers are automatically adjusted for changes in the weighted-average price paid for fuel oil and certain components of purchased power, and the relative amounts of company-generated power and purchased power. Act 162 of the 2006 Hawaii legislature requires an examination of the need for continued use of ECACs and specifies certain factors that must be considered. See "Energy cost adjustment clauses" in Note 3 of HEI's "Notes to consolidated financial statements."

Also see "HCEI Energy Agreement" above for a discussion of the proposal to implement a new regulatory model which would decouple revenues from sales.

Fuel oil and purchased power. The electric utilities rely on fuel oil suppliers and IPPs to deliver fuel oil and power, respectively. See "Fuel contracts" and "Power purchase agreements" in Note 3 of HEI's "Notes to Consolidated Financial Statements." The Company estimates that 74% of the net energy generated and purchased by HECO and its subsidiaries in 2010 will be generated from the burning of fossil fuel oil. Purchased KWHs provided approximately 40.2% of the total net energy generated and purchased in 2009 compared to 40.4% in 2008 and 39.5% in 2007.

Failure or delay by the electric utilities' oil suppliers and shippers to provide fuel pursuant to existing supply contracts, or failure by a major IPP to deliver the firm capacity anticipated in its PPA, could interrupt the ability of the electric utilities to deliver electricity, thereby materially adversely affecting the Company's results of operations and financial condition. HECO generally maintains an average system fuel inventory level equivalent to 35 days of forward consumption. HELCO and MECO generally maintain an inventory level equivalent to one month's supply of both medium sulfur fuel oil and diesel fuel. Some, but not all, of the electric utilities' PPAs require that the IPPs maintain minimum fuel inventory levels and all of the firm capacity PPAs include provisions imposing substantial penalties for failure to produce the firm capacity anticipated by those agreements.

Other operation and maintenance expenses. Other operation and maintenance expenses increased 3%, 8% and 16% for 2009, 2008 and 2007, respectively, when compared to the prior year. This trend of increased operation and maintenance expenses is expected to continue in 2010 as the electric utilities expect higher production expenses (primarily to support the level of demand that has occurred over the past five years), higher costs for material and contract services and higher transmission and distribution expense to maintain system reliability. The timing and amount of these expenses can vary as circumstances change. For example, recent overhauls have been more expensive than in the past due to the larger scope of work necessary to maintain aging equipment, which has experienced heavier usage as demand has increased to current levels. Also, the cost of overhauls can be higher than originally planned after full assessments of the repair work are performed. Increased operation and maintenance expenses were among the reasons HECO, HELCO and MECO filed requests with the PUC in recent years to increase base rates. In addition, the costs of environmental compliance continue to increase with more stringent regulatory requirements.

Other regulatory and permitting contingencies. Many public utility projects require PUC approval and various permits (e.g., environmental and land use permits) from other agencies. Delays in obtaining PUC approval or permits can result in increased costs. If a project does not proceed or if the PUC disallows costs of the project, the project costs may need to be written off in amounts that could have a material adverse effect on the Company. Two major capital improvement utility projects, the Keahole project (consisting of CT-4, CT-5 and ST-7) and the East Oahu Transmission Project, encountered opposition and were seriously delayed (although CT-4, CT-5 and ST-7 at Keahole are now operating). See Note 3 of HEI's "Notes to Consolidated Financial Statements" for a discussion of additional regulatory contingencies.

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 3 of HEI'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.

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 of the Oahu Renewable Energy RFP and 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 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 and fourth quarters of 2008, the PUC granted requests for waivers from the Competitive Bidding Framework for five projects. The waivers for four of the five projects subsequently expired without reaching agreement on a term sheet. Discussions on the fifth waivered project continued. HECO and HELCO then proposed a competitive bidding process to acquire renewable generation on the island of Hawaii.

In March 2009, HELCO reached agreement on a term sheet with the fifth and remaining waivered biomass project. Since this term sheet agreement would have an effect on the proposed competitive bidding process, 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 recommended that HELCO not proceed with an RFP at this time and instead conduct further analyses to determine what resource attributes would be most beneficial to the HELCO system and then assess how best to acquire those resources. Those analyses are currently being performed 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 for the three projects. HECO and Kahuku Wind Power signed a PPA in July 2009. The PPA and an amendment were submitted to the PUC for approval in August 2009 and February 2010, respectively. HECO and Honua Power signed a PPA in December 2009, and the PPA was submitted to the PUC for approval in January 2010. Negotiations to reach a PPA with OTEC International, LLC (formerly known as Sea Solar Power International) are currently ongoing.

In September 2009, HECO filed a request for an exemption or waiver from the competitive bidding framework for the City and County of Honolulu's proposed HPower expansion project, which involves a modification of an existing PPA with the City. In December 2009, the PUC declared the project exempt from the competitive bidding framework.

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. 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 rate-making treatment for $0.4 million of capital and overhaul reimbursement payments by HECO to the Department of Transportation under the terms of the agreement. HECO and the Department of Transportation amended the agreement to provide HECO with the ability to seek cost recovery for these expenses in accordance with the PUC order. The amendment was filed for PUC approval in November 2009. HECO will seek cost recovery of overhaul reimbursement payments in the next applicable general rate case proceeding.

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. HECO is conducting planning analyses to determine whether to keep the temporary DG units that were installed at various HECO substations in 2005 to 2007 in service. If a positive determination is made, HECO will conduct feasibility reviews of extending use of the units 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 was placed in service in September 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 with the PUC in June 2009, concluding that the process has been working efficiently.

On January 7, 2010, a request to modify the DG interconnection tariff was filed by the utilities. Among other modifications, the utilities are seeking to relax requirements for conducting detailed interconnection studies, and are proposing modifications to some technical requirements to accommodate the significant increase in distributed renewable energy generating unit installations that is anticipated as a result of initiatives such as the feed-in tariff. On January 27, 2010, the PUC suspended the request and opened a separate proceeding to examine the proposed modifications.

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

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

The 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.

Environmental matters. The HECO, HELCO and MECO generating stations operate under air pollution control permits issued by the Hawaii Department of Health (DOH) and, in a limited number of cases, by the EPA. The 2004 Hawaii State Legislature passed legislation that clarifies that the accepting agency or authority for an environmental impact statement is not required to be the approving agency for the permit or approval and also requires an environmental assessment for proposed waste-to-energy facilities, landfills, oil refineries, power-generating facilities greater than 5 MW and wastewater facilities, except individual wastewater systems. These requirements result in increased project costs.

The 1990 amendments to the Clean Air Act, changes to the National Ambient Air Quality Standard (NAAQS) for ozone, and adoption of a NAAQS for fine particulate matter resulted in substantial changes for the electric utility industry. Further significant impacts may occur if currently proposed legislation, rules and standards are adopted (e.g., greenhouse gas emission reduction rules, proposed sulfur dioxide NAAQS) or are deemed applicable to company facilities (e.g., Regional Haze Rule amendments, nitrogen dioxide NAAQS), or if new legislation, rules or standards are adopted in the future.

Pending environmental matters that may adversely affect the Company's future operating results and financial condition include the ongoing Honolulu Harbor environmental investigation, the July 1999 Regional Haze Rule amendments, section 112 of the Clean Air Act and section 316(b) of the federal Clean Water Act, which are discussed under "Environmental regulation" in Note 3 of HEI's "Notes to Consolidated Financial Statements." There can be no assurance that a significant environmental liability will not be incurred by the electric utilities or that the related costs will be recoverable through rates.

Additional environmental compliance costs are expected to be incurred as a result of the initiatives called for in the Energy Agreement, including permitting and siting costs for new facilities and testing and permitting costs related to changing to the use of biofuels.

Management believes that the recovery through rates of most, if not all, of any costs incurred by HECO and its subsidiaries in complying with environmental requirements would be allowed by the PUC, but no assurance can be given that this will in fact be the case.

Technological developments. New technological developments (e.g., the commercial development of fuel cells, DG, and generation from renewable sources.) may impact the electric utility's future competitive position, results of operations and financial condition.

Material estimates and critical accounting policies. Also see "Material estimates and critical accounting policies" for Consolidated HEI above.

Property, plant and equipment. Property, plant and equipment are reported at cost. Self-constructed electric utility plant includes engineering, supervision, and administrative and general costs, and an allowance for the cost of funds used during the construction period. These costs are recorded in construction in progress and are transferred to property, plant and equipment when construction is completed and the facilities are either placed in service or become useful for public utility purposes. Upon the retirement or sale of electric utility plant, no gain or loss is recognized. The cost of the plant retired is charged to accumulated depreciation. Amounts collected from customers for cost of removal (expected to exceed salvage value in the future) are included in regulatory liabilities.

HECO and its subsidiaries evaluate the impact of applying FASB Accounting Standards Codification (ASC) Topic 840-10 to their new PPAs, PPA amendments and other arrangements they enter into. A possible outcome of the evaluation is that an arrangement results in its classification as a capital lease, which could have a material effect on HECO's consolidated balance sheet if a significant amount of capital assets and lease obligations needed to be recorded.

Management believes that the PUC will allow recovery of property, plant and equipment in its electric rates. If the PUC does not allow recovery of any such costs, the electric utility would be required to write off the disallowed costs at that time. See the discussion under "Major projects" in Note 3 of HEI's "Notes to Consolidated Financial Statements" concerning costs of major projects that have not yet been approved for inclusion in the applicable utility's rate base.

Regulatory assets and liabilities. The electric utilities are regulated by the PUC. In accordance with ASC Topic 980, the Company's financial statements reflect assets, liabilities, revenues and costs of HECO and its subsidiaries based on current cost-based rate-making regulations. The actions of regulators can affect the timing of recognition of revenues, expenses, assets and liabilities.

Regulatory liabilities represent amounts collected from customers for costs that are expected to be incurred in the future. Regulatory assets represent incurred costs that have been deferred because their recovery in future customer rates is probable. As of December 31, 2009, the consolidated regulatory liabilities and regulatory assets of the utilities amounted to $288 million and $427 million, respectively, compared to $289 million and $531 million as of December 31, 2008, respectively. Regulatory liabilities and regulatory assets are itemized in Note 3 of HEI's "Notes to Consolidated Financial Statements." Management continually assesses whether the regulatory assets are probable of future recovery by considering factors such as changes in the applicable regulatory environment. Because current rates include the recovery of regulatory assets existing as of the last rate case and rates in effect allow the utilities to earn a reasonable rate of return, management believes that the recovery of the regulatory assets as of December 31, 2009 is probable. This determination assumes continuation of the current political and regulatory climate in Hawaii, and is subject to change in the future.

Management believes HECO and its subsidiaries' operations currently satisfy the criteria for regulatory accounting. If events or circumstances should change so that those criteria are no longer satisfied, the electric utilities expect that the regulatory assets would be charged to expense and the regulatory liabilities would be credited to income or refunded to ratepayers. In the event of unforeseen regulatory actions or other circumstances, however, management believes that a material adverse effect on the Company's results of operations and financial position may result if regulatory assets have to be charged to expense without an offsetting credit for regulatory liabilities or if regulatory liabilities are required to be refunded to ratepayers.

Revenues. Electric utility revenues are based on rates authorized by the PUC and include revenues applicable to energy consumed in the accounting period but not yet billed to customers. As of December 31, 2009, revenues applicable to energy consumed, but not yet billed to customers, amounted to $84 million.

Revenue amounts recorded pursuant to a PUC interim order are subject to refund, with interest, pending a final order. As of December 31, 2009, HECO and its subsidiaries had recognized $281 million of such revenues with respect to interim orders. Also, the rate schedules of the electric utilities include ECACs under which electric rates are adjusted for changes in the weighted-average price paid for fuel oil and certain components of purchased power, and the relative amounts of company-generated power and purchased power. See "Regulation of electric utility rates" above.

Consolidation of variable interest entities (VIEs). In December 2003, the FASB issued a revised standard on the consolidation of VIEs, which addresses how a business enterprise should evaluate whether it has a controlling financial interest in an entity through means other than voting rights and accordingly should consolidate the entity. The Company evaluates the impact of applying ASC Topic 810 to its relationships with IPPs with whom the electric utilities execute new PPAs or execute amendments of existing PPAs. A possible outcome of the analysis is that HECO (or its subsidiaries, as applicable) may be found to meet the definition of a primary beneficiary of a VIE (the IPP) which finding may result in the consolidation of the IPP in HECO's consolidated financial statements. The consolidation of IPPs 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. The electric utilities do not know how the consolidation of IPPs would be treated for regulatory or credit ratings purposes. See Notes 1 and 5 of HEI's "Notes to Consolidated Financial Statements."

Bank

Executive overview and strategy. When ASB was acquired by HEI in 1988, it was a traditional thrift with assets of $1 billion and net income of about $13 million. ASB has grown by both acquisition and internal growth since 1988 and ended 2009 with assets of $4.9 billion and net income of $22 million, compared to assets of $5.4 billion as of December 31, 2008 and net income of $18 million in 2008. During 2009, ASB sold its private issue mortgage-related securities portfolio to reduce its credit risk and improve the prospects for consistent future earnings. The sales resulted in a net charge of $19 million in the fourth quarter of 2009. ASB also improved its interest rate risk by selling substantially all of its salable fixed rate residential loan production during 2009 into the secondary market. A portion of the excess liquidity was used to pay off other borrowings that were maturing.

ASB is now a full-service community bank serving both consumer and commercial customers. In order to remain competitive and continue building core franchise value, the bank continues to develop and introduce new products and services in order to meet the needs of those markets. Additionally, the banking industry is constantly changing and ASB is making the investments in people and technology necessary to adapt and remain competitive. ASB's ongoing challenge is to increase revenues and control expenses through its performance improvement project.

The interest rate environment, the quality of ASB's assets, and the strategic transformation of ASB from a traditional thrift to a community bank have impacted and will continue to impact its financial results.

ASB continues to face a challenging interest rate environment. The weak global, national and local economic environments have resulted in a persistent, low level of interest rates, weak loan demand, and excess liquidity in the financial system. In addition, expectations are increasing that interest rates will rise rapidly once there are strong signs that the economic recovery is taking hold. The bank's decision to sell substantially all fixed rate mortgage production throughout 2009, weak loan demand, and challenges in finding investments with adequate risk-adjusted returns resulted in declining loan balances and an increase in the bank's liquidity position, which had a negative impact on the bank's asset yields and net interest margin. The potential for compression of ASB's margin when interest rates rise is an ongoing concern.

As part of its interest rate risk management process, ASB uses simulation analysis to measure net interest income sensitivity to changes in interest rates (see "Quantitative and Qualitative Disclosures about Market Risk"). ASB then employs strategies to limit the impact of changes in interest rates on net interest income. ASB's key strategies include:

(1) attracting and retaining low-cost, core deposits, particularly those in non-interest bearing transaction accounts;
(2) reducing the overall exposure to fixed-rate residential mortgage loans and diversifying the loan portfolio with higher-spread, shorter-maturity loans or variable-rate loans such as commercial, commercial real estate and consumer loans;
(3) managing costing liabilities to optimize cost of funds and manage interest rate sensitivity; and
(4) focusing new investments on shorter duration or variable rate securities.

ASB's loan quality weakened in 2009, although not to the same level of decline in loan quality seen in many mainland U.S. markets. The slowdown in the economy, both nationally and locally, has caused increased levels of financial stress on the part of ASB's customers, resulting in higher levels of loan delinquencies and losses. As a result, ASB's provision for loan losses has increased, following several years of historically low loan losses and loan loss allowances. The outlook for the Hawaii economy is mixed. While the prospects for a mild recovery in Hawaii to begin in 2010 are growing as the global economic recovery begins to take hold, many challenges remain. Consumers and businesses are expected to continue to struggle in 2010 as significant improvement in measures such as job growth, unemployment and real personal income are not expected until 2011. Continued financial stress on ASB's customers and falling home prices may result in higher levels of loan delinquencies and losses.

The weak national economic environment and declines in the national housing market impacted securities in ASB's investment portfolio. The rating agencies downgraded the ratings on a significant number of mortgage-related securities in 2009, including several mortgage-related securities held in ASB's portfolio. During the first nine months of 2009, ASB recognized a pretax OTTI charge of $15 million on its private-issue mortgage-related securities portfolio. In the fourth quarter of 2009, ASB sold its private-issue mortgage-related securities portfolio and recognized a pretax charge of $32 million.

Results of operations.

(dollars in millions)		2009	% change		2008	% change		2007
Revenues	$	275	(23)	$	359	(16)	$	425
Net interest income		201	(3)		207	5		197
Operating income		32	18		27	(68)		84
Net income		22	22		18	(66)		53
Return on average common equity [1]		4.5%			3.2%			9.4%
Earning assets								
Average balance [1]	$	4,804	(16)	$	5,722	(12)	$	6,473
Weighted-average yield		5.10%	(7)		5.46%	(1)		5.52%
Costing liabilities								
Average balance [1]	$	3,801	(20)	$	4,754	(14)	$	5,515
Weighted-average rate		1.15%	(48)		2.22%	(23)		2.90%
Net interest margin [2]		4.19%	16		3.62%	19		3.05%

1 Calculated using the average daily balances.

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

- Net interest income before provision for loan losses for 2009 decreased by $5.7 million, or 2.8%, when compared to 2008 due to lower balances and yields of earning assets, partly offset by lower funding costs. ASB's average interest earning assets decreased by $918 million primarily due to the balance sheet restructure in June 2008 and ASB's sales of the residential loans it produced in 2009. Net interest margin increased from 3.62% in 2008 to 4.19% in 2009 due to the balance sheet restructure, which removed lower-spread net assets (investment and mortgage-related securities and other borrowings) and lowered funding costs as a result of the outflow of higher costing term certificates, a shift in deposit mix and the paydown of other borrowings. The decrease in the average loan portfolio balance was due to a decrease in the average 1-4 family residential loan portfolio of $315 million as ASB sold substantially all of its salable residential loan production in the current low interest rate environment. Offsetting the decrease in the residential loan portfolio were increases in the average balances of the home equity line of credit and commercial markets portfolios of $66 million and $39 million, respectively. The average investment and mortgage-related securities portfolio balances decreased by $797 million due to the balance sheet restructure in June 2008 and the sale of the private-issue mortgage-related securities portfolio in the fourth quarter of 2009. The other investments average balance increased by $114 million due to an increase in liquidity as a result of the bank's fixed rate mortgage production sales throughout 2009, weak loan demand, and challenges in finding investments with adequate risk-adjusted returns. Average deposit balances for 2009 decreased by $140 million compared to 2008 as ASB experienced an outflow of term certificates of $337 million, partly offset by an inflow in core deposits of $197 million. The decrease in other borrowings average balance was due to the early extinguishment of other borrowings in the balance sheet restructure in 2008 and the paydown of maturing other borrowings in 2009 with excess liquidity.

During 2009, ASB recorded a provision for loan losses of $32 million, or $21.7 million higher than the provision for loan losses in 2008, primarily due to a $10 million provision for loan loss on a commercial loan that was subsequently sold and a higher level of nonperforming residential 1-4 family, residential lot and consumer loans and increases in the historical loss ratios for these loan types. ASB's nonaccrual and renegotiated loans represented 2.3%, 0.7% and 0.2% of total loans outstanding as of December 31, 2009, 2008 and 2007, respectively. Current levels of delinquencies and loan loss provisions are expected to be higher than pre-2009 historical levels.

Net charge-offs for 2009 totaled $26.1 million compared to $4.7 million in 2008. The increase from 2008 to 2009 in net charge-offs was primarily due to the $10 million partial charge-off of a commercial loan that was subsequently sold and higher residential 1-4 family, residential lot and home equity lines of credit charge-offs. In the fourth quarter of 2009, ASB recorded charge-offs of $7.2 million relating to residential 1-4 family, residential lot and home equity lines of credit loans, which had specific allowance for loan losses allocated to them in prior periods. ASB took a partial charge-off on these loans for the amount of the specific allowance for loan losses.

Noninterest income for 2009 of $29.9 million was $16.2 million lower than noninterest income for 2008, primarily due to higher losses on sale of securities and higher OTTI charges. Excluding the losses on sale of securities and the OTTI charges, noninterest income for 2009 was $6.1 million higher than 2008, primarily due to higher gains on sale of loans and deposit account fees. 2008 noninterest income included insurance recoveries on legal and litigation matters of $4.3 million and a $1.9 million gain on sale of stock in membership organizations

Noninterest expense for 2009 decreased by $48.6 million when compared to 2008, primarily due to losses on the early extinguishment of certain borrowings from the balance sheet restructuring in 2008. Excluding the losses from the balance sheet restructuring, noninterest expense for 2009 decreased by $8.7 million primarily due to lower consulting and contract services, compensation and equipment expenses, partly offset by higher data processing expenses and an FDIC special assessment of $2.3 million. In 2008, ASB began a performance improvement project, which is expected to last through 2010, to increase revenues, reduce the bank's cost structure through improved processes and procedures and improve the efficiency of ASB. The performance improvement project includes changes to bank operating processing, reorganization of personnel and review of bank real estate, and may require ASB to record charges to earnings during 2010 in order to be able to recognize benefits in future periods. Included in 2009 noninterest expenses were the following charges related to ASB's performance improvement project:

- Real estate transaction losses and expenses of $3.9 million
- Professional services costs of $2.5 million
- Severance of $1.7 million
- Fiserv (service bureau) conversion costs of $1.7 million
- Prepayment penalty on early extinguishment of debt of $0.7 million
- Technology software write-off of $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 $2.3 million (to be incurred in the first half of 2010).

- Net interest income before provision for loan losses for 2008 increased by $10 million, or 5.0%, when compared to 2007 as falling interest rates lowered funding costs faster than yields on earning assets. Net interest margin increased from 3.05% in 2007 to 3.62% in 2008 due to the restructuring of the balance sheet, which removed lower spread net assets (investment and mortgage-related securities and other borrowings), growth in the loan portfolio and lower funding costs. The growth in the loan portfolio was due to growth in home equity lines of credit and continued growth in commercial market loans and residential loans purchased. The decrease in average interest-bearing deposit balances was due to the downward trend in interest rates that made it difficult to retain deposits. The level of interest rates contributed to lower funding costs as interest-bearing deposits and other borrowings repriced to lower rates.

ASB had good loan quality during 2008 despite a weakening economy and slowing real estate market. A provision for loan losses of $10.3 million was recorded in 2008, primarily due to an increase in the classification of commercial loans and an increase in nonperforming residential lot loans. This compares with a provision for loan losses of $5.7 million in 2007 primarily due to specific reserves for one commercial borrower and the reclassification of certain commercial loans that had identified weaknesses. The allowance is adjusted continuously through the provision for loan losses to reflect factors such as charge-offs; outstanding loan balances; loan grading; external factors affecting the national and Hawaii economy, specific industries and sectors and interest rates; and historical and projected loan losses.

Noninterest income for 2008 decreased by $22.3 million from 2007 primarily due to losses on the sale of securities from the balance sheet restructuring and the write-down of two securities for other-than-temporary impairment. Excluding the losses from the balance sheet restructuring and the other-than-temporary impairment charge, noninterest income for 2008 increased by $4.8 million due to $4.3 million of insurance recoveries on legal and litigation matters and a $1.9 million gain on sales of stock in Mastercard International and VISA, Inc.

Noninterest expense for 2008 increased by $40.1 million over 2007 primarily due to losses on early extinguishment of certain borrowings from the balance sheet restructuring. Excluding the losses from the balance sheet restructuring, noninterest expense increased by $0.3 million due to higher compensation expense (as a result of the recognition in 2007 of a pension curtailment gain of $8.8 million) and higher incentive and severance costs, partly offset by lower consulting, contract services and legal expenses.

In the fourth quarter of 2008, ASB's results were impacted by the sharp decline in the Hawaii economy, the depressed national economy and the volatility in the financial markets. Credit risk for ASB has risen--residential loan delinquencies started to trend upward resulting in the increased provision for loan losses and the value of mortgage-related securities became impaired resulting in the write-down of two securities to fair value.

See Note 4 of HEI's "Notes to Consolidated Financial Statements" for a discussion of guarantees and further information about ASB.

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 2009, 2008 and 2007.

	2009			2008		
($ in thousands)	Average balance	Interest	Average rate (%)	Average balance	Interest	Average rate (%)
Assets:						
Other investments [1]	$ 237,770	$ 329	0.14	$ 123,819	$ 1,542	1.25
Investment and mortgage-related securities	627,365	26,648	4.25	1,424,015	63,666	4.47
Loans receivable [2]	3,938,575	217,838	5.53	4,173,802	247,210	5.92
Total interest-earning assets	4,803,710	244,815	5.10	5,721,636	312,418	5.46
Allowance for loan losses	(42,121)			(30,829)		
Non-interest-earning assets	352,398			415,822		
Total assets	$5,113,987			$6,106,629		
Liabilities and Stockholder's Equity:						
Interest-bearing demand and savings deposits	$2,234,259	6,676	0.30	$2,094,396	11,953	0.57
Time certificates	1,140,997	27,370	2.40	1,478,427	49,530	3.35
Total interest-bearing deposits	3,375,256	34,046	1.01	3,572,823	61,483	1.72
Other borrowings	425,947	9,497	2.23	1,180,844	43,941	3.72
Total interest-bearing liabilities	3,801,203	43,543	1.15	4,753,667	105,424	2.22
Non-interest bearing liabilities:						
Deposits	743,982			686,461		
Other	89,248			104,539		
Stockholder's equity	479,554			561,962		
Total Liabilities and Stockholder's Equity	$5,113,987			$6,106,629		
Net interest income		$201,272			$206,994	
Net interest margin (%) [3]			4.19			3.62

($ in thousands)	2007 Average balance	Interest	Average rate (%)
Assets:			
Other investments [1]	$ 196,504	$ 5,581	2.84
Investment and mortgage-related securities	2,350,821	105,889	4.50
Loans receivable [2]	3,925,186	245,593	6.26
Total interest-earning assets	6,472,511	357,063	5.52
Allowance for loan losses	(31,509)		
Non-interest-earning assets	376,655		
Total assets	$6,817,657		
Liabilities and Stockholder's Equity:			
Interest-bearing demand and savings deposits	$2,168,672	16,805	0.77
Time certificates	1,633,871	65,074	3.98
Total interest-bearing deposits	3,802,543	81,879	2.15
Other borrowings	1,712,642	78,019	4.56
Total interest-bearing liabilities	5,515,185	159,898	2.90
Non-interest bearing liabilities:			
Deposits	640,198		
Other	96,461		
Stockholder's equity	565,813		
Total Liabilities and Stockholder's Equity	$6,817,657		
Net interest income		$197,165	
Net interest margin (%) [3]			3.05

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

2 Includes loan fees of $6.9 million, $4.4 million and $4.5 million for 2009, 2008 and 2007, respectively, together with interest accrued prior to suspension of interest accrual on nonaccrual loans.

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

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

Loan originations and 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. See Note 4 of HEI's "Notes to Consolidated Financial Statements" for the composition of ASB's loans receivable.

The decrease in the total loan portfolio from $4.2 billion at the end of 2008 to $3.7 billion at the end of 2009 was primarily due to ASB's strategic decision to sell substantially all of its 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.

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

December 31 (dollars in thousands)	2009	2008
Real estate loans:		
Residential 1-4 family	$31,686	$ 7,335
Commercial real estate	344	–
Home equity line of credit	2,755	716
Residential land	25,162	7,458
Commercial construction	–	–
Residential construction	325	189
	60,272	15,698
Commercial	4,171	2,801
Consumer	715	488
Total nonperforming loans	65,158	18,987
Real estate owned:		
Residential 1-4 family	1,806	–
Residential land	2,153	1,492
Total real estate owned loans	3,959	1,492
Total nonperforming assets	$69,117	$20,479
Nonperforming assets to total loans and REO	1.85%	0.48%

The increase in nonperforming loans was primarily due to higher amounts of residential first mortgage and land loans that are 90 days or more past due and also reflects the impact of rising unemployment in Hawaii and the weak economic environment globally, nationally and in Hawaii.

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:

December 31	2009		2008	
(dollars in thousands)	Balance	% of total	Balance	% of total
Real estate loans:				
Residential 1-4 family	$ 5,522	62.5	$ 4,024	66.2
Commercial real estate	861	6.9	2,229	5.7
Home equity line of credit	4,679	8.8	548	6.4
Residential land	4,252	2.6	1,953	3.0
Commercial construction	3,068	1.8	1,748	1.7
Residential construction	19	0.5	88	0.8
Total real estate loans, net	18,401	83.1	10,590	83.8
Commercial	19,498	14.6	22,294	14.0
Consumer	2,590	2.3	2,190	2.2
	40,489	100.0	35,074	100.0
Unallocated	1,190		724	
Total allowance for loan losses	$41,679		$35,798	

The increase in the allowance for loan losses was primarily due to higher delinquencies of residential first mortgage and land loans and home equity lines of credit and increases in the historical loss ratios for these loan types and also reflects the impact of rising unemployment and the weak economic environment globally, nationally and in Hawaii.

Investment and mortgage-related securities. As of December 31, 2009, ASB's investment portfolio consisted of 75% mortgage-related securities issued by Federal National Mortgage Association (FNMA), Federal Home Loan Mortgage Corporation (FHLMC) or Government National Mortgage Association (GNMA), 24% federal agency obligations and 1% municipal bonds. In the fourth quarter of 2009, ASB sold its private-issue mortgage-related securities portfolio. As of December 31, 2008, ASB's investment portfolio consisted of 46% mortgage-related securities issued by FNMA, FHLMC or GNMA, 45% private-issue mortgage-related securities and 9% federal agency obligations.

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. ASB sold its private-issue mortgage related securities to reduce the bank's overall credit risk and improve prospects for more consistent future earnings. Private-issue mortgage-related securities carried a risk of loss due to delinquencies, foreclosures and losses in the mortgage loans that collateralized the securities. The velocity of economic decline had exacerbated already weak home sales, which were impacted not only by borrowers being unable to secure financing, but also by those that defaulted on current loans as a result of unemployment trends or payment shocks (such as when interest rates increase substantially under an adjustable rate mortgage). The flood of inventory as a result of foreclosures pressured prices and thus the credit of securities held in the portfolio.

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 December 31, 2009, ASB's costing liabilities consisted of 93% deposits and 7% other borrowings. As of December 31, 2008, ASB's costing liabilities consisted of 86% deposits and 14% other borrowings. See Note 4 of HEI's "Notes to Consolidated Financial Statements" for the composition of ASB's deposit liabilities and 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. The bank has reduced its overall credit risk by selling its private-issue mortgage-related securities portfolio.

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 fourth quarter of 2009 and in the 2008 balance sheet restructure) or an "other-than-temporary" impairment in the value of the securities. As of December 31, 2009, ASB had unrealized gains, net of taxes, on available-for-sale investments and mortgage-related securities (including securities pledged for repurchase agreements) in AOCI of $5 million compared to unrealized losses, net of tax benefits, of $33 million at December 31, 2008. The change in AOCI was primarily due to the sale of the private-issue mortgage-related securities portfolio. In addition the pricing for agency securities improved during the year. See "Quantitative and qualitative disclosures about market risk."

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 U. S. Department of the Treasury released *Financial Regulatory Reform: A New Foundation (Proposal)*. The Proposal, if adopted in its current form, would eliminate the OTS and the federal thrift charter. On December 11, 2009, the House of Representatives passed the Wall Street Reform and Consumer Protection Act of 2009, which also would abolish the OTS and transfer its functions and personnel to a division within the Office of the Comptroller of the Currency.

The Proposal identified a number of so-called "loopholes" in the current regulatory framework that 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 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. Through the Wall Street Reform and Consumer Protection Act of 2009 (H. R. 4173 of the 111th Congress, 1st Session), however, the Congress is continuing the discussion of "grandfathered" bank holding companies in the context of the Gramm-Leach-Bliley Act of 1999 (the Gramm Act). Management will continue to follow this issue closely as adoption of this legislation or the Proposal could result in HEI being required to divest ASB.

In January 2010, the FDIC released for comment a proposal to modify its risk-based deposit insurance system to account for risks posed by the compensation systems of insured banks and their holding companies. Management cannot predict at this time whether the proposed rule will be adopted as proposed or in some modified form or, if adopted, what impact it may have on ASB's FDIC insurance rate.

FHLB of Seattle stock. 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. The FHLB of Seattle reported a net loss of $144 million for the nine months ended September 30, 2009. The loss was attributed to $264 million of OTTI charges on its private-label mortgage-backed securities. The FHLB of Seattle noted that all of these securities have performed according to their contractual terms, and the FHLB of Seattle maintains a strong credit position with respect to any losses on these securities. Despite the loss, the FHLB of Seattle reported retained earnings of $70 million and was in compliance with all of its regulatory capital requirements, including its risk-based capital requirement as of September 30, 2009. However, the FHLB of Seattle remains classified as "undercapitalized" by its regulator, the Federal Housing Finance Agency, and may not redeem or repurchase capital stock or pay dividends on its stock. ASB does not believe that the Federal Housing Finance Agency's classification of the FHLB of Seattle 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 $0.6 million in 2007, $0.9 million in 2008 and nil in 2009.

Periodically and as conditions warrant, ASB reviews its investment in the stock of FHLB of Seattle for impairment. See "FHLB of Seattle stock" in Note 4 of HEI's "Notes to Consolidated Financial Statements" for a discussion of ASB's evaluation of its investment in FHLB stock for OTTI as of December 31, 2009.

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

Recent accounting pronouncements. See "Recent accounting pronouncements and interpretations" in Note 1 of HEI's "Notes to Consolidated Financial Statements."

Liquidity and capital resources.

December 31	2009	% change	2008	% change
(dollars in millions)				
Total assets	$4,941	(9)	$5,437	(21)
Available-for-sale investment and mortgage-related securities	433	(34)	658	(69)
Loans receivable, net	3,670	(13)	4,206	3
Deposit liabilities	4,059	(3)	4,180	(4)
Other bank borrowings	298	(56)	681	(62)

As of December 31, 2009, ASB was one of Hawaii's largest financial institutions based on assets of $4.9 billion and deposits of $4.1 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.

ASB's principal sources of liquidity are customer deposits, borrowings and the maturity and repayment of portfolio loans and securities. ASB's deposits as of December 31, 2009 were $121 million lower than December 31, 2008. ASB's principal sources of borrowings are advances from the FHLB and securities sold under agreements to repurchase from broker/dealers. As of December 31, 2009, FHLB borrowings totaled approximately $65 million, representing 1% of assets. ASB is approved to borrow from the FHLB up to 35% of ASB's assets to the extent it provides qualifying collateral and holds sufficient FHLB stock. As of December 31, 2009, ASB's unused FHLB borrowing capacity was approximately $1.6 billion. As of December 31, 2009, securities sold under agreements to repurchase totaled $233 million, representing 5% of assets. ASB utilizes deposits, advances from the FHLB and securities sold under agreements to repurchase to fund maturing and withdrawable deposits, repay maturing borrowings, fund existing and future loans and purchase investment and mortgage-related securities. As of December 31, 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 December 31, 2009 and 2008, ASB had $65.3 million and $19.5 million of loans on nonaccrual status, respectively, or 1.8% and 0.5% of net loans outstanding, respectively. As of December 31, 2009 and 2008, ASB had $4.0 million and $1.5 million, respectively, of real estate acquired in settlement of loans.

In 2009, operating activities provided cash of $85 million. Net cash of $730 million was provided by investing activities primarily due to net decreases in loans held for investment, repayments of investment and mortgage-related securities, proceeds from the sale of and the private-issue mortgage-related securities and proceeds from the sale of real estate, partly offset by purchases of investment and mortgage-related securities and capital expenditures. Financing activities used net cash of $557 million due to net decreases in other borrowings and deposits and the payment of common stock dividends.

ASB believes that maintaining 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 December 31, 2009, ASB was well-capitalized (see "Capital requirements" below for ASB's capital ratios).

For a discussion of ASB dividends, see "Common stock equity" in Note 4 of HEI's "Notes to Consolidated Financial Statements."

Certain factors that may affect future results and financial condition. Also see "Forward-Looking Statements" and "Certain factors that may affect future results and financial condition" for Consolidated HEI above.

Competition. The banking industry in Hawaii is highly competitive. ASB is one of Hawaii's largest financial institutions, based on total assets, and is in direct competition for deposits and loans, not only with larger institutions, but also with smaller institutions that are heavily promoting their services in certain niche areas, such as providing financial services to small- and medium-sized businesses, and national organizations offering financial services. ASB's main competitors are banks, savings associations, credit unions, mortgage brokers, finance companies and securities brokerage firms. These competitors offer a variety of lending, deposit and investment products to retail and business customers.

The primary factors in competing for deposits are interest rates, the quality and range of services offered, marketing, convenience of locations, hours of operation and perceptions of the institution's financial soundness and safety. To meet competition, ASB offers a variety of savings and checking accounts at competitive rates, convenient business hours, convenient branch locations with interbranch deposit and withdrawal privileges at each branch and convenient automated teller machines. ASB also conducts advertising and promotional campaigns.

The primary factors in competing for first mortgage and other loans are interest rates, loan origination fees and the quality and range of lending and other services offered. ASB believes that it is able to compete for such loans primarily through the competitive interest rates and loan fees it charges, the type of mortgage loan programs it offers and the efficiency and quality of the services it provides to individual borrowers and the business community.

ASB is a full-service community bank serving both consumer and commercial customers and has been diversifying its loan portfolio from single-family home mortgages to higher-spread, shorter-duration consumer, commercial and commercial real estate loans. The origination of consumer, commercial and commercial real estate loans involves risks and other considerations different from those associated with originating residential real estate loans. For example, the sources and level of competition may be different and credit risk is generally higher than for mortgage loans. These different risk factors are considered in the underwriting and pricing standards and in the allowance for loan losses established by ASB for its consumer, commercial and commercial real estate loans.

U.S. capital markets and credit and interest rate environment. Volatility in U.S. capital markets may negatively impact the fair values of investment and mortgage-related securities held by ASB. As of December 31, 2009, the fair value and carrying value of the investment and mortgage-related securities held by ASB were $0.4 billion. ASB's strategic sales of its private-issue mortgage-related securities in the fourth quarter of 2009 and substantially all of its salable residential loan production during 2009 helped to reduce its exposure to credit risk and interest rate risk.

Interest rate risk is a significant risk of ASB's operations. ASB actively manages this risk, including managing the relationship of its interest-sensitive assets to its interest-sensitive liabilities. Persistent low levels of interest rates, weak loan demand, and excess liquidity in the financial system have made it challenging to find investments with adequate risk-adjusted returns, resulting in declining loan balances and an increase in the bank's liquidity position, with a negative impact on ASB's asset yields and net interest margin. If the current interest rate environment persists, the potential for compression of ASB's net interest margin will continue. ASB also manages the credit risk associated with its lending and securities portfolios, but a deep and prolonged recession led by a material decline in housing prices could materially impair the value of its portfolios. See "Net interest margin and other factors" above and "Quantitative and Qualitative Disclosures about Market Risk" below.

Technological developments. New technological developments (e.g., significant advances in internet banking) may impact ASB's future competitive position, results of operations and financial condition.

Environmental matters. Prior to extending a loan secured by real property, ASB conducts due diligence to assess whether or not the property may present environmental risks and potential cleanup liability. In the event of default and foreclosure of a loan, ASB may become the owner of the mortgaged property. For that reason, ASB seeks to avoid lending upon the security of, or acquiring through foreclosure, any property with significant potential environmental risks; however, there can be no assurance that ASB will successfully avoid all such environmental risks.

Regulation. ASB is subject to examination and comprehensive regulation by the Department of Treasury, OTS and the FDIC, and is subject to reserve requirements established by the Board of Governors of the Federal Reserve System. Regulation by these agencies focuses in large measure on the adequacy of ASB's capital and the results of periodic "safety and soundness" examinations conducted by the OTS.

Capital requirements. The OTS, which is ASB's principal regulator, administers two sets of capital standards—minimum regulatory capital requirements and prompt corrective action requirements. The FDIC also has prompt corrective action capital requirements. As of December 31, 2009, ASB was in compliance with OTS minimum regulatory capital requirements and was "well-capitalized" within the meaning of OTS prompt corrective action regulations and FDIC capital regulations, as follows:

- ASB met applicable minimum regulatory capital requirements (noted in parentheses) as of December 31, 2009 with a tangible capital ratio of 9.0% (1.5%), a core capital ratio of 9.0% (4.0%) and a total risk-based capital ratio of 14.0% (8.0%).
- ASB met the capital requirements to be generally considered "well-capitalized" (noted in parentheses) as of December 31, 2009 with a leverage ratio of 9.0% (5.0%), a Tier-1 risk-based capital ratio of 12.9% (6.0%) and a total risk-based capital ratio of 14.0% (10.0%).

The purpose of the prompt corrective action capital requirements is to establish thresholds for varying degrees of oversight and intervention by regulators. Declines in levels of capital, depending on their severity, will result in increasingly stringent mandatory and discretionary regulatory consequences. Capital levels may decline for any number of reasons, including reductions that would result if there were losses from operations, deterioration in collateral values or the inability to dispose of real estate owned (such as by foreclosure). The regulators have substantial discretion in the corrective actions they might direct and could include restrictions on dividends and other distributions that ASB may make to HEI (through ASHI) and the requirement that ASB develop and implement a plan to restore its capital. Under an agreement with regulators entered into by HEI when it acquired ASB, HEI currently could be required to contribute to ASB up to an additional $28.3 million of capital, if necessary to maintain ASB's capital position.

Examinations. ASB is subject to periodic "safety and soundness" examinations and other examinations by the OTS. In conducting its examinations, the OTS utilizes the Uniform Financial Institutions Rating System adopted by the Federal Financial Institutions Examination Council, which system utilizes the "CAMELS" criteria for rating financial institutions. The six components in the rating system are: Capital adequacy, Asset quality, Management, Earnings, Liquidity and Sensitivity to market risk. The OTS examines and rates each CAMELS component. An overall CAMELS rating is also given, after taking into account all of the component ratings. A financial institution may be subject to formal regulatory or administrative direction or supervision such as a "memorandum of understanding" or a "cease and desist" order following an examination if its CAMELS rating is not satisfactory. An institution is prohibited from disclosing the OTS's report of its safety and soundness examination or the component and overall CAMELS rating to any person or organization not officially connected with the institution as an officer, director, employee, attorney, or auditor, except as provided by regulation. The OTS also regularly examines ASB's information technology practices and its performance under Community Reinvestment Act measurement criteria.

The Federal Deposit Insurance Act, as amended, addresses the safety and soundness of the deposit insurance system, supervision of depository institutions and improvement of accounting standards. Pursuant to this Act, federal banking agencies have promulgated regulations that affect the operations of ASB and its holding companies (e.g., standards for safety and soundness, real estate lending, accounting and reporting, transactions with affiliates and loans to insiders). FDIC regulations restrict the ability of financial institutions that fail to meet relevant capital measures to engage in certain activities, such as offering interest rates on deposits that are significantly higher than the rates offered by competing institutions. As of December 31, 2009, ASB was "well-capitalized" and thus not subject to these restrictions.

Qualified Thrift Lender status. ASB is a "qualified thrift lender" (QTL) under its federal thrift charter and, in order to maintain this status, ASB is required to maintain at least 65% of its assets in "qualified thrift investments," which include housing-related loans (including mortgage-related securities) as well as certain small business loans, education loans, loans made through credit card accounts and a basket (not exceeding 20% of total assets) of other consumer loans and other assets. Savings associations that fail to maintain QTL status are subject to various penalties, including limitations on their activities. In ASB's case, the activities of HEI, ASHI and HEI's other subsidiaries would also be subject to restrictions if ASB failed to maintain its QTL status, and a failure or inability to comply with those restrictions could effectively result in the required divestiture of ASB. As of December 31, 2009, approximately 81% of ASB's assets were qualified thrift investments.

Unitary Savings and Loan Holding Company. The Gramm Act permitted banks, insurance companies and investment firms to compete directly against each other, thereby allowing "one-stop shopping" for an array of financial services. Although the Gramm Act further restricted the creation of so-called "unitary savings and loan holding companies" (i.e., companies such as HEI whose subsidiaries include one or more savings associations and one or more nonfinancial subsidiaries), the unitary savings and loan holding company relationship among HEI, ASHI and ASB is "grandfathered" under the Gramm Act so that HEI and its subsidiaries will be able to continue to engage in their current activities so long as ASB maintains its QTL status. Under the Gramm Act, any proposed sale of ASB would have to satisfy applicable statutory and regulatory requirements and potential acquirers of ASB would most likely be limited to companies that are already qualified as, or capable of qualifying as, either a traditional savings and loan association holding company or a bank holding company, or as one of the newly authorized financial holding companies permitted under the Gramm Act. In addition, as noted above under "Legislation and Regulation," there are currently before Congress legislative proposals which would operate to eliminate the grandfathered status of HEI as a unitary thrift holding company and effectively require the divestiture of ASB.

Credit CARD Act. On May 22, 2009, President Obama signed the Credit Card Accountability Responsibility and Disclosure Act of 2009 into law. Among other things, it requires that consumers receive a reasonable amount of time to make their credit card payments, prohibits payment allocation methods that unfairly maximize interest charges, prohibits issuers from raising the interest rate on an existing credit card balance in certain circumstances, and prohibits issuers from charging over-limit fees unless the cardholder agreed to allow the issuer to complete over-limit transactions and restricts the manner in which the issuer may assess over-limit fees. The major provisions of the Act are effective February 22, 2010 and are expected to have a negative impact on ASB's noninterest income, but the magnitude of the impact cannot be determined at this time.

New Overdraft Rules. On November 12, 2009, the Board of Governors of the Federal Reserve System issued a notice that it amended Regulation E (which implements the Electronic Fund Transfer Act) to limit the ability of a financial institution to assess an overdraft fee for paying automated teller machine or one-time debit card transactions that overdraw a consumer's account, unless the consumer affirmatively consents, or opts in, to the institution's payment of overdrafts for those transactions. The compliance deadline is July 1, 2010. The amendment is expected to have a negative impact on ASB's noninterest income, but the magnitude of the impact cannot be determined at this time.

Material estimates and critical accounting policies. Also see "Material estimates and critical accounting policies" for Consolidated HEI above.

Investment and mortgage-related securities. ASB owns federal agency obligations and mortgage-related securities issued by the FNMA, GNMA and FHLMC and municipal bonds, all of which are classified as available-for-sale and reported at fair value, with unrealized gains and temporary losses excluded from earnings and reported in AOCI.

ASB views the determination of whether an investment security is temporarily or other-than-temporarily impaired as a critical accounting policy since the estimate is susceptible to significant change from period to period because it requires management to make significant judgments, assumptions and estimates in the preparation of its consolidated financial statements.

See "Investment and mortgage-related securities" in Note 1 of HEI's "Notes to Consolidated Financial Statements" for a discussion of securities impairment assessment and other-than-temporary impaired securities.

Prices for investments and mortgage-related securities are provided by independent market participants and are based on observable inputs using market-based valuation techniques. The prices of these securities may be influenced by factors such as market liquidity, corporate credit considerations of the underlying collateral, the levels of interest rates, expectations of prepayments and defaults, limited investor base, market sector concerns, and overall market psychology. Adverse changes in any of these factors may result in losses, and such losses could be material. As of December 31, 2009, ASB had investment and mortgage-related securities issued by FHLMC, GNMA and FNMA valued at $0.4 billion.

Allowance for loan losses. See Note 1 of HEI's "Notes to Consolidated Financial Statements" and the discussion above under "Net interest margin and other factors." As of December 31, 2009, ASB's allowance for loan losses was $41.7 million and ASB had $65.3 million of loans on nonaccrual status, compared to $35.8 million and $19.5 million at December 31, 2008, respectively. In 2009, ASB recorded a provision for loan losses of $32 million.

The determination of the allowance for loan losses is sensitive to the credit risk ratings assigned to ASB's loan portfolio and loss ratios inherent in the ASB loan portfolio at any given point in time. A sensitivity analysis provides insight regarding the impact that adverse changes in credit risk ratings may have on ASB's allowance for loan losses. At December 31, 2009, in the event that 1% of the homogenous loans move down one delinquency classification (e.g., 1% of the loans in the 0-29 days delinquent category move to the 30-59 days delinquent category, 1% of the loans in the 30-59 days delinquent category move to the 60-89 days delinquent category and 1% of the loans in the 60-89 days delinquent category move to the 90+ days delinquent category) and 1% of non-homogenous loans were downgraded one credit risk rating category for each category (e.g., 1% of the loans in the "pass" category moved to the "special mention" category, 1% of the loans in the "special mention" category moved to the "substandard" category, 1% of the loans in the "substandard" category moved to the "doubtful" category and 1% of the loans in the "doubtful" category moved to the "loss" category), the allowance for loan losses would have increased by approximately $0.9 million. The sensitivity analyses do not imply any expectation of future deterioration in ASB loans' risk ratings and they do not necessarily reflect the nature and extent of future changes in the allowance for loan losses due to the numerous quantitative and qualitative factors considered in determining ASB's allowance for loan losses. The example above is only one of a number of reasonably possible scenarios.

Although management believes ASB's allowance for loan losses is adequate, the actual loan losses, provision for loan losses and allowance for loan losses may be materially different if conditions change (e.g., if there is a significant change in the Hawaii economy or real estate market), and material increases in those amounts could have a material adverse affect on the Company's results of operations and financial position.

Quantitative and Qualitative Disclosures about Market Risk

The Company manages various market risks in the ordinary course of business, including credit risk and liquidity risk. The Company believes the electric utility and the "other" segment's exposures to these two risks are not material as of December 31, 2009.

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. See "Net interest margin and other factors" and "Allowance for loan losses" above.

Liquidity risk for ASB is the risk that the bank will not meet its obligations when they become due. Liquidity risk is mitigated by ASB's asset/liability management process, on-going analytical analysis, monitoring and reporting information such as weekly cash-flow analyses and maintenance of liquidity contingency plans.

The Company is exposed to some commodity price risk primarily related to the fuel supply and IPP contracts of the electric utilities. The Company's commodity price risk is substantially mitigated so long as the electric utilities have their current ECACs in their rate schedules. See discussion of the ECACs in "Electric utility—Certain factors that may affect future results and financial condition—Regulation of electric utility rates." The Company currently has no hedges against its commodity price risk. The Company currently has no exposure to market risk from trading activities nor foreign currency exchange rate risk.

The Company considers interest rate risk to be a very significant market risk as it could potentially have a significant effect on the Company's results of operations and financial condition, especially as it relates to ASB, but also as it may affect the discount rate used to determine pension liabilities, the market value of pension plans' assets and the electric utilities' allowed rates of return. Interest rate risk can be defined as the exposure of the Company's earnings to adverse movements in interest rates.

Bank interest rate risk

The Company's success is dependent, in part, upon ASB's ability to manage interest rate risk. ASB's interest-rate risk profile is strongly influenced by its primary business of making fixed-rate residential mortgage loans and taking in retail deposits. Large mismatches in the amounts or timing between the maturity or repricing of interest sensitive assets or liabilities could adversely affect ASB's earnings and the market value of its interest-sensitive assets and liabilities in the event of significant changes in the level of interest rates. Many other factors also affect ASB's exposure to changes in interest rates, such as general economic and financial conditions, customer preferences, and competition for loans or deposits.

ASB's Asset/Liability Management Committee (ALCO), whose voting members are officers and employees of ASB, is responsible for managing interest rate risk and carrying out the overall asset/liability management objectives and activities of ASB as approved by the ASB Board of Directors. ALCO establishes policies under which management monitors and coordinates ASB's assets and liabilities.

See Note 4 of HEI's "Notes to Consolidated Financial Statements" for a discussion of the use of rate lock commitments on loans held for sale and forward sale contracts to manage some interest rate risk associated with ASB's residential loan sale program.

Management of ASB measures interest-rate risk using simulation analysis with an emphasis on measuring changes in net interest income (NII) and the market value of interest-sensitive assets and liabilities in different interest-rate environments. The simulation analysis is performed using a dedicated asset/liability management software system enhanced with a mortgage prepayment model and a collateralized mortgage obligation database. The simulation software is capable of generating scenario-specific cash flows for all instruments using the specified contractual information for each instrument and product specific prepayment assumptions for mortgage loans and mortgage-related securities.

NII sensitivity analysis measures the change in ASB's twelve-month, pre-tax NII in alternate interest rate scenarios. NII sensitivity is measured as the change in NII in the alternate interest-rate scenarios as a percentage of the base case NII. The base case interest-rate scenario is established using the current yield curve and assumes interest rates remain constant over the next twelve months. The alternate scenarios are created by assuming "rate ramps" or gradual interest changes and accomplished by moving the yield curve in a parallel fashion, over the next twelve month period, in increments of +/- 100 basis points. The simulation model forecasts scenario-specific principal and interest cash flows for the interest-bearing assets and liabilities, and the NII is calculated for each scenario. Key balance sheet modeling assumptions used in the NII sensitivity analysis include: the size of the balance sheet remains relatively constant over the simulation horizon and maturing assets or liabilities are reinvested in similar instruments in order to maintain the current mix of the balance sheet. In addition, assumptions are made about the prepayment behavior of mortgage-related assets, future pricing spreads for new assets and liabilities, and the speed and magnitude with which deposit rates change in response to changes in the overall level of interest rates.

ASB's net portfolio value (NPV) ratio is a measure of the economic capitalization of ASB. The NPV ratio is the ratio of the net portfolio value of ASB to the present value of expected net cash flows from existing assets. Net portfolio value represents the theoretical market value of ASB's net worth and is defined as the present value of expected net cash flows from existing assets minus the present value of expected cash flows from existing liabilities plus the present value of expected net cash flows from existing off-balance sheet contracts. The NPV ratio is calculated by ASB pursuant to guidelines established by the OTS in Thrift Bulletin 13a and The OTS Net Portfolio Value Model Manual. Key assumptions used in the calculation of ASB's NPV ratio include the prepayment behavior of loans and investments, the possible distribution of future interest rates, pricing spreads for assets and liabilities in the alternate scenarios and the rate and balance behavior of deposit accounts with indeterminate maturities. Typically, if the value of ASB's assets grows relative to the value of its liabilities, the NPV ratio will increase. Conversely, if the value of ASB's liabilities grows relative to the value of its assets, the NPV ratio will decrease. The NPV ratio is calculated in multiple scenarios. As with the NII simulation, the base case is represented by the current yield curve. Alternate scenarios are created by assuming immediate parallel shifts in the yield curve in increments of +/- 100 basis points.

The NPV ratio sensitivity measure is the change from the NPV ratio calculated in the base case to the NPV ratio calculated in the alternate rate scenarios. The sensitivity measure alone is not necessarily indicative of the interest-rate risk of an institution, as institutions with high levels of capital may be able to support a high sensitivity measure. This measure is evaluated in conjunction with the NPV ratio calculated in each scenario.

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

December 31	2009			2008		
Change in interest rates	Change in NII	NPV ratio	NPV ratio sensitivity*	Change in NII	NPV ratio	NPV ratio sensitivity*
(basis points)	Gradual change	Instantaneous change		Gradual change	Instantaneous change	
+300	(0.3)	10.92	(245)	1.2%	6.94%	(379)
+200	(0.3)	11.86	(151)	1.2	8.42	(231)
+100	(0.2)	12.72	(65)	0.7	9.84	(89)
Base	–	13.37	–	–	10.73	-
-100	(0.9)	13.53	16	(1.6)	10.43	(30)
-200	**	**	**	**	**	**
-300	**	**	**	**	**	**

* Change from base case in basis points.

** For December 31, 2008, the -200 and -300 bp scenarios were not performed due to the low level of interest rates.

Management believes that ASB's interest rate risk position as of December 31, 2009 represents a reasonable level of risk. Under the rising interest rate change scenarios, the December 31, 2009 NII profile shifted from asset to liability sensitive compared to December 31, 2008 due to the decrease in size and change in mix of the balance sheet and changes in assumptions about sensitivity to changes in interest rates.

ASB's base NPV ratio as of December 31, 2009 increased compared to December 31, 2008 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 as of December 31, 2009 was less sensitive in the rising rate scenarios 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. 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.

Other than bank interest rate risk

The Company's general policy is to manage "other than bank" interest rate risk through use of a combination of short-term debt, long-term debt (currently fixed-rate debt) and preferred securities. As of December 31, 2009, management believes the Company is exposed to "other than bank" interest rate risk because of its periodic borrowing requirements, the impact of interest rates on the discount rate and the market value of plan assets used to determine retirement benefits expenses and obligations (see "Retirement benefits (pension and other postretirement benefits)" in "Management's discussion and analysis of financial condition and results of operations" and Note 8 of HEI's "Notes to Consolidated Financial Statements") and the possible effect of interest rates on the electric utilities' allowed rates of return (see "Electric utility—Certain factors that may affect future results and financial condition—Regulation of electric utility rates"). Other than these exposures, management believes its exposure to "other than bank" interest rate risk is not material. The Company's longer-term debt, in the form of revenue bonds and Medium-Term Notes, is at fixed rates. Such rates are favorable (i.e., lower) compared to current market rates, and therefore, the estimated fair value of such debt is notably lower than the amount outstanding (see Note 14 of HEI's "Notes to Consolidated Financial Statements").

Index to Consolidated Financial Statements

Annual Report of Management on Internal Control Over Financial Reporting

The Board of Directors and Shareholders
Hawaiian Electric Industries, Inc.:

Management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) promulgated under the Securities Exchange Act of 1934, as amended. The Company's internal control system was designed to provide reasonable assurance to management and the Board of Directors regarding the preparation and fair presentation of its consolidated financial statements.

All internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation.

Management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting as of December 31, 2009 based on the framework in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this evaluation, management has concluded that the Company's internal control over financial reporting was effective as of December 31, 2009.

KPMG LLP, an independent registered public accounting firm, has issued an audit report on the Company's internal control over financial reporting as of December 31, 2009. This report appears on page 68.

Constance H. Lau
President and
Chief Executive Officer

James A. Ajello
Senior Financial Vice President,
Treasurer and Chief Financial Officer

David M. Kostecki
Vice President-Finance, Controller
and Chief Accounting Officer

February 19, 2010

Report of Independent Registered Public Accounting Firm on Internal Control Over Financial Reporting

The Board of Directors and Shareholders
Hawaiian Electric Industries, Inc.:

We have audited Hawaiian Electric Industries, Inc.'s internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Hawaiian Electric Industries, Inc.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying annual report of management on internal control over financial reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Hawaiian Electric Industries, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control—Integrated Framework issued by the COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Hawaiian Electric Industries, Inc. and subsidiaries as of December 31, 2009 and 2008, and the related consolidated statements of income, changes in stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2009, and our report dated February 19, 2010 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Honolulu, Hawaii
February 19, 2010

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
Hawaiian Electric Industries, Inc.:

We have audited the accompanying consolidated balance sheets of Hawaiian Electric Industries, Inc. and subsidiaries as of December 31, 2009 and 2008, and the related consolidated statements of income, changes in stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2009. These consolidated financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these consolidated financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Hawaiian Electric Industries, Inc. and subsidiaries as of December 31, 2009 and 2008, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2009 in conformity with U.S. generally accepted accounting principles.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Hawaiian Electric Industries, Inc.'s internal control over financial reporting as of December 31, 2009, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 19, 2010 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

KPMG LLP

Honolulu, Hawaii
February 19, 2010

Consolidated Statements of Income

Hawaiian Electric Industries, Inc. and Subsidiaries

Years ended December 31	2009	2008	2007
(in thousands, except per share amounts)			
Revenues			
Electric utility	$ 2,035,009	$ 2,860,350	$ 2,106,314
Bank	274,719	358,553	425,495
Other	(138)	17	4,609
	2,309,590	3,218,920	2,536,418
Expenses			
Electric utility	1,865,338	2,668,991	1,975,729
Bank	242,955	331,601	341,485
Other	13,633	14,171	15,472
	2,121,926	3,014,763	2,332,686
Operating income (loss)			
Electric utility	169,671	191,359	130,585
Bank	31,764	26,952	84,010
Other	(13,771)	(14,154)	(10,863)
	187,664	204,157	203,732
Interest expense – other than on deposit liabilities and other bank borrowings	(76,330)	(76,142)	(78,556)
Allowance for borrowed funds used during construction	5,268	3,741	2,552
Allowance for equity funds used during construction	12,222	9,390	5,219
Income before income taxes	128,824	141,146	132,947
Income taxes	43,923	48,978	46,278
Net income	84,901	92,168	86,669
Less net income attributable to noncontrolling interest - preferred stock of subsidiaries	1,890	1,890	1,890
Net income for common stock	$ 83,011	$ 90,278	$ 84,779
Basic earnings per common share	$ 0.91	$ 1.07	$ 1.03
Diluted earnings per common share	$ 0.91	$ 1.07	$ 1.03
Dividends per common share	$ 1.24	$ 1.24	$ 1.24
Weighted-average number of common shares outstanding	91,396	84,631	82,215
Dilutive effect of stock-based compensation	120	89	204
Adjusted weighted-average shares	91,516	84,720	82,419

For 2009, 2008 and 2007, under the two-class method of computing basic and diluted earnings per share, distributed earnings were $1.24 per share and undistributed earnings (loss) were $(0.33), $(0.17) and $(0.21) per share, respectively, for both unvested restricted stock awards and unrestricted common stock.

See accompanying "Notes to Consolidated Financial Statements."

Consolidated Balance Sheets

Hawaiian Electric Industries, Inc. and Subsidiaries

December 31		2009		2008
(dollars in thousands)				
ASSETS				
Cash and equivalents		$ 502,443		$ 182,903
Federal funds sold		1,479		532
Accounts receivable and unbilled revenues, net		241,116		300,666
Available-for-sale investment and mortgage-related securities		432,881		657,717
Investment in stock of Federal Home Loan Bank of Seattle (estimated fair value $97,764)		97,764		97,764
Loans receivable, net		3,670,493		4,206,492
Property, plant and equipment, net				
Land	$ 67,381		$ 55,857	
Plant and equipment	4,832,740		4,433,105	
Construction in progress	133,972		270,227	
	5,034,093		4,759,189	
Less – accumulated depreciation	(1,945,482)	3,088,611	(1,851,813)	2,907,376
Regulatory assets		426,862		530,619
Other		381,163		328,823
Goodwill, net		82,190		82,190
		$ 8,925,002		$ 9,295,082
LIABILITIES AND STOCKHOLDERS' EQUITY				
Liabilities				
Accounts payable		$ 186,994		$ 183,584
Deposit liabilities		4,058,760		4,180,175
Short-term borrowings—other than bank		41,989		–
Other bank borrowings		297,628		680,973
Long-term debt, net—other than bank		1,364,815		1,211,501
Deferred income taxes		188,875		143,308
Regulatory liabilities		288,214		288,602
Contributions in aid of construction		321,544		311,716
Other		700,242		871,476
		7,449,061		7,871,335
Stockholders' equity				
Common stock, no par value, authorized 200,000,000 shares; issued and outstanding: 92,520,638 shares and 90,515,573 shares		1,265,157		1,231,629
Retained earnings		184,213		210,840
Accumulated other comprehensive loss, net of income tax benefits				
Net unrealized gains (losses) on securities	$ 4,728		$(33,025)	
Retirement benefit plans	(12,450)	(7,722)	(19,990)	(53,015)
Common stock equity		1,441,648		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
		1,475,941		1,423,747
		$ 8,925,002		$ 9,295,082

See accompanying "Notes to Consolidated Financial Statements."

Consolidated Statements of Changes in Stockholders' Equity

Hawaiian Electric Industries, Inc. and Subsidiaries

(in thousands, except per share amounts)	Common stock Shares	Common stock Amount	Retained earnings	Accumulated other compre-hensive income (loss)	Noncontrolling interest: cumulative preferred stock of subsidiaries	Total
Balance, December 31, 2006	**81,461**	**$1,028,101**	**$242,667**	**$ (175,528)**	**$34,293**	**$1,129,533**
Comprehensive income:						
Net income	–	–	84,779	–	1,890	86,669
Net unrealized gains on securities:						
Net unrealized gains arising during the period, net of taxes of $11,944	–	–	–	18,087	–	18,087
Less: reclassification adjustment for net realized gains included in net income, net of taxes of $441	–	–	–	(668)	–	(668)
Retirement benefit plans:						
Prior service credit arising during the period, net of taxes of $6,990	–	–	–	10,584	–	10,584
Net gains arising during the period, net of taxes of $11,400	–	–	–	17,825	–	17,825
Less: amortization of transition obligation, prior service credit and net losses recognized during the period in net periodic benefit cost, net of tax benefits of $5,545	–	–	–	8,694	–	8,694
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory asset, net of taxes of $11,007	–	–	–	(17,282)	–	(17,282)
Less: reclassification adjustment for curtailment gain included in net income, net of taxes of $3,503	–	–	–	(5,305)	–	(5,305)
Comprehensive income (loss)	–	–	84,779	31,935	1,890	118,604
Adjustment to initially apply PUC D&Os related to retirement benefit plans, net of taxes of $77,546	–	–	–	121,751	–	121,751
Adjustment to initially apply an accounting standard prescribing a "more-likely-than-not" recognition criterion to a tax position	–	–	(228)	–	–	(228)
Issuance of common stock: Dividend reinvestment and stock purchase plan	1,447	34,443	–	–	–	34,443
Retirement savings and other plans	524	10,804	–	–	–	10,804
Expenses and other, net	–	(1,247)	–	–	–	(1,247)
Common stock dividends ($1.24 per share)	–	–	(102,050)	–	–	(102,050)
Preferred stock dividends	–	–	–	–	(1,890)	(1,890)
Balance, December 31, 2007	**83,432**	**1,072,101**	**225,168**	**(21,842)**	**34,293**	**1,309,720**
Comprehensive income:						
Net income	–	–	90,278	–	1,890	92,168
Net unrealized losses on securities:						
Net unrealized losses arising during the period, net of tax benefits of $19,892	–	–	–	(30,124)	–	(30,124)
Less: reclassification adjustment for net realized losses included in net income, net of tax benefits of $9,998	–	–	–	15,142	–	15,142
Retirement benefit plans:						
Prior service credit arising during the period, net of taxes of $641	–	–	–	992	–	992
Net losses arising during the period, net of tax benefits of $111,967	–	–	–	(175,240)	–	(175,240)
Less: amortization of transition obligation, prior service credit and net losses recognized during the period in net periodic benefit cost, net of tax benefits of $3,696	–	–	–	5,801	–	5,801
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory asset, net of tax benefits of $96,975	–	–	–	152,256	–	152,256
Comprehensive income (loss)	–	–	90,278	(31,173)	1,890	60,995
Issuance of common stock: Common stock offering	5,000	115,000	–	–	–	115,000
Dividend reinvestment and stock purchase plan	1,425	34,607	–	–	–	34,607
Retirement savings and other plans	659	15,267	–	–	–	15,267
Expenses and other, net	–	(5,346)	–	–	–	(5,346)
Common stock dividends ($1.24 per share)	–	–	(104,606)	–	–	(104,606)
Preferred stock dividends	–	–	–	–	(1,890)	(1,890)
Balance, December 31, 2008	**90,516**	**1,231,629**	**210,840**	**(53,015)**	**34,293**	**1,423,747**
Cumulative effect of adoption of a standard on other-than-temporary impairment recognition, net of taxes of $2,497	–	–	3,781	(3,781)	–	–
Comprehensive income:						
Net income	–	–	83,011	–	1,890	84,901
Net unrealized gains on securities:						
Net unrealized gains on securities arising during the period, net of taxes of $8,543	–	–	–	12,938	–	12,938
Less: reclassification adjustment for net realized losses included in net income, net of tax benefits of $18,882	–	–	–	28,596	–	28,596
Retirement benefit plans:						
Net transition asset arising during the period, net of taxes of $4,172	–	–	–	6,549	–	6,549
Prior service credit arising during the period, net of taxes of $921	–	–	–	1,446	–	1,446
Net gains arising during the period, net of taxes of $41,218	–	–	–	64,547	–	64,547
Less: amortization of transition obligation, prior service credit and net losses recognized during the period in net periodic benefit cost, net of tax benefits of $6,861	–	–	–	10,754	–	10,754
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory asset, net of taxes of $48,251	–	–	–	(75,756)	–	(75,756)
Comprehensive income (loss)	–	–	83,011	49,074	1,890	133,975
Issuance of common stock: Dividend reinvestment and stock purchase plan	1,714	27,701	–	–	–	27,701
Retirement savings and other plans	291	4,771	–	–	–	4,771
Expenses and other, net	–	1,056	–	–	–	1,056
Common stock dividends ($1.24 per share)	–	–	(113,419)	–	–	(113,419)
Preferred stock dividends	–	–	–	–	(1,890)	(1,890)
Balance, December 31, 2009	**92,521**	**$1,265,157**	**$184,213**	**$ (7,722)**	**$34,293**	**$1,475,941**

As of December 31, 2009, HEI had reserved a total of 17,001,318 shares of common stock for future issuance under the HEI Dividend Reinvestment and Stock Purchase Plan (DRIP), the Hawaiian Electric Industries Retirement Savings Plan (HEIRS), the 1987 Stock Option and Incentive Plan, the HEI 1990 Nonemployee Director Stock Plan and the ASB 401(k) Plan.

See accompanying "Notes to Consolidated Financial Statements."

Consolidated Statements of Cash Flows

Hawaiian Electric Industries, Inc. and Subsidiaries

Years ended December 31	2009	2008	2007
(in thousands)			
Cash flows from operating activities			
Net income	$ 84,901	$ 92,168	$ 86,669
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation of property, plant and equipment	151,282	150,977	147,881
Other amortization	5,389	5,085	11,878
Provision for loan losses	32,000	10,334	5,700
Writedown of utility plant	–	–	11,701
Gain on pension curtailment	–	(472)	(8,809)
Loans receivable originated and purchased, held for sale	(443,843)	(204,457)	(39,688)
Proceeds from sale of loans receivable, held for sale	471,194	185,291	33,876
Net losses (gains) on sale of investment and mortgage-related securities	32,034	17,376	(1,109)
Other-than-temporary impairment on available-for-sale mortgage-related securities	15,444	7,764	–
Change in deferred income taxes	12,787	5,134	(34,624)
Change in excess tax benefits from share-based payment arrangements	310	(405)	(195)
Allowance for equity funds used during construction	(12,222)	(9,390)	(5,219)
Changes in assets and liabilities			
Decrease (increase) in accounts receivable and unbilled revenues, net	59,550	(6,219)	(45,808)
Decrease (increase) in fuel oil stock	(946)	14,157	(27,559)
Increase (decrease) in accounts payable	3,410	(18,715)	36,794
Changes in prepaid and accrued income taxes and utility revenue taxes	(61,977)	16,466	42,617
Changes in other assets and liabilities	(64,845)	(5,280)	5,126
Net cash provided by operating activities	284,468	259,814	219,231
Cash flows from investing activities			
Available-for-sale investment and mortgage-related securities purchased	(297,864)	(489,264)	(402,071)
Principal repayments on available-for-sale investment and mortgage-related securities	357,233	610,521	652,083
Proceeds from sale of available-for-sale investment and mortgage-related securities	185,134	1,311,596	1,109
Proceeds from sale of other investments	–	17	35,920
Net decrease (increase) in loans held for investment	484,960	(92,241)	(315,786)
Proceeds from sale of real estate acquired in settlement of loans	1,555	–	–
Capital expenditures	(304,761)	(282,051)	(218,297)
Contributions in aid of construction	14,170	17,319	19,011
Other	1,199	1,116	5,902
Net cash provided by (used in) investing activities	441,626	1,077,013	(222,129)
Cash flows from financing activities			
Net decrease in deposit liabilities	(121,415)	(167,085)	(228,288)
Net increase (decrease) in short-term borrowings with original maturities of three months or less	41,989	(91,780)	(84,492)
Net increase (decrease) in retail repurchase agreements	(3,829)	(37,142)	71,205
Proceeds from other bank borrowings	310,000	2,592,635	1,338,432
Repayments of other bank borrowings	(689,517)	(3,682,119)	(1,166,112)
Proceeds from issuance of long-term debt	153,186	19,275	242,539
Repayment of long-term debt	–	(50,000)	(136,000)
Principal payments on nonrecourse debt	–	–	(17,242)
Change in excess tax benefits from share-based payment arrangements	(310)	405	195
Net proceeds from issuance of common stock	15,329	136,443	21,072
Common stock dividends	(96,843)	(83,604)	(81,489)
Preferred stock dividends of noncontrolling interest	(1,890)	(1,890)	(1,890)
Increase (decrease) in cash overdraft	(9,545)	1,265	(3,545)
Other	(2,762)	350	1,067
Net cash used in financing activities	(405,607)	(1,363,247)	(44,548)
Net increase (decrease) in cash and equivalents and federal funds sold	320,487	(26,420)	(47,446)
Cash and equivalents and federal funds sold, January 1	183,435	209,855	257,301
Cash and equivalents and federal funds sold, December 31	$ 503,922	$ 183,435	$ 209,855

See accompanying "Notes to Consolidated Financial Statements."

1 • Summary of significant accounting policies

General

Hawaiian Electric Industries, Inc. (HEI) is a holding company with direct and indirect subsidiaries principally engaged in electric utility and banking businesses, primarily in the State of Hawaii. HEI's common stock is traded on the New York Stock Exchange.

Basis of presentation. In preparing the consolidated 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.

Material estimates that are particularly susceptible to significant change include the amounts reported for investment and mortgage-related securities; property, plant and equipment; pension and other postretirement benefit obligations; contingencies and litigation; income taxes; regulatory assets and liabilities; electric utility revenues; variable interest entities (VIEs); and allowance for loan losses.

Consolidation. The consolidated financial statements include the accounts of HEI and its subsidiaries (collectively, the Company), but exclude subsidiaries which are VIEs of which the Company is not the primary beneficiary. Investments in companies over which the Company has the ability to exercise significant influence, but not control, are accounted for using the equity method. All material intercompany accounts and transactions have been eliminated in consolidation.

See Note 5 for information regarding unconsolidated VIEs.

Cash and equivalents and federal funds sold. The Company considers cash on hand, deposits in banks, deposits with the Federal Home Loan Bank (FHLB) of Seattle, money market accounts, certificates of deposit, short-term commercial paper of non-affiliates, reverse repurchase agreements and liquid investments (with original maturities of three months or less) to be cash and equivalents. Federal funds sold are excess funds that American Savings Bank, F.S.B. (ASB) loans to other banks overnight at the federal funds rate.

Investment and mortgage-related securities. Debt securities that the Company intends to and has the ability to hold to maturity are classified as held-to-maturity securities and reported at amortized cost. Marketable equity securities and debt securities that are bought and held principally for the purpose of selling them in the near term are classified as trading securities and reported at fair value, with unrealized gains and losses included in earnings. Marketable equity securities and debt securities not classified as either held-to-maturity or trading securities are classified as available-for-sale securities and reported at fair value, with unrealized gains and temporary losses excluded from earnings and reported on a net basis in accumulated other comprehensive income (AOCI).

For securities that are not trading securities, individual securities are assessed for impairment at least on a quarterly basis, and more frequently when economic or market conditions warrant. An investment is impaired if the fair value of the security is less than its carrying value at the financial statement date. When a security is impaired, the Company determines whether this impairment is temporary or other-than-temporary. If the Company does not expect to recover the entire amortized cost basis of the security, an other-than-temporary impairment (OTTI) exists. If the Company intends to sell the security, or will more likely than not be required to sell the security before recovery of its amortized cost, the OTTI shall be recognized in earnings. If the Company does not intend to sell the security and it is not more likely than not that the Company will be required to sell the security before recovery of its amortized cost, the OTTI shall be separated into the amount representing the credit loss and the amount related to all other factors. The amount of OTTI related to the credit loss is recognized in earnings while the remaining OTTI is recognized in other comprehensive income. Once an OTTI has been recognized on a security, the Company accounts for the security as if the security had been purchased on the measurement date of the OTTI at an amortized cost basis equal to the previous amortized cost basis less the OTTI recognized in earnings. The difference between the new amortized cost basis and the cash flows expected to be collected shall be accreted in accordance with existing applicable guidance as interest income. Any discount or reduced premium recorded for the security will be amortized over the remaining life of the security in a prospective manner based on the amount and timing of future estimated cash flows. If upon subsequent evaluation, there is a significant increase in cash flows expected to be collected or if actual cash flows are significantly greater than cash flows previously expected, such changes shall be accounted for as a prospective adjustment to the accretable yield.

The specific identification method is used in determining realized gains and losses on the sales of securities.

Discounts and premiums on investment and mortgage-related securities are accreted or amortized over the remaining lives of the securities, adjusted for actual portfolio prepayments, using the interest method.

Equity method. Investments in up to 50%-owned affiliates over which the Company has the ability to exercise significant influence over the operating and financing policies and investments in unconsolidated subsidiaries (e.g. HECO Capital Trust III) are accounted for under the equity method, whereby the investment is carried at cost, plus (or minus) the Company's equity in undistributed earnings (or losses) and minus distributions since acquisition. Equity in earnings or losses is reflected in operating revenues. Equity method investments are evaluated for other-than-temporary impairment. Also see "Variable interest entities" below.

Property, plant and equipment. Property, plant and equipment are reported at cost. Self-constructed electric utility plant includes engineering, supervision, administrative and general costs and an allowance for the cost of funds used during the construction period. These costs are recorded in construction in progress and are transferred to property, plant and equipment when construction is completed and the facilities are either placed in service or become useful for public utility purposes. Costs for betterments that make property, plant or equipment more useful, more efficient, of greater durability or of greater capacity are also capitalized. Upon the retirement or sale of electric utility plant, generally no gain or loss is recognized. The cost of the plant retired is charged to accumulated depreciation. Amounts collected from customers for cost of removal (expected to exceed salvage value in the future) are included in regulatory liabilities.

If a power purchase agreement (PPA) falls within the scope of FASB Accounting Standards Codification™ (ASC) Topic 840 and results in the classification of the agreement as a capital lease, the electric utility would recognize a capital asset and a lease obligation. Currently, none of the PPAs is required to be recorded as a capital asset and long-term lease obligation.

Depreciation. Depreciation is computed primarily using the straight-line method over the estimated lives of the assets being depreciated. Electric utility plant additions in the current year are depreciated beginning January 1 of the following year. Electric utility plant has lives ranging from 20 to 45 years for production plant, from 25 to 60 years for transmission and distribution plant and from 7 to 45 years for general plant. The electric utilities' composite annual depreciation rate, which includes a component for cost of removal, was 3.8% in 2009, 2008 and 2007.

Retirement benefits. Pension and other postretirement benefit costs are charged primarily to expense and electric utility plant. Funding for the Company's qualified pension plans (Plans) is based on actuarial assumptions adopted by the Pension Investment Committee administering the Plans on the advice of an enrolled actuary. The participating employers contribute amounts to a master pension trust for the Plans in accordance with the funding requirements of Employee Retirement Income Security Act of 1974, as amended (ERISA), including changes promulgated by the Pension Protection Act of 2006, and considering the deductibility of contributions under the Internal Revenue Code. The Company generally funds at least the net periodic pension cost during the fiscal year, subject to limits and targeted funded status as determined with the consulting actuary. Under a pension tracking mechanism approved by the Public Utilities Commission of the State of Hawaii (PUC) on an interim basis, Hawaiian Electric Company, Inc. (HECO) generally will make contributions to the pension fund at the minimum level required under the law, until its pension asset (existing at the time of the PUC decision and determined based on the cumulative fund contributions in excess of the cumulative net periodic pension cost recognized) is reduced to zero, at which time HECO would fund the pension cost as specified in the pension tracking mechanism. Hawaii Electric Light Company, Inc. (HELCO) and Maui Electric Company, Limited (MECO) will generally fund the net periodic pension cost. Future decisions in rate cases could further impact funding amounts.

Certain health care and/or life insurance benefits are provided to eligible retired employees and the employees' beneficiaries and covered dependents. The Company generally funds the net periodic postretirement benefit costs other than pensions and the amortization of the regulatory asset for postretirement benefits other than pensions (OPEB), while maximizing the use of the most tax advantaged funding vehicles, subject to cash flow requirements and reviews of the funded status with the consulting actuary. The electric utilities must fund OPEB costs as specified in the OPEB tracking mechanisms, which were approved by the PUC on an interim basis. Future decisions in rate cases could further impact funding amounts.

The Company recognizes on its balance sheet the funded status of its defined benefit pension and other postretirement benefit plans, as adjusted by the impact of decisions of the PUC.

Environmental expenditures. The Company is subject to numerous federal and state environmental statutes and regulations. In general, environmental contamination treatment costs are charged to expense, unless it is probable that the PUC would allow such costs to be recovered in future rates, in which case such costs would be capitalized as regulatory assets. Also, environmental costs are capitalized if the costs extend the life, increase the capacity, or improve the safety or efficiency of property; the costs mitigate or prevent future environmental contamination; or the costs are incurred in preparing the property for sale. Environmental costs are either capitalized or charged to expense when environmental assessments and/or remedial efforts are probable and the cost can be reasonably estimated.

Financing costs. Financing costs related to the registration and sale of HEI common stock are recorded in stockholders' equity.

HEI uses the effective interest method to amortize the long-term debt financing costs of the holding company over the term of the related debt.

HECO and its subsidiaries use the straight-line method to amortize long-term debt financing costs and premiums or discounts over the term of the related debt. Unamortized financing costs and premiums or discounts on HECO and its subsidiaries' long-term debt retired prior to maturity are classified as regulatory assets (costs and premiums) or liabilities (discounts) and are amortized on a straight-line basis over the remaining original term of the retired debt. The method and periods for amortizing financing costs, premiums and discounts, including the treatment of these items when long-term debt is retired prior to maturity, have been established by the PUC as part of the rate-making process.

HEI and HECO and its subsidiaries use the straight-line method to amortize the fees and related costs paid to secure a firm commitment under their line-of-credit arrangements.

Income taxes. Deferred income tax assets and liabilities are established for the temporary differences between the financial reporting bases and the tax bases of the Company's assets and liabilities at federal and state tax rates expected to be in effect when such deferred tax assets or liabilities are realized or settled. The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences become deductible.

Federal and state investment tax credits are deferred and amortized over the estimated useful lives of the properties which qualified for the credits.

Governmental tax authorities could challenge a tax return position taken by management. If the Company's position does not prevail, the Company's results of operations and financial condition may be adversely affected as the related deferred or current income tax asset might be impaired and written down or written off or an unanticipated tax liability might be incurred.

The Company uses a "more-likely-than-not" recognition threshold and measurement standard for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return.

Earnings per share. Basic earnings per share (EPS) is computed by dividing net income for common stock by the weighted-average number of common shares outstanding for the period. Diluted EPS is computed similarly, except that common shares for dilutive stock compensation are added to the denominator. The Company uses the two-class method of computing EPS as restricted stock grants include non-forfeitable rights to dividends and are participating securities.

As of December 31, 2009 and 2008, the antidilutive effect of stock appreciation rights (SARs) on 480,000 and 791,000 shares of common stock (for which the SARs' exercise prices were greater than the closing market price of HEI's common stock), respectively, was not included in the computation of diluted EPS.

Share-based compensation. The Company applies the fair value based method of accounting to account for its stock compensation, including the use of a forfeiture assumption. See Note 9.

Impairment of long-lived assets and long-lived assets to be disposed of. The Company reviews long-lived assets and certain identifiable intangibles for impairment whenever events or changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Recoverability of assets to be held and used is measured by a comparison of the carrying amount of an asset to future net cash flows expected to be generated by the asset. If such assets are considered to be impaired, the impairment to be recognized is measured by the amount by which the carrying amount of the assets exceeds the fair value of the assets. Assets to be disposed of are reported at the lower of the carrying amount or fair value, less costs to sell.

Recent accounting pronouncements and interpretations. See "Fair Value Measurements" in Note 14.

Noncontrolling interests. In December 2007, the FASB issued a standard that 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. 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 the standard 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 are 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 a standard under which unvested share-based-payment awards that contain non-forfeitable rights to dividends or dividend equivalents are "participating securities" and therefore should be included in computing earnings per share using the two-class method. The Company adopted this standard in the first quarter of 2009 retrospectively and determined that restricted stock award grants were participating securities. The impact of adoption on the Company's financial statements was not material.

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

The first standard relates to determining fair values when there is no active market or where the price inputs being used represent distressed sales. It provides guidelines for making fair value measurements more consistent with the principles presented in an earlier standard 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, it reaffirms the need to use judgment in determining fair values when markets have become inactive.

The second standard 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 this standard, fair values for these assets and liabilities were only disclosed annually. This standard 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.

The third standard 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. This standard also requires increased and more timely disclosures regarding expected cash flows, credit losses and an aging of securities with unrealized losses.

The Company adopted these standards in the second quarter of 2009 and provided additional disclosures regarding fair value measurements and other-than-temporary impairments (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. Upon adoption of the standards, the Company reclassified $3.8 million of the previously recognized impairment to accumulated other comprehensive income. See Note 4 for OTTIs in 2009.

In connection with the adoption of the fair value measurement standards, the Company adopted the provisions of Accounting Standards Update No. 2009-12, "Investments in Certain Entities that Calculate Net Asset Value per Share (or Its Equivalent)," which allows for the estimation of the fair value of investments in investment companies for which the investment does not have a readily determinable fair value, using net asset value per share or its equivalent as a practical expedient.

Subsequent events. In May 2009, the FASB established 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, which provide: (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 the standards in the second quarter of 2009. See Note 15.

Variable interest entities. In June 2009, the FASB issued a standard that amends the guidance in ASC Topic 810 related to the consolidation of VIEs. The standard 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 VIE. It also clarifies, but does not significantly change, the characteristics that identify a VIE. The Company will adopt this standard in the first quarter of 2010 and the adoption is not expected to impact the Company's or HECO's consolidated financial condition, results of operations or liquidity.

FASB Codification. In June 2009, the FASB issued a standard that establishes the ASC as the single source of authoritative U.S. generally accepted accounting principles (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 GAAP for SEC registrants. The Company adopted this standard in the third quarter of 2009 and has eliminated or revised citations for previous standards in this report.

Measuring liabilities at fair value. Accounting Standards Update No. 2009–05 amends Subtopic 820-10, Fair Value Measurements and Disclosures—Overall, and provides clarification that (1) in circumstances in which a quoted price in an active market for an identical liability is not available, a reporting entity is required to measure fair value using specified techniques, (2) when estimating the fair value of a liability, a reporting entity is not required to include a separate input, or adjustment to other inputs, relating to the existence of a restriction that prevents the transfer of the liability, and (3) both a quoted price in an active market for the identical liability at the measurement date and the quoted price for the identical liability when traded as an asset in an active market when no adjustments to the quoted price of the asset are required are Level 1 fair value measurements. The Company adopted this guidance in the fourth quarter of 2009 and the adoption did not have an impact on its financial condition, results of operations or liquidity.

Reclassifications. Certain reclassifications have been made to prior years' financial statements to conform to the 2009 presentation, which did not affect previously reported results of operations.

Electric utility

Regulation by the PUC. The electric utilities are regulated by the PUC and account for the effects of regulation under ASC Topic 980. As a result, the actions of regulators can affect the timing of recognition of revenues, expenses, assets and liabilities. Management believes HECO and its subsidiaries' operations currently satisfy the ASC Topic 980 criteria. If events or circumstances should change so that those criteria are no longer satisfied, the electric utilities expect that their regulatory assets would be charged to expense and regulatory liabilities would be credited to income or refunded to ratepayers. In the event of unforeseen regulatory actions or other circumstances, however, management believes that a material adverse effect on the Company's results of operations and financial position may result if regulatory assets have to be charged to expense without an offsetting credit for regulatory liabilities or if regulatory liabilities are required to be refunded to ratepayers.

Accounts receivable. Accounts receivable are recorded at the invoiced amount. The electric utilities generally assess a late payment charge on balances unpaid from the previous month. The allowance for doubtful accounts is the Company's best estimate of the amount of probable credit losses in the Company's existing accounts receivable. On a monthly basis, the Company adjusts its allowance, with a corresponding charge (credit) on the statement of income, based on its historical write-off experience. Account balances are charged off against the allowance after collection efforts have been exhausted and the potential for recovery is considered remote.

Contributions in aid of construction. The electric utilities receive contributions from customers for special construction requirements. As directed by the PUC, contributions are amortized on a straight-line basis over 30 years as an offset against depreciation expense.

Electric utility revenues. Electric utility revenues are based on rates authorized by the PUC and include revenues applicable to energy consumed in the accounting period but not yet billed to the customers. Revenues related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. However, the determination of the energy sales to individual customers for billing purposes is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on the meter readings in the beginning of the following month, monthly generation volumes, estimated customer usage by account, line losses and applicable customer rates based on historical values and current rate schedules. As of December 31, 2009, customer accounts receivable include unbilled energy revenues of $84 million on a base of annual revenue of $2.0 billion. Revenue amounts recorded pursuant to a PUC interim order are subject to refund, with interest, pending a final order.

The rate schedules of the electric utilities include energy cost adjustment clauses (ECACs) under which electric rates are adjusted for changes in the weighted-average price paid for fuel oil and certain components of purchased power, and the relative amounts of company-generated power and purchased power. The ECACs also include a provision requiring a quarterly reconciliation of the amounts collected through the ECACs. See "Energy cost adjustment clauses" in Note 3 for a discussion of the ECACs and Act 162 of the 2006 Hawaii State Legislature.

HECO and its subsidiaries' operating revenues include amounts for various revenue taxes. Revenue taxes are generally recorded as an expense in the year the related revenues are recognized. However, HECO and its subsidiaries' revenue tax payments to the taxing authorities are based on the prior years' revenues. For 2009, 2008 and 2007, HECO and its subsidiaries included approximately $181 million, $252 million and $185 million, respectively, of revenue taxes in "operating revenues" and in "taxes, other than income taxes" expense.

Repairs and maintenance costs. Repairs and maintenance costs for overhauls of generating units are generally expensed as they are incurred.

Allowance for funds used during construction (AFUDC). AFUDC is an accounting practice whereby the costs of debt and equity funds used to finance plant construction are credited on the statement of income and charged to construction in progress on the balance sheet. If a project under construction is delayed for an extended period of time, as it was in the case of HELCO's installation of CT-4 and CT-5, AFUDC on the delayed project may be stopped.

The weighted-average AFUDC rate was 8.1% in 2009, 2008 and 2007, and reflected quarterly compounding.

Bank

Loans receivable. ASB states loans receivable at amortized cost less the allowance for loan losses, loan origination fees (net of direct loan origination costs), commitment fees and purchase premiums and discounts. Interest on loans is credited to income as it is earned. Discounts and premiums are accreted or amortized over the life of the loans using the interest method.

Loan origination fees (net of direct loan origination costs) are deferred and recognized as an adjustment in yield over the life of the loan using the interest method or taken into income when the loan is paid off or sold. Nonrefundable commitment fees (net of direct loan origination costs, if applicable) received for commitments to originate or purchase loans are deferred and, if the commitment is exercised, recognized as an adjustment of yield over the life of the loan using the interest method. Nonrefundable commitment fees received for which the commitment expires unexercised are recognized as income upon expiration of the commitment.

Loans held for sale, gain on sale of loans, and mortgage servicing assets and liabilities. Mortgage and educational loans held for sale are stated at the lower of cost or estimated market value on an aggregate basis. Generally, the determination of market value is based on the fair value of the loans. A sale is recognized only when the consideration received is other than beneficial interests in the assets sold and control over the assets is transferred irrevocably to the buyer. Gains or losses on sales of loans are recognized at the time of sale and are determined by the difference between the net sales proceeds and the allocated basis of the loans sold.

ASB capitalizes mortgage servicing assets or liabilities when the related loans are sold with servicing rights retained. Accounting for the servicing of financial assets requires that mortgage servicing assets or liabilities resulting from the sale or securitization of loans be initially measured at fair value at the date of transfer, and permits a class-by-class election between fair value and the lower of amortized cost or fair value for subsequent measurements of mortgage servicing asset classes. Mortgage servicing assets or liabilities are included as a component of gain on sale of loans. Upon adoption of that standard, ASB elected to continue to amortize all mortgage servicing assets in proportion to and over the period of estimated net servicing income and assess servicing assets for impairment based on fair value at each reporting date. Such amortization is reflected as a component of revenues on the consolidated statements of income. The fair value of mortgage servicing assets, for the purposes of impairment, is 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. ASB measures impairment of mortgage servicing assets on a disaggregated basis based on certain risk characteristics including loan type and note rate. Impairment losses are recognized through a valuation allowance for each impaired stratum, with any associated provision recorded as a component of loan servicing fees included in ASB's noninterest income.

Allowance for loan losses. ASB maintains an allowance for loan losses that it believes is adequate to absorb losses inherent in its loan portfolio. The level of allowance for loan losses is based on a continuing assessment of existing risks in the loan portfolio, historical loss experience, changes in collateral values and current conditions (e.g., economic conditions, real estate market conditions and interest rate environment). Adverse changes in any of these factors could result in higher charge-offs and provision for loan losses.

For commercial and commercial real estate loans, a risk rating system is used. Loans are rated based on the degree of risk at origination and periodically thereafter, as appropriate. ASB's credit review department performs an evaluation of these loan portfolios to ensure compliance with the internal risk rating system and timeliness of rating changes. The allowance for loan loss allocations for these loans are based on internal migration analyses with actual net losses. For loans classified as substandard with a total exposure exceeding $500,000, an analysis is done to determine if the loan is impaired. A loan is deemed impaired when it is probable that ASB will be unable to collect all amounts due according to the contractual terms of the loan agreement. Once a loan is deemed impaired, ASB applies a valuation methodology to determine whether there is an impairment loss. The measurement of impairment may be based on (i) the present value of the expected future cash flows of the impaired loan discounted at the loan's original effective interest rate, (ii) the observable market price of the impaired loan, or (iii) the fair value of the collateral, net of costs to sell. For all loans secured by real estate, ASB measures impairment by utilizing the fair value of the collateral, net of costs to sell; for other loans, discounted cash flows are used to measure impairment. Losses from impairment are charged to the provision for loan losses and included in the allowance for loan losses.

For the residential, consumer and homogeneous commercial loans receivable portfolios, the allowance for loan loss allocations use historical loss ratio analyses based on actual net charge-offs. For residential loans, the loan portfolio is segmented by loan categories and geographic location within the State of Hawaii (Oahu vs. the neighbor islands) and a three-year historical look-back period of actual loss experience is used to calculate historical loss ratios for these loans. For consumer and homogenous commercial loans, the loan portfolios are segmented by loan categories and a three-year historical look-back period of actual loss experience is used. The look-back period of actual loss experience is reviewed annually and may vary depending on the credit environment. In addition to the actual loss experience, ASB considers the following qualitative factors in estimating the allowance for loan losses:

- Changes in lending policies and procedures
- Changes in economic and business conditions and developments that affect the collectability of the portfolio
- Changes in the nature, volume and terms of the loan portfolio
- Changes in lending management and other relevant staff
- Changes in loan quality (past due, non-accrual, classified loans)
- Changes in the quality of the loan review system
- Changes in the value of underlying collateral
- Effect and changes in the level of any concentrations of credit
- Effect of other external and internal factors

ASB generally ceases the accrual of interest on loans when they become contractually 90 days past due or when there is reasonable doubt as to collectibility. Subsequent recognition of interest income for such loans is generally on the cash method. When, in management's judgment, the borrower's ability to make periodic principal and interest payments resumes, a loan not accruing interest (nonaccrual loan) is returned to accrual status. ASB uses either the cash or cost-recovery method to record cash receipts on impaired loans that are not accruing interest. While the majority of consumer loans are subject to ASB's policies regarding nonaccrual loans, certain past due consumer loans may be charged off upon reaching a predetermined delinquency status varying from 120 to 180 days.

Management believes its allowance for loan losses adequately estimates actual loan losses that will ultimately be incurred. However, such estimates are based on currently available information and historical experience, and future adjustments may be required from time to time to the allowance for loan losses based on new information and changes that occur (e.g., due to changes in economic conditions, particularly in the State of Hawaii). Actual losses could differ from management's estimates, and these differences and subsequent adjustments could be material.

Real estate acquired in settlement of loans. ASB records real estate acquired in settlement of loans at the lower of cost or fair value, less estimated selling expenses. ASB obtains appraisals based on recent comparable sales to assist management in estimating the fair value of real estate acquired in settlement of loans. Subsequent declines in value are charged to expense through a valuation allowance. Costs related to holding real estate are charged to operations as incurred. As of December 31, 2009 and 2008, ASB had $4.0 million and $1.5 million, respectively, of real estate acquired in settlement of loans.

Goodwill and other intangibles. Goodwill is tested for impairment at least annually. Intangible assets with definite useful lives are amortized over their respective estimated useful lives to their estimated residual values, and reviewed for impairment in accordance with ASC 350.

Goodwill. At December 2009 and 2008, the amount of goodwill was $82.2 million, which is the Company's only intangible asset with an indefinite useful life and is tested for impairment annually in the fourth quarter using data as of September 30. In December 2008, ASB recorded a write-off of $0.9 million of goodwill related to the sale of the business of Bishop Insurance Agency. For the three years ended December 31, 2009, there has been no impairment of goodwill. The fair value of ASB was estimated by an unrelated third party using a valuation method based on a market approach and discounted cash flows with each method having an equal weighting in determining the fair value of ASB. The market approach primarily considers publicly traded financial institutions with assets of $3 billion to $10 billion and measures the institutions' market values as a multiple to (1) net income and (2) book equity. The median market value multiples for net income and book equity are then applied to ASB's net income and book equity to calculate ASB's fair value using the market approach. The discounted cash flow analysis uses ASB's forecasted cash flows and applies a discount rate to present value the cash flows. The discount rate used in the analysis was 15%. The fair value under each valuation method also included a 20% control premium. The fair value of ASB exceeded its book value by approximately 50%.

Amortized intangible assets.

December 31	2009		2008	
(in thousands)	Gross carrying amount	Accumulated amortization	Gross carrying amount	Accumulated Amortization
Core deposit intangibles	$20,276	$20,276	$20,276	$20,276
Mortgage servicing assets	15,205	10,804	12,150	10,005
	$35,481	$31,080	$32,426	$30,281

Changes in the valuation allowance for mortgage servicing assets were as follows:

(in thousands)	2009	2008	2007
Valuation allowance, January 1	$268	$189	$119
Provision	166	278	92
Other-than-temporary impairment	(233)	(199)	(22)
Valuation allowance, December 31	$201	$268	$189

In 2009, 2008 and 2007, aggregate amortization expenses were $0.8 million, $0.4 million and $2.0 million, respectively.

The estimated aggregate amortization expenses for mortgage servicing assets for 2010, 2011, 2012, 2013 and 2014 are $0.7 million, $0.6 million, $0.5 million, $0.4 million and $0.4 million, respectively.

Core deposit intangibles are amortized each year based on the greater of the actual attrition rate of such deposit base or the applicable rate on a 10-year amortization table. Core deposit intangibles were fully amortized in 2007.

ASB capitalizes mortgage servicing assets acquired through either the purchase or origination of mortgage loans for sale or the securitization of mortgage loans with servicing rights retained. Changes in mortgage interest rates impact the value of ASB's mortgage servicing assets. Rising interest rates typically result in slower prepayment speeds in the loans being serviced for others which increases the value of mortgage servicing assets, whereas declining interest rates typically result in faster prepayment speeds which decrease the value of mortgage servicing assets and increase the amortization of the mortgage servicing assets. As of December 31, 2009 and 2008, the mortgage servicing assets had a net carrying value of $4.2 million and $1.9 million, respectively. In 2009, 2008 and 2007, mortgage servicing assets acquired through the sale or securitization of loans held for sale was $3.3 million, $0.6 million and $0.1 million, respectively. Amortization expenses for ASB's mortgage servicing assets amounted to $0.8 million, $0.4 million, and $0.4 million for 2009, 2008 and 2007, respectively, and are recorded as a reduction in revenues on the consolidated statements of income.

2 • Segment financial information

The electric utility and bank segments are strategic business units of the Company that offer different products and services and operate in different regulatory environments. The accounting policies of the segments are the same as those described in the summary of significant accounting policies, except that federal and state income taxes for each segment are calculated on a "stand-alone" basis. HEI evaluates segment performance based on net income. The Company accounts for intersegment sales and transfers as if the sales and transfers were to third parties, that is, at current market prices. Intersegment revenues consist primarily of interest and preferred dividends.

Electric utility

HECO and its wholly-owned operating subsidiaries, HELCO and MECO, are public electric utilities in the business of generating, purchasing, transmitting, distributing and selling electric energy on all major islands in Hawaii other than Kauai, and are regulated by the PUC. HECO also owns the following non-regulated subsidiaries: Renewable Hawaii, Inc. (RHI), which was formed to invest in renewable energy projects; HECO Capital Trust III, which is a financing entity; and Uluwehiokama Biofuels Corp., which was formed to own a new biodiesel refining plant to be built on the island of Maui, which project has been terminated.

Bank

ASB is a federally chartered savings bank providing a full range of banking services to individual and business customers through its branch system in Hawaii. ASB is subject to examination and comprehensive regulation by the Department of Treasury, Office of Thrift Supervision (OTS) and the Federal Deposit Insurance Corporation (FDIC), and is subject to reserve requirements established by the Board of Governors of the Federal Reserve System.

Other

"Other" includes amounts for the holding companies (HEI and American Savings Holdings, Inc), other subsidiaries not qualifying as reportable segments and intercompany eliminations.

Segment financial information was as follows:

(in thousands)	Electric utility	Bank	Other	Total
2009				
Revenues from external customers	$2,034,834	$ 274,719	$ 37	$2,309,590
Intersegment revenues (eliminations)	175	–	(175)	–
Revenues	2,035,009	274,719	(138)	2,309,590
Depreciation and amortization	154,578	1,309	784	156,671
Interest expense	57,944	43,543	18,386	119,873
Profit (loss)*	129,217	31,705	(32,098)	128,824
Income taxes (benefit)	47,776	9,938	(13,791)	43,923
Net income (loss)	81,441	21,767	(18,307)	84,901
Less net income attributable to noncontrolling interest – preferred stock of HECO and its subsidiaries	1,995	–	(105)	1,890
Net income (loss) for common stock	79,446	21,767	(18,202)	83,011
Capital expenditures	302,327	2,188	246	304,761
Assets (at December 31, 2009)	3,978,392	4,940,985	5,625	8,925,002
2008				
Revenues from external customers	$2,860,177	$ 358,553	$ 190	$3,218,920
Intersegment revenues (eliminations)	173	–	(173)	–
Revenues	2,860,350	358,553	17	3,218,920
Depreciation and amortization	150,297	4,884	881	156,062
Interest expense	54,757	105,424	21,385	181,566
Profit (loss)*	149,733	26,791	(35,378)	141,146
Income taxes (benefit)	55,763	8,964	(15,749)	48,978
Net income (loss)	93,970	17,827	(19,629)	92,168
Less net income attributable to noncontrolling interest – preferred stock of HECO and its subsidiaries	1,995	–	(105)	1,890
Net income (loss) for common stock	91,975	17,827	(19,524)	90,278
Capital expenditures	278,476	3,499	76	282,051
Assets (at December 31, 2008)	3,856,109	5,437,120	1,853	9,295,082
2007				
Revenues from external customers	$2,106,096	$ 425,495	$ 4,827	$2,536,418
Intersegment revenues (eliminations)	218	–	(218)	–
Revenues	2,106,314	425,495	4,609	2,536,418
Depreciation and amortization	145,311	13,574	874	159,759
Interest expense	53,268	159,898	25,288	238,454
Profit (loss)*	85,088	83,989	(36,130)	132,947
Income taxes (benefit)	30,937	30,882	(15,541)	46,278
Net income (loss)	54,151	53,107	(20,589)	86,669
Less net income attributable to noncontrolling interest – preferred stock of HECO and its subsidiaries	1,995	–	(105)	1,890
Net income (loss) for common stock	52,156	53,107	(20,484)	84,779
Capital expenditures	209,821	7,866	610	218,297
Assets (at December 31, 2007)	3,423,888	6,861,493	8,535	10,293,916

* Income (loss) before income taxes.

** Includes net assets of discontinued operations.

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

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

Selected financial information

Hawaiian Electric Company, Inc. and Subsidiaries

Consolidated Statements of Income Data

Years ended December 31	2009	2008	2007
(in thousands)			
Revenues			
Operating revenues	$2,026,672	$2,853,639	$2,096,958
Other – nonregulated	8,337	6,711	9,356
	2,035,009	2,860,350	2,106,314
Expenses			
Fuel oil	671,970	1,229,193	774,119
Purchased power	499,804	689,828	536,960
Other operation	248,515	243,249	214,047
Maintenance	107,531	101,624	105,743
Depreciation	144,533	141,678	137,081
Taxes, other than income taxes	191,699	261,823	194,607
Other – nonregulated	1,286	1,596	13,172
	1,865,338	2,668,991	1,975,729
Operating income from regulated and nonregulated activities	169,671	191,359	130,585
Allowance for equity funds used during construction	12,222	9,390	5,219
Interest and other charges	(57,944)	(54,757)	(53,268)
Allowance for borrowed funds used during construction	5,268	3,741	2,552
Income before income taxes	129,217	149,733	85,088
Income taxes	47,776	55,763	30,937
Net income	81,441	93,970	54,151
Less net income attributable to noncontrolling interest – preferred stock of subsidiaries	915	915	915
Net income attributable to HECO	80,526	93,055	53,236
Preferred stock dividends of HECO	1,080	1,080	1,080
Net income for common stock	$ 79,446	$ 91,975	$ 52,156

Consolidated Balance Sheet Data

December 31	2009	2008
(in thousands)		
Assets		
Utility plant, at cost		
Property, plant and equipment	$ 4,748,787	$ 4,320,040
Less accumulated depreciation	(1,848,416)	(1,741,453)
Construction in progress	132,980	266,628
Net utility plant	3,033,351	2,845,215
Regulatory assets	426,862	530,619
Other	518,179	480,275
	$ 3,978,392	$ 3,856,109
Capitalization and liabilities		
Common stock ($6 2/3 par value, authorized 50,000,000 shares, outstanding 13,786,959 shares and 12,805,843 shares)	$ 91,931	$ 85,387
Premium on common stock	385,659	299,214
Retained earnings	827,036	802,590
Accumulated other comprehensive income, net of income taxes	1,782	1,651
Common stock equity	1,306,408	1,188,842
Cumulative preferred stock – not subject to mandatory redemption ($20 par value, authorized 5,000,000 shares, outstanding 1,114,657 shares, dividend rates of 4.25-5.25%; $100 par value, authorized 5,000,000 shares, none outstanding)	22,293	22,293
Noncontrolling interest – cumulative preferred stock of subsidiaries – not subject to mandatory redemption ($100 par value, authorized 2,000,000 shares, outstanding 120,000 shares, dividend rate of 7.625%)	12,000	12,000
Stockholders' equity	1,340,701	1,223,135
Long-term debt, net	1,057,815	904,501
Total capitalization	2,398,516	2,127,636
Short-term borrowings – affiliate	–	41,550
Deferred income taxes	180,603	166,310
Regulatory liabilities	288,214	288,602
Contributions in aid of construction	321,544	311,716
Other	789,515	920,295
	$ 3,978,392	$ 3,856,109

Regulatory assets and liabilities. In accordance with ASC Topic 980, HECO and its subsidiaries' financial statements reflect assets, liabilities, revenues and expenses based on current cost-based rate-making regulations. Their continued accounting under ASC Topic 980 generally requires that rates are established by an independent, third-party regulator; rates are designed to recover the costs of providing service; and it is reasonable to assume that rates can be charged to and collected from customers. Management believes HECO and its subsidiaries' operations currently satisfy the ASC Topic 980 criteria. If events or circumstances should change so that those criteria are no longer satisfied, the electric utilities expect that the regulatory assets would be charged to expense and the regulatory liabilities would be credited to income or refunded to ratepayers. In the event of unforeseen regulatory actions or other circumstances, management believes that a material adverse effect on the Company's results of operations and financial position may result if regulatory assets have to be charged to expense without an offsetting credit for regulatory liabilities or if regulatory liabilities are required to be refunded to ratepayers.

Regulatory assets represent deferred costs expected to be fully recovered through rates over PUC-authorized periods. Generally, HECO and its subsidiaries do not earn a return on their regulatory assets; however, they have been allowed to recover interest on their regulatory assets for demand-side management (DSM) program costs. Regulatory liabilities represent amounts included in rates and collected from ratepayers for costs expected to be incurred in the future. For example, the regulatory liability for cost of removal in excess of salvage value represents amounts that have been collected from ratepayers for costs that are expected to be incurred in the future to retire utility plant. Noted in parentheses are the original PUC authorized amortization or recovery periods and the remaining amortization or recovery periods as of December 31, 2009, if different.

Regulatory assets were as follows:

December 31 (in thousands)	2009	2008
Retirement benefit plans (5 years; 2 years remaining for HELCO's $6 million prepaid pension regulatory asset; 5 years remaining for HECO's $8 million prepaid pension and OPEB tracking mechanisms; indeterminate for remainder)	$303,927	$416,680
Income taxes, net (1 to 36 years)	82,046	77,660
Postretirement benefits other than pensions (18 years; 3 years remaining)	5,369	7,159
Unamortized expense and premiums on retired debt and equity issuances (14 to 30 years; 2 to 19 years remaining)	14,878	16,191
Demand-side management program costs, net (1 year)	836	2,571
Vacation earned, but not yet taken (1 year)	6,849	6,654
Other (1 to 50 years)	12,957	3,704
	$426,862	$530,619

Regulatory liabilities were as follows:

December 31 (in thousands)	2009	2008
Cost of removal in excess of salvage value (1 to 60 years)	$280,674	$282,400
Retirement benefit plans (5 years beginning with respective utility's next rate case; 5 years remaining for HECO's $4 million regulatory liability)	5,193	4,718
Other (1 to 5 years)	2,347	1,484
	$288,214	$288,602

The regulatory asset and liability relating to retirement benefit plans was created as a result of pension and OPEB tracking mechanisms adopted by the PUC in interim rate case decisions for HECO, MECO and HELCO in 2007 (see Note 8).

Cumulative preferred stock. The cumulative preferred stock of HECO and its subsidiaries is redeemable at the option of the respective company at a premium or par, but is not subject to mandatory redemption.

Major customers. HECO and its subsidiaries received $199 million (10%), $295 million (10%) and $194 million (9%) of their operating revenues from the sale of electricity to various federal government agencies in 2009, 2008 and 2007, respectively.

Sale of non-electric utility property. In August 2007, HECO sold land and a building that executives and management had been using as a recreational facility. The sale of the non-electric utility property resulted in an after-tax gain in the third quarter of 2007 of approximately $2.9 million.

Commitments and contingencies.

Fuel contracts. HECO and its subsidiaries have contractual agreements to purchase minimum quantities of fuel oil and diesel fuel for multi-year periods, some through December 31, 2014 (at prices tied to the market prices of crude oil and petroleum products in the Far East and U.S. West Coast). Based on the average price per barrel as of January 1, 2010, the estimated cost of minimum purchases under the fuel supply contracts is $0.8 billion in each of 2010, 2011 and 2012 and a total of $0.9 billion for the period 2013 through 2014. The actual cost of purchases in 2010 and future years could vary substantially from this estimate as a result of changes in market prices, quantities actually purchased and/or other factors. HECO and its subsidiaries purchased $0.7 billion, $1.2 billion and $0.8 billion of fuel under contractual agreements in 2009, 2008 and 2007, respectively.

On December 2, 2009, HECO and Chevron Products Company, a division of Chevron USA, Inc. (Chevron) executed an amendment to their existing contract for the purchase/sale of low sulfur fuel oil (LSFO). The amendment modified the pricing formula, which could result in higher prices. The amended agreement terminates on April 30, 2013. On January 28, 2010, the PUC approved the amendment on an interim basis, and allowed HECO to include the costs incurred under the amendment in its ECAC, to the extent such costs are not recovered through HECO's base rates. The costs recovered as a result of the interim decision are not subject to retroactive disallowance, provided HECO complies with the remaining procedural schedule, which includes additional discovery by the

Consumer Advocate, and there is no evidence of intentional misrepresentation or omission of facts by HECO or Chevron, or any other form of malfeasance.

HECO and Tesoro Hawaii Corporation are exploring whether there may be a mutually beneficial amendment to the terms of their LSFO contract.

Power purchase agreements. As of December 31, 2009, HECO and its subsidiaries had six firm capacity PPAs for a total of 540 megawatts (MW) of firm capacity. Purchases from these six independent power producers (IPPs) and all other IPPs totaled $500 million, $690 million and $537 million for 2009, 2008 and 2007, respectively. The PUC allows rate recovery for energy and firm capacity payments to IPPs under these agreements. Assuming that each of the agreements remains in place for its current term and the minimum availability criteria in the PPAs are met, aggregate minimum fixed capacity charges are expected to be approximately $0.1 billion per year for 2010 through 2014 and a total of $0.8 billion in the period from 2015 through 2030.

In general, HECO and its subsidiaries base their payments under the PPAs upon available capacity and actually supplied energy and they are generally not required to make payments for capacity if the contracted capacity is not available, and payments are reduced, under certain conditions, if available capacity drops below contracted levels. In general, the payment rates for capacity have been predetermined for the terms of the agreements. Energy payments will vary over the terms of the agreements. HECO and its subsidiaries pass on changes in the fuel component of the energy charges to customers through the ECAC in their rate schedules (see "Energy cost adjustment clauses" below). HECO and its subsidiaries do not operate, or participate in the operation of, any of the facilities that provide power under the agreements. Title to the facilities does not pass to HECO or its subsidiaries upon expiration of the agreements, and the agreements do not contain bargain purchase options for the facilities.

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 is produced and 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:

Renewable energy and energy efficiency goals. 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 provided for the parties to seek amendment to the Hawaii Renewable Portfolio Standards (RPS) law to (1) increase the current renewable energy requirements from 20% to 25% by the year 2020 and to add a further RPS goal of 40% by the year 2030, and (2) require that after 2014 the RPS goal be met solely with renewable energy generation versus including energy savings from energy efficiency measures (although 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 enacted 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 (PBF) 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 provided 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, 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 encourage achievement of these goals.

Public benefits fund (PBF). 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 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% was to be collected via the DSM surcharge and 40% via the PBF surcharge. Beginning January 1, 2009, the 1% was assessed on customers of HECO and its subsidiaries. In November 2009, the PUC issued an order that the PBF surcharge for 2010 will collect revenues through a kilowatthour surcharge assessed statewide that is intended to target revenue equal to 1% of the projected total electric revenue, plus revenue taxes.

Clean Energy Infrastructure Surcharge (CEIS). The Energy Agreement provides for the establishment of a CEIS. The CEIS, which will need to be approved by the PUC, is to be designed to expedite cost recovery for a variety of infrastructure that supports greater use of renewable energy or grid efficiency within the utility systems (such as advanced metering, energy storage, interconnections and interfaces). The Energy Agreement provides that the surcharge should be available to recover costs that would normally be expensed in the year incurred and capital costs (including the allowed return on investment, AFUDC, depreciation, applicable taxes and other approved costs), and could also be used to recover costs stranded by clean energy initiatives. On November 28, 2008, HECO and the Consumer Advocate filed a joint letter informing the PUC that the 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. An REIP Surcharge was approved by the PUC in December 2009. The utilities need to file for cost inclusion in the surcharge on a project-by-project basis.

Renewable energy projects. HECO and its subsidiaries will continue to negotiate with developers of currently proposed projects (identified in the Energy Agreement) to integrate into its grid approximately 1,100 MW from a variety of renewable energy sources, including solar, biomass, wind, ocean thermal energy conversion, wave, and others. This includes HECO's commitment to integrate, with the assistance of the State 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. This includes work performed by HECO in February 2010 on behalf of the State to conduct a Request for Information (RFI) process for the development of an undersea cable system. The primary objective of the RFI process is to dialogue with and collect information from market participants that have knowledge and experience in alternative business structures and financing mechanisms relevant to the planned development of the undersea cable system. The information collected from experienced undersea cable system developers, equipment suppliers, and project financiers participating in the RFI process, combined with the results from ongoing technical analyses focused on developing the preferred cable system architecture and functional requirements, is intended to guide subsequent activity to develop and issue an invitation to bid or request for proposal for the undersea 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 REIP.

Feed-in tariff (FIT). As another method of accelerating the acquisition of renewable energy by the utilities, the Energy Agreement includes support for the parties to develop a 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 a 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 intervenor or participant status. 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, 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. A 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 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 a 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 a FIT is not available.

In September 2009, the PUC issued a D&O that sets forth general principles for the FIT, approved the FIT as a mechanism for the procurement of renewable resources and directed the parties to file a stipulated procedural schedule that governs tasks for implementing a FIT, including development of queuing and interconnection procedures, reliability standards and FIT rates. The D&O contemplates that, for the initial FIT, there will be rates for PV, concentrated solar power, onshore wind, and in-line hydropower projects up to 5 MW depending on technology and location. There will also be a "baseline" FIT rate to encourage other renewable energy technologies. Net energy metering, competitive bidding, negotiated PPAs, Schedule Q, and avoided cost offerings will continue to exist as additional and complementary mechanisms to provide multiple avenues for the procurement of renewable energy. FIT rates will be based on the project cost and reasonable profit of a typical project. The rates will be differentiated by technology or resource, size, and interconnection costs; and will be levelized. The FIT program will be reexamined two years after it first becomes effective and every three years thereafter. The D&O directs the utilities to develop reliability standards for each company, and states that the PUC will direct the companies: (1) to establish FITs in their respective service territories; (2) to file status reports on the progress of the FIT program; and (3) to collaborate with the other parties to craft queuing and interconnection procedures that will minimize delays associated with numerous potential FIT projects and the various interconnection studies they could require.

In January 2010, the utilities and other intervenors filed their respective proposals for the tier 1 and 2 rates under the FIT for consideration by the PUC. Filings of Queuing and Interconnection Procedures and Reliability Standards were made in February 2010. Filing of proposed FIT Tier 3 (with pricing) is due in April 2010.

Net energy metering (NEM). The Energy Agreement also provides that system-wide caps on NEM should be removed after implementation of the FITs. 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.

In December 2008, HELCO, MECO and the Consumer Advocate filed stipulations to increase their NEM system caps from 1% to 3% of system peak demand (among other changes) and the PUC approved the proposed caps. The PUC directed the utilities and Consumer Advocate to file a proposed plan to address the provisions regarding NEM in the Energy Agreement, which plans were filed in August 2009. In January 2010, a stipulated agreement between the utilities and the Consumer Advocate was filed with the PUC that proposed the removal of the present system-wide cap with the adoption of revised interconnection standards to ensure ongoing reliability and safety, as well as the establishment of Reliability Standards. The proposal included adoption of a 15% per circuit distribution generation trigger for conducting further circuit-level impact studies; removal of individual NEM program caps in favor of more overall system-wide assessments; and use of Locational Value Maps, a component of a formal Clean Energy Scenario Planning framework as an indicator of circuit penetration levels.

Using biofuels. 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 July 2009, HECO and MECO each filed applications for approval of biodiesel fuel supply contracts, the inclusion of the cost of the biodiesel fuel purchased under such contracts in their respective ECACs and, in the case of HECO, the commitment of funds in excess of $2.5 million (estimated at $5.2 million) for the purchase of capital equipment, in connection with proposed demonstration projects to test the use of biofuels to determine, in the case of HECO, the maximum blend of biofuels with low sulfur fuels for use in its steam electric generation units and, in the case of MECO, biodiesel's potential as a primary fuel in utility scale diesel engines with the objective of evaluating the longer term effects biodiesel will have on efficiency, emissions, storage and handling, operations and other issues. In September 2009, the PUC denied the application of Life of the Land to intervene in the two proceedings, but allowed it to participate with respect to the issue of the environmental sustainability of palm oil base biodiesel. In December 2009, the parties and participant in the respective dockets reached agreement on all of the issues and filed joint motions for approval of a stipulation, which recommends approval of the biofuel fuel supply contract applications.

In December of 2009, HECO also filed an application of a two-year biodiesel supply contract for the supply of biodiesel fuel primarily for use in operating HECO CIP CT-1.

Decoupling rates from sales. 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 to the Energy Agreement agreed 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 final statement of position in May 2009. Panel hearings at the PUC were completed on July 1, 2009. Briefing by the parties was completed in September 2009. In November 2009, the utilities filed a motion for interim approval of a decoupling mechanism for the utilities.

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 deferred consideration of the proposal pending the outcome of the decoupling proceeding. The Energy Agreement also contemplated that additional rate cases based on a 2009 test year would be filed by HELCO and MECO in order to provide their respective baselines for implementation of the new regulatory model, but HELCO and MECO were unable to file 2009 test year rate case applications. MECO filed its general rate increase application on September 30, 2009, requesting approval of a revenue increase of 9.7%, or $28.2 million, over revenues at current rates. HELCO's general rate increase application was filed on December 9, 2009, seeking a revenue increase of 6.0%, or $20.9 million, over revenues at current rates.

ECAC. 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.

Purchased power surcharge. Pursuant to the Energy Agreement, with PUC approval, a separate surcharge would be established to allow the utilities to pass through all reasonably incurred purchased power costs, including all capacity, operation and maintenance expenses and other non-energy payments.

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 approved by the PUC, which are currently recovered through base rates, with the purchased power adjustment clause to be adjusted monthly and reconciled quarterly. In their 2010 test year rate cases, MECO and HELCO each proposed the same purchased power adjustment clause proposed by HECO in its 2009 test year rate case.

Other initiatives. 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 PV 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 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) delinking prices paid under all new renewable energy contracts from oil prices; and (g) 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 PUC approval at the end of April 2009, would provide a monthly bill credit to qualified, low-income customers. In December 2009, the Consumer Advocate filed a statement of position on the Lifeline Rate program stating it has no objections to implementing the program on a pilot basis for a period of no less than three years to allow time to evaluate the benefits of the program.

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.

On July 2, 2009, the PUC issued an interim D&O in HECO's 2009 test year rate case, which 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. HECO calculated the interim increase amount at $61.1 million annually, or a 4.7% increase, and submitted the information to the PUC on July 8, 2009. The PUC approved HECO's calculation and HECO implemented the interim increase on August 3, 2009.

As of December 31, 2009, HECO and its subsidiaries had recognized $281 million of revenues with respect to interim orders ($5 million related to interim orders regarding certain integrated resource planning costs and $276 million related to interim orders regarding general rate increase requests). Revenue amounts recorded pursuant to interim orders are subject to refund, with interest, if they exceed amounts allowed in a final order.

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 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 October 2007, the PUC issued an interim D&O in the HECO 2007 test year rate case, 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.

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 a project, project costs may need to be written off in amounts that could result in significant reductions in HECO's consolidated net income. Significant projects (with capitalized and deferred costs accumulated through December 31, 2009 noted in parentheses) include HECO's Campbell Industrial Park (CIP) combustion turbine No. 1 (CT-1) and transmission line ($193 million), HECO's East Oahu Transmission Project ($49 million), HELCO's ST-7 ($90 million) and HECO's Customer Information System (CIS) ($24 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. Current plans are for the CT to be run primarily as a "peaking" unit and to be fueled by biodiesel, when a supply of biodiesel fuel becomes available.

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.

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, including synchronizing into the grid and performing all operational tests necessary for commercial operation. In November 2009, HECO filed a motion for a second increase to recover CIP CT-1 costs by allowing HECO to include the costs in its rate base or by allowing HECO to continue to accrue AFUDC on the costs.

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. 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 August 2009, the PUC denied approval of the amended HECO contract with Imperium GH and a 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." As a result of the PUC decision, the amended contract was terminated.

In October 2009, a process was established with PUC approval to allow HECO to use CIP CT-1 for critical load purposes, which HECO has done on one occasion.

On October 2, 2009, HECO filed an application with the PUC for approval of a biodiesel supply contract for the CIP CT-1 biodiesel emissions data project and to include the contract costs in HECO's ECAC. The application also requests that HECO be allowed to use biodiesel blended with no more than 1% petroleum diesel (in addition to 100% biodiesel) to benefit from the federal biofuel blenders' tax credit if available. On October 6, 2009, HECO purchased approximately 400,000 gallons of biodiesel under the biodiesel supply contract, although the recovery of costs under the contract has not yet been approved by the PUC. Subsequently, testing using biodiesel was completed to determine the appropriate control settings using biodiesel and to obtain data necessary for modification of the unit's air permit.

On December 21, 2009, HECO entered into a two-year contract with Renewable Energy Group (REG) to supply biodiesel for the generating unit, subject to PUC approval. On December 22, 2009, HECO filed an application with the PUC for approval of the fuel contract with REG and to include the contract costs in HECO's ECAC.

As of December 31, 2009, HECO's cost estimate for the Project was $196 million (of which $193 million had been incurred, including $9 million of AFUDC). 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 December 31, 2009. However, if it becomes probable that the PUC will disallow some or all of the incurred costs for rate-making purposes, HECO may be required to write off a material portion or all of the project costs incurred in its efforts to put the project into service.

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) for an EOTP, revised to use a 46 kV system and a 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 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.

As a result of higher than estimated construction costs, an increase in the cost of materials and the overall delay in the project, 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. HECO, however, is evaluating an alternative that might result in faster implementation and lower cost for the second phase. A portion of this alternative has been awarded funding through the Smart Grid Investment Grant Program of the American Recovery and Reinvestment Act of 2009. PUC approval is required before the alternative can be implemented.

As of December 31, 2009, the accumulated costs recorded for the EOTP amounted to $49 million, including (i) $12 million of planning and permitting costs incurred prior to 2003, (ii) $15 million of planning, permitting and construction costs incurred after 2002 and (iii) $22 million for AFUDC. Management believes no adjustment to project costs is required as of December 31, 2009. However, if it becomes probable that the PUC will disallow some or all of the incurred costs for rate-making purposes, HECO may be required to write off a material portion or all of the project costs incurred in its efforts to put the project into service whether or not it is completed.

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

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

CT-4 and CT-5 became operational in mid-2004 and currently can be operated as required to meet HELCO's system needs, but additional efforts have been ongoing to achieve compliance with the night-time noise standard in the Settlement Agreement and/or to modify the standard.

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.

On June 22, 2009, ST-7 was placed into service. As of December 31, 2009, HELCO's cost estimate for ST-7 was $92 million (of which $90 million had been incurred). HELCO is seeking to recover the costs of ST-7 in HELCO's 2010 test year rate case.

Management believes no adjustment to project costs is required at December 31, 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 in HELCO's 2006 rate case or disallow any ST-7 costs in HELCO's 2010 rate case, HELCO will be required to record an additional write-off.

Customer Information System (CIS) Project. On August 26, 2004, HECO, HELCO and MECO filed a joint application with the PUC for approval of the accounting treatment and recovery of certain costs related to acquiring and implementing a new CIS. The application stated that the new CIS would allow the utilities to (i) more quickly and accurately store, maintain and manage customer-specific information necessary to provide basic customer service functions, such as producing bills, collecting payments, establishing service and fulfilling customer requests in the field, and (ii) have substantially greater capabilities and features than the existing system, enabling the utilities to enhance their operations, including customer service. In a D&O filed on May 3, 2005, the PUC approved the utilities' request to (i) expend the then-estimated amount of $20.4 million for the new CIS, provided that no part of the project costs may be included in rate base until the project is in service and is "used and useful for public utility purposes," and (ii) defer certain computer software development costs, accumulate an allowance for funds used during construction during the deferral period, amortize the deferred costs over a specified period and include the unamortized deferred costs in rate base, subject to specified conditions.

Following a competitive bidding process, HECO signed a contract with Peace Software US Inc. (Peace) in March 2006 to have Peace develop, deliver and implement the new CIS (implementation contract), with a transition to the new CIS originally scheduled to occur in February 2008. The transition did not occur as scheduled. In June 2008, HECO notified Peace that HECO considered Peace to be in material breach of the implementation contract because of Peace's failure to satisfy the project schedule. 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. Through August 2009, HECO attempted to work with Peace to develop a plan to minimize additional delay and complete installation of the new CIS using the Peace software, despite Peace's failure to cure the breaches identified by HECO in June 2008. However, on August 31, 2009, Peace provided HECO a notice of termination of the implementation contract, alleging that HECO had wrongfully withheld payment of invoices under the contract. Peace filed a lawsuit against HECO the same day in the Hawaii United States District Court. Peace alleges, among other things, that HECO breached the contract by not paying amounts due. HECO contends the lawsuit is without merit. On October 5, 2009, HECO filed its response to the Peace complaint and also filed a counterclaim against Peace for breach of contract and a third-party claim against Peace's former owner, First Data Corporation, for tortious interference with HECO's contract.

The CIS project will continue with HECO selecting a new software vendor and system integrator through a competitive bid process. The selections are expected to be made before the end of the second quarter of 2010. As of December 31, 2009, the accumulated deferred and capital costs recorded for the CIS amounted to $24 million. HECO's portion of the costs of the CIS project were originally included in HECO's 2009 rate case, but were removed from that case when HECO no longer expected the system to be in place in 2009. Management believes no adjustment to project costs is required as of December 31, 2009. However, if it becomes probable that the PUC will disallow some or all of the incurred costs for rate-making purposes, HECO may be required to write off a material portion or all of the project costs incurred in its efforts to put the project into service whether or not it is completed.

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 agreed to support, facilitate and help expedite renewable projects, including expediting permitting processes.

In July 2009, HECO filed an application for the recovery of Big Wind Implementation Studies costs through the REIP Surcharge, which asked the PUC to approve the deferral and recovery of costs for studies and analyses needed to integrate large amounts of wind-generated renewable energy potentially located on the islands of Molokai and Lanai to the Oahu electric grid through a surcharge mechanism. On December 11, 2009, the PUC issued a D&O that allows HECO to defer costs for the Big Wind Implementation Studies for later review for prudence and reasonableness, but refrained from making any decision as to the specific recovery mechanism or the terms of any recovery mechanism (e.g. amortization period or carrying treatment).

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 HECO's consolidated results of operations, financial condition or liquidity.

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 to address petroleum contamination at the site. The Participating Parties are funding the investigative and remediation work using an interim cost allocation method (subject to a final allocation) and have organized a limited liability company to perform the work. Although the Honolulu Harbor investigation involves four units—Iwilei, Downtown, Kapalama and Sand Island, to date all the investigative and remedial work has focused on the Iwilei Unit.

The Participating Parties have conducted subsurface investigations, assessments and preliminary oil removal tasks. A HECO investigation of its operations in the Iwilei Unit in 2003 and subsequent maintenance and inspections have confirmed that its facilities are not releasing petroleum.

The Participating Parties anticipate that that all remedial design work for the Iwilei Unit required under the Enforceable Agreement will be completed in 2010. The Participating Parties will begin implementation of remedial design elements as they are approved by the DOH.

Through December 31, 2009, HECO has accrued a total of $3.3 million for the estimated HECO share of costs for continuing investigative work, remedial activities and monitoring for the Iwilei unit. As of December 31, 2009, the remaining accrual (amounts expensed less amounts expended) for the Iwilei unit was $1.5 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 developed a BART implementation plan. 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 Supreme Court dismissed appeals of the Circuit Court's decision.

The EPA is required to develop Maximum Achievable Control Technology (MACT) standards for oil-fired EGU HAP emissions. The Clean Air Act 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 EPA's issuance of an Information Collection Request (ICR) is the first step in the regulatory process to develop the MACT standards for utility EGUs. Under the current schedule in the ICR, all emissions testing on HECO units identified by EPA must be completed and emissions information submitted to EPA by September 4, 2010.

On October 22, 2009, the EPA filed in the United States District Court for the District of Columbia a proposed consent decree in American Nurses Association, et al. v. Jackson. The consent decree would require the EPA to propose MACT standards for coal- and oil-fired EGUs no later than March 16, 2011 and promulgate final standards no later than November 16, 2011. The EPA is required to respond to any adverse public comments before the consent decree becomes final.

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.

Hazardous Air Pollutant (HAP) Control–Reciprocating Internal Combustion Engines (RICE). On February 17, 2010, the EPA issued final MACT standards that regulate HAPs from certain existing diesel compression ignition engines (Compression Ignition RICE). The EPA announced that it will also issue final MACT standards for certain gasoline and propane spark ignition engines (Spark Ignition RICE) by August 10, 2010. The Compression Ignition RICE MACT regulations require installation of pollution control devices on approximately 80 RICE at the utilities' facilities. Approximately 20 of the utilities' Compression Ignition RICE are required to implement only specified maintenance practices, rather than install pollution control devices. The Compression Ignition RICE MACT rule provides a three-year compliance period after the date of its publication in the Federal Register. Management is currently evaluating the impacts of the final Compression Ignition RICE rule, including capital expenditures and other compliance costs, and is also assessing the potential impacts of the proposed Spark Ignition RICE requirements.

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.

On April 1, 2009, the U.S. Supreme Court issued an 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. 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, will be applicable to its facilities. When issued, the applicable final cooling water intake requirements will be incorporated into the National Pollutant Discharge Elimination System permits governing HECO's Kahe, Waiau and Honolulu Power Plants. It is anticipated that the EPA will issue draft rules in mid-2010.

Global climate change and greenhouse gas (GHG) emissions reduction. National and international concern about climate change and the contribution of GHG emissions to global warming have led to action by the state of Hawaii and federal legislative and regulatory proposals to reduce GHG emissions. Carbon dioxide emissions, including those from the combustion of fossil fuels, comprise the largest percentage of GHG emissions.

In July 2007, Act 234, which requires a statewide reduction of GHG emissions by January 1, 2020 to levels at or below the statewide GHG emission levels in 1990, became law in Hawaii. 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. The Task Force retained a consultant to prepare the work plan, which was submitted to the Hawaii Legislature in December 2009. The Task Force also unanimously recommended that the work plan include the HCEI as a means to meet the Act 234 GHG emission reduction goals, though costs and funding mechanisms would need further exploration and consideration. (For a discussion of the HCEI, see "Hawaii Clean Energy Initiative" above.) Because the regulations implementing Act 234 have not yet been developed or promulgated, management cannot predict the impact of Act 234 on the electric utilities and the Company.

In June 2009, the U.S. House of Representatives passed H.R. 2454, the American Clean Energy and Security Act of 2009 (ACES). Among other things, ACES establishes a declining cap on GHG emissions requiring a 3% emissions reduction by 2012 that increases to 17% by 2020, 42% by 2030, and 83% by 2050. The ACES also establishes a trading and offset scheme for GHG allowances. The trading program combined with the declining cap is known as a "cap and trade" approach to emissions reduction. In September 2009, the U.S. Senate began consideration of the Clean Energy Jobs and American Power Act (S. 1733). S. 1733 also includes cap and trade provisions to reduce GHG emissions. Since then, several other approaches to GHG emission reduction have been either introduced or discussed in the U.S. Senate; however, no legislation has yet been enacted.

In response to the 2007 U.S. Supreme Court decision in Massachusetts v. EPA, which ruled that the Agency has the authority to regulate GHG emissions from motor vehicles under the Clean Air Act (CAA), the EPA has accelerated rulemaking addressing GHG emissions from both mobile and stationary sources. In April 2009, the EPA proposed making the finding that motor vehicle GHG emissions endanger public health or welfare. Management believes the EPA will make the same or similar endangerment finding regarding GHG emissions from stationary sources like the utilities' generating units. On June 30, 2009, the EPA granted the California Air Resources Board's request for a waiver from CAA preemption to enforce GHG emission standards for motor vehicles. On September 22, 2009, the EPA issued the Final Mandatory Reporting of Greenhouse Gases Rule. The rule requires that sources above certain threshold levels monitor and report GHG emissions beginning in 2010. On September 28, 2009, the EPA and the National Transportation Safety Administration jointly proposed federal GHG emission standards for motor vehicles.

In addition, the Prevention of Significant Deterioration (PSD) permit program of the CAA applies to any pollutant that is "subject to regulation" under the CAA. The PSD program applies to designated air pollutants from new or modified stationary sources, such as utility electrical generation units. Currently, the PSD program does not apply to GHGs. However, on October 27, 2009, the Federal Register published the EPA's proposed "Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas (GHG) Tailoring Rule" that would create a new emissions threshold for GHG emissions from new and existing facilities. The proposed rule would phase in applicability thresholds for both PSD and Title V programs for sources of GHG emissions. The first phase would last for six years. The EPA would conduct, if appropriate, another rulemaking by the end of the sixth year to revise applicability and significance level thresholds and other streamlining techniques. States may need to increase fees to cover the increased level of activity caused by this rule. If adopted in its current form, the proposed tailoring rule would require a number of existing HECO, HELCO and MECO facilities that are not currently subject to the Covered Source Permit program to submit an initial Covered Source Permit application to the DOH within one year following the effective date of the final rule. These rules are being proposed and adopted on a parallel track with federal climate change legislation. If comprehensive GHG emission control legislation is not adopted, then these (and other future) EPA rules would likely be finalized and be applicable to the utilities.

HECO and its subsidiaries have taken, and continue to identify opportunities to take, direct action to reduce GHG emissions from their operations, including, but not limited to, supporting DSM programs that foster energy efficiency, using renewable resources for energy production and purchasing power from IPPs generated by renewable resources, committing to burn renewable biodiesel in HECO's CIP generating unit, using biodiesel for startup and shutdown of selected MECO generation units, and pursuing plans to test biofuel blends in other HECO and MECO generating units. HECO seeks to identify and support viable technology for electricity production that will increase energy efficiency and reduce or eliminate GHG emissions. Implementation of actions included in the Energy Agreement under the HCEI can further help achieve reduction or elimination of GHG emissions. Since the specific GHG reductions the electric utilities would have to meet under GHG reduction legislation and rule-making remain unclear, management is unable to evaluate the ultimate impact on the Company's operations of eventual GHG regulation. However, the Company believes that the various initiatives it is undertaking will provide a sound basis for managing the electric utilities' carbon foot print and meeting GHG reduction goals that will ultimately emerge.

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

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

The Company is undertaking an adaptation survey of its facilities as a step in developing a longer term strategy for responding to the consequences of global climate change.

BlueEarth Biofuels LLC. 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 Biodiesel 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 April 2011. 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 and UBC's investment in the venture was written off in 2009.

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 allowed output of the wind farm is 20.5 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. A panel of three neutral arbitrators conducted a hearing which concluded on January 22, 2010. Briefs were filed in February 2010, and a decision is expected in March 2010.

By letter to Tawhiri dated September 23, 2009, HELCO requested binding arbitration as provided for under the provisions of the RAC on three issues related to the Kamao'a switching station under the terms of the RAC: (1) transfer of the title/bill of sale for the switching station to HELCO; (2) transfer of an interest in land for the switching station necessary for HELCO to operate and maintain it; and (3) reimbursements of certain of HELCO's interconnection costs in connection with the construction of the switching station. HELCO also indicated the Tawhiri RAC would be terminated if Tawhiri did not cure its breaches under the RAC. On October 13, 2009, Tawhiri submitted its response, denying any breaches of the RAC that would justify its termination and stating that the issues related to interconnection costs involve the interpretation of the various orders of the PUC related to the RAC, rather than the interpretation and application of the terms and conditions of the RAC itself. On October 19, 2009, Tawhiri petitioned the PUC for a ruling that the RAC and the PUC's order approving it required HELCO to reimburse Tawhiri $2.1 million for interconnections costs. The PUC denied Tawhiri's petition and motion for reconsideration. Tawhiri filed a notice of appeal on January 25, 2010. On February 3, 2010, Tawhiri moved for a stay of the arbitration pending a decision on the appeal. The parties have selected arbitrators and, if no stay is granted, expect an arbitration of this matter in the second quarter of 2010.

In addition to the curtailment and switching station issues, HELCO and Tawhiri have a dispute relating to reconciliation of transmission line losses, which dispute has not yet proceeded to arbitration.

Asset retirement obligation. In July 2009, HECO hired an industrial hygienist to conduct an inspection at HECO's Honolulu power plant to determine the extent of asbestos and lead-based paint at a non-operating portion of the plant. The inspection indicated that retired Generating Units Nos. 5 and 7 at the plant were now deteriorating, and the industrial hygienist recommended removing the asbestos-containing materials and lead-based paint. Based on prior assessments, HECO believed the timing of the removal of asbestos and lead-based paint was not estimable. The asbestos and lead-based paint, in their current state, do not pose any health risks, as these hazardous materials are confined to a sealed/vacant portion of the plant. Based on the recent study, however, HECO now intends to remove Units Nos. 5 and 7, including abating the asbestos and lead-based paint, over a 5-year period (2010 to 2014). In accordance with accounting principles for asset retirements and environmental obligations, in September 2009 HECO recorded an asset retirement obligation estimated at $23 million.

Collective bargaining agreements. As of December 31, 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 $5 billion and are uninsured. Similarly, HECO, HELCO and MECO have no business interruption insurance. If a hurricane or other uninsured catastrophic natural disaster were to occur, and if the PUC were not to allow the utilities to recover from ratepayers restoration costs and revenues lost from business interruption, their results of operations 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.

4 • Bank subsidiary

Selected financial information

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

Consolidated Statements of Income Data

Years ended December 31	2009	2008	2007
(in thousands)			
Interest and dividend income			
Interest and fees on loans	$217,838	$247,210	$245,593
Interest and dividends on investment and mortgage-related securities	26,977	65,208	111,470
	244,815	312,418	357,063
Interest expense			
Interest on deposit liabilities	34,046	61,483	81,879
Interest on other borrowings	9,497	43,941	78,019
	43,543	105,424	159,898
Net interest income	**201,272**	**206,994**	**197,165**
Provision for loan losses	32,000	10,334	5,700
Net interest income after provision for loan losses	**169,272**	**196,660**	**191,465**
Noninterest income			
Fee income on deposit liabilities	30,713	28,332	26,342
Fees from other financial services	25,267	24,846	27,916
Fee income on other financial products	5,833	6,683	7,418
Net gains (losses) on sale of securities	(32,034)	(17,376)	1,109
Losses on available-for-sale securities (includes $32,167 and $7,764 of other-than-temporary impairment losses, net of $16,723 and nil of non-credit losses recognized in other comprehensive income, for 2009 and 2008, respectively)	(15,444)	(7,764)	–
Other income	15,569	11,414	5,647
	29,904	46,135	68,432
Noninterest expense			
Compensation and employee benefits	73,990	77,858	61,937
Occupancy	22,057	21,890	21,051
Data processing	14,382	10,678	10,458
Services	11,189	16,706	29,173
Equipment	8,849	12,544	14,417
Office supplies, printing and postage	3,758	4,243	4,586
Marketing	2,134	4,007	4,245
Communication	2,446	3,241	3,740
Loss on early extinguishment of debt	760	39,843	–
Other expense	27,906	24,994	26,301
	167,471	216,004	175,908
Income before income taxes	**31,705**	**26,791**	**83,989**
Income taxes	9,938	8,964	30,882
Net income	**$ 21,767**	**$ 17,827**	**$ 53,107**

Consolidated Balance Sheet Data

December 31 (in thousands)	2009	2008
Assets		
Cash and equivalents	$ 425,896	$ 168,766
Federal funds sold	1,479	532
Available-for-sale investment and mortgage-related securities	432,881	657,717
Investment in stock of Federal Home Loan Bank of Seattle	97,764	97,764
Loans receivable, net	3,670,493	4,206,492
Other	230,282	223,659
Goodwill, net	82,190	82,190
	$4,940,985	$5,437,120
Liabilities and stockholder's equity		
Deposit liabilities–noninterest-bearing	$ 808,474	$ 701,090
Deposit liabilities–interest-bearing	3,250,286	3,479,085
Other borrowings	297,628	680,973
Other	92,129	98,598
	4,448,517	4,959,746
Common stock	329,439	328,162
Retained earnings	172,655	197,235
Accumulated other comprehensive loss, net of tax benefits	(9,626)	(48,023)
	492,468	477,374
	$4,940,985	$5,437,120

Balance sheet restructure. In 2008, ASB 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-Net gains (losses) 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 taxes 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 matured in 2008.

As a result of this balance sheet restructuring, ASB freed up capital and paid a dividend of approximately $55 million to HEI in 2008. HEI used the dividend to repay commercial paper and for other corporate purposes.

Investment and mortgage-related securities. ASB owns investment securities (federal agency obligations) and mortgage-related securities issued by the Federal National Mortgage Association (FNMA), Federal Home Loan Mortgage Corporation (FHLMC), Government National Mortgage Association (GNMA) and municipal bonds.

In the past, ASB owned private-issue mortgage-related securities (PMRS). To further improve its credit risk profile and reduce the potential volatility of future earnings, and in light of the improvement in the fixed-income securities markets, ASB sold the PMRS held in its investment portfolio in the fourth quarter of 2009. Sales of the available-for-sale PMRS were made to various broker/dealers. The PMRS sold were backed by mortgages throughout the mainland U.S. The sales resulted in an after-tax charge to net income of $19 million ($32 million pre-tax included in "Noninterest income-Net gains (losses) on sale of securities") in the fourth quarter of 2009, which amount had been previously recognized as a reduction to equity as a result of mark-to-market charges to other comprehensive income in earlier periods. A portion of the proceeds from the sales were used to prepay $40 million of advances from FHLB with a weighted average rate of 2.64% and a weighted average maturity of approximately 0.8 years. ASB incurred an after-tax loss of $0.4 million ($0.7 million pre-tax) related to this early extinguishment of debt. Over time, ASB intends to use the remaining proceeds from the sale of the PMRS to pay down high costing liabilities (maturing certificates of deposit and/or wholesale borrowings), to fund loan growth and/or to reinvest in securities with low credit risk and high liquidity, such as government or agency notes and mortgage-related securities.

Federal agency obligations have contractual terms to maturity. Mortgage-related securities have contractual terms to maturity, but require periodic payments to reduce principal. In addition, expected maturities will differ from contractual maturities because borrowers have the right to prepay the underlying mortgages (see contractual maturities table below).

As of December 31, 2009, ASB's investment portfolio distribution was 24% federal agency obligations, 75% mortgage-related securities issued by FNMA, FHLMC or GNMA and 1% municipal bonds.

Prices for investments and mortgage-related securities are provided by independent market participants and are based on observable inputs using market-based valuation techniques. The prices of these securities may be influenced by factors such as market liquidity, corporate credit considerations of the underlying collateral, the levels of interest rates, expectations of prepayments and defaults, limited investor base, market sector concerns and overall market psychology. Adverse changes in any of these factors may result in additional losses.

December 31, 2009

					Gross unrealized losses			
					Less than 12 months		12 months or longer	
(dollars in thousands)	Book value	Gross unrealized gains	Gross unrealized losses	Estimated fair value	Fair value	Amount	Fair value	Amount
Available-for-sale								
Investment securities-federal agency obligation	$104,091	$ 109	$(156)	$104,044	$54,834	$(156)	$ –	$ –
Mortgage-related securities-FNMA, FHLMC and GNMA	319,642	7,967	(88)	327,521	15,352	(88)	–	–
Municipal bonds	1,300	16	–	1,316	–	–	–	–
	$425,033	$8,092	$(244)	$432,881	$70,186	$(244)	$ –	$ –

December 31, 2008

(dollars in thousands)	Book value	Gross unrealized gains	Gross unrealized losses	Estimated fair value	Gross unrealized losses: Less than 12 months: Fair value	Less than 12 months: Amount	12 months or longer: Fair value	12 months or longer: Amount
Available-for-sale								
Investment securities-federal agency obligation	$ 59,939	$ 61	$ –	$ 60,000	$ –	$ –	$ –	$ –
Mortgage-related securities:								
FNMA, FHLMC and GNMA	301,106	4,420	(119)	305,407	1,352	(23)	15,266	(96)
Private issue	351,504	20	(59,214)	292,310	66,947	(24,227)	224,662	(34,987)
	$712,549	$4,501	$(59,333)	$657,717	$68,299	$(24,250)	$239,928	$(35,083)

December 31, 2007

(dollars in thousands)	Book value	Gross unrealized gains	Gross unrealized losses	Estimated fair value	Gross unrealized losses: Less than 12 months: Fair value	Less than 12 months: Amount	12 months or longer: Fair value	12 months or longer: Amount
Available-for-sale								
Investment securities-federal agency obligation	$ 59,990	$ 45	$ (7)	$ 60,028	$ –	$ –	$ 24,983	$ (7)
Mortgage-related securities:								
FNMA, FHLMC and GNMA	1,554,201	1,943	(22,155)	1,533,989	81,200	(186)	1,133,457	(21,969)
Private issue	556,537	593	(10,375)	546,755	227,411	(3,513)	267,498	(6,862)
	$2,170,728	$2,581	$(32,537)	$2,140,772	$308,611	$(3,699)	$1,425,938	$(28,838)

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-related securities) are disclosed based upon the bond's contractual maturity. Actual average maturities may be substantially shorter than those detailed below because borrowers have the ability to prepay the underlying mortgages.

December 31, 2009

(dollars in thousands)	Book value	Weighted average yield (%)	Maturity<1 year: Book value	Maturity<1 year: Yield (%)	Maturity 1-5 years: Book value	Maturity 1-5 years: Yield (%)	Maturity 5-10 years: Book value	Maturity 5-10 years: Yield (%)	Maturity>10 years: Book value	Maturity>10 years: Yield (%)
Available-for-sale										
Investment securities-federal agency obligation	$104,091	1.08	$ –	–	$ 94,091	1.01	$ 10,000	1.80	$ –	–
Mortgage-related securities-FNMA, FHLMC and GNMA	319,642	3.85	–	–	5,787	2.32	138,617	3.80	175,238	3.94
Municipal bonds	1,300	2.27	500	1.92	800	2.50	–	–	–	–
	$425,033	3.17	$500	1.92	$100,678	1.10	$148,617	3.67	$175,238	3.94

In 2008, proceeds from sales of available-for-sale investment securities was $75 million, resulting in gross realized gains of $0.1 million and gross realized losses of $0.2 million.

In 2009, 2008 and 2007, proceeds from sales of available-for-sale mortgage-related securities were $185.1 million, $1.2 billion and nil, resulting in gross realized gains of $0.8 million, $0.6 million and nil and gross realized losses of $32.9 million, $19.8 million and nil, respectively.

ASB pledged mortgage-related securities with a carrying value of approximately $33.5 million and $220.9 million as of December 31, 2009 and 2008, respectively, as collateral to secure advances from the FHLB of Seattle, secure discount window borrowings from the Federal Reserve Bank of San Francisco, collateralize public funds deposits, collateralize automated clearinghouse (ACH) transactions with Bank of Hawaii, and collateralize deposits in the Bank's bankruptcy and treasury, tax, and loan accounts with the Federal Reserve Bank of San Francisco. As of December 31, 2009 and 2008, mortgage-related securities with a carrying value of $270.1 million and $274.1 million, respectively, were pledged as collateral for securities sold under agreements to repurchase.

Federal agency mortgage-related securities. The unrealized gains on ASB's investment in federal agency mortgage-backed securities were primarily caused by lower interest rates. The low interest rate environment coupled with tighter spreads on all mortgage collateralized securities caused the market value of the securities held to increase above the carrying book value. All contractual cash flows of those investments are guaranteed by an agency of the U.S. government. See "Investment and mortgage-related securities" in Note 1 for a discussion of securities impairment assessment.

Private-issue mortgage-related securities. At December 31, 2008, the private-issue mortgage-related securities portfolio had $59 million of unrealized losses, due to multiple factors primarily related to deterioration in the residential housing market and spread widening for all credit sensitive sectors of the market. Increasing foreclosures coupled with recessionary employment pressures and declining housing prices had depressed the values of all private-issue mortgage collateralized securities as risks for this sector had increased. Changes in credit rating for issues originated in 2006 and 2007 had dramatically depressed valuations in this sector of the portfolio. In 2008, ASB recorded an OTTI charge of $7.8 million on two private-issue mortgage-related securities. In the fourth quarter of 2009, ASB sold its private-issue mortgage-related securities portfolio and had no OTTI as of December 31, 2009.

FHLB of Seattle stock. As of December 31, 2009, 2008 and 2007, ASB's investment in stock of the FHLB of Seattle was carried at cost because it can only be redeemed at par and it is a required investment based on measurements of ASB's capital, assets and/or borrowing levels. Periodically and as conditions warrant, ASB reviews its investment in the stock of the FHLB of Seattle for impairment. ASB evaluated its investment in FHLB stock for OTTI as of December 31, 2009, consistent with its accounting policy. ASB did not recognize an OTTI loss for 2009 based on its evaluation of the underlying investment (including the significance of the decline in net assets of the FHLB of Seattle as compared to its capital stock amount and the length of time this situation has persisted; commitments by the FHLB of Seattle to make payments required by law or regulation and the level of such payments in relation to the operating performance of the FHLB of Seattle; the impact of legislative and regulatory changes on institutions and, accordingly, on the customer base of the FHLB of Seattle; the liquidity position of the FHLB of Seattle; and ASB's intent and assessment of whether it will more likely than not be required to sell before recovery of its par value). Continued deterioration in the FHLB of Seattle's financial position may result in future impairment losses.

Other-than-temporary impaired securities. All securities are reviewed for impairment in accordance with U.S. standards for OTTI recognition. 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. If ASB's intent is to hold positions determined to be other-than-temporarily impaired, credit losses, which are recognized in earnings, are quantified using the position's pre-impairment discount rate and the net present value of the losses. Non-credit related impairments are reflected in other comprehensive income.

The following table reflects cumulative OTTIs for expected losses that have been recognized in earnings. The beginning balance for the nine months ended December 31, 2009 relates to credit losses realized prior to April 1, 2009 on debt securities held by ASB as of March 31, 2009. This beginning balance includes the net impact of non-credit losses that were originally reported as losses prior to March 31, 2009 and were subsequently recharacterized from retained earnings as a result of the adoption of new U.S. standards for OTTI recognition effective April 1, 2009. Additions to this balance include new securities in which initial credit impairments have been identified and incremental increases of credit impairments on positions that had already taken similar impairments. The additions to cumulative OTTI occurred in the second and third quarter of 2009. In the fourth quarter of 2009, ASB sold its private-issue mortgage-related securities portfolio.

(in thousands)	Nine months ended December 31, 2009
Balance, beginning of period	$ 1,486
Additions:	
Initial credit impairments	4,870
Subsequent credit impairments	10,574
Reductions:	
For securities sold	(16,930)
Balance, end of period	$ –

Investments in membership organizations. ASB obtained its Mastercard and VISA Inc. stock as a member financial institution in connection with the initial public offerings of their common stock in 2006 and 2008, respectively, and ASB's basis in such stock was nil. In 2008, proceeds from sales of Mastercard International (Mastercard) and VISA, Inc. stock were $1.9 million, resulting in a gross realized gain of $1.9 million. In 2007, proceeds from the sale of Mastercard stock were $1.1 million, resulting in a gross realized gain of $1.1 million.

Loans receivable.

December 31	2009		2008	
(dollars in thousands)	Balance	% of total	Balance	% of total
Real estate loans:				
Residential 1-4 family	$2,319,738	62.5	$2,808,611	66.2
Commercial real estate	255,458	6.9	242,952	5.7
Home equity line of credit	328,164	8.8	272,505	6.4
Residential land	96,515	2.6	126,963	3.0
Commercial construction	68,107	1.8	71,518	1.7
Residential construction	16,598	0.5	34,458	0.8
Total real estate loans, net	3,084,580	83.1	3,557,007	83.8
Commercial	542,686	14.6	594,677	14.0
Consumer	84,906	2.3	90,606	2.2
	3,712,172	100.0	4,242,290	100.0
Less: Allowance for loan losses	41,679		35,798	
Total loans, net	$3,670,493		$4,206,492	

As of December 31, 2009, ASB had impaired loans totaling $65.8 million, which consisted of $31.6 million of commercial loans, $16.6 million of residential land loans, $15.2 million of commercial real estate loans and $2.4 million of residential 1-4 family loans. As of December 31, 2008, ASB had impaired loans totaling $51.0 million, which consisted of $27.8 million of commercial loans, $2.1 million of residential land loans, $6.0 million of commercial real estate loans, $1.9 million of residential 1-4 family loans and $13.2 of commercial construction loans. Of ASB's impaired loans as of December 31, 2009 and 2008, $4.5 million and $12.8 million, respectively, had related allowances for loan losses of $1.6 million and $4.4 million, respectively, and the other impaired loans had no related allowances for loan losses. ASB realized $3.2 million, $3.0 million and $2.0 million of interest income on impaired loans in 2009, 2008 and 2007, respectively. The average balances of impaired loans during 2009, 2008 and 2007 were $58.2 million, $45.0 million and $25.5 million, respectively.

As of December 31, 2009 and 2008, ASB had nonaccrual and renegotiated loans of $86.4 million and $28.1 million, respectively.

ASB had no loans that were 90 days or more past due on which interest was being accrued as of December 31, 2009 and 2008.

As of December 31, 2009 and 2008, ASB's commitments to originate loans, including the undisbursed portion of loans in process, approximated $51.7 million and $85.2 million, respectively. The decrease was primarily due to $17 million lower residential loan commitments and construction loans in process and $12 million lower commercial real estate commitments and loans in process. Commitments to extend credit are agreements to lend to a customer as long as there is no violation of any condition established in the commitments. Commitments generally have fixed expiration dates or other termination clauses and may require payment of a fee. Since certain of the commitments are expected to expire without being drawn upon, the total commitment amounts do not necessarily represent future cash requirements. ASB minimizes its exposure to loss under these commitments by requiring that customers meet certain conditions prior to disbursing funds. The amount of collateral, if any, is based on a credit evaluation of the borrower and may include residential real estate, accounts receivable, inventory, and property, plant, and equipment.

As of December 31, 2009 and 2008, ASB had commitments to sell residential loans of $18.6 million and $84.0 million, respectively. The loans are included in loans receivable as held for sale or represent commitments to make loans at an interest rate set prior to funding (rate lock commitments). Rate lock commitments guarantee a specified interest rate for a loan if ASB's underwriting standards are met, but do not obligate the potential borrower. Rate lock commitments on loans intended to be sold in the secondary market are derivative instruments, but have not been designated as hedges. Rate lock commitments are carried at fair value and adjustments are recorded in "Other income," with an offset on the ASB balance sheet in "Other" liabilities. As of December 31, 2009 and 2008, rate lock commitments were made on loans totaling $13.8 million and $65.1 million, respectively. To offset the impact of changes in market interest rates on the rate lock commitments on loans held for sale, ASB utilizes short-term forward sale contracts. Forward sales contracts are also derivative instruments, but have not been designated as hedges, and thus any changes in fair value are also recorded in ASB "Other income," with an offset in the ASB balance sheet in "Other" assets or liabilities. As of December 31, 2009 and 2008, the notional amounts for forward sales contracts were $18.6 million and $84.0 million, respectively. Valuation models are applied using current market information to estimate fair value. There was a net loss on derivatives of $0.2 million in 2009. For 2008, there was a net gain on derivatives of $0.3 million.

As of December 31, 2009 and 2008, ASB had commitments to sell education loans of $20.5 million and $18.1 million, respectively.

As of December 31, 2009 and 2008, standby, commercial and banker's acceptance letters of credit totaled $19.5 million and $18.5 million, respectively. Letters of credit are conditional commitments issued by ASB to guarantee payment and performance of a customer to a third party. The credit risk involved in issuing letters of credit is essentially the same as that involved in extending loan facilities to customers. ASB holds collateral supporting those commitments for which collateral is deemed necessary. As of December 31, 2009 and 2008, undrawn consumer lines of credit, including credit cards, totaled $801.1 million and $805.9 million respectively, and undrawn commercial loans including lines of credit totaled $315.1 million and $322.2 million, respectively.

ASB services real estate loans for investors ($0.6 billion, $0.3 billion and $0.3 billion as of December 31, 2009, 2008 and 2007, respectively), which are not included in the accompanying consolidated financial statements. ASB reports fees earned for servicing such loans as income when the related mortgage loan payments are collected and charges loan servicing costs to expense as incurred.

As of December 31, 2009 and 2008, ASB had pledged loans with an amortized cost of approximately $1.6 billion and $1.9 billion, respectively, as collateral to secure advances from the FHLB of Seattle.

As of December 31, 2009 and 2008, the aggregate amount of loans to directors and executive officers of ASB and its affiliates and any related interests (as defined in Federal Reserve Board Regulation O) of such individuals, was $79.3 million and $87.7 million, respectively. The $8.4 million decrease in such loans in 2009 was attributed to closed lines of credit and repayments of $9.1 million, offset by loans and lines of credit to new and existing directors and executive officers of $0.7 million. As of December 31, 2009 and 2008, $65.4 million and $72.0 million of the loan balances, respectively, were to related interests of individuals who are directors of ASB. All such loans were made at ASB's normal credit terms except that residential real estate loans and consumer loans to directors and executive officers of ASB were made at preferred employee interest rates. Management believes these loans do not represent more than a normal risk of collection.

Allowance for loan losses. Changes in the allowance for loan losses were as follows:

(dollars in thousands)	2009	2008	2007
Allowance for loan losses, January 1	$35,798	$30,211	$31,228
Provision for loan losses	32,000	10,334	5,700
Charge-offs, net of recoveries			
Real estate loans	9,526	308	17
Other loans	16,593	4,439	6,700
Net charge-offs	26,119	4,747	6,717
Allowance for loan losses, December 31	$41,679	$35,798	$30,211
Ratio of net charge-offs to average loans outstanding	0.66%	0.11%	0.17%

Deposit liabilities.

December 31	2009		2008	
(dollars in thousands)	Weighted-average stated rate	Amount	Weighted-average stated rate	Amount
Savings	0.19%	$1,592,739	0.52%	$1,382,796
Other checking				
Interest-bearing	0.09	580,737	0.66	558,629
Noninterest-bearing	–	427,585	–	373,513
Commercial checking	–	380,889	–	327,577
Money market	0.43	202,115	0.59	148,255
Term certificates	1.65	874,695	2.92	1,389,405
	0.46%	$4,058,760	1.25%	$4,180,175

As of December 31, 2009 and 2008, certificate accounts of $100,000 or more totaled $208 million and $407 million, respectively.

The approximate amounts of term certificates outstanding as of December 31, 2009 with scheduled maturities for 2010 through 2014 were $619 million in 2010, $131 million in 2011, $55 million in 2012, $16 million in 2013 and $36 million in 2014.

Interest expense on deposit liabilities by type of deposit was as follows:

(in thousands)	2009	2008	2007
Term certificates	$27,369	$49,530	$65,074
Savings	4,952	8,577	11,170
Money market	886	1,793	4,094
Interest-bearing checking	839	1,583	1,541
	$34,046	$61,483	$81,879

Other borrowings.

Securities sold under agreements to repurchase.

December 31, 2009			
Maturity	Repurchase liability	Weighted-average interest rate	Collateralized by mortgage-related securities– fair value plus accrued interest
(dollars in thousands)			
Overnight	$182,331	0.45%	$210,565
1 to 29 days	–	–	–
30 to 90 days	–	–	–
Over 90 days	50,297	4.75	60,355
	$232,628	1.38%	$270,920

At December 31, 2009, $50 million of securities sold under agreements to repurchase with a weighted average rate of 4.75% and maturity date over 90 days is callable quarterly at par until maturity.

The securities underlying the agreements to repurchase are book-entry securities and were delivered by appropriate entry into the counterparties' accounts at the Federal Reserve System. Securities sold under agreements to repurchase are accounted for as financing transactions and the obligations to repurchase these securities are recorded as liabilities in the consolidated balance sheets. The securities underlying the agreements to repurchase continue to be reflected in ASB's asset accounts.

The following table sets forth information concerning securities sold under agreements to repurchase, which provided for the repurchase of identical securities:

(dollars in millions)	2009	2008	2007
Amount outstanding as of December 31	$233	$241	$765
Average amount outstanding during the year	$230	$507	$887
Maximum amount outstanding as of any month-end	$241	$817	$979
Weighted-average interest rate as of December 31	1.38%	1.86%	3.92%
Weighted-average interest rate during the year	1.55%	2.98%	4.22%
Weighted-average remaining days to maturity as of December 31	544	601	1,318

Advances from Federal Home Loan Bank.

December 31, 2009	Weighted-average stated rate	Amount
(dollars in thousands)		
Due in		
2010	– %	$ –
2011	2.64	15,000
2012	–	–
2013	–	–
2014	–	–
Thereafter	4.28	50,000
	3.90%	$65,000

At December 31, 2009, $50 million of fixed rate FHLB advances with a rate of 4.28% is callable quarterly at par until maturity in 2017.

ASB and the FHLB of Seattle are parties to an Advances, Security and Deposit Agreement (Advances Agreement), which applies to currently outstanding and future advances, and governs the terms and conditions under which ASB borrows and the FHLB of Seattle makes loans or advances from time to time. Under the Advances Agreement, ASB agrees to abide by the FHLB of Seattle's credit policies, and makes certain warranties and representations to the FHLB of Seattle. Upon the occurrence of and during the continuation of an "Event of Default" (which term includes any event of nonpayment of interest or principal of any advance when due or failure to perform any promise or obligation under the Advances Agreement or other credit arrangements between the parties), the FHLB of Seattle may, at its option, declare all indebtedness and accrued interest thereon, including any prepayment fees or charges, to be immediately due and payable. Advances from the FHLB of Seattle are secured by loans and stock in the FHLB of Seattle. ASB is required to obtain and hold a specific number of shares of capital stock of the FHLB of Seattle. ASB was in compliance with all Advances Agreement requirements as of December 31, 2009 and 2008.

Common stock equity. In 1988, HEI agreed with the OTS predecessor regulatory agency to contribute additional capital to ASB up to a maximum aggregate amount of approximately $65 million (Capital Maintenance Agreement). As of December 31, 2009, as a result of capital contributions in prior years, HEI's maximum obligation to contribute additional capital under the Capital Maintenance Agreement had been reduced to approximately $28.3 million. As of December 31, 2009, ASB was in compliance with the minimum capital requirements under OTS regulations.

The $38.4 million decrease in accumulated other comprehensive loss from December 31, 2008 to December 31, 2009 was primarily due to the sale of the private-issue mortgage-related securities portfolio and improved pricing on agency securities. Changes in the market value of investment or mortgage-related securities do not result in a charge to net income in the absence of an "other-than-temporary" impairment in the value of the securities.

In 2009, ASB paid dividends of $50.1 million to HEI, compared to $108.3 million in 2008. The OTS had approved ASB's payment of quarterly dividends through the quarter ended September 30, 2010 to the extent that payment of dividends would not cause ASB's leverage and total risk-based capital ratios to fall below 8% and 12%, respectively, as of the end of the applicable quarter. However, in December 2009, the western region of the OTS notified all western region financial institutions that it will require institutions to file capital distribution notices or applications for a single period and, thus, the preapproval of ASB's dividends was no longer valid. A dividend application for one period will be accepted for review prior to 30 days of the proposed date of declaration or approval by the board of directors. ASB paid an $11 million dividend to HEI in February 2010.

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.

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.

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. ASB is classified in Risk Category I and its assessment rate was 13.9 basis points of deposits, or $5.8 million (excluding the special assessment recorded in June 2009), for 2009, compared to an assessment rate of 5.3 basis points of deposits, or $1.5 million (net of a one-time assessment credit), for 2008.

In November 2009, the Board of Directors of the FDIC approved a restoration plan that required banks to prepay, on December 30, 2009, their estimated quarterly, risk-based assessments for the fourth quarter of 2009, and for all of 2010, 2011 and 2012. For the fourth quarter of 2009 and all of 2010, the prepaid assessment rate was assessed according to the risk-based premium schedule adopted earlier in 2009. The prepaid assessment rate for 2011 and 2012 was the current assessment rate plus 3 basis points. The prepaid assessment was recorded as a prepaid asset as of December 30, 2009, and each quarter thereafter ASB will record a charge to earnings for its regular quarterly assessment and offset the prepaid expense until the asset is exhausted. Once the asset is exhausted, ASB will record an accrued expense payable each quarter for the assessment to be paid. If the prepaid assessment is not exhausted by December 30, 2014, any remaining amount will be returned to ASB. ASB's prepaid assessment was approximately $24 million.

The FDIC may impose additional special assessments in the future 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. Management cannot predict with certainty the timing or amounts of any additional assessments.

Deposit insurance coverage. The Emergency Economic Stabilization Act of 2008 temporarily raised 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. In August 2009, the FDIC extended the Transaction Account Guarantee Program for six months, through June 30, 2010. Institutions currently participating in the program have the option to continue in the program or opt out. The annual assessment rate during the extension period will increase from 10 basis points to either 15 basis points, 20 basis points or 25 basis points, depending on the risk category assigned to the institution under the FDIC's risk-based premium system. ASB has elected to remain in the program and the increase in the annual assessment rate is not significant.

Capital Purchase Program. On October 14, 2008, President Bush's Working Group on Financial Markets announced a voluntary Capital Purchase Program to encourage U.S. financial institutions to build capital to increase the flow of financing to U.S. businesses and consumers and to support the U.S. economy. ASB elected not to participate in the program.

5 • 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 HELCO and MECO in the respective principal amounts of $10 million, (iii) making distributions on these trust securities and (iv) engaging in only those other activities necessary or incidental thereto. The 2004 Trust Preferred Securities are mandatorily redeemable at the maturity of the underlying debt on March 18, 2034, which maturity may be extended to no later than March 18, 2053; and are currently redeemable at the issuer's option without premium. The 2004 Debentures, together with the obligations of HECO, HELCO and MECO under an expense agreement and HECO's obligations under its trust guarantee and its guarantee of the obligations of HELCO and MECO under their respective debentures, are the sole assets of Trust III. Trust III has at all times been an unconsolidated subsidiary of HECO. Since HECO, as the common security holder, does not absorb the majority of the variability of Trust III, HECO is not the primary beneficiary and does not consolidate Trust III in accordance with accounting rules on the consolidation of variable interest entities (VIEs). Trust III's balance sheet as of December 31, 2009 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 statement for 2009 consisted of $3.4 million of interest income received from the 2004 Debentures; $3.3 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 December 31, 2009, HECO and its subsidiaries had six PPAs for a total of 540 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 kW 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 2009 totaled $0.5 billion with purchases from AES Hawaii, Kalaeloa, HEP and HPOWER totaling $141 million, $184 million, $57 million and $42 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.

An enterprise with an interest in a VIE or potential VIE created before December 31, 2003 (and not thereafter materially modified) is not required to apply accounting standards for VIEs to that entity if the enterprise is unable to obtain, 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 accounting standards for VIEs 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 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), and thus excluded from the scope of accounting standards for VIEs. Other IPPs, including the three largest, declined to provide the information necessary for HECO to determine the applicability of accounting standards for VIEs.

Since 2004, HECO has continued its efforts to obtain from the IPPs the information necessary to make the determinations required under accounting standards for VIEs. In each year from 2005 to 2009, HECO and its subsidiaries sent letters to the identified IPPs requesting the required information. All of these IPPs declined to provide the 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 the Company's and 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 accounting standards for VIEs.

Kalaeloa Partners, L.P. In October 1988, HECO entered into a PPA with Kalaeloa, subsequently approved by the PUC, which provided that HECO would purchase 180 MW of firm capacity for a period of 25 years beginning in May 1991. In October 2004, HECO and Kalaeloa entered into amendments to the PPA, subsequently approved by the PUC, which together effectively increased the firm capacity from 180 MW to 208 MW. The energy payments that HECO makes to Kalaeloa include: (1) a fuel component, with a fuel price adjustment based on the cost of low sulfur fuel oil, (2) a fuel additives cost component, and (3) a non-fuel component, with an adjustment based on changes in the Gross National Product Implicit Price Deflator. The capacity payments that 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 current accounting standards for VIEs, 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 have the power to direct the activities that most significantly impact Kalaeloa's economic performance nor the obligation to absorb Kalaeloa's expected losses, if any, that could potentially be significant to Kalaeloa. Thus, HECO has not consolidated Kalaeloa in its consolidated financial statements. A significant factor affecting the level of expected losses HECO could potentially 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.

6 • Short-term borrowings

As of December 31, 2009, HEI had $42 million of outstanding commercial paper with a weighted-average interest rate of 0.6%, and HECO had no commercial paper outstanding. No commercial paper of either HEI or HECO was outstanding at December 31, 2008.

As of December 31, 2009, HEI and HECO maintained syndicated credit facilities which totaled $100 million and $175 million, respectively. As of December 31, 2008, HEI maintained a syndicated credit facility which totaled $100 million and HECO maintained two syndicated credit facilities which totaled $250 million. HEI had no borrowings under its facility during 2009. HECO drew on its facility in June and July 2009; all such borrowings were repaid in August 2009. HEI drew on its facility in September and October 2008; all such borrowings were repaid in November and December 2008. HECO had no borrowings under its facilities during 2008. None of the facilities are secured.

Credit agreements. Effective April 3, 2006, HEI entered into a revolving unsecured credit agreement establishing a line of credit facility of $100 million, with a letter of credit sub-facility, expiring on March 31, 2011, with a syndicate of eight financial institutions. Any draws on the facility bear interest, at the option of HEI, at either the "Adjusted LIBO Rate" plus 50 basis points or the greater of (a) the "Prime Rate" and (b) the sum of the "Federal Funds Rate" plus 50 basis points, as defined in the agreement. The annual fee is 10 basis points on the undrawn commitment amount. The agreement contains provisions for revised pricing in the event of a ratings change. For example, a ratings downgrade of HEI's Senior Debt Rating (e.g., from BBB/Baa2 to BBB-/Baa3 by Standard & Poor's (S&P) and Moody's Investors Service's (Moody's), respectively) would result in a commitment fee increase of 2.5 basis points and an interest rate increase of 10 basis points on any drawn amounts. On the other hand, a ratings upgrade (e.g., from BBB/Baa2 to BBB+/Baa1 by S&P or Moody's, respectively) would result in a commitment fee decrease of 2 basis points and an interest rate decrease of 10 basis points on any drawn amounts. The agreement does not contain clauses that would affect access to the lines by reason of a ratings downgrade, nor does it have a broad "material adverse change" clause. However, the agreement does contain customary conditions which must be met in order to draw on it, such as the accuracy of certain of its representations at the time of a draw and compliance with its covenants (such as covenants preventing its subsidiaries from entering into agreements that restrict the ability of the subsidiaries to pay dividends to, or to repay borrowings from, HEI). In addition to customary defaults, HEI's failure to maintain its financial ratio, as defined in the agreement, or meet other requirements will result in an event of default. For example, under the agreement, it is an event of default if HEI fails to maintain a nonconsolidated "Capitalization Ratio" (funded debt) of 50% or less (ratio of 20% as of December 31, 2009, as calculated under the agreement) and "Consolidated Net Worth" of $850 million (Net Worth of $1.5 billion as of December 31, 2009, as calculated under the agreement), if there is a "Change in Control" of HEI, if any event or condition occurs that results in any "Material Indebtedness" of HEI being subject to acceleration prior to its scheduled maturity, if any "Material Subsidiary Indebtedness" actually becomes due prior to its scheduled maturity, or if ASB fails to remain well capitalized and to maintain specified minimum capital ratios.

HEI's credit facility is maintained to support the issuance of commercial paper, but may also be drawn to make investments in and advances to its subsidiaries, and for the Company's working capital and general corporate purposes.

Effective April 3, 2006, HECO entered into a revolving unsecured credit agreement establishing a line of credit facility of $175 million with a syndicate of eight financial institutions. On March 14, 2007 the PUC issued a D&O approving HECO's request to maintain the credit facility for five years (until March 31, 2011), to borrow under the credit facility (including borrowings with maturities in excess of 364 days), to use the proceeds from any borrowings with maturities in excess of 364 days to finance capital expenditures and/or to repay short-term or other borrowings used to finance or refinance capital expenditures and to use an expedited approval process to obtain PUC approval to increase the facility amount, renew the facility, refinance the facility or change other terms of the facility if such changes are required or desirable.

Any draws on the facility bear interest, at the option of HECO, at either the "Adjusted LIBO Rate" plus 40 basis points or the greater of (a) the "Prime Rate" and (b) the sum of the "Federal Funds Rate" plus 50 basis points, as defined in the agreement. The annual fee is 8 basis points on the undrawn commitment amount. The agreement contains provisions for revised pricing in the event of a ratings change. For example, a ratings downgrade of HECO's Senior Debt Rating (e.g., from BBB+/Baa1 to BBB/Baa2 by S&P and Moody's, respectively) would result in a commitment fee increase of 2 basis points and an interest rate increase of 10 basis points on any drawn amounts. On the other hand, a ratings upgrade (e.g., from BBB+/Baa1 to A-/A3 by S&P or Moody's, respectively) would result in a commitment fee decrease of 1 basis point and an interest rate decrease of 10 basis points on any drawn amounts. The agreement does not contain clauses that would affect access to the lines by reason of a ratings downgrade, nor does it have a broad "material adverse change" clause. However, the agreement does contain customary conditions that must be met in order to draw on it, such as the accuracy of certain of its representations at the time of a draw and compliance with its covenants (such as covenants preventing its subsidiaries from entering into agreements that restrict the ability of the subsidiaries to pay dividends to, or to repay borrowings from, HECO, and restricting HECO's ability, as well as the ability of any of its subsidiaries, to guarantee indebtedness of the subsidiaries if such additional debt would cause the subsidiary's "Consolidated Subsidiary Funded Debt to Capitalization Ratio" to exceed 65% (ratios of 48% for HELCO and 44% for MECO as of December 31, 2009, as calculated under the agreement)). In addition to customary defaults, HECO's failure to maintain its financial ratios, as defined in its agreement, or meet other requirements will result in an event of default. For example, under the agreement, it is an event of default if HECO fails to maintain a "Consolidated Capitalization Ratio" (equity) of at least 35% (ratio of 54% as of December 31, 2009, as calculated under the agreement), if HECO fails to remain a wholly-owned subsidiary of HEI or if any event or condition occurs that results in any "Material Indebtedness" of HECO or any of its significant subsidiaries being subject to acceleration prior to its scheduled maturity. HECO's syndicated credit facility is maintained to support the issuance of commercial paper, but it may also be drawn for general corporate purposes and capital expenditures.

On May 23, 2007, S&P lowered the long-term corporate credit and unsecured debt ratings on HECO, HELCO and MECO to BBB from BBB+. The pricing for future borrowings under the line of credit facility did not change since the pricing level is "determined by the higher of the two" ratings by S&P and Moody's, and Moody's ratings did not change.

7 • Long-term debt

December 31 (dollars in thousands)	2009	2008
6.50% Junior Subordinated Deferrable Interest Debentures, Series 2004, due 2034 (see Note 5)	$ 51,546	$ 51,546
Obligations to the State of Hawaii for the repayment of special purpose revenue bonds issued on behalf of electric utility subsidiaries		
4.75-4.95%, due 2012-2025	118,500	118,500
5.00-5.50%, due 2014-2032	203,400	203,400
5.65-5.88%, due 2018-2027	216,000	216,000
6.15-6.20%, due 2020-2029	55,000	55,000
4.60-4.65%, due 2026-2037	265,000	265,000
6.50%, due 2039	150,000	–
	1,007,900	857,900
Less funds on deposit with trustee	–	(3,186)
Less unamortized discount	(1,631)	(1,759)
	1,006,269	852,955
HEI medium-term notes 4.23-6.141%, due 2011	150,000	150,000
HEI medium-term note 7.13%, due 2012	7,000	7,000
HEI medium-term note 5.25%, due 2013	50,000	50,000
HEI medium-term note 6.51%, due 2014	100,000	100,000
	$1,364,815	$1,211,501

As of December 31, 2009, the aggregate principal payments required on long-term debt for 2010 through 2014 are nil in 2010, $150 million in 2011, $65 million in 2012, $50 million in 2013 and $111 million in 2014.

8 • Retirement benefits

Defined benefit plans. Substantially all of the employees of HEI and the electric utilities participate in the Retirement Plan for Employees of Hawaiian Electric Industries, Inc. and Participating Subsidiaries (HEI/HECO Pension Plan). Substantially all of the employees of ASB and its subsidiaries participated in the American Savings Bank Retirement Plan (ASB Pension Plan) until it was frozen on December 31, 2007. The HEI/HECO Pension Plan and the ASB Pension Plan (collectively, the Plans) are qualified, non-contributory defined benefit pension plans and include benefits for union employees determined in accordance with the terms of the collective bargaining agreements between the utilities and their respective unions. The Plans are subject to the provisions of ERISA. In addition, some current and former executives and directors of HEI and its subsidiaries participate in noncontributory, nonqualified plans (collectively, Supplemental Plans). In general, benefits are based on the employees' or directors' years of service and compensation.

The continuation of the Plans and the Supplemental Plans and the payment of any contribution thereunder are not assumed as contractual obligations by the participating employers. The Directors' Plan has been frozen since 1996. The ASB Pension Plan was frozen as of December 31, 2007. The HEI Supplemental Executive Retirement Plan and ASB Supplemental Executive Retirement, Disability, and Death Benefit Plan (noncontributory, nonqualified, defined benefit plans) were frozen as of December 31, 2008. No participants have accrued any benefits under these plans after the respective plan's freeze and the plans will be terminated at the time all remaining benefits have been paid. The Company recognized a curtailment gain of $8.8 million ($5.3 million, net of taxes) in December 2007 and a curtailment gain of $0.5 million ($0.3 million, net of taxes) in December 2008.

Each participating employer reserves the right to terminate its participation in the applicable plans at any time, and HEI and ASB reserve the right to terminate their respective plans at any time. If a participating employer terminates its participation in the Plans, the interest of each affected participant would become 100% vested to the extent funded. Upon the termination of the Plans, assets would be distributed to affected participants in accordance with the applicable allocation provisions of ERISA and any excess assets that exist would be paid to the participating employers. Participants' benefits in the Plans are covered up to certain limits under insurance provided by the Pension Benefit Guaranty Corporation.

To determine pension costs for HEI and its subsidiaries under the Plans and the Supplemental Plans, it is necessary to make complex calculations and estimates based on numerous assumptions, including the assumptions identified below.

Postretirement benefits other than pensions. HEI and the electric utilities provide eligible employees health and life insurance benefits upon retirement under the Postretirement Welfare Benefits Plan for Employees of Hawaiian Electric Company, Inc. and participating employers (HECO Benefits Plan). Health benefits are also provided to dependents of eligible retired employees. The contribution for health benefits paid by the participating employers is based on the retirees' years of service and retirement dates. Generally, employees are eligible for these benefits if, upon retirement from active employment, they are eligible to receive benefits from the HEI/HECO Pension Plan.

In the third quarter 2009, (1) the Company amended the executive life benefit plan to limit it to current participants and to freeze the executive life benefits at current levels and (2) HECO eliminated the electric discount benefit for retirees. The Company's cost for postretirement benefits other than pensions has been adjusted to reflect the plan amendment, which reduced benefits. The elimination of HECO's electric discount benefit will generate credits through other benefit costs over the next few years as the total amendment credit is amortized.

Among other provisions, the HECO Benefits Plan provides prescription drug benefits for Medicare-eligible participants who retire after 1998. Retirees who are eligible for the drug benefits are required to pay a portion of the cost each month. The Medicare Prescription Drug, Improvement and Modernization Act of 2003 (the 2003 Act) expanded Medicare to include for the first time coverage for prescription drugs. The 2003 Act provides that persons eligible for Medicare benefits can enroll in Part D, prescription drug coverage, for a monthly premium. Alternatively, if an employer sponsors a retiree health plan that provides benefits determined to be actuarially equivalent to those covered under the Medicare standard prescription drug benefit, the employer will be paid a subsidy of 28 percent of a participant's drug costs between $250 and $5,000 (indexed for inflation) if the participant waives coverage under Medicare Part D.

The continuation of the HECO Benefits Plan and the payment of any contribution thereunder is not assumed as a contractual obligation by the participating employers. Each participating employer reserves the right to terminate its participation in the plan at any time.

Balance sheet recognition of the funded status of retirement plans. In September 2006, the FASB issued a standard that requires employers to recognize on their balance sheets the funded status of defined benefit pension and other postretirement benefit plans with an offset to AOCI in stockholders' equity (using the projected benefit obligation (PBO), rather than the accumulated benefit obligation (ABO), to calculate the funded status of pension plans).

By application filed on December 8, 2005 (AOCI Docket), the electric utilities requested the PUC to permit them to record, as a regulatory asset pursuant to current accounting standards on the effects of regulation, the amount that would otherwise be charged against stockholders' equity as a result of recording a minimum pension liability as prescribed by the current accounting standard. The electric utilities updated their application in the AOCI Docket in November 2006 to take into account an accounting standard requiring balance sheet recognition of the funded status of retirement plans. On January 26, 2007, the PUC issued a D&O in the updated AOCI Docket, which denied the electric utilities' request to record a regulatory asset on the grounds that the electric utilities had not met their burden of proof to show that recording a regulatory asset was warranted, or that there would be adverse consequences if a regulatory asset was not recorded. The PUC also required HECO to submit a pension study (determining whether ratepayers are better off with a well-funded pension plan, a minimally-funded pension plan, or something in between) in its pending 2007 test year rate case, as proposed by the electric utilities in support of their request.

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 OPEB tracking mechanisms, which are intended to smooth the impact to ratepayers of potential fluctuations in pension and OPEB costs.

In the PUC's 2007 interim decisions in HELCO's 2006 test year rate case and HECO and MECO's 2007 test year rate cases, the PUC allowed the utilities to adopt pension and OPEB tracking mechanisms. The amount of the net periodic pension cost (NPPC) and net periodic benefits costs (NPBC) to be recovered in rates is established by the PUC in each rate case. Under the utilities' tracking mechanisms, any actual costs determined in accordance with U.S. generally accepted accounting principles that are over/under amounts allowed in rates are charged/credited to a regulatory asset/liability. The regulatory asset/liability for each utility will then be amortized over 5 years beginning with the respective utility's next rate case. Accordingly, all retirement benefit expenses (except for executive life and nonqualified pension plan expenses, which amounted to $1.5 million in 2009) determined in accordance with U.S. generally accepted accounting principles will be recovered.

Under the tracking mechanisms, amounts that would otherwise be recorded in AOCI (excluding amounts for executive life and nonqualified pension plans), which amounts include the prepaid pension asset, net of taxes, as well as other pension and OPEB charges, are allowed to be reclassified as a regulatory asset, as those costs will be recovered in rates through the NPPC and NPBC in the future.

In the PUC's 2007 interim decision on HELCO's 2006 test year rate case, the PUC allowed HELCO to record a regulatory asset in the amount of $12.8 million (representing HELCO's prepaid pension asset and reflecting the accumulated pension contributions to its pension fund in excess of accumulated NPPC), which is included in rate base, and allowed recovery of that asset over a period of five years. HELCO is required to make contributions to the pension trust in the amount of the actuarially calculated NPPC that would be allowed without penalty by the tax laws.

In the PUC's 2007 interim decisions on HECO and MECO's 2007 test year rate cases (and in its final decision on HECO's 2005 test year rate case), the PUC did not allow HECO and MECO to include their pension assets (representing the accumulated contributions to their pension fund in excess of accumulated NPPC), in their rate bases. However, under the tracking mechanisms, HECO and MECO are required to fund only the minimum level required under the law until their pension assets are reduced to zero, at which time HECO and MECO will make contributions to the pension trust in the amount of the actuarially calculated NPPC, except when limited by the ERISA minimum contribution requirements or the maximum contribution limitations on deductible contributions imposed by the Internal Revenue Code (IRC).

The PUC's exclusion of HECO's and MECO's pension assets from rate base does not allow HECO and MECO to earn a return on the pension asset, but this exclusion does not result in the exclusion of any pension benefit costs from their rates. The pension asset is to be (or was, in the case of MECO) recovered in rates (as NPPC is recorded in excess of contributions). As of December 31, 2009, MECO did not have any remaining pension asset, and HECO's pension asset had been reduced to $7 million.

The OPEB tracking mechanisms generally require the electric utilities to make contributions to the OPEB trust in the amount of the actuarially calculated NPBC, except when limited by material, adverse consequences imposed by federal regulations.

As a result of the 2007 interim orders, the electric utilities have reclassified to a regulatory asset charges for retirement benefits that would otherwise be recorded in AOCI (amounting to the elimination of a potential charge/(credit) to AOCI of $(124) million pre-tax, $249 million pre-tax and $171 million pre-tax at December 31, 2009, December 31, 2008 and December 31, 2007, respectively.

Retirement benefits expense for the electric utilities for 2009, 2008 and 2007 was $32 million, $27 million and $27 million, respectively.

Pension and other postretirement benefit plans information. The changes in the obligations and assets of the Company's retirement benefit plans and the changes in AOCI (gross) for 2009 and 2008 and the funded status of these plans and amounts related to these plans reflected in the Company's balance sheet as of December 31, 2009 and 2008 were as follows:

	2009		2008	
(in thousands)	Pension benefits	Other benefits	Pension benefits	Other benefits
Benefit obligation, January 1	$ 964,388	$180,656	$998,610	$187,099
Service cost	25,688	4,846	28,356	4,777
Interest cost	61,988	10,981	59,765	11,008
Amendments	109	(13,198)	(2,105)	–
Actuarial (gains) losses	14,323	(3,907)	(70,974)	(12,949)
Benefits paid and expenses	(52,209)	(8,806)	(49,264)	(9,279)
Benefit obligation, December 31	1,014,287	170,572	964,388	180,656
Fair value of plan assets, January 1	619,134	106,415	907,295	148,343
Actual return (loss) on plan assets	154,942	27,386	(245,828)	(41,161)
Employer contribution	15,883	9,471	6,039	8,496
Benefits paid and expenses	(50,988)	(8,664)	(48,372)	(9,263)
Fair value of plan assets, December 31	738,971	134,608	619,134	106,415
Accrued benefit liability, December 31	(275,316)	(35,964)	(345,254)	(74,241)
AOCI, January 1 (excluding impact of PUC D&Os)	400,875	52,433	160,828	16,403
Recognized during year – net recognized transition obligation	(2)	(1,831)	(2)	(3,138)
Recognized during year – prior service (cost)/credit	387	79	421	(13)
Recognized during year – net actuarial losses	(15,847)	(401)	(6,765)	–
Occurring during year – prior service cost	109	(2,476)	(1,633)	–
Occurring during year – net actuarial losses (gains)	(83,375)	(22,390)	248,026	39,181
Other adjustments	–	(10,721)	–	–
	302,147	14,693	400,875	52,433
Cumulative impact of PUC D&Os	(278,582)	(17,650)	(365,874)	(54,365)
AOCI, December 31	23,565	(2,957)	35,001	(1,932)
Net actuarial loss	303,437	16,972	402,659	39,763
Prior service cost (gain)	(1,295)	(2,279)	(1,792)	118
Net transition obligation	5	–	8	12,552
	302,147	14,693	400,875	52,433
Cumulative impact of PUC D&Os	(278,582)	(17,650)	(365,874)	(54,365)
AOCI, December 31	23,565	(2,957)	35,001	(1,932)
Income taxes	(9,309)	1,151	(13,831)	752
AOCI, net of taxes, December 31	$ 14,256	$ (1,806)	$ 21,170	$ (1,180)

The Company does not expect any plan assets to be returned to the Company during calendar year 2010.

The dates used to determine retirement benefit measurements for the defined benefit plans were December 31 of 2009, 2008 and 2007.

The defined benefit pension plans' ABOs, which do not consider projected pay increases (unlike the PBOs shown in the table above), as of December 31, 2009 and 2008 were $858 million and $872 million, respectively.

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 under the pension plan and restrictions on participant benefit accruals may be placed on the plan. Other factors could cause changes to the required contribution levels.

The Company's current estimate of contributions to the qualified defined benefit plans and all other retirement benefit plans in 2010 is $34 million.

Additional guidance on funding relief for qualified defined benefit pension plans was received in March 2009 including: (1) IRS Notice 2009-22 relating 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" relating to yield curve selection for the target liability calculation. Additional guidance on minimum required contribution determinations for 2010 was released in "Special Edition September 25, 2009 employee plans news" necessitating selection of a different yield curve for 2010 valuations forward from what was used for 2009. As a result, the Company estimates that the cash funding for the qualified defined benefit pension plans in 2010 and 2011 will be about \$30 million and \$46 million, respectively, which should fully satisfy the minimum required contribution, including requirements of the utilities pension tracking mechanisms and the Plan's funding policy.

As of December 31, 2009, the benefits expected to be paid under the retirement benefit plans in 2010, 2011, 2012, 2013, 2014 and 2015 through 2019 amounted to \$65 million, \$67 million, \$70 million, \$72 million, \$76 million and \$433 million, respectively.

The Company has determined the market-related value of retirement benefit plan assets by calculating the difference between the expected return and the actual return on the fair value of the plan assets, then amortizing the difference over future years – 0% in the first year and 25% in years two to five – and finally adding or subtracting the unamortized differences for the past four years from fair value. The method includes a 15% range around the fair value of such assets (i.e., 85% to 115% of fair value). If the market-related value is outside the 15% range, then the amount outside the range will be recognized immediately in the calculation of annual net periodic benefit cost.

A primary goal of the plans is to achieve long-term asset growth sufficient to pay future benefit obligations at a reasonable level of risk. The investment policy target for defined benefit pension and OPEB plans reflects the philosophy that long-term growth can best be achieved by prudent investments in equity securities while balancing overall fund volatility by an appropriate allocation to fixed income securities. In order to reduce the level of portfolio risk and volatility in returns, efforts have been made to diversify the plans' investments by asset class, geographic region, market capitalization and investment style.

The weighted-average asset allocation of defined benefit retirement plans was as follows:

	Pension benefits				Other benefits			
			Investment policy				Investment policy	
December 31	2009	2008	Target	Range	2009	2008	Target	Range
Asset category								
Equity securities	68%	62%	70%	65-75%	67%	63%	70%	65-75%
Fixed income	32	37	30	25-35%	33	37	30	25-35%
Other [1]	–	1	–	–	–	–	–	–
	100%	100%	100%		100%	100%	100%	

1 Other includes alternative investments, which are relatively illiquid in nature and will remain as plan assets until an appropriate liquidation opportunity occurs.

See Note 14 for additional disclosures about the fair value of the retirement benefit plans' assets.

The following weighted-average assumptions were used in the accounting for the plans:

	Pension benefits			Other benefits		
December 31	2009	2008	2007	2009	2008	2007
Benefit obligation						
Discount rate	6.50%	6.625%	6.125%	6.50%	6.50%	6.125%
Rate of compensation increase	3.5	3.5	4.2	NA	3.5	4.2
Net periodic benefit cost (years ended)						
Discount rate	6.625	6.125	6.00	6.50	6.125	6.00
Expected return on plan assets	8.25	8.50	8.50	8.25	8.50	8.50
Rate of compensation increase	3.5	4.2	4.2	3.5	4.2	4.2

NA Not applicable

The Company based its selection of an assumed discount rate for 2010 net periodic cost and December 31, 2009 disclosure on a cash flow matching analysis that utilized bond information provided by Standard & Poor's for all non-callable, high quality bonds (i.e., rated AA- or better) as of December 31, 2009. In selecting the expected rate of return on plan assets of 8.25% for 2010 net periodic benefit cost, the Company considered economic forecasts for the types of investments held by the plans (primarily equity and fixed income investments), the plans' asset allocations and the past performance of the plans' assets. The methods of selecting the assumed discount rate and expected return on plan assets at December 31, 2009 did not change from December 31 2008.

As of December 31, 2009, the assumed health care trend rates for 2010 and future years were as follows: medical, 10%, grading down to 5% for 2015 and thereafter; dental, 5%; and vision, 4%. As of December 31, 2008, the assumed health care trend rates for 2009 and future years were as follows: medical, 10.00%, grading down to 5.00% for 2014 and thereafter; dental, 5.00%; and vision, 4.00%.

The components of net periodic benefit cost were as follows:

	Pension benefits			Other benefits		
(in thousands)	2009 (1)	2008 (1)	2007	2009	2008	2007
Service cost	$25,688	$ 28,356	$ 30,996	$ 4,846	$ 4,777	$ 4,773
Interest cost	61,988	59,765	57,851	10,981	11,008	10,829
Expected return on plan assets	(57,244)	(73,172)	(68,381)	(8,902)	(10,970)	(9,939)
Amortization of net transition obligation	2	2	3	1,831	3,138	3,138
Amortization of net prior service cost (gain)	(387)	(421)	(197)	(79)	13	13
Amortization of net actuarial loss	15,847	6,765	11,282	401	–	–
Net periodic benefit cost	45,894	21,295	31,554	9,078	7,966	8,814
Impact of PUC D&Os	(10,570)	5,859	1,195	(132)	1,038	187
Net periodic benefit cost (adjusted for impact of PUC D&Os)	$35,324	$ 27,154	$ 32,749	$ 8,946	$ 9,004	$ 9,001

(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 estimated prior service credit, net actuarial loss and net transition obligation for defined benefits pension plans that will be amortized from AOCI or regulatory asset into net periodic pension benefit cost over 2010 are $(0.4) million, $6.9 million and de minimis, respectively. The estimated prior service credit, net actuarial gain and net transitional obligation for other benefit plans that will be amortized from AOCI or regulatory asset into net periodic other than pension benefit cost over 2010 are $(0.2) million, de minimis and nil, respectively.

The Company recorded pension expense of $27 million, $20 million and $26 million and OPEB expense of $7 million, $7 million and $7 million in 2009, 2008 and 2007, respectively, and charged the remaining amounts primarily to electric utility plant.

All pension plans, with the exception of the ASB Retirement Plan as of December 31, 2009, had ABOs exceeding plan assets as of December 31, 2009 and 2008. All other benefits plans had APBOs exceeding plan assets as of December 31, 2009 and December 31, 2008.

The health care cost trend rate assumptions can have a significant effect on the amounts reported for other benefits. As of December 31, 2009, a one-percentage-point increase in the assumed health care cost trend rates would have increased the total service and interest cost by $0.1 million and the PBO by $2 million, and a one-percentage-point decrease would have reduced the total service and interest cost by $0.2 million and the PBO by $2 million.

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. ASB has accrued $1.5 million in 2009 for its anticipated Amerishare contribution in early 2010. For 2009 and 2008, ASB's total expense for its employees participating in the HEI retirement savings plan and the new ASB 401(k) Plan combined was $3.3 million and $4.4 million, respectively, and cash contributions were $3.9 million and $1.7 million, respectively.

9 • 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 available for issuance under outstanding and future grants and awards as of December 31, 2009) to officers and key employees as incentive stock options, nonqualified stock options (NQSOs), restricted stock awards, restricted stock units, stock appreciation rights (SARs), stock performance awards or dividend equivalents. HEI has issued new shares for NQSOs, restricted stock awards (nonvested stock), restricted stock units, stock performance awards, SARs and dividend equivalents under the SOIP.

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 four to five years after the date of grant and are forfeited for terminations of employment during the vesting period, except that pro-rata vesting is provided for terminations by reason of death, disability or termination without cause. 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 that pro-rata vesting is provided for terminations due to death, disability and retirement. 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 that pro-rata vesting is provided for terminations due to death, disability and retirement 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:

($ in millions)	2009	2008	2007
Share-based compensation expense [1]	1.1	0.8	1.3
Income tax benefit	0.3	0.1	0.4

[1] The Company has not capitalized any share-based compensation cost. For 2009, the estimated forfeiture rates were 41.0% for restricted stock awards, 5.9% for restricted stock units, and 10.3% for performance shares.

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

	2009		2008		2007	
	Shares	(1)	Shares	(1)	Shares	(1)
Outstanding, January 1	375,500	$19.73	603,800	$19.68	660,000	$19.68
Granted	–	–	–	–	–	–
Exercised	–	–	(220,300)	$19.62	(56,200)	$19.70
Forfeited	–	–	–	–	–	–
Expired	(1,000)	$17.61	(8,000)	$19.23	–	–
Outstanding, December 31	374,500	$19.73	375,500	$19.73	603,800	$19.68
Options exercisable, December 31	374,500	$19.73	375,500	$19.73	603,800	$19.68

(1) Weighted-average exercise price

December 31, 2009		Outstanding & Exercisable		
Year of Grant	Range of exercise prices	Number of options	Weighted-average remaining contractual life	Weighted-average exercise price
2000	$ 14.74	46,000	0.3	$14.74
2001	17.96	65,000	1.3	17.96
2002	21.68	122,000	2.1	21.68
2003	20.49	141,500	2.7	20.49
	$14.74 – 21.68	374,500	2.0	$19.73

As of December 31, 2009, all NQSOs outstanding were exercisable and had an aggregate intrinsic value (including dividend equivalents) of $1.7 million.

NQSO activity and statistics are summarized as follows:

($ in thousands, except prices)	2009	2008	2007
Shares vested	–	–	79,000
Aggregate fair value of vested shares	–	–	$350
Cash received from exercise	–	$4,323	$1,107
Intrinsic value of shares exercised [1]	–	$2,235	$575
Tax benefit realized for the deduction of exercises	–	$705	$195
Dividend equivalent shares distributed under Section 409A	–	6,125	21,971
Weighted-average Section 409A distribution price	–	$22.38	$26.14
Intrinsic value of shares distributed under Section 409A	–	$137	$574
Tax benefit realized for Section 409A distributions	–	$53	$224

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.

As of December 31, 2009, all NQSOs were vested.

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

	2009		2008		2007	
	Shares	(1)	Shares	(1)	Shares	(1)
Outstanding, January 1	791,000	$26.12	857,000	$26.12	879,000	$26.12
Granted	–	–	–	–	–	–
Exercised	–	–	(36,000)	$26.05	(4,000)	$26.18
Forfeited	(6,000)	$26.18	(30,000)	$26.18	(18,000)	$26.18
Expired	(305,000)	$26.10	–	–	–	–
Outstanding, December 31	480,000	$26.13	791,000	$26.12	857,000	$26.12
Options exercisable, December 31	480,000	$26.13	557,000	$26.10	464,000	$26.08

(1) Weighted-average exercise price

December 31, 2009		Outstanding & Exercisable		
Year of Grant	Range of exercise prices	Number of shares underlying SARs	Weighted-average remaining contractual life	Weighted-average exercise price
2004	$ 26.02	150,000	3.3	$26.02
2005	26.18	330,000	3.6	26.18
	$26.02 –26.18	480,000	3.5	$26.13

As of December 31, 2009, all SARs outstanding were exercisable and had no intrinsic value. SARs activity and statistics are summarized as follows:

($ in thousands, except prices)	2009	2008	2007
Shares vested	228,000	129,000	69,000
Aggregate fair value of vested shares	$1,354	$733	$341
Cash received from exercise	–	–	–
Intrinsic value of shares exercised [1]	–	$127	$3
Tax benefit realized for the deduction of exercises	–	$49	$1
Dividend equivalent shares distributed under Section 409A	3,143	–	23,760
Weighted-average Section 409A distribution price	$13.64	–	$26.15
Intrinsic value of shares distributed under Section 409A	$43	–	$621
Tax benefit realized for Section 409A distributions	$17	–	$242

[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. As a result of the changes enacted in Section 409A of the Internal Revenue Code of 1986, as amended (Section 409A), in 2009, 2008 and 2007, a total of 3,143, 6,125 and 45,732 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 2½ 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 had no intrinsic value at December 31, 2009; thus, no distribution will be made in 2010. No further dividend equivalents are intended to be paid in accordance with this Section 409A modified distribution.

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

	2009		2008		2007	
	Shares	(1)	Shares	(1)	Shares	(1)
Outstanding, January 1	160,500	$25.51	146,000	$25.82	91,800	$23.68
Granted	–	–	45,000	$24.71	75,700	$23.50
Restrictions ended	(3,851)	$24.52	(6,170)	$25.44	(16,000)	$23.48
Forfeited	(27,649)	$25.67	(24,330)	$25.90	(5,500)	$26.04
Outstanding, December 31	129,000	$25.50	160,500	$25.51	146,000	$25.82

(1) Weighted-average grant date fair value per share

The grant date fair value of a restricted stock award share was the closing or average price of HEI common stock on the date of grant.

For 2008 and 2007, total restricted stock granted had a weighted-average grant date fair value of $1.1 million and $1.9 million, respectively. For 2009, 2008 and 2007, total restricted stock vested had a fair value of $94,000, $157,000 and $376,000, respectively.

The tax benefits realized for the tax deductions related to restricted stock awards were $0.1 million for 2009, $0.2 million for 2008 and $0.2 million for 2007.

As of December 31, 2009, there was $0.9 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 1.8 years.

Restricted stock units. In February 2009, 70,500 restricted stock units (representing the same number of underlying shares) were granted with a weighted-average grant date fair value of $1.2 million (weighted-average grant date fair value of $16.99 per restricted stock unit). The grant date fair value of a restricted stock unit was the average price of HEI common stock on the date of grant.

As of December 31, 2009, there were 70,500 restricted stock units outstanding with a weighted-average grant date fair value of $16.99 per restricted stock unit. For 2009, no restricted stock units were vested or forfeited. As of December 31, 2009, there was $0.9 million of total unrecognized compensation cost related to the nonvested restricted stock units. The cost is expected to be recognized over a weighted-average period of 3.1 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.

Performance shares linked to TRS. In February 2009, 36,198 performance shares with the TRS condition (based on target performance levels) were granted with a weighted-average grant date fair value of $0.5 million based on the weighted-average grant date fair value per share of $13.08. 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 three-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 December 31, 2009, there were 36,198 performance shares linked to TRS outstanding (based on target performance levels), with a weighted-average grant date fair value of $13.08 per share. For 2009, no performance share awards linked to TRS were vested or forfeited. As of December 31, 2009, there was $0.3 million of total unrecognized compensation cost related to the nonvested performance shares linked to TRS. The cost is expected to be recognized over a weighted-average period of 2.0 years.

Performance shares linked to ROACE. In February 2009, 24,131 shares underlying the performance share awards with the ROACE condition (based on target performance levels) were granted with a weighted-average grant date fair value of $0.3 million based on the weighted-average grant-date fair value per share of $13.34. The grant date fair value of a performance share linked to ROACE 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 December 31, 2009, there were 24,131 performance shares linked to ROACE outstanding (based on target performance levels), with a weighted-average grant date fair value of $13.34 per share. For 2009, no performance shares linked to ROACE were vested or forfeited. As of December 31, 2009, there was $0.2 million of total unrecognized compensation cost related to the nonvested performance shares linked to ROACE. The cost is expected to be recognized over a weighted-average period of 2.0 years.

10 • Income taxes

The components of income taxes attributable to net income for common stock were as follows:

Years ended December 31	2009	2008	2007
(in thousands)			
Federal			
Current	$25,691	$38,041	$71,028
Deferred	14,161	7,045	(27,855)
Deferred tax credits, net	(593)	(1,094)	(1,154)
	39,259	43,992	42,019
State			
Current	6,930	4,409	8,194
Deferred	(783)	(815)	(5,615)
Deferred tax credits, net	(1,483)	1,392	1,680
	4,664	4,986	4,259
Total	$43,923	$48,978	$46,278

A reconciliation of the amount of income taxes computed at the federal statutory rate of 35% to the amount provided in the Company's consolidated statements of income was as follows:

Years ended December 31	2009	2008	2007
(in thousands)			
Amount at the federal statutory income tax rate	$45,088	$48,740	$45,870
Increase (decrease) resulting from:			
State income taxes, net of effect on federal income taxes	3,033	3,241	2,768
Other, net	(4,198)	(3,003)	(2,360)
Total	$43,923	$48,978	$46,278
Effective income tax rate	34.1%	35.2%	35.3%

The tax effects of book and tax basis differences that give rise to deferred tax assets and liabilities were as follows:

December 31 (in thousands)	2009	2008
Deferred tax assets		
Cost of removal in excess of salvage value	$109,210	$109,882
Contributions in aid of construction and customer advances	77,766	78,834
Allowance for loan losses	16,869	14,020
Net unrealized losses on available-for-sale investment and mortgage-related securities (AOCI)	–	21,807
Retirement benefits (AOCI)	8,269	13,079
Other	39,533	34,313
	251,647	271,935
Deferred tax liabilities		
Property, plant and equipment	336,569	311,027
Retirement benefits	6,367	8,546
Goodwill	18,233	16,335
Regulatory assets, excluding amounts attributable to property, plant and equipment	31,947	30,240
FHLB stock dividend	20,552	20,552
Change in accounting method related to contributions in aid of construction	8,010	16,020
Other	18,844	12,523
	440,522	415,243
Net deferred income tax liability	$188,875	$143,308

The ultimate realization of deferred tax assets is dependent upon the generation of future taxable income during the periods in which those temporary differences are deductible. Based upon historical taxable income and projections for future taxable income, management believes it is more likely than not the Company will realize substantially all of the benefits of the deferred tax assets.

In 2009, 2008 and 2007, interest expense on income taxes was reflected in "Interest expense – other than on deposit liabilities and bank borrowings" in the amount of $0.7 million, $0.2 million and $1.2 million, respectively. The Company will record associated penalties, if any, in the respective segment's expenses. As of December 31, 2009 and 2008, the total amount of accrued interest related to uncertain tax positions and recognized on the balance sheet was $3.6 million and $2.9 million, respectively.

As of December 31, 2009, the total amount of liability for uncertain tax positions was $7.8 million and, of this amount, $1.6 million, if recognized, would affect the Company's effective tax rate. Management concluded that it is reasonably possible that the liability for uncertain tax positions will significantly change within the next 12 months due to the resolution of issues under examination by the Internal Revenue Service and estimates the range of the reasonably possible change to be a decrease of between nil and $5.7 million in 2010.

The changes in total unrecognized tax benefits were as follows:

Years ended December 31 (in millions)	2009	2008
Unrecognized tax benefits, January 1	$ 27.9	$ 31.3
Additions based on tax positions taken during the year	–	–
Reductions based on tax positions taken during the year	–	–
Additions for tax positions of prior years	0.4	0.8
Reductions for tax positions of prior years	(1.8)	(4.2)
Decreases due to tax positions taken	–	–
Settlements	–	–
Lapses of statute of limitations	–	–
Unrecognized tax benefits, December 31	$ 26.5	$ 27.9

In addition to the liability for uncertain tax positions, the Company's unrecognized tax benefits include $18.7 million of tax benefits related to refund claims, which did not meet the recognition threshold. Consequently, tax benefits have not been recorded on these claims and no liability for uncertain tax positions was required to offset these potential benefits.

Tax years 2003 to 2008 currently remain subject to examination by the Internal Revenue Service and Department of Taxation of the State of Hawaii. HEI Investments, Inc., which owned leveraged lease investments in other states prior to 2008, is also subject to examination by those state tax authorities for tax years 2003 to 2007.

As of December 31, 2009, the disclosures above present the Company's accrual for potential tax liabilities and related interest. Based on information currently available, the Company believes this accrual has adequately provided for potential income tax issues with federal and state tax authorities and related interest, and that the ultimate resolution of tax issues for all open tax periods will not have a material adverse effect on its results of operations, financial condition or liquidity.

11 • Cash flows

Supplemental disclosures of cash flow information. In 2009, 2008 and 2007, the Company paid interest to non-affiliates amounting to $106 million, $182 million and $233 million, respectively.

In 2009, 2008 and 2007, the Company paid income taxes amounting to $21 million, $91 million and $39 million, respectively.

Supplemental disclosures of noncash activities. Under the HEI DRIP, common stock dividends reinvested by shareholders in HEI common stock in noncash transactions amounted to $17 million, $21 million and $21 million in 2009, 2008 and 2007, respectively. HEI satisfied the requirements of the HEI DRIP and the HEIRS (from April 16, 2009 through September 3, 2009) and the ASB 401(k) Plan (from May 7, 2009 through September 3, 2009) by acquiring for cash its common shares through open market purchases rather than by issuing additional shares. Effective September 4, 2009, HEI resumed satisfying the requirements of the HEI DRIP, HEIRS and ASB 401(k) Plan through the issuance of additional shares of common stock.

In 2009, 2008 and 2007, other noncash increases in common stock issued under director and officer compensatory plans was $2 million.

In 2009, 2008 and 2007, HECO and its subsidiaries capitalized as part of the cost of electric utility plant an allowance for equity funds used during construction amounting to $12 million, $9 million and $5 million, respectively.

In 2009, 2008 and 2007, the estimated fair value of noncash contributions in aid of construction amounted to $12 million, $10 million and $18 million, respectively.

12 • Regulatory restrictions on net assets

As of December 31, 2009, HECO and its subsidiaries could not transfer approximately $588 million of net assets to HEI in the form of dividends, loans or advances without PUC approval.

ASB is required to file a notice with the OTS prior to making any capital distribution to HEI. Generally, the OTS may disapprove or deny ASB's notice of intention to make a capital distribution if the proposed distribution will cause ASB to become undercapitalized, or the proposed distribution raises safety and soundness concerns, or the proposed distribution violates a prohibition contained in any statute, regulation, or agreement between ASB and the OTS. As of December 31, 2009, ASB could transfer approximately $138 million of net assets to HEI in the form of dividends and still maintain its "well-capitalized" position.

HEI management expects that the regulatory restrictions will not materially affect the operations of the Company nor HEI's ability to pay common stock dividends.

13 • Significant group concentrations of credit risk

Most of the Company's business activity is with customers located in the State of Hawaii. Most of ASB's financial instruments are based in the State of Hawaii, except for the investment and mortgage-related securities it owns. Substantially all real estate loans receivable are secured by real estate in Hawaii. ASB's policy is to require mortgage insurance on all real estate loans with a loan to appraisal ratio in excess of 80% at origination.

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 in determining such fair values.

Fair Value Measurements. The Company groups its financial assets measured at fair value in three levels outlined 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.

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 and investment in stock of Federal home Loan Bank of Seattle . Fair value was based on observable inputs using market-based valuation techniques.

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

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

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

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

December 31	2009		2008	
(in thousands)	Carrying or notional amount	Estimated fair value	Carrying or notional amount	Estimated fair value
Financial assets				
Cash and equivalents	$ 502,443	$ 502,443	$ 182,903	$ 182,903
Federal funds sold	1,479	1,479	532	532
Available-for-sale investment and mortgage-related securities	432,881	432,881	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	3,670,493	3,760,954	4,206,492	4,322,153
Financial liabilities				
Deposit liabilities	4,058,760	4,063,888	4,180,175	4,197,429
Short-term borrowings—other than bank	41,989	41,989	–	–
Other bank borrowings	297,628	307,154	680,973	701,998
Long-term debt, net—other than bank	1,364,815	1,336,250	1,211,501	949,170
Off-balance sheet items				
HECO-obligated preferred securities of trust subsidiary	50,000	48,480	50,000	40,420

As of December 31, 2009 and 2008, loan commitments and unused lines and letters of credit issued by ASB had notional amounts of $1.2 billion and their estimated fair value on such dates was $0.2 million and $0.8 million, respectively. As of December 31, 2009 and 2008, loans serviced by ASB for others had notional amounts of $577.5 million and $307.6 million and the estimated fair value of the servicing rights for such loans was $5.6 million and $2.6 million, respectively.

Assets measured at fair value on a recurring basis. While securities held in ASB's investment portfolio trade in active markets, they do not trade on listed exchanges nor do the specific holdings trade in quoted markets by dealers or brokers. All holdings are valued using market-based approaches that are based on exit prices that are taken from identical or similar market transactions, even in situations where trading volume may be low when compared with prior periods as has been the case during the 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. Available-for-sale securities were comprised of federal agency obligations and mortgage-backed securities and municipal bonds.

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

		Fair value measurements using		
(in millions)	Available-for-sale securities	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
December 31, 2009	$433	–	$433	–
December 31, 2008	658	–	658	–

Assets measured at fair value on a nonrecurring basis. From time to time, ASB may be required to measure certain assets at fair value on a nonrecurring basis in accordance with U.S. GAAP. These adjustments to fair value usually result from the application of lower-of-cost-or-market accounting or write-downs of individual assets. ASB does not record loans at fair value on a recurring basis. However, from time to time, ASB records nonrecurring fair value adjustments to loans to reflect specific reserves on loans based on the current appraised value of the collateral or unobservable market assumption. Unobservable assumptions reflect ASB's own estimate of the fair value of collateral used in valuing the loan. Mortgage servicing rights do not trade in an active market with readily observable market data. From time to time, ASB may be required to measure mortgage servicing rights at fair value. ASB estimates the fair value of mortgage servicing rights by discounting expected net servicing income streams using discount rates that reflect industry pricing for similar assets. Expected net servicing income streams are estimated based on industry assumptions regarding prepayment speeds and income and expenses associated with servicing residential mortgage loans for others. ASB may also be required to measure goodwill at fair value on a nonrecurring basis. See "Goodwill and other intangibles" in Note 1 for ASB's goodwill valuation methodology. During 2009 and 2008, goodwill was not measured at fair value.

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

		Fair value measurements using		
(in millions)	Balance	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
December 31, 2009				
Loans	$17	$ –	$14	$3
Mortgage servicing rights	4	–	–	4
Total	$21	$ –	$14	$7
December 31, 2008				
Loans	$ 8	$ –	$3	$5
Mortgage servicing rights	2	–	–	2
Total	$10	$ –	$3	$7

Specific reserves as of December 31, 2009 and 2008 were $1.6 million and $4.4 million, respectively, and were included in loans receivable held for investment, net. For 2009 and 2008, there were no adjustments to fair value for ASB's loans held for sale.

Retirement benefit plans

On January 1, 2008, the retirement benefit plans (Plans) adopted new standards for fair value measurements of financial assets and liabilities and for fair value measurements of nonfinancial items that are recognized or disclosed at fair value in the financial statements on a recurring basis.

Assets held in various trusts are measured at fair value on a recurring basis (including items that are required to be measured at fair value and items for which the fair value option has been elected) and at December 31, 2009 were as follows:

	Pension benefits				Other benefits			
		Fair value measurements using				Fair value measurements using		
(in millions)	December 31, 2009	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)	December 31, 2009	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Equity securities	$405	$384	$ –	$21	$ 71	$ 67	$ –	$ 4
Equity index funds	70	70	–	–	46	46	–	–
Fixed income securities	241	32	209	–	8	1	7	–
Pooled and mutual funds	26	–	–	26	5	–	–	5
Other	18	–	(2)	20	5	–	–	5
Total	$760[1]	$486	$207	$67	$135	$114	$ 7	$14

1 The pension benefits fair value does not include accrued income, receivables and cash of $4 million and has not been reduced by payables of $25 million as of December 31, 2009.

The fair values of the financial instruments shown in the table above represent the Company's best estimates of the amounts that would be received upon sale of those assets or that would be paid to transfer those liabilities in an orderly transaction between market participants at that date. Those fair value measurements maximize the use of observable inputs. However, in situations where there is little, if any, market activity for the asset or liability at the measurement date, the fair value measurement reflects the Company's judgments about the assumptions that market participants would use in pricing the asset or liability. Those judgments are developed by the Company based on the best information available in the circumstances.

In connection with the adoption of the fair value measurement standards, the Company adopted the provisions of Accounting Standards Update No. 2009-12, "Investments in Certain Entities that Calculate Net Asset Value per Share (or Its Equivalent)," which allows for the estimation of the fair value of investments in investment companies for which the investment does not have a readily determinable fair value, using net asset value per share or its equivalent as a practical expedient.

The Company used the following valuation methodologies for assets measured at fair value. There have been no changes in the methodologies used at December 31, 2009 and 2008.

Equity securities, equity index funds and U.S. Treasury fixed income securities (Level 1). Valued at the closing price reported on the active market on which the individual securities are traded.

Fixed income securities (Level 2). Fixed income securities, other than those issued by the U.S. Treasury, are valued based on yields currently available on comparable securities of issuers with similar credit ratings.

Equity securities, pooled and mutual funds, and other (Level 3). Equity securities and pooled and mutual funds include commingled equity funds and other closed funds, respectively, that are not open to public investment and are valued at the net asset value per share. Certain other investments are valued based on discounted cash flow analyses. The venture capital and limited partnership interests are valued at historical cost, modified by revaluation of financial assets and financial liabilities at fair value through profit or loss.

For 2009, the changes in Level 3 assets were as follows:

	Pension benefits					Other benefits				
(in thousands)	Equity invest-ments	Fixed income securities	Pooled and mutual funds	Other	Total	Equity invest-ments	Fixed income securities	Pooled and mutual funds	Other	Total
Balance, January 1	$11,802	$(185)	$22,824	$15,200	$49,641	$2,223	$ (6)	$6,904	$3,592	$12,713
Realized gains	19	4	–	120	143	47	–	–	11	58
Unrealized gains related to instruments still held at December 31, 2009	9,024	544	–	5,421	14,989	1,601	18	–	1,624	3,243
Purchases, sales, issuances and settlements, net	(128)	(4)	3,589	(810)	2,647	(2)	–	(2,229)	(80)	(2,311)
Balance, December 31	$20,717	$ 359	$26,413	$19,931	$67,420	$3,869	$12	$4,675	$5,147	$13,703

15 • Subsequent events

The Company has evaluated subsequent events through February 19, 2010, the date the financial statements were issued.

16 • Quarterly information (unaudited)

Selected quarterly information was as follows:

	Quarters ended				Years ended
(in thousands, except per share amounts)	March 31	June 30	Sept. 30	Dec. 31	December 31
2009					
Revenues [1]	$543,797	$525,901	$620,313	$619,579	$2,309,590
Operating income [1]	44,658	35,055	68,639	39,312	187,664
Net income for common stock [1]	20,395	15,479	33,483	13,654	83,011
Distributed earnings per common share	0.31	0.31	0.31	0.31	1.24
Undistributed earnings (loss) per common share	(0.08)	(0.14)	0.06	(0.16)	(0.33)
Basic earnings per common share [2]	0.23	0.17	0.37	0.15	0.91
Diluted earnings per common share [3]	0.22	0.17	0.37	0.15	0.91
Dividends per common share	0.31	0.31	0.31	0.31	1.24
Market price per common share [4]					
High	22.73	19.25	19.45	21.55	22.73
Low	12.09	13.52	16.50	16.70	12.09
2008					
Revenues [5]	$729,617	$774,055	$915,431	$799,817	$3,218,920
Operating income [5]	70,746	21,602	74,129	37,680	204,157
Net income for common stock [5]	33,967	5,136	37,281	13,894	90,278
Distributed earnings per common share	0.31	0.31	0.31	0.31	1.24
Undistributed earnings (loss) per common share	0.10	(0.25)	0.13	(0.15)	(0.17)
Basic and diluted earnings per common share [2,3]	0.41	0.06	0.44	0.16	1.07
Dividends per common share	0.31	0.31	0.31	0.31	1.24
Market price per common share [4]					
High	23.95	27.16	29.75	29.06	29.75
Low	20.95	23.89	23.50	21.29	20.95

[1] For 2009, amounts included interim rate relief totaling $141 million. The fourth quarter of 2009 includes a $19.3 million, net of tax benefits, loss on ASB's sale of its private-issue mortgage-related securities. The first and second quarters of 2009 includes a $3.4 million and a $5.9 million, net of tax benefits, respectively, charge for other-than-temporary impairments of securities owned by ASB.

[2] The quarterly basic earnings (loss) per common share are based upon the weighted-average number of shares of common stock outstanding in each quarter.

[3] The quarterly diluted earnings (loss) per common share are based upon the weighted-average number of shares of common stock outstanding in each quarter plus the dilutive incremental shares at quarter end.

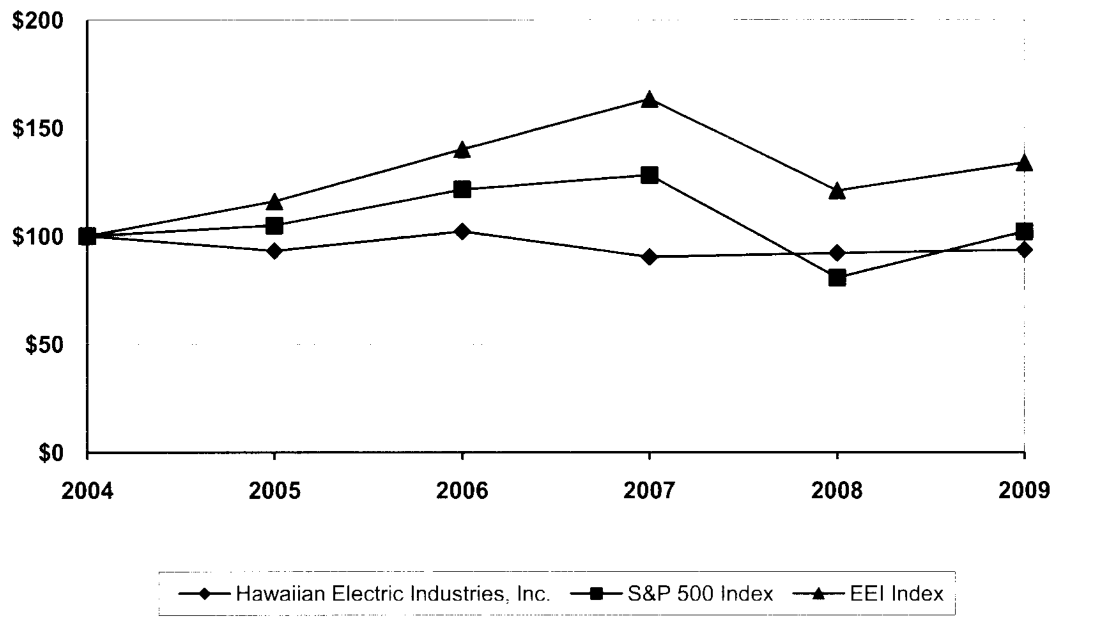
[4] Market prices of HEI common stock (symbol HE) shown are as reported on the NYSE Composite Tape for the indicated date.

[5] For 2008, amounts included interim rate relief totaling $108 million. The second quarter of 2008 includes a $35.6 million, net of tax benefits, charge related to a balance sheet restructuring at ASB. The fourth quarter of 2008 includes a reduction of $1.3 million, net of taxes, of electric sales revenues related to prior periods and a $4.7 million, net of tax benefits, charge for other-than-temporary impairments of securities owned by ASB.

Shareholder Performance Graph

The graph below compares the cumulative total shareholder return on HEI Common Stock against the cumulative total return of companies listed on the S&P 500 Stock Index and the Edison Electric Institute (EEI) Index of Investor-Owned Electric Companies (58 companies were included as of December 31, 2009). The graph is based on the market price of common stock for all companies in the indexes at December 31 each year and assumes that $100 was invested on December 31, 2004 in HEI Common Stock and the common stock of all companies in the indexes and that dividends were reinvested.

COMPARISON OF CUMULATIVE FIVE YEAR TOTAL RETURN



SHAREHOLDER INFORMATION

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Telephone: 808-543-5662

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New York Stock Exchange
Common stock symbol: HE
Trust preferred securities symbol: HEPrU (HECO)

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Toll Free: 866-672-5841
Facsimile: 808-532-5868
E-mail: invest@hei.com
Office hours: 7:30 a.m. to 3:30 p.m. H.S.T.

Correspondence about common stock and utility preferred stock ownership, dividend payments, transfer requirements, changes of address, lost stock certificates, duplicate mailings, and account status may be directed to shareholder services.

A copy of the 2009 Form 10-K Annual Report for Hawaiian Electric Industries, Inc. and Hawaiian Electric Company, Inc., including financial statements and schedules, will be provided by HEI without charge upon written request directed to Laurie Loo-Ogata, Director, Shareholder Services, at the above address for shareholder services or through HEI's website.

Website
Internet users can access information about HEI and its subsidiaries at http://www.hei.com.

Dividends and Distributions
Common stock quarterly dividends are customarily paid on or about the 10th of March, June, September, and December to shareholders of record on the dividend record date.

Quarterly distributions on trust preferred securities are paid by HECO Capital Trust III, an unconsolidated financing subsidiary of HECO, on or about March 31, June 30, September 30, and December 31 to holders of record on the business day before the distribution is paid.

Utility company preferred stock quarterly dividends are paid on the 15th of January, April, July, and October to preferred shareholders of record on the 5th of these months.

Direct Registration
HEI common stock can be issued in direct registration (book entry) form. The stock is DRS (Direct Registration System) eligible.

Dividend Reinvestment and Stock Purchase Plan
Any individual of legal age or any entity may buy HEI common stock at market prices directly from the Company. The minimum initial investment is $250. Additional optional cash investments may be as small as $25. The annual maximum investment is $120,000. After your account is open, you may reinvest all of your dividends to purchase additional shares, or elect to receive some or all of your dividends in cash. You may instruct the Company to electronically debit a regular amount from a checking or savings account. The Company can also deposit dividends automatically to your checking or savings account. A prospectus describing the plan may be obtained through HEI's website or by contacting shareholder services.

Annual Meeting
Tuesday, May 11, 2010, 9:30 a.m.
American Savings Bank Tower
1001 Bishop Street
8th Floor, Room 805
Honolulu, Hawaii 96813

Please direct inquiries to:
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Senior Vice President -
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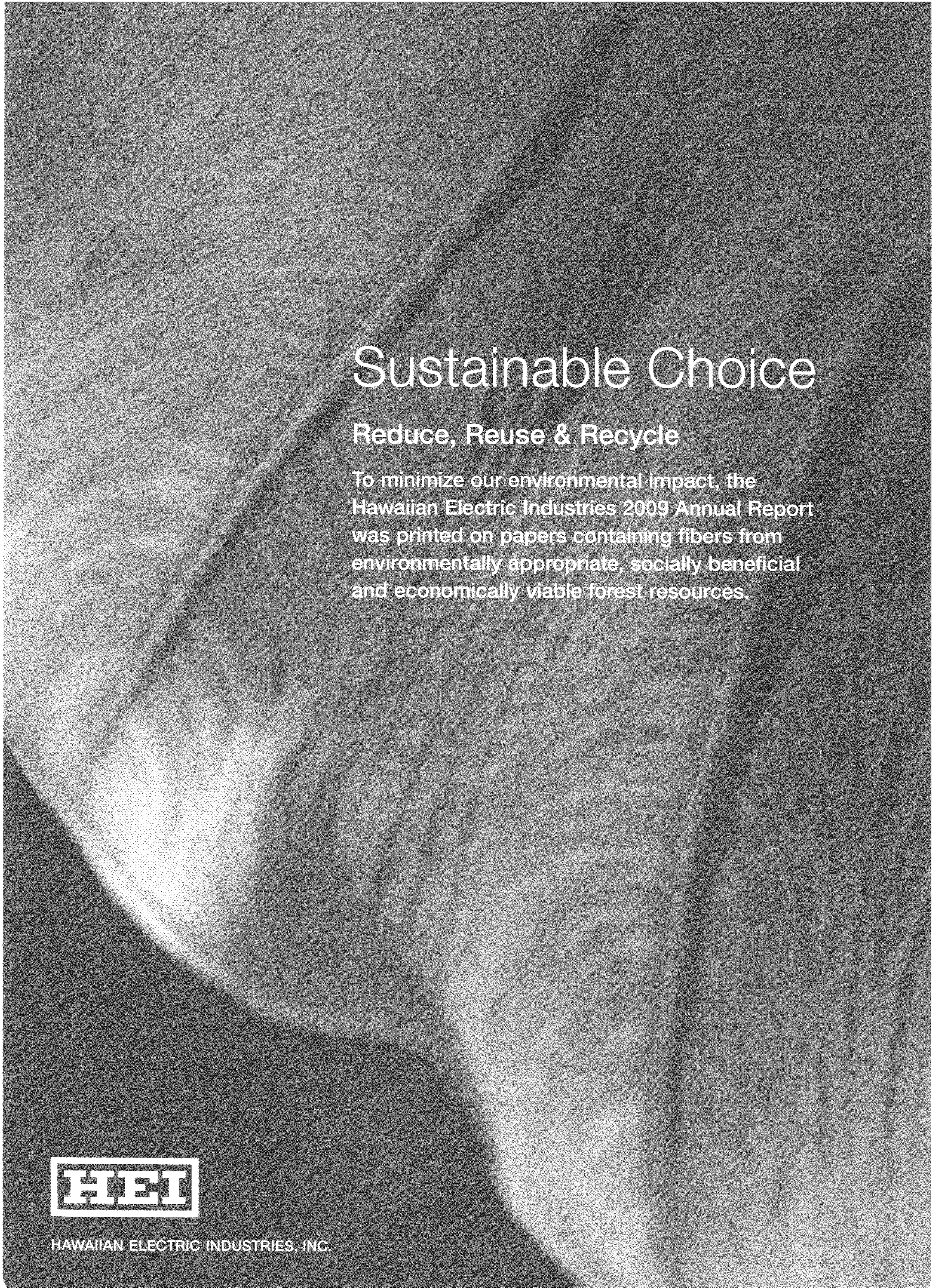
Trust preferred securities:
Contact your investment broker for information on transfer procedures.

FORWARD-LOOKING STATEMENTS

This report contains "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 (including future revenues, expenses, earnings or losses or growth rates), ongoing business strategies or prospects and possible future actions, which may be provided by management, 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 assumptions about HEI and its subsidiaries, 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.

Forward-looking statements should be read in conjunction with the "Forward-Looking Statements" discussion (which is incorporated by reference herein) set forth on pages 1 and 2 of the enclosed 2009 Annual Report to Shareholders – Financial and Other Information, and in HEI's future periodic or current reports that discuss important factors that could cause HEI's results to differ materially from those anticipated in such statements. Forward-looking statements speak only as of the date of this report.



Sustainable Choice

Reduce, Reuse & Recycle

To minimize our environmental impact, the Hawaiian Electric Industries 2009 Annual Report was printed on papers containing fibers from environmentally appropriate, socially beneficial and economically viable forest resources.

HEI

HAWAIIAN ELECTRIC INDUSTRIES, INC.