How we get from here to *there*.

HEI

2010 Annual Report to Shareholders

Hawaiian Electric Industries (HEI), through its subsidiaries, Hawaiian Electric Company (Hawaiian Electric) and American Savings Bank (ASB), provides essential energy and financial services, ensuring a brighter future for our shareholders and all stakeholders.

Our Answers to Your Questions

Throughout this book you will see examples of how HEI is working proactively to improve the future of Hawaii and its communities. These efforts are integrated into our core business strategies. By helping our state achieve economic prosperity and a clean environment, and by addressing our communities' needs, we build a sustainable future for our companies and our communities.

Financial Highlights

Years ended December 31 (dollars in millions, except per share amounts)	2010	2009 [1]	2008 [2]
Operating income	$ 256	$ 188	$ 204
Net income (loss) by segment			
Electric utility	77	79	92
Bank	58	22	18
Other	(21)	(18)	(20)
Net income	114	83	90
Basic earnings per common share	1.22	0.91	1.07
Diluted earnings per common share	1.21	0.91	1.07
Dividends per common share	1.24	1.24	1.24
Book value per common share [3]	15.67	15.58	15.35
Market price per common share			
High	24.99	22.73	29.75
Low	18.63	12.09	20.95
December 31	22.79	20.90	22.14
Return on average common equity	7.8%	5.9%	6.8%
Indicated annual yield [3]	5.4%	5.9%	5.6%
Price earnings ratio [4]	18.7x	23.0x	20.7x
Common shares (millions)			
December 31	94.7	92.5	90.5
Weighted-average	93.4	91.4	84.6

[1] 2009 consolidated and bank net income 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, adjusted to exclude the $19 million after-tax charge, was 7.2%.

[2] 2008 consolidated and bank net income 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, adjusted to exclude the $36 million after-tax balance sheet restructuring charge, was 9.3%.

[3] At December 31.

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

Forbes 100 Most Trustworthy Companies 2010

Forbes Places HEI on 100 Most Trustworthy Companies List

HEI has been recognized by Forbes as one of the 100 Most Trustworthy Companies. The list is based on an independent study by Audit Integrity and recognizes companies that have proven over time to have the most transparent accounting, prudent management, and solid corporate governance. With less than 2% of the companies in the entire U.S. stock market qualifying, we are proud to be recognized as part of this group.

How do we get from here to *there?*

Build fundamental earnings and profitability of both operating companies

Provide an attractive dividend

Create long-term benefits for all stakeholders

Beginning in 2008, we initiated strategies to set both of our operating companies on a new course — our utility entered into an agreement with the State of Hawaii to help create a clean energy future for Hawaii and our bank set new performance standards while continuing our commitment to help our communities grow and prosper. In 2010, we saw major progress on these initiatives and HEI's unique business model continues to provide our company with a strong balance sheet and the financial resources to invest in the strategic growth of our companies while providing an attractive dividend for our shareholders. While we have more to accomplish, I am confident that we are on the right course to make a difference in creating a better tomorrow for our shareholders, customers, and other stakeholders.

Why is clean energy a high priority for our company?

We have a critical responsibility to help Hawaii achieve its clean energy goals. Reducing Hawaii's dependence on oil is not only an environmental concern, it is an economic imperative. Approximately 90% of Hawaii's energy needs are met through the importation of fossil fuels, mostly imported oil. Of that, about a third is for electricity generation and 13% of Hawaii's gross state product leaves our state to pay for oil. With our state's clean energy public policy, our company can help promote economic growth and energy security for Hawaii, preserve our environment, provide energy at a more stable and lower cost for our customers, and provide good investment opportunities for shareholders.

How do we create a clean energy future for Hawaii and reduce our dependence on imported oil?

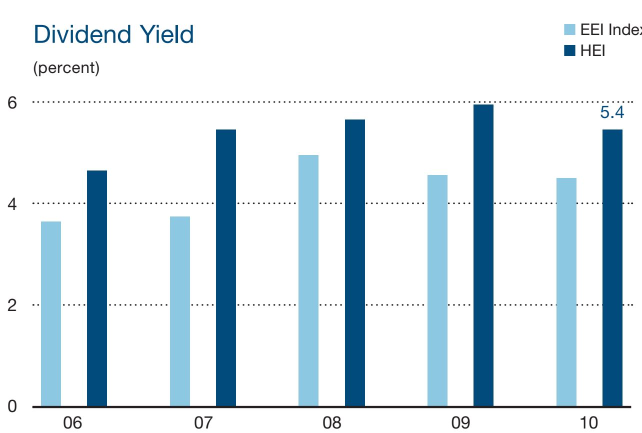
Achieving a clean energy future for Hawaii requires all stakeholders, including policy makers, private industry, consumers, our communities, and our companies, to work together. It takes a willingness to make the needed investments now to achieve the long-term benefits of a clean energy future. It takes working with industry experts to develop the technical solutions to harness and reliably integrate our islands' indigenous energy resources. And it takes recognition that we must pursue a diverse portfolio of solutions, including greater conservation and efficiency, to achieve our clean energy goals.

How does the utilities' new regulatory model support clean energy and benefit our stakeholders?

Aligning regulation with the objectives of the clean energy initiative in our state is critical to achieving a greener Hawaii. The new decoupled regulatory model, which was approved in 2010 by the Hawaii Public Utilities Commission and implemented for our largest utility on Oahu, will reward energy efficiency, encourage investment in our grids to support clean energy, help us earn competitive returns for our shareholders to attract capital for clean energy investments, and spur development of the renewable energy industry in Hawaii. Over the next two years we will focus on implementing this comprehensive redesign of our regulatory model to capture these benefits.

How did the bank achieve such strong financial results in 2010 and how will it continue to improve?

In 2010, we successfully completed the bank's Performance Improvement Project started in 2008. We significantly improved profitability, while remaining a safe and sound bank for our customers and communities. We completed a major system



Sources: Capital IQ and EEI

We believe the market is just beginning to recognize the value of the strategic milestones achieved in 2010 and the benefits for our future. HEI provided a 15% total return to shareholders in 2010, more than double the 7% return from the EEI utility index.

Total Return
(percent)

	HEI	S&P 500 Index	EEI Index	KBW Regional Banking Index
2010	15.3	15.1	7.0	20.4
3-Year	19.5	-8.3	-12.2	-23.6
5-Year	15.9	12.0	23.6	-35.3
10-Year	111.8	15.1	69.2	-0.7

Sources: Capital IQ and Bloomberg / HEI NYSE symbol: HE

conversion, allowing us to better enhance customer service and management of our operations. In November 2010, we welcomed Rich Wacker, a very seasoned and talented executive, as the President and CEO of the bank. Under his leadership, we are striving to solidify the gains from our recent successes and continue to grow our bank franchise.

Did these strategic initiatives deliver value for shareholders in 2010?

We believe the market is just beginning to recognize the value of the strategic milestones achieved in 2010 and the benefits for our future. HEI provided a 15% total return to shareholders in 2010, more than double the 7% return from the EEI utility index.

Our financial results are also beginning to reflect our strategic progress. HEI earned $1.21 diluted earnings per share in 2010 compared to $0.91 per share in 2009 and $1.07 in 2008. This significant improvement is primarily attributable to stronger bank earnings. At the utility, we made significant progress in implementing our clean energy strategies, including approval of a new regulatory model.

How does HEI's dividend yield compare to other utilities?

We are very proud that we maintained your dividend through the worst financial crisis since the Great Depression. As of December 31, 2010, our dividend yield was an attractive 5.4%, notably above the average EEI dividend yield of 4.5%. HEI has historically paid an above average dividend yield and has continuously paid a dividend for over 100 years. We believe that the dividend is an important component of providing value to our shareholders.

What is the outlook for the future?

We are very pleased about the prospects for our companies. Both companies are on the right course with strong fundamental business models and strategies that align, more than ever, with shareholder and stakeholder interests. The hard work invested over the last few years has improved our profitability and earnings power and reduced risk. There are many promising signs of economic recovery in our state and our companies are well-positioned to benefit from the recovery. We look forward to the opportunities we have to strengthen and grow our businesses in order to best serve you, our shareholders. We thank you for your continued confidence in us.

A sincere mahalo (thank you) to our directors for their sage guidance and careful oversight, and to all of our employees for their extraordinary efforts to achieve our ambitious goals.

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

How Hawaiian Electric will get *there.*

Achieving our clean energy goals to build

a better future

Our mission is to provide clean, secure energy for Hawaii. Our utility is committed to being a leader in our State's effort to significantly reduce our dependence on imported oil. At the same time, we must continue providing exceptional service to our customers and increase our financial strength.

We are making significant investments to achieve our energy goals of 40% renewable generation by 2030. To meet these goals, we are pursuing a range of renewable energy resources: solar, wind, biofuels, geothermal, ocean power, and more. These energy sources operate very differently than traditional power plants, so we are also modernizing our electric system to allow these new energy sources to efficiently and reliably serve our customers.

How will transitioning to clean energy result in lower and more stable costs to our customers?

We have a unique opportunity that is not available to other utilities across the nation. More than half of a customer's electric bill goes to pay for fuel costs. Replacing imported oil that is expensive and volatile in price with fixed price renewable energy can result in lower and more stable costs for our customers in the long run. That is why the investments we are making today are so important.

How will electric vehicles support Hawaii's clean energy goals?

Ground transportation makes up a third of all petroleum use in Hawaii, so the transition to electric vehicles (EVs) is critical. Hawaii's short driving distances make our islands an ideal location for EVs. Our new pilot program offering special rates for electric vehicle charging during off-peak hours will help encourage interest in these new vehicles. As more clean energy is added to our grids, electric vehicles represent a "two for one" opportunity to "green" transportation, replacing petroleum-based fuels with electricity generated from renewable sources.

How will biofuels support Hawaii's clean energy goals?

Unlike utilities in other states which rely on nuclear, coal or natural gas, we have a unique opportunity to replace the "black" oil used in our conventional generating units with "green" biofuels. In fact, we have successfully tested one of our oil-fired steam units running at 100% capacity on 100% sustainable biofuel. In addition, our new 110 MW combustion turbine at Campbell Industrial Park runs exclusively on sustainable biodiesel, demonstrating how clean renewable fuels can help meet our energy needs.

How will connecting the islands help meet our clean energy goals?

Lanai and Molokai are home to abundant wind resources, but there is currently no way to transmit that power to Oahu, where we have the heaviest energy demand. We are working with others to develop an undersea transmission cable to connect the islands and maximize the use of renewable resources throughout the state.

What is being done to make more use of solar power in Hawaii?

Solar power had a banner year in Hawaii in 2010, as the number of customer-sited photovoltaic (PV) installations nearly doubled compared to 2009. Today, Hawaii leads the nation in solar watts per person. To support continued growth, we are working on technical solutions to reliably integrate even more solar power. More projects are on the way through our net energy metering program and the new Feed-In Tariff, which provides developers simplified and price-certain contracts to sell renewable power to our companies.

What is decoupling and how does it support Hawaii's clean energy goals?

Decoupling is a new method of setting electric rates that is designed to help Hawaii reduce its dependence on imported oil. Approved by the PUC in 2010, decoupling removes the link between utility revenues and electricity usage. This aligns our business with our state's public policy to promote

- Current Renewable Energy Projects
- Future Proposed Renewable Energy Projects

Biofuels (B), Biomass (M), Concentrating Solar Power (C), Geothermal (G), Hydroelectric (H), Photovoltaic (P), Wind (W)

Our utilities are aggressively pursuing a broad portfolio of renewable energy resources. To reach our goals, we are supporting clean energy projects on all islands in our service territories.

KAHUKU WIND. First Wind's 30 MW wind farm in Kahuku went into operation in early 2011.

KAHEAWA II. First Wind's 21 MW project will be an addition to the 30 MW Kaheawa Wind Farm above Maalaea in West Maui.

BIOMASS POWER. Honua Power will burn construction debris, green waste, agricultural biomass crops, scrap tires, and non-recyclable paper and plastics to generate 6.6 MW of renewable energy.

LANAI WIND. Castle & Cooke is proposing a 200 to 400 MW wind farm on Lanai. The energy would be transmitted to Oahu.

CT-1 BIODIESEL POWER PLANT. Running on 100% biodiesel, our new 110 MW generating station will help create a local market for biofuel production in Hawaii.

LA OLA SOLAR FARM. Work is continuing with Castle & Cooke on a battery back-up system for La Ola, a 1.2 MW photovoltaic facility providing power on Lanai.

Representative of major planned renewable projects as of February 2011.

energy efficiency and conservation. Decoupling also allows more timely recovery of our company's investments and operating costs.

What are our utilities doing to prepare their grids for this clean energy future?

A strong, reliable grid is essential to meeting our clean energy goals. We are committed to developing a grid better able to integrate renewable energy resources, improve reliability and give customers more options and more control over their energy usage.

To do this, we are undertaking a strategic, multi-year approach to modernizing our systems. We believe it's better to make improvements, retire old equipment and install new technologies before problems occur. Using the latest techniques allows us to make improvements that will provide better service and help manage future operating costs. Wherever it makes sense, we are upgrading our technology, incorporating smart computerized controls and protective devices that will make our system stronger and better prepared for the future.

KEAHOLE SOLAR POWER. Sopogy's 500 KW micro-concentrating solar power farm uses a unique energy storage buffer to produce power even when it's cloudy.

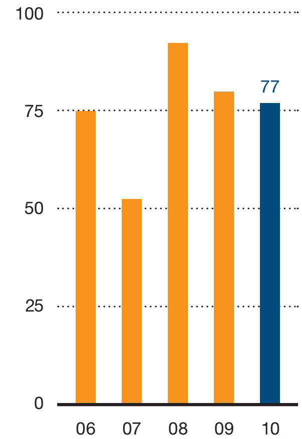
PUNA GEOTHERMAL VENTURES. A new power purchase agreement will result in expanding the 30 MW plant to provide an additional 8 MW of power.

FEED-IN TARIFF. A new feed-in tariff offers standard rates, contract terms and specifications for renewable energy developers. The FIT is planned to add up to 60 MW from a variety of renewable sources to utility grids on Oahu, 10 MW in Maui County and 10 MW on Hawaii Island.

SUPPORT FOR ELECTRIC VEHICLES. The PUC approved Electric Vehicle (EV) pilot charging rates, which offer special off-peak rates to encourage EV adoption.

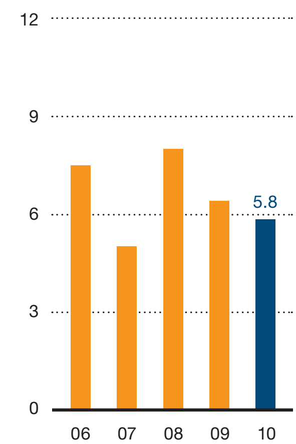
Net Income

(millions of dollars)



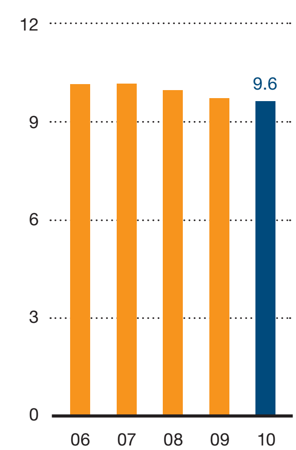
Return on Average Common Equity

(percent)



Kilowatthour Sales

(billions)



How American Savings Bank will get *there.*

Focusing on the needs of our customers and communities. Building on

our achievements.

American Savings Bank is Hawaii's community bank, committed to helping our individual and business customers achieve their financial goals. Through the hard work of our management and employees, the bank is now also a high-performer for shareholders with financial results that compare favorably with high-performing peers across the country. The bank will build on its sound financial health and prudent risk management to grow as the economy improves.

How did American Savings Bank achieve such dramatic performance improvement?

2010 was the culmination of our successful multi-year Performance Improvement Project (PIP) that delivered clear customer and financial benefits.

- Our 2008 balance sheet restructuring reduced our exposure to riskier non-core wholesale assets and liabilities, bringing us back to our core local banking business.
- With that clear focus, we reduced non-interest expenses to 2002 levels by streamlining our operations, real estate, and staffing. We reinforced a strong expense management culture and invested in our future by converting to an improved core information technology system.
- We improved our competitive position by offering the most convenient banking hours in the state and customer-friendly products such as our ASB Free Checking and Equity Express home equity loan programs.
- With lower funding and operating costs combined with an improved risk profile, the bank delivered a strong 1.2% Return on Assets in 2010.
- Over the past three years, these improvements allowed the bank to generate over $220 million in dividends to HEI while maintaining strong capital ratios for the future.

Why did American Savings Bank perform so well through the economic downturn?

ASB's risk management culture and our focus on the Hawaii market, combined with our strong capital position, enabled us to weather the storm better than many of our mainland peers. Sound underwriting standards have helped us maintain the good overall quality of our loan portfolio. Our focus on our Hawaii customers benefited us as well, as the downturn here has not been as severe as in other parts of the nation. We remain strongly capitalized and have never required private or government bailouts of any kind.

How is the heightened regulatory environment affecting American Savings Bank?

Our management believes that good regulatory compliance goes hand-in-hand with good business management. Our employees work hard every day to meet high standards of compliance and ethics. The regulatory environment is changing constantly, so we train our staff continuously and have dedicated teams ensuring we keep the bank compliant.

We have seen significant financial impacts from recent government directives, such as a federal regulatory change affecting the way banks can charge overdraft fees. More regulatory directives are under evaluation that could affect other income sources or drive higher overhead costs. The bank will need to flexibly adapt to ensure we are achieving the proper returns for the shareholder capital we have been entrusted to manage.

How is American Savings Bank contributing to the growth of the Hawaii economy?

ASB continues to offer competitive corporate, middle-market, and small business loans and credit lines; cash management products; and other financial services to help Hawaii businesses grow and prosper.

We leverage U.S. Small Business Administration (SBA) loan programs designed to help small and start-up businesses. In fact, in 2010, HEDCO—a Hawaii non-profit organization certified and licensed by the SBA to administer its 504 Loan Program—recognized ASB as "Lender of the Year"[1]. We had the distinction of booking the largest loan in HEDCO's 20-year history, a $4 million debenture to a local business.

American Savings Bank's customer focus, convenient hours, and corporate culture earn positive endorsements from businesses, consumers, and employees.

ASB is proud to provide best-in-class customer service, market-leading products, the most convenient banking hours, and one of the largest branch networks in the state. We are committed to making ASB a fun and rewarding place to work. We were honored to be selected for the following awards from our local communities.

- **Hawaii's Best Bank or Credit Union**
  Honolulu Star-Advertiser Hawaii's Best 2010 People's Choice Awards
- **2010 Lender of the Year**[1]
  HEDCO, a Hawaii non-profit organization certified and licensed by the SBA to administer its 504 Loan Program
- **2010 "Psychologically Healthy Workplace Award" in large business category**
  Hawaii Psychological Association
- **One of 2010's "Best Places to Work" in Hawaii**
  Hawaii Business Magazine

Star-Advertiser Hawaii's Best 2010 People's Choice Awards FIRST PLACE

Hawaii Business magazine Best Places to Work 2010

(1) In Category II SBA 504

How is the bank incorporating new technology into its operations?

In 2010, we successfully converted to a new core operating system, which is expected to provide approximately $6 million in annual cost savings while providing customers with upgraded online banking and improved branch processes. Technology continues to move quickly, and ASB will be a leader in incorporating proven technologies that bring convenience and security to our customers and lower costs for the bank.

Why do customers trust the bank with their information?

We work hard to earn the trust of our customers every day. Protecting our customer information is one of our top priorities and we are committed to complying with all applicable state and federal laws.

Customers can trust that any personal information provided to ASB is safe and secure. We use multi-layered security applications to detect possible threats to our information systems. In addition, we provide all employees with security training that includes identity theft detection and prevention.

What makes American Savings Bank one of the "Best Places to Work" in Hawaii?

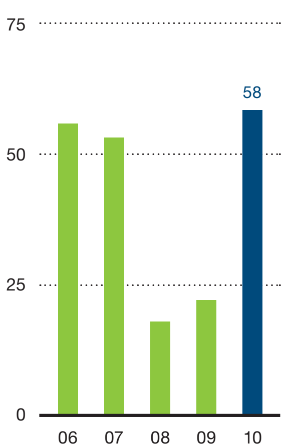
Our corporate culture values trust, open communication, community involvement, hard work, and – importantly – having fun at work. Our executives have an open door policy for employees to share feedback and multiple channels for communicating their ideas, including our online "Idea Bank". Employee feedback produced new programs such as "ASB LifeBalance", a comprehensive wellness program that includes financial and lifestyle seminars as well as fitness courses. Additionally, we implemented a host of ideas generated by our Employee Excellence Council, a representative group of employees who have direct input on employee matters and benefits planning.

ASB core values also include being involved in our communities. Through our Seeds of Service program, our teams volunteer their time and energy to support good causes and organizations that are important to our employees and customers.

We are proud that our employees selected us as one of the "Best Places to Work" in Hawaii as published by *Hawaii Business Magazine.*

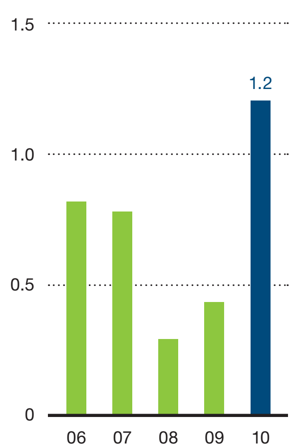
Net Income [1, 2]

(millions of dollars)



Return on Assets* [1, 2]

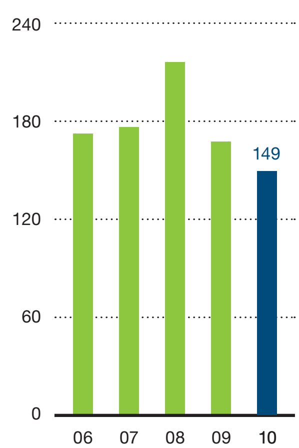
(percent)



* Net income for common stock divided by average total assets

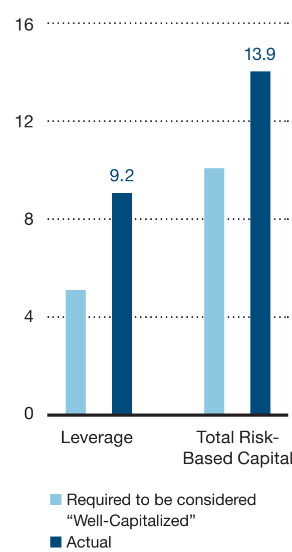
Noninterest Expense [2]

(millions of dollars)



Regulatory Capital at 12/31/10

(percent)



[1] 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 and return on assets, adjusted to exclude the PMRS losses, were $41 million and 0.80 percent, respectively.

[2] 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, return on assets, and noninterest expense, adjusted to exclude the balance sheet restructuring charge, was $53 million, 0.88 percent and $176 million, respectively.

Helping our communities get *there.*

Partnering to make Hawaii a better place to live

American Diabetes Association Walk

An ocean of trademark employee yellow and blue t-shirts flooded the 11th annual American Diabetes Association Step Out Walk to Fight Diabetes. More than 700 HEI, Hawaiian Electric, Maui Electric and Hawaii Electric Light Company employees, retirees, family members and friends traversed the 2.3 mile course around Kapiolani Park. Together they raised $140,000 for diabetes research, prevention, and education in Hawaii.

First Lego League

Kids ages 9 to 14 applied science and math to build solutions and solve problems at the Hilo First Lego League tournament. Sixteen teams from Big Island elementary and intermediate schools competed at the event sponsored by Hawaii Electric Light Company. Volunteers from the company assisted with the tournament, which introduces students to the fun and excitement of science and technology while building self-confidence, knowledge and life skills.

Maui Keiki Tilapia Fishing Tournament

Maui Electric sponsored the 2nd annual Keiki Tilapia Fishing Tournament at the Kaanapali Golf Resort. More than 600 kids ages 2 to 18 competed for prizes for the biggest and smallest catch. But the big winner was the Maui United Way, which benefitted from funds raised at the event.

Through the contributions of employee time, talent, and resources, our HEI family of companies is an integral part of the communities we serve. In 2010, the HEI companies and charitable foundation contributed over $2.6 million to organizations that help Hawaii's communities.

Seeds of Service 5th Anniversary

As part of the bank's Seeds of Service volunteerism program, ASB employees helped to pack boxes of food for needy families at the Hawaii Foodbank. This year marked Seeds of Service's 5th anniversary. Since the program's inception, ASB employees have donated over 9,500 hours of "sweat equity" to their local communities.

Supporting Affordable Housing

In 2010, ASB committed $9.5 million in equity to low-income housing tax credit projects throughout Hawaii. ASB's efforts helped provide approximately 300 new, affordable rental housing units for senior citizens and low-income families in the following projects:

- Franciscan Vistas Ewa in Ewa Beach, Oahu
- Hale Wai Vista in Waianae, Oahu
- Hale Mahaolu Ehiku II in Kihei, Maui

Bank for Education

ASB awarded over $372,000 of unrestricted funds to Hawaii schools through our Bank for Education program. The campaign promoted ASB's consumer checking and home equity line of credit products while helping our communities raise funds for public and private schools.

Executive Management

Hawaiian Electric Industries, Inc.

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

Chairman,
Hawaiian Electric Company, Inc.

Chairman,
American Savings Bank, F.S.B.

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

Chet 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

Colton K. Ching
Vice President
System Operation and Planning

Ronald R. Cox
Vice President
Generation and Fuels

Darcy L. Endo-Omoto
Vice President
Government and Community Affairs

Dan V. Giovanni
Vice President
Energy Delivery

American Savings Bank, F.S.B.

Susan A. Li
Vice President
General Counsel

Scott W. H. Seu
Vice President
Energy Resources

Thomas C. Simmons
Vice President
Power Supply

Lynne T. Unemori
Vice President
Corporate Relations

David G. Waller
Vice President
Customer Service

Richard F. Wacker
President and Chief Executive Officer

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 December 31, 2010.

Pictured this spread from left to right: Richard C. Robel, Darcy L. Endo-Omoto, Ray G. Skinner, Patricia U. Wong, Jay M. Ignacio, Lynne T. Unemori, Edward L. Reinhardt, James A. Ajello, Chet A. Richardson, Richard F. Wacker, Constance H. Lau, Richard M. Rosenblum, Ronald R. Cox, Gabriel S. H. Lee, Natalie M. H. Taniguchi, Colton K. Ching, Stephen M. McMenamin, Thomas C. Simmons, Tayne S. Y. Sekimura, David G. Waller, Robert A. Alm, Scott W. H. Seu, Terence C. Y. Yeh, Dan V. Giovanni, Susan A. Li, Alvin N. Sakamoto, K. Elizabeth Whitehead.

Board of Directors

Above from left to right, Row 1 (seated): Timothy E. Johns, Kelvin H. Taketa, Constance H. Lau, Jeffrey N. Watanabe, Thomas B. Fargo, Barry K. Taniguchi.
Row 2 (standing): Bert A. Kobayashi, Jr., Don E. Carroll, Richard F. Wacker, Keith P. Russell, Louise K. Y. Ing, A. Maurice Myers, Jorge G. Camara, Peggy Y. Fowler, James K. Scott, David M. Nakada, Alan M. Oshima, Richard M. Rosenblum, Shirley J. Daniel, Victor H. Li, Bert A. Kobayashi, Sr.

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,
American Savings Bank, F.S.B.

Don E. Carroll (3)
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) (3, 4)
Operating Executive Board Member,
J.F. Lehman & Company

Former Commander of the
U.S. Pacific Command

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

A. Maurice Myers (3)
Chief Executive Officer and Owner,
Myers Equipment Leasing LLC

Retired Chairman, President and
Chief Executive Officer,
Waste Management, Inc.

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 (1, 2)
President and
Chief Executive Officer,
KTA Super Stores

HAWAIIAN ELECTRIC COMPANY DIRECTORS

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

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

Bert A. Kobayashi, Jr.
Managing Partner,
BlackSand Capital, LLC

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

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

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

AMERICAN SAVINGS BANK DIRECTORS

Jorge G. Camara, M.D.
Physician and Owner,
Camara Eye Clinic

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

Keith P. Russell
President,
Russell Financial, Inc.

Richard F. Wacker
President and Chief Executive Officer,
American Savings Bank, F.S.B.

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

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

Constance H. Lau, Chairman
Don E. Carroll
Shirley J. Daniel
Victor H. Li
James K. Scott
Barry K. Taniguchi
Jeffrey N. Watanabe

Committees of the Board of Directors:

(1) Executive
Jeffrey N. Watanabe, Chairman

(2) Audit
Barry K. Taniguchi, Chairman

(3) Compensation
Thomas B. Fargo, Chairman

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

Information as of December 31, 2010.

Hawaiian Electric Industries, Inc.

2010 Annual Report to Shareholders
Financial and Other Information

Hawaiian Electric Industries, Inc.
2010 Annual Report to Shareholders (Financial and Other Information)

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 or possible future actions are also forward-looking statements. Forward-looking statements are based on current expectations and projections about future events and are subject to risks, uncertainties and the accuracy of assumptions concerning HEI and its subsidiaries (collectively, the Company), the performance of the industries in which they do business and economic and market factors, among other things. These forward-looking statements are not guarantees of future performance.

Risks, uncertainties and other important factors that could cause actual results to differ materially from those 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;
- 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 Afghanistan, potential conflict or crisis with North Korea or in the Middle East;
- the timing and extent of changes in interest rates and the shape of the yield curve;
- the ability of the Company to access credit markets to obtain commercial paper and other short-term and long-term debt financing (including lines of credit) and to access capital markets to issue HEI common stock under volatile and challenging market conditions, and the cost of such financings, if available;
- the risks inherent in changes in the value of pension and other retirement plan assets and securities available for sale;
- changes in laws, regulations, market conditions and other factors that result in changes in assumptions used to calculate retirement benefits costs and funding requirements;
- the impact of the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010 (Dodd-Frank Act) and of the rules and regulations that the Dodd-Frank Act requires to be promulgated over the next several months;
- 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 (to bring power to Oahu from Lanai and/or Molokai), biofuels, environmental assessments and the impacts of implementation of the HCEI on future costs of electricity);
- capacity and supply constraints or difficulties, especially if generating units (utility-owned or IPP-owned) fail or measures such as demand-side management (DSM), distributed generation (DG), combined heat and power (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) or their competitors;
- federal, state, county and international governmental and regulatory actions, such as changes in laws, rules and regulations applicable to HEI, HECO, ASB and their subsidiaries (including changes in taxation, increases in capital requirements, regulatory changes resulting from the HCEI, environmental laws and regulations, the regulation of greenhouse gas emissions (GHG), healthcare reform, governmental fees and assessments (such as Federal Deposit Insurance Corporation assessments), and potential carbon "cap and trade" legislation that may fundamentally alter costs to produce electricity and accelerate the move to renewable generation);
- decisions by the PUC in rate cases and other proceedings (including the risks of delays in the timing of decisions, adverse changes in final decisions from interim decisions and the disallowance of project costs);
- decisions by the PUC and by other agencies and courts on land use, environmental and other permitting issues (such as required corrective actions and restrictions and penalties that may arise, such as with respect to environmental conditions or renewable portfolio standards (RPS));
- potential enforcement actions by the Office of Thrift Supervision (OTS) (or its regulatory successors, the Office of the Comptroller of the Currency and the Federal Reserve Board) and other governmental authorities (such as consent orders, required corrective actions, restrictions and penalties that may arise, for example, with respect to compliance deficiencies under existing or new banking and consumer protection laws and regulations or with respect to capital adequacy);
- ability to recover and earn on increasing costs and capital investments not covered by revenue adjustment mechanisms;
- the risks associated with the geographic concentration of HEI's businesses and ASB's loans, ASB's concentration in a single product type (first mortgages) and ASB's significant credit relationships (i.e., concentrations of large loans and/or credit lines with certain customers);
- changes in accounting principles applicable to HEI, HECO, ASB and their subsidiaries, including the adoption of International Financial Reporting Standards or new U.S. accounting standards, the potential discontinuance of regulatory accounting and the effects of potentially required consolidation of variable interest entities (VIEs) or required capital lease accounting for PPAs with IPPs;
- changes by securities rating agencies in their ratings of the securities of HEI and HECO and the results of financing efforts;
- faster than expected loan prepayments that can cause an acceleration of the amortization of premiums on loans and investments and the impairment of mortgage servicing assets of ASB;
- changes in ASB's loan portfolio credit profile and asset quality which may increase or decrease the required level of allowance for loan losses and charge-offs;
- changes in ASB's deposit cost or mix which may have an adverse impact on ASB's cost of funds;
- the final outcome of tax positions taken by HEI, HECO, ASB and their subsidiaries;
- the risks of suffering losses and incurring liabilities that are uninsured or underinsured; and
- other risks or uncertainties described elsewhere in this report and in other reports previously and subsequently filed by HEI and/or HECO with the Securities and Exchange Commission (SEC) (e.g., under "Item 1A. Risk Factors" in the Company's Annual Report on Form 10-K).

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	2010	2009	2008	2007	2006
(dollars in thousands, except per share amounts)					
Results of operations					
Revenues	$ 2,664,982	$ 2,309,590	$ 3,218,920	$ 2,536,418	$ 2,460,904
Net income for common stock	$ 113,535	$ 83,011	$ 90,278	$ 84,779	$ 108,001
Basic earnings per common share	$ 1.22	$ 0.91	$ 1.07	$ 1.03	$ 1.33
Diluted earnings per common share	$ 1.21	$ 0.91	$ 1.07	$ 1.03	$ 1.33
Return on average common equity	7.8%	5.9%	6.8%	7.2%	9.3%
Financial position *					
Total assets	$ 9,085,344	$ 8,925,002	$ 9,295,082	$ 10,293,916	$ 9,891,209
Deposit liabilities	3,975,372	4,058,760	4,180,175	4,347,260	4,575,548
Other bank borrowings	237,319	297,628	680,973	1,810,669	1,568,585
Long-term debt, net	1,364,942	1,364,815	1,211,501	1,242,099	1,133,185
Preferred stock of subsidiaries –					
not subject to mandatory redemption	34,293	34,293	34,293	34,293	34,293
Common stock equity	1,483,637	1,441,648	1,389,454	1,275,427	1,095,240
Common stock					
Book value per common share *	$ 15.67	$ 15.58	$ 15.35	$ 15.29	$ 13.44
Market price per common share					
High	24.99	22.73	29.75	27.49	28.94
Low	18.63	12.09	20.95	20.25	25.69
December 31	22.79	20.90	22.14	22.77	27.15
Dividends per common share	1.24	1.24	1.24	1.24	1.24
Dividend payout ratio	102%	137%	116%	120%	93%
Market price to book value per common share *	145%	134%	144%	149%	202%
Price earnings ratio **	18.7x	23.0x	20.7x	22.1x	20.4x
Common shares outstanding (thousands) *	94,691	92,521	90,516	83,432	81,461
Weighted-average	93,421	91,396	84,631	82,215	81,145
Shareholders ***	32,624	33,302	33,588	34,281	35,021
Employees *	3,427	3,453	3,560	3,520	3,447

* At December 31.

** Calculated using December 31 market price per common share divided by basic earnings per common share. 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 10, 2011, HEI had 32,542 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 2010, 2009, 2008, 2007 and 2006, under the two-class method of computing basic earnings per share, distributed earnings were $1.24 per share each year and undistributed earnings (loss) were $(0.02), $(0.33), $(0.17), $(0.21) and $0.09 per share, respectively, for both unvested restricted stock awards and unrestricted common stock. For 2010, 2009, 2008, 2007 and 2006, under the two-class method of computing diluted earnings per share, distributed earnings were $1.24 per share each year and undistributed earnings (loss) were $(0.03), $(0.33), $(0.17), $(0.21) and $0.09 per share, respectively, for both unvested restricted stock awards and unrestricted common stock.

Supplementary financial information is provided in Note 16 of HEI's "Notes to Consolidated Financial Statements."

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.

In 2010, net income for HEI common stock was $114 million, compared to $83 million in 2009. Basic earnings per share were $1.22 per share in 2010, up 34% from $0.91 per share in 2009 due to higher earnings for the bank segment, partly offset by slightly lower earnings at the electric utility segment and higher losses for the "other" segment and the effects of the higher weighted average number of shares outstanding.

Electric utility net income for common stock in 2010 of $76.6 million decreased 4% from the prior year due primarily to lower kilowatthour (KWH) sales and higher other operation and maintenance (O&M) and depreciation expenses, partly offset by higher rate relief and interest income due to a federal tax settlement. Key to results for 2011 will be the impacts of actions taken under the Hawaii Clean Energy Initiative (HCEI) and Energy Agreement, 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 implementing a new regulatory rate-making model that decouples revenues from KWH sales.

ASB's earnings in 2010 of $58.5 million increased $36.7 million over prior year net income and included a $12.6 million net charge for provision for loan losses. Net income for 2009 reflected a $19.3 million after-tax 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. In 2010, management focused on increasing revenues and reducing costs through ASB's performance improvement project, which has been completed. ASB's future financial results will continue to be impacted by the interest rate environment, the quality of ASB's loan portfolio, and the ongoing results of the performance improvement project.

HEI's "other" segment had a net loss in 2010 of $21.5 million, compared to a net loss of $18.2 million in 2009. HEI's consolidated effective tax rate was 37% in 2010 compared to 34% in 2009. In 2010, HEI recognized $2 million in tax expense for the write-off of a deferred tax asset due to the expiration of capital loss carryforwards.

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, 2010 was 5.4%. The dividend payout ratios based on net income for common stock for 2010, 2009 and 2008 were 102%, 137% and 116%, 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 from public third-party sources (e.g., Department of Business, Economic Development and Tourism; University of Hawaii Economic Research Organization (UHERO); U.S. Bureau of Labor Statistics; Blue Chip Economic Indicators; Blue Chip Financial Forecasts; Hawaii Tourism Authority; Honolulu Board of REALTORS®; and national and local newspapers).

The U.S. economy, as measured by gross domestic product (GDP), grew 2.6% in the third quarter of 2010, with the "advance" estimate of fourth quarter growth at 3.2%. According to the February 2011 Blue Chip Economic Indicators, GDP growth is estimated to be 3.5% in the first quarter of 2011. 2010 annual growth was 2.9%, an improvement over the 2.6% contraction in 2009. The outlook for 2011 has improved, with growth now projected at 3.2% in 2011 compared to 2.6% growth in the December 2010 Blue Chip consensus forecast. The more positive outlook reflects increased consumer spending and gains in the manufacturing and service sectors, which suggest that the economy may be starting a transition from recovery to expansion.

Economic growth has not yet translated into job growth. The U.S. unemployment rate was 9.4% in December 2010, down from 9.8% in November 2010. Since December 2009, total payroll employment has increased by 1.1 million, averaging a very low 94,000 jobs per month. Although 2010 was the best year for job growth since 2007, the growth remains small relative to the 8.5 million jobs lost since the Great Recession began. The February 2011 Blue Chip consensus is for the unemployment rate to average 9.3% in 2011.

Japan's economic growth was a strong 3.1% in 2010, but is forecast to decline to 1.5% in 2011 according to the government. Slower growth is expected due to the end of government stimulus measures and a decline in exports. Deflation is also expected to continue in 2011, but consumer prices should fall at a lower rate than in 2009 and 2010.

In 2010, the Hawaii economy benefited from economic growth in both the U.S. and Japan. UHERO projects that following a 0.1% contraction in 2009, Hawaii's economy (real GDP) grew by 1.1% in 2010 and will continue to expand by 2.7% in 2011.

The visitor industry has provided a much needed boost to Hawaii's economy. In 2010, total visitor arrivals were up 8.7% over 2009. Total visitor expenditures rose 16.2% in 2010 due to the increase in visitor arrivals as well as higher average daily visitor spending. In 2011, UHERO projects further growth with arrivals up 3.8%, with the growth moderated by challenging global economic conditions.

Hawaii's construction industry continued to struggle in 2010, but UHERO economists believe we are at the cycle's bottom. For the first eleven months of 2010, the value of total private building permits in the State of Hawaii declined by 0.8% from the same period in 2009 (permits for new residential construction and additions and alterations declined, but commercial and industrial permit values increased). Statewide, construction jobs were down 5.5% year-to-date in November 2010 compared to 2009, however, for the last two months there has been year-over-year growth. UHERO is forecasting that construction jobs will increase by 0.9% in 2011.

Hawaii's resale housing market in 2010 improved based on number of sales, but has struggled in terms of price. For the year 2010, Oahu single-family home resales were up 13.4% compared to 2009, with condominium resales up 10.3%. The median sales price for single-family homes was up 3.1% year-over-year, while the median sales price for condominiums remained flat. Similarly on Maui, Kauai and the island of Hawaii, residential and condominium sales volumes were up by double digit percentages in 2010 compared to 2009. However, median sale prices were down on all three islands with the exception of residential sales on Kauai. The neighbor island markets have been affected by the downturn more than Oahu due to a higher proportion of vacation home development and purchases during the last real estate boom.

In 2010, the Hawaii job market had not yet benefited from the positive trends in the visitor industry. Although job losses slowed from the 4.4% decline experienced in 2009, UHERO projects total payroll jobs will end 2010 down 0.5%, followed by an increase of 1.3% in 2011. Furloughs for county employees in all four counties were implemented for the fiscal year beginning July 1, 2010 and state employee furloughs, with the exception of teachers, continued. Hawaii's preliminary seasonally adjusted unemployment rate in December 2010 was 6.4%, which remains well below the national unemployment rate of 9.4% and is seventh lowest in the nation, but is much higher than the 4.1% rate experienced just two years ago. There is some reason for optimism, according to UHERO economists, "Gradual progress in the transition to a jobs recovery is confirmed by lower initial unemployment insurance claims in recent months."

Real personal income (which includes unemployment compensation) growth in Hawaii in 2010 is expected to be 0.3% according to UHERO's estimate, following two consecutive years of decline. The expectation is for growth of 2.3% in 2011 as the recovery in the visitor industry and resumption of job growth start to have an impact.

The price of a barrel of West Texas Intermediate crude oil averaged $79 in 2010 and $85 in the fourth quarter of 2010 according to the U.S. Energy Information Administration January 2011 Short-Term Energy Outlook. The forecast for 2011 is an average of $93 per barrel.

Interest rates during 2011 are expected to remain low, putting downward pressure on yields of loans and investments. Although still at historical lows, long-term rates increased during the fourth quarter of 2010, dampening the momentum gained in the housing market during previous quarters. Based on comments from the Federal Open Market Committee, the Fed will continue to support the current low rate environment until a broader recovery in the labor market and overall economy is realized, as long as core inflation levels remain reasonable.

With the recession over, Hawaii showed signs of positive economic activity in 2010, while one of the key indicators, job growth, continued to lag behind. The outlook for 2011 is for continued improvement and for the recovery to spread beyond just the visitor industry.

Major tax legislation in 2010. Congress enacted several bills in 2010 dealing with health care reform, job creation and economic stimulus. Two bills enacted in the latter half of the year contained major tax provisions directly affecting the Company. The first was the Small Business Jobs Act of 2010, which included the extension of 50% bonus depreciation for all businesses retroactive to January 1, 2010. The second was the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010. This legislation included the extension of the lower individual income tax rates on income, dividends and capital gains; the increase in the estate and gift tax exemption amounts; and a 2% reduction in Social Security tax on employees and self-employed individuals. Also, businesses received an extension of 50% bonus depreciation for property placed into service before January 1, 2013 and 100% bonus depreciation for property acquired between September 8, 2010 and January 1, 2012. For the Company, the bonus depreciation provisions resulted in an increase in federal tax depreciation of approximately $75 million for 2010, primarily attributable to HECO and its subsidiaries. The Company is still evaluating the impact of this additional bonus depreciation for 2011 since the transition rules related to the definition of property qualified for 100% bonus depreciation are still unclear. A number of energy-related tax breaks were also extended, including the biodiesel credit through 2012 and the grants in lieu of the electricity production credit through 2011.

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

Results of operations.

(dollars in millions, except per share amounts)	2010	% change	2009	% change	2008
Revenues	$ 2,665	15	$ 2,310	(28)	$ 3,219
Operating income	256	37	188	(8)	204
Net income for common stock	114	37	83	(8)	90
Electric utility	$ 77	(4)	$ 79	(14)	$ 92
Bank	58	169	22	22	18
Other	(21)	NM	(18)	NM	(20)
Net income for common stock	$ 114	37	$ 83	(8)	$ 90
Basic earnings per share	$ 1.22	34	$ 0.91	(15)	$ 1.07
Diluted earnings per share	$ 1.21	33	$ 0.91	(15)	$ 1.07
Dividends per share	$ 1.24	–	$ 1.24	–	$ 1.24
Weighted-average number of common shares outstanding (millions)	93.4	2	91.4	8	84.6
Dividend payout ratio	102%		137%		116%

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. During 2011, changes to the early retirement reduction factors are being phased in with regard to new retirement benefit accruals. The change is expected to decrease ongoing cost through a reduction in service cost. (See Note 9 of HEI’s “Notes to Consolidated Financial Statements” for a listing of plans that have been frozen in prior years. No other changes were made to the retirement benefit plans’ provisions in 2010, 2009 and 2008 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 2010, the Company’s retirement benefit plans’ assets generated a gain, net of investment management fees, of 16.6%, resulting in net earnings and unrealized gains of $145 million, compared to net earnings and unrealized gains of $186 million for 2009 and net losses and unrealized losses of $287 million for 2008. The market value of the retirement benefit plans’ assets as of December 31, 2010 was $983 million. See “Liquidity and Capital Resources” below for the Company’s cash contributions to the retirement benefit plans.

The Company expects that the minimum required contribution to the qualified retirement plans 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, 2010 will be as set forth below for plan years 2011 and 2012. 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. As of December 31, 2010, HECO's prepaid pension asset was $3 million, HELCO's was $2 million and MECO's had been eliminated. The "Cash funding requirement" in the following table considers the utilities' funding commitment (based on various assumptions described in Note 9 of HEI's "Notes to Consolidated Financial Statements").

(in millions)	2011	2012
Pension Protection Act minimum required contribution:		
(net of applied credit balances)		
Based on plan assets as of December 31, 2010		
Consolidated HECO	$85	$79
Consolidated HEI	$86	$80
Cash funding to satisfy the Pension Protection Act minimum required contribution:		
Based on plan assets as of December 31, 2010		
Consolidated HECO	$46	$116
Consolidated HEI	$47	$117

See Note 9 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 9 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)	2010	2009	(Estimated) 2011 [1]	2010	2009	2008	2010	2009	2008
Consolidated HEI	$(15)	$(12)	$24	$24	$21	$17	$64	$61	$59
Consolidated HECO	1	2	23	24	19	17	60	57	55
ASB	(10)	(10)	–	(1)	–	(1)	3	3	2

[1] 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, 2011).

The following table reflects the sensitivities of the projected benefit obligation (PBO) and accumulated postretirement benefit obligation (APBO) as of December 31, 2010, 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	$(72)/$80
Other benefits		
Discount rate	+/– 50	(10)/12
Health care cost trend rate	+/– 100	3/(3)

Baseline assumptions: 5.68% discount rate for pension benefits; 5.60% discount rate for other benefits; 8% asset return rate; 9% medical trend rate for 2011, grading down to 5% for 2019 and thereafter; 5% dental trend rate; and 4% vision trend rate.

The impact on 2011 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. See Note 9 of HEI's "Notes to Consolidated Financial Statements" for further retirement benefits information.

Other segment.

(dollars in millions)	2010	% change	2009	% change	2008
Revenues [1]	$ –	NM	$ –	NM	$ –
Operating income (loss)	(15)	NM	(14)	NM	(14)
Net loss	(22)	NM	(18)	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), 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 which provided windfarm operational and maintenance services to an affiliated electric utility until the windfarm was dismantled in the fourth quarter of 2010; HEI Properties, Inc. (HEIPI), a company holding passive, venture capital investments (venture capital investments valued at $1.3 million as of December 31, 2010); 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.

HEI corporate-level operating, general and administrative expenses were $13.3 million in 2010 compared to $12.7 million in each of 2009 and 2008. In 2010, expenses increased primarily due to higher compensation expense, partly offset by lower retirement benefit expense and an accrual in 2009 to dismantle a windfarm in 2010. In 2009, expenses decreased slightly from 2008 due to not funding the HEI Charitable Foundation and lower consulting fees, partly offset by the accrual to dismantle a windfarm.

The "other" segment's interest expenses were $20.0 million in 2010, $18.4 million in 2009 and $21.4 million in 2008. In 2010, financing costs were higher due to the higher level of borrowings and the recognition of the ineffective portion of the change in fair value of the forward starting swaps in 2010. 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.

Effects of inflation. U.S. inflation, as measured by the U.S. Consumer Price Index (CPI), averaged 1.6% in 2010, (0.4%) in 2009 and 3.8% in 2008. Hawaii inflation, as measured by the Honolulu CPI, was 0.5% in 2009 and 4.3% in 2008. The Department of Business, Economic Development and Tourism estimates average Honolulu CPI to have been 2.2% in 2010 and forecasts it to be 2.2% for 2011.

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. On March 23, 2010, the Affordable Care Act became law and mandated that employers provide medical coverage to all their employees. The Company provides health insurance benefits to their employees under the provisions of the Hawaii Prepaid Health Care Act. Thus, the financial impact of the Affordable Care Act is not expected to be significant to the Company. In January 2011, a bill was introduced, which, if implemented as written, would repeal the Affordable Care Act.

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, 2010		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]	$ 3,975	$3,745	$ 115	$ 100	$ 15
Other bank borrowings	237	137	–	–	100
Long-term debt	1,366	150	115	111	990
Interest on certificates of deposit, other bank borrowings and long-term debt	1,089	83	143	124	739
Operating leases, service bureau contract and maintenance agreements	108	20	33	24	31
Open purchase order obligations [2]	110	69	40	1	–
Fuel oil purchase obligations (estimate based on December 31, 2010 fuel oil prices)	3,335	967	1,715	653	–
Power purchase obligations–minimum fixed capacity charges	1,249	118	234	232	665
Liabilities for uncertain tax positions	12	–	10	2	–
Total (estimated)	$11,481	$5,289	$2,405	$1,247	$2,540

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, 2010	Total
(in millions)	
Other commercial commitments to ASB customers	
Loan commitments (primarily expiring in 2011)	$ 22
Loans in process	56
Unused lines and letters of credit	1,136
Total	$ 1,214

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 D&Os of the PUC. As of December 31, 2010, the fair value of the assets held in trusts to satisfy the obligations of the Company's retirement benefit plans did not exceed the retirement benefit 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 2011 and 2012.

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 $9.1 billion as of December 31, 2010 and $8.9 billion as of December 31, 2009.

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

December 31	2010		2009	
(dollars in millions)				
Short-term borrowings—other than bank	$ 25	1%	$ 42	2%
Long-term debt, net—other than bank	1,365	47	1,365	47
Preferred stock of subsidiaries	34	1	34	1
Common stock equity	1,484	51	1,442	50
	$2,908	100%	$2,883	100%

HEI’s short-term borrowings and HEI’s line of credit facility were as follows for the period and as of the dates indicated:

	Year ended December 31, 2010		
(in millions)	Average balance	End-of-period balance	December 31, 2009
Short-term borrowings [1]			
HEI commercial paper	$ 34	$ 25	$ 42
HEI line of credit draws	–	–	–
	$ 34	$ 25	$ 42
Line of credit facility (expiring May 7, 2013)		$125	$100
Undrawn capacity under HEI’s line of credit facility		125	100

[1] This table does not include HECO’s separate commercial paper issuances and line of credit facilities and draws, which are discussed below under “Electric utility—Financial Condition—Liquidity and capital resources. At February 10, 2011, HEI’s outstanding commercial paper balance was $26 million and its line of credit facility was undrawn. The maximum amount of HEI’s short-term borrowings in 2010 was $50 million.

HEI utilizes short-term debt, typically commercial paper, to support normal operations, to refinance commercial paper, to retire long-term debt, to pay dividends and for other temporary requirements. HEI also periodically makes short-term loans to HECO to meet HECO’s cash requirements, including the funding of loans by HECO to HELCO and MECO, but no such short-term loans to HECO were outstanding as of December 31, 2010. HEI periodically utilizes long-term debt, historically consisting of medium-term notes and other unsecured indebtedness, to fund investments in and loans to its subsidiaries to support their capital improvement or other requirements, to repay long-term and short-term indebtedness and for other corporate purposes.

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

The agreement contains provisions for revised pricing in the event of a ratings change. For example, a ratings downgrade of HEI’s Issuer Rating (e.g., from BBB/Baa2 to BBB-/Baa3 by Standard & Poor’s (S&P) and

Moody's Investors Service (Moody's), respectively) would result in a commitment fee increase of 5 basis points and an interest rate increase of 25 basis points on any drawn amounts. On the other hand, a ratings upgrade (e.g., from BBB/Baa2 to BBB+/Baa1 by S&P or Moody's, respectively) would result in a commitment fee decrease of 10 basis points and an interest rate decrease of 25 basis points on any drawn amounts. The agreement contains customary conditions which must be met in order to draw on it, including compliance with its covenants (such as covenants preventing its subsidiaries from entering into agreements that restrict the ability of the subsidiaries to pay dividends to, or to repay borrowings from, HEI). In addition to customary defaults, HEI's failure to maintain its financial ratios, as defined in its agreement, or meet other requirements may result in an event of default. For example, under its agreement, it is an event of default if HEI fails to maintain a nonconsolidated "Capitalization Ratio" (funded debt) of 50% or less (actual ratio of 18% as of December 31, 2010, as calculated under the agreement) and "Consolidated Net Worth" of at least $975 million (actual Net Worth of $1.5 billion as of December 31, 2010, as calculated under the agreement).

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

As of February 10, 2011, the S&P and Moody's ratings of HEI securities were as follows:

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

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

Management believes that, if HEI's commercial paper ratings were to be downgraded, or if credit markets for commercial paper with HEI's ratings or in general were to tighten, it would be difficult and expensive for HEI to sell commercial paper or HEI might not be able to sell commercial paper in the future. Such limitations could cause HEI to draw on its syndicated credit facility instead, and the costs of such borrowings could increase under the terms of the credit agreement as a result of any such ratings downgrades. Similarly, if HEI's long-term debt ratings were to be downgraded, it would be difficult and more expensive for HEI to issue long-term debt. Such limitations and/or increased costs could materially adversely affect the results of operations, financial condition and cash flows of HEI and its subsidiaries.

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

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), Hawaiian Electric Industries Retirement Savings Plan (HEIRSP) and the ASB 401(k) Plan have been important sources of capital for HEI. Issuances of common stock through DRIP, HEIRSP and the ASB 401(k) Plan (which was split off from HEIRSP in 2009) provided new capital of $43 million (approximately 1.9 million shares) in 2010 and $43 million (approximately 1.8 million shares) in 2008. From January 1, 2009 through April 15, 2009, issuances of common stock through these plans increased significantly, with HEI raising $14 million of new capital through the issuance of approximately 1.0 million shares for these plans during this period. HEI ceased new issuances of stock through DRIP and HEIRSP effective April 16, 2009 and began satisfying the HEI common stock requirements of DRIP and HEIRSP (and the ASB 401(k) Plan upon its inception on May 7, 2009) through open market purchases. On September 4, 2009, HEI resumed satisfying the HEI common stock requirements of DRIP, HEIRSP and the ASB 401(k) Plan through new issuances of 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 $341 million in 2010, $284 million in 2009 and $260 million in 2008. Investing activities provided (used) net cash of $(279) million in 2010, $442 million in 2009 and $1.1 billion in 2008. In 2010, net cash used in investing activities was primarily due to purchases of investment and mortgage-related securities and HECO's consolidated capital expenditures (net of contributions in aid of construction), partly offset by repayments of investment and mortgage-related securities and a net decrease in loans held for investment. Financing activities used net cash of $235 million in 2010, $406 million in 2009, and $1.4 billion in 2008. In 2010, net cash used in financing activities included net decreases in short-term borrowings, 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.

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% (actual ratio of 55% at December 31, 2010), 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 13 of HEI's "Notes to Consolidated Financial Statements."

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

As further explained in “Retirement benefits” above and Notes 1 and 9 of HEI’s “Notes to Consolidated Financial Statements,” the Company maintains pension and other postretirement benefit plans. The Company was required to make contributions of $19.1 million for 2010, but was not required to make any contributions for 2009 and 2008 to the qualified pension plans to meet minimum funding requirements pursuant to ERISA, including changes promulgated by the Pension Protection Act of 2006. The Company made voluntary contributions in 2010, 2009 and 2008. Contributions to the retirement benefit plans totaled $32 million in 2010 (comprised of $31 million by the utilities, $1 million by HEI and nil by ASB), $25 million in 2009 and $15 million in 2008 and are expected to total $64 million in 2011 ($63 million by the utilities, $1 million by HEI and nil by ASB). In addition, the Company paid directly $2 million of benefits in 2010 and $1 million of benefits in each of 2009 and 2008 and expects to pay $2 million of benefits in 2011. 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 cash flow or 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., Afghanistan war) 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 in recent years led to declines in KWH sales, delinquencies in ASB's loan portfolio and other adverse effects on HEI's businesses. GDP declined by 2.6% in 2009, but grew by 2.9% in 2010.

If S&P or Moody's were to further 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 9 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 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. However, with the fourth quarter 2009 sale of ASB's remaining private-issue mortgage-related securities portfolio and substantial residential loan production in 2009 and 2010, 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. HECO, HELCO and MECO's transmission and distribution systems (excluding 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, financial condition and cash flows could be materially adversely impacted. 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 an insurance 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, financial condition and cash flows.

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; 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 9 of HEI's "Notes to Consolidated Financial Statements."

Contingencies and litigation. The Company is subject to proceedings, lawsuits and other claims. 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 "Income taxes" in Notes 1 and 11 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 (including the use of biofuels) and taking the necessary steps to secure regulatory support for their plans.

Reliability projects remain a priority for HECO and its subsidiaries. HECO has completed construction of a new generating unit designed to operate using biodiesel fuel, has completed the first phase and is currently constructing the remaining phase of the East Oahu Transmission Project (EOTP)—a needed alternative route to move power from the west side of Oahu to load centers on the east side—and is working with the State and U.S. Department of Energy on an undersea cable system to interconnect proposed independent power producer (IPP) wind farms on the islands of Lanai and Molokai with the Oahu grid.

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 offering them specialized services and energy efficiency audits to help them save on energy costs is critical to long-term success.

Hawaii Clean Energy Initiative. 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 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. See "Hawaii Clean Energy Initiative" in Note 3 of HEI's "Notes to Consolidated Financial Statements."

Decoupling. Decoupling is a new method of setting electric rates that is designed to support Hawaii's efforts to reduce its dependence on imported oil. In December 2010, the PUC allowed HECO to implement decoupling, which removes the link between electricity usage and utility revenues. This aligns the utility with public policy to promote energy efficiency and conservation. Customers will still have an incentive to conserve energy because their bills continue to be based on how much electricity they use. Decoupling also allows the utility to recover on a more timely basis the investments and costs to further support reliability and clean energy. See "Decoupling proceeding" below.

Renewable energy strategy. The electric utilities have been taking actions intended to protect Hawaii's island ecology and reduce greenhouse gas (GHG) emissions, while continuing to provide reliable power to customers, and committed to a number of related actions in the Energy Agreement. A three-pronged strategy supports attainment of the requirements and goals of the State of Hawaii Renewable Portfolio Standards (RPS), the Hawaii Global Warming Solutions Act of 2007 and the HCEI by: (1) the "greening" of existing assets, (2) the expansion of renewable energy generation and (3) the acceleration of energy efficiency and load management programs. Major initiatives are being pursued in each category.

In 2009, Hawaii's RPS law was amended to require electric utilities to meet an RPS of 10%, 15%, 25% and 40% by December 31, 2010, 2015, 2020 and 2030, respectively. For the eleven months ended November 30, 2010, HECO's consolidated RPS was 16.2%, including electrical energy savings. Accordingly, the utilities are expected to meet the 2010 RPS. 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. Demand-side management (DSM) programs contributed significantly to achieving the 16.2% RPS level and, without including the DSM energy savings, the RPS would have been 9.1%. Energy savings resulting from energy efficiency programs will not count toward the RPS after 2014.

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

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

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

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

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

In 2008, HECO issued an Oahu Renewable Energy Request for Proposals (2008 RFP) for combined renewable energy projects up to 100 MW. HECO is currently negotiating PPAs with the bidders in the Award Group—a proposed wind project (70 MW) and a proposed solar project (5 MW).

Included in the bids received in response to the 2008 RFP were proposals for two large scale neighbor island wind projects that would produce energy to be imported from Lanai and Molokai to Oahu via a yet-to-be-built undersea transmission cable system (Interisland Wind projects). In accordance with the Energy Agreement, the proposals for the Interisland Wind Projects were bifurcated from the Oahu Renewable Energy RFP for separate negotiation. Subsequently, HECO received a PUC waiver from the competitive bidding framework for the two non-conforming proposals and negotiations are ongoing.

In September 2010 and January 2011, MECO executed PPAs with Kaheawa Wind Power II, LLC and Auwahi Wind Energy, LLC, respectively, for the purchase of 21 MW (each) of as available wind energy. The PPA with Auwahi Wind Energy, LLC is subject to PUC approval. In January 2011, MECO requested that the PUC open a docket for MECO's plans to acquire up to 50 MW of renewable, firm dispatchable capacity generation resources on Maui, with the initial increment coming on line in 2015.

On September 30, 2010, the PUC approved the electric utilities' proposed Electric Vehicle (EV) Charging Time of Use Pilot Rates, which are now available to 1,000 HECO, 300 HELCO and 300 MECO customers for charging highway-capable, four-wheeled EVs. The EV Pilot Rates will remain in effect for three years and are designed to encourage early adoption of EVs and incentivize customers to charge EVs during off-peak times of the day.

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

Results of operations.

(dollars in millions, except per barrel amounts)	2010	% change	2009	% change	2008
Revenues [1]	$ 2,382	17	$ 2,035	(29)	$ 2,860
Expenses					
Fuel oil	900	34	672	(45)	1,229
Purchased power	549	10	500	(28)	690
Other	755	9	694	(8)	750
Operating income	178	5	170	(11)	191
Allowance for funds used during construction	9	(51)	17	33	13
Net income for common stock	77	(4)	79	(14)	92
Return on average common equity	5.8%		6.4%		8.0%
Average fuel oil cost per barrel [1]	$ 87.62	37	$ 63.91	(44)	$ 114.50
Kilowatthour sales (millions)	9,579	(1)	9,690	(2)	9,936
Cooling degree days (Oahu)	4,661	(3)	4,815	(3)	4,943
Number of employees (at December 31)	2,318	1	2,297	4	2,203

[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 $77 million in 2010 compared to $79 million in 2009. The net income decrease in 2010 compared to 2009 was primarily due to higher O&M spending (excluding DSM program expenses) to maintain system reliability, lower KWH sales and lower allowance for funds used during construction (AFUDC), partly offset by higher interim rate increases that became effective for HECO (test year 2009) in August 2009 and February 2010 and for MECO (test year 2010) in August 2010 and $6 million of interest income, net of taxes, due to a federal tax settlement.

In 2010, the electric utilities' revenues increased by 17%, or $347 million, from 2009 primarily due to higher fuel prices ($326 million), interim rate relief granted by the PUC to HECO for its 2009 test year ($43 million) and interim rate relief granted by the PUC to MECO for its 2010 test year ($4 million) (see "Most recent rate requests" below), partly offset by the impact of lower KWH sales ($22 million) and lower DSM program recovery revenues ($20 million) (see "Demand-side management programs" below). KWH sales were 1.1% lower when compared to 2009 due largely to cooler, less humid weather and continued conservation efforts by customers.

Operating income in 2010 was $9 million higher than in 2009 due primarily to the interim rate relief for HECO and MECO, partly offset by the impact of lower KWH sales, higher other expenses, including higher O&M expenses and higher depreciation expense.

Fuel oil expense in 2010 increased by 34% due primarily to higher fuel costs, partly offset by lower KWHs generated and improved operating unit efficiency. Purchased power expenses in 2010 increased by 10% due primarily to higher purchased energy costs, partly offset by lower KWHs purchased. Higher fuel costs are generally passed on to customers.

Other expenses increased 9% ($61 million) (12% and $78 million excluding DSM expenses) in 2010 due primarily to increases of 16% ($30 million) in taxes, other than income taxes, primarily due to the increase in revenues, 6% ($22 million) in other O&M expenses and 4% ($5 million) in depreciation expenses due to 2009 plant additions. "Other operation" expenses increased by $3 million in 2010 when compared to 2009 due primarily to higher administrative and general expenses ($17 million) including higher employee benefits expense due to higher retirement benefit expense ($7 million) and higher production and transmission and distribution expense ($6 million) to maintain reliable operations, offset in part by lower DSM ($17 million) and bad debt expenses ($5 million). Maintenance expense increased $20 million from 2009 due primarily to increased production maintenance expenses ($13 million), including generating unit overhauls ($9 million), full year operation of CT-1 ($2 million), increased maintenance on boiler plant equipment ($2 million) and higher transmission and distribution expenses ($7 million) due to increased levels of work to address aging infrastructure.

- 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 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), partly offset by interim rate relief granted by the PUC to HECO for its 2009 test year ($26 million). 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.

Operating income in 2009 was $22 million lower than in 2008 due primarily to lower KWH sales, higher other expenses, including higher O&M 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 (6% excluding DSM expenses) 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 ($12 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.

- O&M expenses (excluding DSM program costs) for the year 2011 are expected to be approximately 7% higher than 2010 as the electric utilities expect higher production expenses and higher contract services. Transmission and distribution expenses are expected to increase consistent with the new asset management initiatives to modernize the infrastructure. Also, additional expenses are expected for the costs to operate and maintain CIP CT-1, and are expected to be incurred for environmental compliance in response to existing compliance programs as well as numerous new, more stringent regulatory requirements, and to execute the provisions of the Energy Agreement. HCEI-related initiatives appear to be progressing at a pace to achieve the state’s clean energy goals under the HCEI.

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

ROACEs of 10.0% (reflects implementation of decoupling), 10.7% (without decoupling) and 10.7% (without decoupling) were found to be reasonable by the PUC in the most recent final rate decisions issued in December 2010, October 2010 and July 2010 in HECO, HELCO and MECO rate cases based on 2009, 2006 and 2007 test years, respectively. The ROACE used by the PUC for the purposes of the most recent interim rate increases issued in November 2010 and July 2010 in HELCO and MECO rate cases, respectively, based on 2010 test years was 10.5% (without decoupling).

For 2010, the actual ROACEs (calculated under the rate-making method, which excludes the effects of items not included in determining electric utility rates, and reported to the PUC) for HECO, HELCO and MECO were 6.15%, 6.24% and 3.90%, respectively. The utilities’ actual ROACEs were lower than their final and interim D&O ROACEs primarily due to lower KWH sales than the sales used to determine the interim rates and increased O&M expenses.

The RORBs found to be reasonable by the PUC in the most recent final rate decisions were 8.16% for HECO, 8.33% for HELCO and 8.67% for MECO (final D&Os noted above). The RORBs used by the PUC for purposes of the most recent interim increases were 8.59% for HELCO and 8.43% for MECO (interim D&Os noted above). For 2010, the actual RORBs (calculated under the rate-making method, which excludes the effects of items not included in determining electric utility rates, and reported to the PUC) for HECO, HELCO and MECO were 5.93%, 5.86% and 4.86%, respectively.

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

HECO.

2007 test year rate case. On December 22, 2006, HECO filed a request for a general rate increase of $99.6 million, or 7.1% over the electric rates then in effect, based on a 2007 test year, an 11.25% ROACE and an 8.92% RORB on a $1.214 billion average rate base. HECO'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.

On September 6, 2007, HECO, the Consumer Advocate and the federal Department of Defense (DOD) (collectively, the parties) executed and filed an agreement on most of the issues in this rate case, and 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 which included, as a negotiated compromise of the parties' respective positions, an ROACE of 10.7%, an 8.62% RORB, a $1.158 billion average rate base and a capital structure which includes a 55.1% common equity capitalization. In May 2008, the interim increase was adjusted from $70 million to $77.9 million in annual revenues to take into account the changes in current effective rates as a result of the final D&O in the 2005 test year rate case. In September 2008, the interim increase was corrected to $77.5 million based on a filing submitted by HECO.

On September 14, 2010, the PUC issued a final D&O that confirmed the interim increase of $77.5 million and approved the stipulated rate design, which includes the new tiered rate structure for residential customers. Decoupling was not addressed in this proceeding and the final D&O did not address the implementation of decoupling.

2009 test year rate case. In July 2008, HECO filed a request for a general rate increase of $97 million, or 5.2% over the electric rates then in effect, based on a 2009 test year, an 11.25% ROACE and an 8.81% RORB on a $1.408 billion average rate base. The requested rate increase was based on higher O&M costs required for HECO's electrical system, higher depreciation expenses since the last rate case and 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 in 2009) to maintain and improve system reliability.

In May 2009, HECO, the Consumer Advocate and the DOD (the parties) executed an agreement (the Settlement Agreement) on most of the issues in the rate case, representing a negotiated compromise of the parties' respective positions. The Settlement Agreement included an interim increase of $79.8 million annually, or a 6.2% increase over the rates then in effect. As part of the settlement, the parties also agreed that the PUC should allow HECO to establish a revenue balancing account, which would provide a mechanism to adjust revenues (increases/decreases) for the differences (shortages/overages) between the actual revenues and the revenues determined in the interim D&O.

In July 2009, the PUC issued an interim D&O, which approved an interim rate increase, but directed that adjustments be made to reduce the Settlement Agreement increase for several items, including certain labor expenses and costs related to CIP CT-1. HECO calculated an interim increase of $61.1 million annually, or a 4.7% increase, based on an ROACE of 10.50% and an 8.45% RORB on a rate base of $1.169 billion. The interim increase was implemented on August 3, 2009.

In February 2010, the PUC issued a second interim D&O in this proceeding granting an additional increase of $12.7 million in annual revenues (implemented effective February 20, 2010) to recover costs associated with CIP CT-1 and related transmission facilities. The increase was based on an ROACE of 10.50% and an RORB of 8.45%, both of which were used for the first interim increase.

The two interim increases granted totaled $73.8 million, or a 5.7% increase.

On December 29, 2010, the PUC issued a final D&O, which allowed HECO to implement the decoupling mechanism approved by the PUC in the decoupling proceeding described below. The PUC determined that, in view of implementing decoupling, the appropriate ROACE is 10.0% and RORB is 8.16% (which reflects a capital structure that includes 55.8% common equity). The PUC also approved a purchased power adjustment clause (PPAC) that will allow HECO to recover purchase power expenses through a surcharge mechanism rather than through base rates as currently recovered. The PPAC provides a mechanism that more closely aligns cost recovery with costs incurred, thus reducing HECO's risk profile associated with its PPAs. The PPAC is expected to enhance HECO's credit quality, help HECO maintain access to capital markets at reasonable costs and help position HECO to invest in infrastructure to both facilitate the addition of new renewable resources from IPPs and to maintain reliable electrical service.

Based on the final D&O, HECO will be refunding $2.1 million to customers (including interest) during February 2011. In December 2010, HECO recorded charges of $1.9 million related to this refund, which reduced net income by approximately $1 million.

On January 24, 2011, HECO filed tariffs for the final rates for the PUC's review and approval and requested the tariffs become effective on March 1, 2011. The tariffs included provisions to establish the decoupling revenue balancing account (which removes the historic link between electricity usage and revenues), the revenue adjustment mechanism (which allows the utility to recover its investments and costs in a timelier manner) and the PPAC. The tariffs also included a tiered rate structure. The final revenue requirements incorporate a ROACE of 10.0%, resulting in an annualized revenue increase of $66.4 million, or 5.1%, compared to the annualized interim increase of $73.8 million (a decrease in annual revenues of $7.4 million).

Management cannot predict when the tariffs implementing the final rate increase will be approved and become effective.

2011 test year rate case. On July 30, 2010, HECO filed a request with the PUC for a general rate increase of $94 million, or 5.4% over the electric rates then in effect (which included the interim increases in the HECO 2007 and 2009 rate cases), based on a 2011 test year, the estimated impacts of the implementation of decoupling and depreciation rates and methods as proposed by HECO. Excluding the effects of the implementation of decoupling, the effective revenue request is $113.5 million, or a 6.6% increase. The request includes an increase of $54 million, or 3.1% (or $74 million, or 4.3% without the implementation of decoupling), primarily to pay for major capital projects (including investments in the 110 MW biofuel generating facility that were not part of the 2009 test year rate case and Phase 1 of the East Oahu Transmission Project, which was placed in service on June 29, 2010) and higher operating and maintenance costs to maintain service reliability. The remainder of the request is to recover the costs for several proposed programs to help reduce Hawaii's dependence on imported oil, further increase reliability and increase fuel security.

The request is based on a 10.75% ROACE, an 8.54% RORB, a $1.57 billion average rate base and a capital structure which includes a 56% common equity capitalization.

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

<u>*HELCO*</u>.

2006 test year rate case. In May 2006, HELCO filed a request for a general rate increase of $29.9 million, or 9.24% over the electric rates then in effect, based on a 2006 test year, an 8.65% RORB, an 11.25% ROACE and a $369 million average rate base. HELCO's request included a proposed new tiered rate structure to reward residential customers who practice energy conservation with lower electric rates for lower monthly usage. The proposed rate increase was requested to 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.

In March 2007, HELCO and the Consumer Advocate reached settlement agreements on all revenue requirement issues in the rate case proceeding. 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 granting HELCO an increase of 7.58%, or $24.6 million in annual revenues, over revenues at present rates. The interim increase reflected the settlement of the revenue requirement issues reached between HELCO and the Consumer Advocate and was 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 RORB of 8.33% (incorporating an ROACE of 10.7%).

On October 28, 2010, the PUC issued a final D&O that confirmed the interim increase of $24.6 million and approved the stipulated rate design, which includes the new tiered rate structure. Decoupling was not addressed in this proceeding nor the final D&O. In November 2010, HELCO filed its revised tariff sheets and rate schedules, which the PUC approved on January 7, 2011 and became effective on January 14, 2011.

On December 17, 2010, Keahole Defense Coalition (KDC) filed a notice of appeal of the final D&O with the Intermediate Court of Appeals. KDC had been granted participant status in the rate case, limited to issues pertinent to HELCO's expansion of the Keahole generating station, and proposed a number of disallowances of costs associated with CT-4 and CT-5, but did not propose a total amount of disallowances. The appeal is pending, and management cannot predict the timing, or the ultimate outcome, of this appeal. However, the pendency of the appeal has not affected implementation of the rate increase approved in the final D&O.

2010 test year rate case. On December 9, 2009, HELCO filed a request for a general rate increase of $20.9 million, or 6.0% over the electric rates then in effect, based on a 2010 test year, a 10.75% ROACE and an 8.73% RORB on 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) and two major transmission line upgrades, as well as increasing O&M expenses. HELCO's proposed RORB and ROACE assume (1) the establishment of a revenue balancing account and a revenue adjustment mechanism, based on the Joint Decoupling Proposal (see "Decoupling proceeding" below), (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 PPA costs proposed in the proceeding. If the cost recovery mechanisms are not approved, the test year revenue requirements would be $22.1 million, based on an 8.87% RORB and an 11.0% ROACE.

HELCO's filing also proposed adoption of inverted tiered rates and an optional residential time-of-use service rate to enable customers to manage their energy usage.

HELCO and the Consumer Advocate executed and filed a settlement agreement on all material issues in this rate case proceeding on September 16, 2010, and filed a Joint Statement of Probable Entitlement (JSPE) on October 5, 2010, both of which are subject to approval by the PUC. If the settlement were to be approved by the PUC, the net interim increase in annual revenues would amount to $4.4 million, or a 1.2% increase. As part of the settlement agreement, HELCO would reset the heat rate used in its ECAC calculation when the interim rates become effective, which would shift $13.9 million of revenues that would have been included in the ECAC revenues to the interim increase and result in a total interim increase of $18.3 million. The agreement included a 10.125% ROACE, an 8.38% RORB, a $465 million average rate base and a capital structure which includes 56% of common equity. In the settlement agreement, the parties agreed to accept the ROACE authorized in the final D&O for HECO's 2009 test year rate case (10.0%, reflecting decoupling) as the final ROACE in this rate case.

The difference between the amounts requested in the initial application and the $4.4 million net increase under the settlement relates primarily to changes in expenses since the rate case was filed and changes in the ROACE and RORB.

On November 3, 2010, the PUC issued an interim D&O granting an interim rate increase as set forth in the JSPE, but adjusting recovery for labor costs downward to 2008 levels, reducing medical, dental and vision benefit costs by approximately 50%, deferring the implementation of decoupling for HELCO until the final D&O, and deferring resetting of the heat rate used in HELCO's ECAC calculation. Since the interim D&O deferred implementation of decoupling, the PUC found that a 10.5% ROACE and an 8.593% RORB (which reflects a capital structure that includes 56% common equity), was reasonable for purposes of the interim D&O.

On January 7, 2011, the PUC approved HELCO's revised revenue requirements resulting in an interim increase of approximately $6.0 million in annual revenues. The difference between the $4.4 million increase in the JSPE and the $6.0 million increase as a result of the interim D&O relates primarily to an adjustment of $1.5 million to the JSPE interim increase amount to take into account the changes in current effective rates as a result of the final rates from the HELCO 2006 test year rate case issued subsequent to the JSPE. The HELCO 2010 test year interim D&O adjustments to the JSPE for lower expenses were largely offset by the higher allowed ROACE. The interim increase reflects the new depreciation rates and methods proposed by HELCO and approved by the PUC on a temporary basis which will result in a $4.7 million annualized decrease in depreciation expense effective with interim rates.

HELCO implemented the interim rate increase and the final rates as a result of the 2006 test year rate case on January 14, 2011.

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

MECO.

2007 test year rate case. In February 2007, MECO filed a request for a general rate increase of $19.0 million, based on a 2007 test year. In September 2007, MECO proposed an updated lower increase in annual revenues of $18.3 million, or 5.1% over the electric rates then in effect based on an 11.25% ROACE and an 8.98% RORB on a $386 million rate base. MECO's request included a proposed new tiered rate structure to reward residential 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, and transmission and distribution infrastructure improvements.

In December 2007, MECO and the Consumer Advocate reached a settlement of all the revenue requirement issues in this rate case, and the PUC issued an interim D&O based on the settlement agreement granting MECO an increase of $13.2 million in annual revenues, or 3.7%, based on a 10.7% ROACE and an 8.67% RORB on a $383 million rate base. On July 30, 2010, the PUC issued a final D&O in the rate case confirming the December 2007 interim D&O rate increase.

2010 test year rate case. On September 30, 2009, MECO filed a request for a general rate increase of $28.2 million, or 9.7% over the electric rates then in effect, based on a 2010 test year, a 10.75% ROACE and an 8.57% RORB on a $390 million rate base. The proposed rate increase was requested to cover investments to improve service reliability, including the replacement and upgrade of power plant control systems, installation of a new 150-kW photovoltaic system, replacement and upgrade of underground lines, new or expanded substations to support growth and improve service, and higher O&M expenses due to MECO's aging infrastructure. MECO's proposed RORB and ROACE assumed the establishment of a revenue balancing account and a revenue adjustment mechanism, based on the Joint Decoupling Proposal. If the Joint Decoupling Proposal is not approved, the test year revenue requirements would be recalculated using an 11% ROACE and an 8.72% RORB.

On June 21, 2010, MECO and the Consumer Advocate executed and filed a settlement agreement on all material issues in this rate case proceeding, which agreement is subject to approval by the PUC. On July 27, 2010, the PUC issued an interim D&O granting MECO an increase of $10.3 million in annual revenues, or 3.3% over revenues currently in effect (implemented effective on August 1, 2010). The interim increase was based on the settlement agreement, which included a 10.5% ROACE, an 8.43% RORB, a $387 million average rate base and a capital structure which includes 56.9% of common equity. The interim increase also reflected the new depreciation rates and methods proposed by MECO and approved by the PUC on a temporary basis in a separate depreciation proceeding, but did not reflect the implementation of decoupling. In the settlement agreement, the parties agreed to accept the ROACE authorized in the final D&O for HECO's 2009 test year rate case (10.0%, reflecting decoupling) as the final ROACE in this rate case.

Under the settlement agreement, MECO agreed to limit to $3.5 million the amount to be included in rate base for the investment in plant for a combined heat and power (CHP) system installed at a hotel site in September 2009, resulting in a charge to expense of approximately $1.3 million in the second quarter of 2010.

On November 24, 2010, MECO and the Consumer Advocate filed a joint motion to adjust the interim increase, based on the final rates approved in the MECO 2007 test year rate case on July 30, 2010. On January 5, 2011, the PUC approved MECO's request to adjust the 2010 test year interim increase to $8.5 million, or 2.7% over revenues based on the rates approved in the MECO 2007 test year rate case. The downward adjustment resulted from a shift in recovery from the interim surcharges to the final 2007 base rates, with no net impact on total rates. On January 12, 2011, the adjusted interim rates (2010 test year) and the final rates (2007 test year) became effective.

Management cannot predict the ultimate outcome or the timing of a 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 HECO 2009 test year rate case interim D&O, a decoupling mechanism, similar to that in place for several California utilities, which decouples revenues from KWH sales and provides for revenue adjustments between rate cases. Overall, general rate cases for each utility would be expected to be less frequent than in the utilities' recent history. The decoupling mechanism would be subject to review at any time by the PUC or upon request of any utility or the Consumer Advocate.

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

On August 31, 2010, the PUC issued a Final D&O, which approved the decoupling mechanism proposed in the Joint Decoupling Proposal, subject to certain modifications. Those modifications excluded merit wage increases and cost overruns for major capital projects (capital projects greater than or equal to $2.5 million) from the RAM (with recovery of such increases and overruns to be considered in the utility's next rate case), required additional information related to capital projects less than $2.5 million, and required the utilities and the Consumer Advocate to jointly file an outreach plan. Implementation of the decoupling mechanism is to occur when rates that reflect a reduced rate of return due to decoupling are approved by the PUC in either an interim or final D&O in the utilities' pending rate cases.

In the final D&O in HECO's 2009 test year rate case issued on December 29, 2010, the PUC approved a reduced ROACE due to decoupling and allowed HECO to implement the approved decoupling mechanism and to immediately begin tracking target revenue and recorded adjusted revenue. In January 2011, HECO filed tariffs for final rates for the PUC's review and approval and requested that the tariffs become effective on March 1, 2011. Upon approval and implementation of the final rates, HECO will implement the approved decoupling mechanism. Authorizations for the implementation of decoupling for HELCO and MECO are pending final D&Os or other action by the PUC in their pending rate cases. Per the decoupling D&O, the utilities will file staggered rate cases every three years, the first being HECO's 2011 test year filed in July 2010.

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."

Demand-side management programs.

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

The PUC continues to permit recovery of reasonably-incurred DSM implementation costs (within approved budgets), under the integrated resource plan framework. Through 2009, the PUC also provided for DSM utility incentives derived from a graduated performance-based schedule of net system benefits. In order to qualify for an incentive, the utility must have met cumulative MW and MWh reduction goals for its EE DSM programs in the commercial, industrial and residential sectors. The amount of the annual incentive has been subject to caps determined separately for each utility. The DSM utility incentive mechanism ended once the energy efficiency programs were transferred to the PBF administrator in July 2009.

HECO and MECO earned their maximum DSM utility incentives of $4 million and $0.3 million, respectively, in 2008. In a December 30, 2010 order, the PUC denied HECO's request to increase its 2009 energy efficiency program budgets and the utilities' request to reallocate a portion of the unspent funding between DSM programs to cover actual expenditures in 2009. Because the utilities were not able reallocate the unspent funding between programs and thus recover the entire amount of 2009 DSM program expenditures, the utilities recorded an expense of $1.3 million in December 2010. In addition, the PUC advised that the utilities cannot include any of the energy savings from the program applications that exceeded their budgets in the calculations of DSM utility incentives. Based on the order, HECO calculated revised 2009 DSM incentives of $0.6 million and has submitted them for PUC review and approval.

Load Management DSM Programs. Unlike the EE DSM programs, load management DSM programs 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 a small business direct load control element.

In December 2009, the PUC approved HECO's requests to extend the Commercial and Industrial Direct Load Control (CIDLC) Program and the Residential Direct Load Control (RDLC) Program through 2012. The CIDLC Program application included an action plan for a load aggregator pilot program.

In October 2010, HECO filed an RDLC Program increase request to accommodate anticipated base expenses for the cost of a program impact evaluation needed to update the cost-effectiveness calculations identified by the PUC. In November 2010, HECO filed its 2011 CIDLC and RDLC Program budgets approval request. The PUC suspended both requests in order to gather additional information to further evaluate the requests.

In August 2010, HECO filed an application for a Fast Demand Response Pilot (Fast DR) Program—a two-year pilot program designed to test commercial and industrial market acceptance of load reductions within 10-minutes of event notification, and demonstrate the technical aspects of semi-automatic and automatic mechanisms to initiate customer reductions in load. The procedural steps in the docket will be completed in February 2011, after which the PUC can make a decision.

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

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

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

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

Under the PUC's IRP framework, the utilities were entitled to recover all appropriate and reasonable integrated resource planning costs either through a surcharge or through their base rates. Under procedural schedules for the IRP cost proceedings, the utilities were able to recover their incremental IRP costs in the month following the filing of their actual costs incurred for the year, subject to refund with interest pending the PUC's final D&O approving recovery in the docket for each year's costs. HELCO (since February 2001), HECO (since September 2005) and MECO (since December 2007) recover IRP costs through base rates. Previously, HECO, HELCO and MECO recovered their costs through a surcharge. The Consumer Advocate had objected to recovery of $1.2 million (before interest) of the $4.0 million of incremental IRP costs incurred by the utilities during 2002-2007. In January 2011, the PUC issued a D&O that allowed the utilities to recover their 2002-2007 IRP planning costs, but disallowed certain costs, primarily costs incurred during a rate case test year. The utilities will be refunding to customers approximately $1.2 million (representing disallowed costs previously recovered through a surcharge and interest) to its customers in February 2011. The utilities had been reserving for a potential refund for portions of the cost previously recovered and related interest, based on final D&Os related to 1995-2001 IRP planning costs. In December 2010, the utilities recorded additional charges of $0.8 million to fully accrue for this refund.

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

HECO and the Consumer Advocate filed a proposed CESP framework with the PUC in April 2009. In May 2009, the PUC opened an investigative proceeding to examine the proposed framework. As consensus between all parties and participants in the proceeding could not be reached, four revised proposed frameworks were separately filed by various parties and participants in August 2010 for the PUC's consideration. The CESP framework filed jointly by HECO and its subsidiaries, the Consumer Advocate, Kauai Island Utility Cooperative and the County of Kauai proposes a planning process resulting in a 5-year Action Plan developed from multiple scenarios and associated 20-year resource plans for each scenario. The proposed focus on scenario planning and shorter-term action plans (rather than 20-year plans) recognizes that planning assumptions are uncertain and that the planning framework should facilitate making adjustments to resource plans as circumstances change. PUC adoption of a CESP framework is pending.

Adequacy of supply.

HECO. In February 2011, HECO filed its 2011 Adequacy of Supply (AOS) letter, which indicated that based on its May 2010 sales and peak forecast, HECO's generation capacity for 2011 to 2015 is sufficiently large to meet all reasonably expected demands for service and provide reasonable reserves for emergencies. HECO anticipates that it will acquire 8 MW from a distributed standby generation facility to be located at the Honolulu International Airport and 27 MW from an expansion of the existing H-Power waste-to-energy facility located at Campbell Industrial Park within the next two years. Beginning in 2016, HECO anticipates that based on increasing demand it will begin experiencing reserve capacity shortfalls if no more firm generating capacity is added to the system. Also, four existing generating units may be retired within the next 10 years. Waiau Units 3 and 4 are being considered for retirement because of their age. Honolulu Units 8 and 9 may need to be retired because of more stringent environmental regulations. HECO estimates it will need approximately 300 MW of new, firm generating capacity to replace the capacity that would be lost with the retirement of these four units and to accommodate load growth. HECO plans to solicit proposals in 2011 for firm renewable generating capacity.

HELCO. In January 2011, HELCO filed its 2011 AOS letter, which indicated that HELCO's generation capacity through 2013 is sufficiently large to meet all reasonably expected demands for service and provide reasonable reserves for emergencies. HELCO is currently negotiating with two IPPs to supply additional firm renewable generating capacity to the HELCO grid. Should these additional firm renewable facilities come on line within the next three years as anticipated, HELCO will not have a need for additional firm capacity in the foreseeable future. HELCO, however, may choose to add additional renewable generating capacity to replace existing nonrenewable generation.

MECO. In January 2011, MECO filed its 2011 AOS letter, which indicated that MECO's generation capacity through 2014 is sufficient to meet the forecasted demands on the islands of Maui, Lanai and Molokai, but also stated that additional increments of firm capacity will be needed on Maui in 2015 and 2018 should a major IPP cease providing capacity and energy to MECO after December 31, 2014. Also, in January 2011, MECO filed a request to open a new docket related to MECO's plan to proceed with a competitive bidding process to acquire up to approximately 50 MW of new, renewable firm dispatchable capacity generation resources on the island of Maui, with the initial increment expected to come on line in the 2015 timeframe.

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

In March 2009, HECO submitted an outage report prepared by its expert consultant, which concluded that the island-wide outage was triggered by lightning strikes and 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 restoration of power as quickly as possible under the circumstances.

In January 2010, the Consumer Advocate submitted its Statement of Position that HECO could not have anticipated or prevented the outage through reasonable measures and 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 its 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, but reinstated it in November 2010. In January 2011, the PUC adopted the procedural schedule proposed by the Parties and Participants, which includes a panel hearing around the fourth quarter of 2012.

Collective bargaining agreements. See "Collective bargaining agreements" in Note 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 "Major tax legislation in 2010" above.

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

Renewable energy. In 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 requires the installation of solar thermal water heaters in residences constructed after January 1, 2010, but allows for limited variances in cases where installation of solar water heating is deemed inappropriate. The measure establishes 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 received PUC approval to enter into and recover the costs of biodiesel fuel contracts under which they are purchasing biofuels to operate HECO's CIP CT-1 and to test their use in other HECO and MECO generating units. HELCO has entered into a 20-year contract, subject to PUC approval, to purchase 16 million gallons of biodiesel per year beginning in 2015.

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.

Other developments.

Advanced Metering Infrastructure. In December 2008, the utilities filed an Advanced Metering Infrastructure (AMI) project application with the PUC for approval of (1) implementation of an AMI project, covering approximately 451,000 meters (65% on Oahu, 20% on the island of Hawaii and 15% on Maui), and (2) a contract between Sensus Metering Systems, Inc. (Sensus) and HECO under which the utilities would purchase smart meters and pay Sensus to provide and maintain a radio frequency communication system to operate the smart meters and related equipment.

HECO submitted a proposal to the PUC in May 2010, describing an extended pilot test of the AMI system and smart meters involving 5,000 new Sensus AMI meters. HECO's proposal also contained an update on developments in the Smart Grid, Customer Information System (CIS) and cyber-security areas.

On July 26, 2010, the PUC issued an Order denying the utilities' request to defer certain costs for an extended pilot test of their AMI system and smart meters on Oahu, and dismissing the utilities' AMI application, but without prejudice to the filing of a new application. In its Order, the PUC reiterated its support for an AMI and smart grid concept to reduce the state's dependence on fossil fuels, but noted that future AMI and smart grid applications should include or be preceded by an overall smart grid plan or proposal filed with the PUC. As of December 31, 2010, the utilities did not have any deferred costs related to the AMI project proceeding.

The utilities, like the PUC and Consumer Advocate, continue to support a broad range of smart grid initiatives, including AMI, as important components of a clean energy strategy and are assessing, testing and deploying various smart grid technologies on its systems. HECO is actively working with Sensus on further testing of its AMI and broader smart grid capabilities. The cost of this testing will be expensed. HECO and Sensus have agreed that their respective rights to terminate their contract (based on the lack of PUC application approval) shall extend until March 31, 2011.

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	2010		2009	
(dollars in millions)				
Short-term borrowings	$ –	–%	$ –	–%
Long-term debt, net	1,058	44	1,058	44
Preferred stock	34	1	34	1
Common stock equity	1,338	55	1,306	55
	$2,430	100%	$2,398	100%

HECO's short-term borrowings (other than from HELCO and MECO), HECO's line of credit facility and the principal amount of special purpose revenue bonds that have been authorized by the Hawaii legislature for future issuance by the DBF for the benefit of the utilities were as follows for the period and as of the dates indicated:

	Year ended December 31, 2010		
(in millions)	Average balance	End-of-period balance	December 31, 2009
Short-term borrowings[1]			
Commercial paper	$ 4	$ –	$ –
Line of credit draws	–	–	–
Borrowings from HEI	–	–	–
Line of credit facilities			
Undrawn capacity under line of credit facility expiring May 7, 2013	N/A	175	175
Special purpose revenue bonds authorized for issue			
2005 legislative authorization (expired June 30, 2010)-HELCO		$ –	$ 20
2007 legislative authorization (expiring June 30, 2012)			
HECO		170	170
HELCO		55	55
MECO		25	25
Total special purpose revenue bonds available for issue		$250	$270

1 The maximum amount of external short-term borrowings in 2010 was $19 million. At December 31, 2010, HECO had $31 million and $30 million of short-term borrowings from HELCO and MECO, respectively, which borrowings are eliminated in consolidation. At February 10, 2011, HECO had no outstanding commercial paper, its line of credit facility was undrawn, it had no borrowings from HEI and it had borrowings of $31 million and $21 million from HELCO and MECO, respectively.

HECO utilizes short-term debt, typically commercial paper, to support normal operations, to refinance short-term debt and for other temporary requirements. HECO also borrows short-term from HEI for itself and on behalf of HELCO and MECO, and HECO may borrow from or loan to HELCO and MECO short-term. The intercompany borrowings among the utilities, but not the borrowings from HEI, are eliminated in the consolidation of HECO's financial statements. HECO and its subsidiaries periodically utilize long-term debt, historically borrowings of the proceeds of special purpose revenue bonds issued by the State of Hawaii Department of Budget and Finance (DBF), to finance the utilities' capital improvement projects, or to repay short-term borrowings used to finance such projects. The PUC must approve issuances, if any, of equity and long-term debt securities by HECO, HELCO and MECO.

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

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

The credit agreement contains provisions for revised pricing in the event of a ratings change. For example, a ratings downgrade of HECO's Issuer Rating (e.g., from BBB/Baa2 to BBB-/Baa3 by S&P and Moody's, respectively) would result in a commitment fee increase of 5 basis points and an interest rate increase of 25 basis points on any drawn amounts. On the other hand, a ratings upgrade (e.g., from BBB/Baa2 to BBB+/Baa1 by S&P or Moody's, respectively) would result in a commitment fee decrease of 10 basis points and an interest rate decrease of 25 basis points on any drawn amounts. The agreement contains customary conditions that must be met in order to draw on it, including compliance with several covenants (such as covenants preventing its subsidiaries from entering into agreements that restrict the ability of the subsidiaries to pay dividends to, or to repay borrowings from, HECO, and restricting its ability as well as the ability of any of its subsidiaries to guarantee additional indebtedness of the subsidiaries if such additional debt would cause the subsidiary's "Consolidated Subsidiary Funded Debt to Capitalization Ratio" to exceed 65% (actual ratio of 43% for HELCO and 43% for MECO as of December 31, 2010, as calculated under the agreement)). In addition to customary defaults, HECO's failure to maintain its financial ratios, as defined in its agreement, or meet other requirements may result in an event of default. For example, under its agreement, it is an event of default if HECO fails to maintain a "Consolidated Capitalization Ratio" (equity) of at least 35% (actual ratio of 55% as of December 31, 2010, as calculated under the agreement).

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

As of February 10, 2011, the S&P and Moody's ratings of HECO securities were as follows:

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

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

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

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

Management believes that, if HECO's commercial paper ratings were to be further downgraded or if credit markets were to further tighten, it would be even more difficult and expensive to sell commercial paper or secure other short-term borrowings. Similarly, management believes that if HECO's long-term credit ratings were to be further downgraded, or if credit markets further tighten, it could be even more difficult and/or expensive for DBF and/or the Company to sell special purpose revenue bonds and other debt securities, respectively, for the benefit of the utilities in the future. Such limitations and/or increased costs could materially adversely affect the results of operations and financial condition of HECO and its subsidiaries.

The PUC must approve issuances, if any, of equity and long-term debt securities by HECO, HELCO and MECO. Revenue bonds are issued by the DBF to finance capital improvement projects of HECO and its subsidiaries, but the source of their repayment is the unsecured obligations of HECO and its subsidiaries under loan agreements and notes issued to the DBF, including HECO's guarantees of its subsidiaries' obligations. The payment of principal and interest due on SPRBs currently outstanding and issued prior to 2009 are insured either by Ambac Assurance Corporation, Financial Guaranty Insurance Company, MBIA (which bonds have been reinsured by National Public Finance Guarantee Corp.) or Syncora Guarantee Inc. (which bonds have been reinsured by Syncora Capital Assurance Inc.). The insured outstanding 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.

On November 15, 2010, the PUC approved the request of HECO, HELCO and MECO for the sale of each utility's common stock over a five-year period from 2010 through 2014 (HECO's sale to HEI of up to $210 million and HELCO and MECO's sales to HECO of up to $43 million and $15 million, respectively), and the purchase of the HELCO and MECO common stock by HECO. In December 2010, HELCO and MECO sold $23 million and $3 million, respectively, of their common stock to HECO, and HECO sold $4 million of its common stock to HEI.

Operating activities provided $248 million in net cash during 2010. Investing activities used net cash of $150 million, primarily for capital expenditures, net of contributions in aid of construction. Financing activities used net cash of $48 million for the payment of common and preferred stock dividends of $51 million, partly offset by $4 million net proceeds from issuance of common stock.

For the five-year period 2011 through 2015, the utilities forecast $2.2 billion of gross capital expenditures, approximately 44% of which is for transmission and distribution projects and 45% for generation projects, with the remaining 11% for general plant and other projects. These estimates do not include expenditures, which could be material, related to significant renewable energy infrastructure projects or environmental compliance requirements 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 2011 through 2015 are currently estimated to total approximately $2.0 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 forecasted 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 ($57.5 million in 2012 and $11.4 million in 2014) and to fund any unanticipated expenditures not included in the 2011 through 2015 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, temporary increases in short-term borrowings and existing cash and cash equivalents are expected to provide the forecast $260 million needed for the net capital expenditures in 2011. For 2011, gross capital expenditures are estimated to be $300 million, including approximately $176 million for transmission and distribution projects, approximately $90 million for generation projects and approximately $34 million for general plant and other projects. Consolidated net capital expenditures for HECO and subsidiaries for 2010, 2009 and 2008 were $173 million, $288 million and $257 million, respectively.

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

For a discussion of funding for the electric utilities' retirement benefits plans, see Note 1 and Note 9 of HEI's "Notes to Consolidated Financial Statements" and "Retirement benefits" above. The electric utilities were required to make contributions of $19.1 million for 2010, but not required to make any contributions for 2009 and 2008 to the qualified pension plans to meet minimum funding requirements pursuant to ERISA, including changes promulgated by the Pension Protection Act of 2006. The electric utilities made voluntary contributions in 2010, 2009 and 2008. Contributions by the electric utilities to the retirement benefit plans for 2010, 2009 and 2008 totaled $31 million, $24 million and $14 million, respectively, and are expected to total $63 million in 2011. In addition, the electric utilities paid directly $2 million of benefits in 2010, less than $1 million of benefits in each of 2009 and 2008 and expect to pay less than $2 million of benefits in 2011. 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 cash flow or access to capital resources to support any necessary funding requirements.

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. 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 implementation of a new regulatory model which will 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 cash flows 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 initiatives 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 studying DG interconnections on a per-circuit basis); 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 cash flows 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 cash flows. 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 cash flows. 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, 2010, HECO and its subsidiaries had recognized $4 million of revenues with respect to interim orders.

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.

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 75% of the net energy generated and purchased by HECO and its subsidiaries in 2011 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 2010 compared to 40.2% in 2009 and 40.4% in 2008.

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 O&M expenses increased 6%, 3% and 8% for 2010, 2009 and 2008, respectively, when compared to the prior year (12%, 7% and 5% respectively, excluding DSM program expense). This trend of increased O&M expenses is expected to continue in 2011 as the electric utilities expect higher production expenses (primarily to maintain and improve the efficiency of the production units), and higher costs for material and contract services. Transmission and distribution expenses are also expected to increase consistent with the new asset management initiatives to modernize the infrastructure. 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. In addition, the costs of environmental compliance continue to increase with more stringent regulatory requirements. Increased O&M expenses were among the reasons HECO, HELCO and MECO filed requests with the PUC in recent years to increase base rates. The successful implementation of decoupling mechanisms may partially and more promptly mitigate the negative net income impact of rising other O&M expenses.

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 before being placed in service, with a write-down being required for the Keahole project. 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 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.

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

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

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

Distributed generation proceeding. In January 2006, the PUC issued a D&O indicating that its policy is to promote the development of a market structure that assures distributed generation (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.

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).

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

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

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

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

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

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

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

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

The Energy Agreement also provides that to the degree that transmission and distribution automation and other smart grid technology investments are needed to facilitate distributed energy resource utilization, those investments should be recoverable through a Clean Energy Infrastructure Surcharge (which was replaced by the Renewable Energy Infrastructure Program 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 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. Meeting this requirement results in increased project costs.

The 1990 amendments to the Clean Air Act (CAA), 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 under newly adopted rules (e.g., one-hour NAAQS for sulfur dioxide and nitrogen dioxide, control of GHGs under the GHG PSD and Title V Tailoring Rule), under rules deemed applicable to the utilities' facilities (e.g., Regional Haze Rule), if currently proposed legislation, rules and standards are adopted (e.g., GHG emission reduction rules), or if new legislation, rules or standards are adopted in the future. Similarly, soon-to-be issued rules governing cooling water intake may significantly impact HECO's steam generating facilities on Oahu.

See "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 lease accounting standards 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 of the IPP 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 accounting standards for regulatory operations, 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, 2010, the consolidated regulatory liabilities and regulatory assets of the utilities amounted to $297 million and $478 million, respectively, compared to $288 million and $427 million as of December 31, 2009, 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, 2010 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 immediately. 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 or if regulatory liabilities are required to be refunded to ratepayers immediately.

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, 2010, revenues applicable to energy consumed, but not yet billed to customers, amounted to $104 million.

Revenue amounts recorded pursuant to a PUC interim order are subject to refund, with interest, pending a final order. As of December 31, 2010, HECO and its subsidiaries had recognized $4 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. Management believes that a material adverse effect on the Company's results of operations, financial position and cash flows may result if the utilities were to lose their ECACs.

Consolidation of variable interest entities. A business enterprise must evaluate whether it should consolidate a VIE. The Company evaluates the impact of applying accounting standards for consolidation to its relationships with IPPs with whom the 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 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."

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, but has been optimizing its balance sheet in recent years as a result of its multi-year performance improvement project, which has resulted in a reduction in asset size and a concomitant improvement in profitability and capital efficiency. ASB ended 2010 with assets of $4.8 billion and net income of $58 million, compared to assets of $4.9 billion as of December 31, 2009 and net income of $22 million in 2009. The weak national economic environment and declines in the national housing market in 2009 and 2008 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 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 ($32 million pretax) 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 and more than 75% of its fixed rate residential loan production in the first nine months of 2010 into the secondary market. A portion of the excess liquidity was used to pay off other borrowings that were maturing. Also in 2009, ASB recorded a net charge of $9 million ($15 million pretax) for other-than-temporary impairment (OTTI) in the value of securities and a higher provision for loan losses than in 2010 and 2008.

ASB is a full-service community bank serving both consumer and commercial customers. In order to remain competitive and continue building core franchise value, ASB 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 continue to increase revenues and control expenses after the completion of its performance improvement project.

The interest rate environment and the quality of ASB's assets 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. ASB's decision to sell substantial fixed rate mortgage production in 2009 and 2010, weak loan demand, and challenges in finding investments with adequate risk-adjusted returns resulted in declining loan balances and an increase in ASB's liquidity position, which had a negative impact on ASB'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.

Although ASB's loan quality improved in 2010, there are still signs of financial stress in the Hawaii and mainland markets. The slowdown in the economy, both nationally and locally, has resulted in ASB experiencing higher levels of loan delinquencies and losses, which were concentrated in the vacant land portfolio and on the neighbor islands. As a result, ASB's provision for loan losses had increased in 2009 and remained at a high level in 2010, following several years of historically low loan losses and loan loss allowances. While a mild recovery began in 2010 as the global economic recovery began to take hold, many challenges remain and the outlook for the Hawaii economy is for a slow, steady recovery. Consumers and businesses are expected to recover slowly in 2011 as gradual improvement in measures such as job growth, unemployment and real personal income are expected. Continued financial stress on ASB's customers may result in higher levels of loan delinquencies and losses.

Results of operations.

(dollars in millions)	2010	% change	2009	% change	2008
Revenues	$ 283	3	$ 275	(23)	$ 359
Net interest income	190	(6)	201	(3)	207
Operating income	93	192	32	18	27
Net income	58	169	22	22	18
Return on average common equity [1]	11.6%	156	4.5%	43	3.2%
Earning assets					
Average balance [1]	$ 4,492	(6)	$ 4,804	(16)	$ 5,722
Weighted-average yield	4.68%	(8)	5.10%	(7)	5.46%
Costing liabilities					
Average balance [1]	$ 3,445	(9)	$ 3,801	(20)	$ 4,754
Weighted-average rate	0.59%	(49)	1.15%	(48)	2.22%
Net interest margin [2]	4.23%	1	4.19%	16	3.62%

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 2010 decreased by $11.5 million, or 5.7%, when compared to 2009 due to lower balances and yields on earning assets, partly offset by lower funding costs. ASB's average interest earning assets and loan portfolio balances decreased by $312 million and $347 million, respectively, primarily due to the sale of substantial residential loan production in 2009 and 2010. The average commercial market and residential land loan portfolio balances decreased by $42 million and $31 million, respectively, due to repayments in the portfolios. The average home equity line of credit portfolio balance increased by $74 million due to promotional campaigns in the first half of 2010. The average investment and mortgage-related securities portfolio balance decreased by $61 million due to the sale of private-issue mortgage-related securities portfolio in the fourth quarter of 2009. The other investments average balance increased by $97 million due to an increase in liquidity as a result of ASB's fixed rate mortgage production sales. Average deposit balances for 2010 decreased by $116 million compared to 2009 due to an outflow of time certificates of $372 million as ASB did not aggressively price its time certificate products, partly offset by a $256 million increase in the average core deposit balance as ASB introduced new core deposit products. The other borrowings average balance decreased by $160 million primarily due to the payoff of maturing amounts. Net interest margin increased from 4.19% in 2009 to 4.23% in 2010 due to lower funding costs as a result of the outflow of higher costing term certificates and a shift in deposit mix.

During 2010, ASB recorded a provision for loan losses of $20.9 million, or $11.1 million lower than the provision for loan losses in 2009, primarily due to a $10 million provision for loan loss in 2009 on a commercial loan that subsequently sold and lower level of nonperforming loans. ASB's nonaccrual and renegotiated loans represented 2.8%, 2.3% and 0.7% of total loans outstanding as of December 31, 2010, 2009 and 2008, respectively.

Net charge-offs for 2010 totaled $21.9 million compared to $26.1 million in 2009. The decrease in net charge-offs was due to a $10 million partial charge-off of a commercial loan in 2009. ASB experienced an increase in net charge-offs of 1-4 family and residential land loans in 2010.

Noninterest income for 2010 of $72.6 million was $42.7 million higher than noninterest income for 2009. Excluding the losses on sale of private-issue mortgage-related securities and OTTI charges in 2009, noninterest income for 2010 was $4.9 million lower than 2009 due to lower deposit fees as a result of new overdraft fee legislation and lower gain on sale of loans.

Noninterest expense for 2010 of $148.9 million was $18.5 million lower than 2009 operating expenses primarily due to lower compensation, occupancy, data processing, services and equipment expenses as a result of ASB's performance improvement project, which reduced ASB's cost structure through improved processes and procedures, and improved the efficiency of ASB. In May 2010, ASB completed the conversion to the Fiserv Inc. banking platform system, which reduced service bureau expenses by approximately $0.5 million per month beginning in June 2010. ASB incurred conversion costs totaling approximately $4.4 million in 2010 to complete the project.

- 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 ASB'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 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.

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. Excluding losses on sale of securities and 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 to increase revenues, reduce ASB'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. For example, 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. Included in 2009 noninterest expenses were the following charges related to ASB's performance improvement project: (1) real estate transaction losses and expenses of $3.9 million; (2) professional services costs of $2.5 million; (3) severance of $1.7 million; (4) Fiserv (service bureau) conversion costs of $1.7 million; (5) prepayment penalty on early extinguishment of debt of $0.7 million; and (6) technology software write-off of $0.2 million.

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 2010, 2009 and 2008.

	2010			2009		
($ in thousands)	Average balance	Interest	Average rate (%)	Average balance	Interest	Average rate (%)
Assets:						
Other investments [1]	$ 334,270	$ 621	0.19	$ 237,770	$ 329	0.14
Investment and mortgage-related securities	566,126	14,468	2.56	627,365	26,648	4.25
Loans receivable [2]	3,591,794	195,192	5.43	3,938,575	217,838	5.53
Total interest-earning assets [3]	4,492,190	210,281	4.68	4,803,710	244,815	5.10
Allowance for loan losses	(39,135)			(42,121)		
Non-interest-earning assets	415,986			352,398		
Total assets	$4,869,041			$5,113,987		
Liabilities and Shareholder's Equity:						
Interest-bearing demand and savings deposits	$2,410,118	3,475	0.14	$2,234,259	6,676	0.30
Time certificates	768,991	11,221	1.46	1,140,997	27,370	2.40
Total interest-bearing deposits	3,179,109	14,696	0.46	3,375,256	34,046	1.01
Other borrowings	266,149	5,653	2.12	425,947	9,497	2.23
Total interest-bearing liabilities	3,445,258	20,349	0.59	3,801,203	43,543	1.15
Non-interest bearing liabilities:						
Deposits	824,039			743,982		
Other	96,510			89,248		
Shareholder's equity	503,234			479,554		
Total Liabilities and Shareholder's Equity	$4,869,041			$5,113,987		
Net interest income		$189,932			$201,272	
Net interest margin (%) [4]			4.23			4.19

($ in thousands)	2008 Average balance	Interest	Average rate (%)
Assets:			
Other investments [1]	$ 123,819	$ 1,542	1.25
Investment and mortgage-related securities	1,424,015	63,666	4.47
Loans receivable [2]	4,173,802	247,210	5.92
Total interest-earning assets [3]	5,721,636	312,418	5.46
Allowance for loan losses	(30,829)		
Non-interest-earning assets	415,822		
Total assets	$6,106,629		
Liabilities and Shareholder's Equity:			
Interest-bearing demand and savings deposits	$2,094,396	11,953	0.57
Time certificates	1,478,427	49,530	3.35
Total interest-bearing deposits	3,572,823	61,483	1.72
Other borrowings	1,180,844	43,941	3.72
Total interest-bearing liabilities	4,753,667	105,424	2.22
Non-interest bearing liabilities:			
Deposits	686,461		
Other	104,539		
Shareholder's equity	561,962		
Total Liabilities and Shareholder's Equity	$6,106,629		
Net interest income		$206,994	
Net interest margin (%) [4]			3.62

1 Includes federal funds sold, interest bearing deposits and stock in the FHLB of Seattle ($98 million as of December 31, 2010).
2 Includes loan fees of $6.3 million, $6.9 million and $4.4 million for 2010, 2009 and 2008, respectively, together with interest accrued prior to suspension of interest accrual on nonaccrual loans.
3 Interest income includes taxable equivalent basis adjustments, based upon a federal statutory tax rate of 35%, of $0.1 million and nil for 2010 and 2009, respectively.
4 Defined as net interest income as a percentage of average earning assets.

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

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

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 $3.7 billion at the end of 2009 to $3.5 billion at the end of 2010 was primarily due to ASB's strategic decision to sell most of the salable residential loans it originated during 2010 ($340 million of loans sold).

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.

See "Allowance for loan losses" in Note 4 of HEI's "Notes to Consolidated Financial Statements" for information with respect to nonperforming assets. The level of nonperforming loans reflects the impact of current unemployment levels in Hawaii and the weak economic environment globally, nationally and in Hawaii.

Allowance for loan losses. See “Allowance for loan losses” in Note 4 of HEI’s “Notes to Consolidated Financial Statements” for the tables which sets forth the allocation of ASB’s allowance for loan losses. For 2010 compared to 2009, the increase in the allowance for loan losses for residential 1-4 family and residential land loans was due to higher historical loss ratios used to compute the loan loss reserves, partly offset by lower balances. The decrease in the allowance for loan losses for commercial construction loans for 2010 compared to 2009 was due to lower loan balances. For 2010 compared to 2009, the decrease in the allowance for loan losses for commercial loans was due to lower historical loss ratios used to compute the loan loss reserves. The increase in the allowance for loan losses for consumer loans for 2010 compared to 2009 was primarily due to an increase in outstanding loan balances.

Investment and mortgage-related securities. As of December 31, 2010, ASB’s investment portfolio consisted of 47% mortgage-related securities issued by Federal National Mortgage Association (FNMA), Federal Home Loan Mortgage Corporation (FHLMC) or Government National Mortgage Association (GNMA), 47% federal agency obligations and 6% municipal bonds. As of December 31, 2009, ASB’s investment portfolio consisted of 75% mortgage-related securities issued by FNMA, FHLMC or GNMA and 24% federal agency obligations and 1% municipal bonds.

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

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.

As of December 31, 2010 and 2009, ASB did not have any private-issue mortgage-related securities. At December 31, 2008, the PMRS 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 PMRS. In the fourth quarter of 2009, ASB sold its PMRS portfolio and had no OTTI as of December 31, 2009.

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 challenging 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, 2010, ASB’s costing liabilities consisted of 94% deposits and 6% other borrowings. As of December 31, 2009, ASB’s costing liabilities consisted of 93% deposits and 7% 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.

Although higher long-term interest rates or other conditions in credit markets (such as the effects of the deteriorated subprime market) could reduce the market value of available-for-sale investment and mortgage-related securities and reduce shareholder's equity through a balance sheet charge to AOCI, this reduction in the market value of investments and mortgage-related securities would not result in a charge to net income in the absence of a sale of such securities (such as those that occurred in the fourth quarter of 2009 and in the 2008 balance sheet restructure) or an OTTI in the value of the securities. As of December 31, 2010 and 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 $4 million and $5 million, respectively. 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), whose regulatory functions are to be transferred to the Office of the Comptroller of the Currency (OCC) as described below, and the Federal Deposit Insurance Corporation (FDIC). Depending on ASB's level of regulatory capital and other considerations, these regulations could restrict the ability of ASB to compete with other institutions and to pay dividends to its shareholder. See the discussion below under "Liquidity and capital resources." Also see "Federal Deposit Insurance Corporation restoration plan" and "Deposit insurance coverage" in Note 4 of HEI's "Notes to Consolidated Financial Statements."

Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act). Regulation of the financial services industry, including regulation of HEI and ASB, will undergo substantial changes as a result of the enactment of the Dodd-Frank Act, which became law in July 2010. The Dodd-Frank Act increases regulation and oversight of the financial services industry and imposes restrictions on the ability of firms within the industry to conduct business consistent with historical practices. Most importantly for HEI and ASB, the Dodd-Frank Act will abolish their historical federal financial institution regulator, the OTS, effective one year from the enactment date (subject to extension by not more than an additional six months). Supervision and regulation of HEI, as a thrift holding company, will move to the Federal Reserve, and supervision and regulation of ASB, as a federally chartered savings bank, will move to the OCC. While the laws and regulations applicable to HEI and ASB will not generally change—the Home Owners Loan Act and regulations issued thereunder will still apply—the applicable laws and regulations will be interpreted, and new and amended regulations will be adopted, by the Federal Reserve and the OCC. HEI will for the first time be subject to minimum consolidated capital requirements, and ASB may be required to be supervised through ASHI, its intermediate holding company. The Dodd-Frank Act requires regulators, at a minimum, to apply to bank and thrift holding companies leverage and risk-based capital standards that are at least as strict as those in effect at the insured depository institution level on the date the Act became effective, although there will be a phase-in period for meeting these standards. In addition, HEI will continue to be required to serve as a source of strength to ASB in the event of its financial distress. The Dodd-Frank Act also imposes new restrictions on the ability of a savings bank to pay dividends should it fail to remain a qualified thrift lender.

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

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

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

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

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

Many of the provisions of the Dodd-Frank Act, as amended, will not become effective until a year or more after its enactment, when implementing regulations are issued and effective. Thus, management cannot predict the ultimate impact of the Dodd-Frank Act, as amended, on the Company or ASB at this time. Nor can management predict the impact or substance of other future federal or state legislation or regulation, or the application thereof.

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

New overdraft rules. On November 12, 2009, the Board of Governors of the Federal Reserve System announced that it amended Regulation E (which implements the Electronic Fund Transfer Act) to limit the ability of a financial institution to assess an overdraft fee for paying automated teller machine or one-time debit card transactions that overdraw a consumer's account, unless the consumer affirmatively consents, or opts in, to the institution's payment of overdrafts for those transactions. These new rules applied on July 1, 2010 for new accounts and August 15, 2010 for existing accounts. In 2009, these types of overdraft fees totaled approximately $15 million pretax. The amendment had a negative impact on ASB's noninterest income of approximately $4.4 million pretax for the second half of 2010.

FHLB of Seattle stock. As of December 31, 2010, ASB's investment in stock of the FHLB of Seattle of $97.8 million was carried at cost because it can only be redeemed at par. There is a minimum required investment based on measurements of ASB's capital, assets and/or borrowing levels. The FHLB of Seattle reported net income of $23.9 million for nine months ended September 30, 2010 compared to a net loss of $144 million for the nine months ended September 30, 2009. The FHLB of Seattle reported retained earnings of $77 million as of September 30, 2010 and was in compliance with all of its regulatory capital requirements. In October 2010, the FHLB of Seattle entered into a Stipulation and Consent to the Issuance of a Consent Order with the Federal Housing Finance Agency, which requires the FHLB of Seattle to take certain actions related to its business and operations. The Consents provide that, following a stabilization period and once the FHLB of Seattle reaches and maintains certain thresholds, it may redeem or repurchase capital stock and begin paying dividends. ASB does not believe that the Consents will affect the FHLB of Seattle's ability to meet ASB's liquidity and funding needs. ASB received cash dividends on its $98 million of FHLB of Seattle stock of $0.9 million in 2008, nil in 2009 and nil in 2010.

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	2010	% change	2009	% change
(dollars in millions)				
Total assets	$4,797	(3)	$4,941	(9)
Available-for-sale investment and mortgage-related securities	678	57	433	(34)
Loans receivable, net	3,498	(5)	3,670	(13)
Deposit liabilities	3,975	(2)	4,059	(3)
Other bank borrowings	237	(20)	298	(56)

As of December 31, 2010, ASB was one of Hawaii's largest financial institutions based on assets of $4.8 billion and deposits of $4.0 billion.

In July 2010, Moody's affirmed ASB's counterparty credit rating of A3 and changed ASB's outlook to "stable" from "negative" based on ASB's better than expected asset quality and earnings performance in the last several periods. 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 July 2010 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 HEI or HECO 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, 2010 were $83 million lower than December 31, 2009. 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, 2010, FHLB borrowings totaled approximately $65 million, representing 1.4% 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, 2010, ASB's unused FHLB borrowing capacity was approximately $1.3 billion. As of December 31, 2010, securities sold under agreements to repurchase totaled $172 million, representing 3.6% 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, 2010, 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, 2010 and 2009, ASB had $58.9 million and $65.3 million of loans on nonaccrual status, respectively, or 1.7% and 1.8% of net loans outstanding, respectively. As of December 31, 2010 and 2009, ASB had $4.3 million and $4.0 million, respectively, of real estate acquired in settlement of loans.

In 2010, operating activities provided cash of $113 million. Net cash of $128 million was used by investing activities primarily due to purchases of investment and mortgage-related securities and capital expenditures, partly offset by net decreases in loans held for investment, repayments of investment and mortgage-related securities and proceeds from the sale of real estate. Financing activities used net cash of $206 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, 2010, 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, 2010, the fair value and carrying value of the investment and mortgage-related securities held by ASB were $0.7 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 and more than 75% of its residential loan production in 2010 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 ASB'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 "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, 2010, 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, 2010 with a tangible capital ratio of 9.2% (1.5%), a core capital ratio of 9.2% (4.0%) and a total risk-based capital ratio of 13.9% (8.0%).
- ASB met the capital requirements to be generally considered "well-capitalized" (noted in parentheses) as of December 31, 2010 with a leverage ratio of 9.2% (5.0%), a Tier-1 risk-based capital ratio of 12.8% (6.0%) and a total risk-based capital ratio of 13.9% (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, 2010, 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, 2010, approximately 80% 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. There have been legislative proposals in the past which would operate to eliminate the thrift charter or the grandfathered status of HEI as a unitary thrift holding company and effectively require the divestiture of ASB.

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 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, 2010, ASB had investment and mortgage-related securities issued by FHLMC, GNMA and FNMA valued at $0.6 billion.

Allowance for loan losses. See Note 1 of HEI's "Notes to Consolidated Financial Statements" and the discussion above under "Earning assets, costing liabilities and other factors." As of December 31, 2010, ASB's allowance for loan losses was $40.6 million and ASB had $58.9 million of loans on nonaccrual status, compared to $41.7 million and $65.3 million at December 31, 2009, respectively. In 2010, ASB recorded a provision for loan losses of $20.9 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, 2010, 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 $0.5 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 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, financial position and cash flows.

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, 2010.

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 "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. 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 retirement benefit liabilities, the market value of retirement benefit 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, pretax 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, 2010 and 2009 constitute "forward-looking statements" and were as follows:

December 31	2010			2009		
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	(1.3)%	12.04%	(196)	(0.3)%	10.92%	(245)
+200	(1.3)	12.84	(116)	(0.3)	11.86	(151)
+100	(0.8)	13.52	(48)	(0.2)	12.72	(65)
Base	–	14.00	–	–	13.37	–
-100	(0.6)	14.04	4	(0.9)	13.53	16

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

Management believes that ASB's interest rate risk position as of December 31, 2010 represents a reasonable level of risk. Under the rising interest rate scenarios, the December 31, 2010 NII profile was more liability sensitive compared to December 31, 2009 due primarily to changes in the asset mix.

ASB's base NPV ratio as of December 31, 2010 increased compared to December 31, 2009 due to the higher relative value of the mortgage portfolio and the decrease in size and change in mix of the balance sheet.

ASB's NPV ratio sensitivity as of December 31, 2010 was less sensitive in the rising rate scenarios compared to December 31, 2009 as the asset mix shifted from longer duration mortgages to shorter duration loans and investments.

The computation of the prospective effects of hypothetical interest rate changes on the NII sensitivity, NPV ratio, and NPV ratio sensitivity analyses is based on numerous assumptions, including relative levels of market interest rates, loan prepayments, balance changes and pricing strategies, and should not be relied upon as indicative of actual results. To the extent market conditions and other factors vary from the assumptions used in the simulation analysis, actual results may differ materially from the simulation results. Furthermore, NII sensitivity analysis measures the change in ASB's twelve-month, pretax 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, 2010, 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 9 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. Therefore, the estimated fair value of such debt is lower than the amount outstanding (see Note 15 of HEI's "Notes to Consolidated Financial Statements"). See Note 6 of HEI's "Notes to Consolidated Financial Statements" for a discussion of the use of forward starting swaps to manage some of the interest rate risk associated with HEI's planned issuance of long-term debt in the future.

Index to Consolidated Financial Statements

Annual Report of Management on Internal Control Over Financial Reporting

Management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) and Rule 15d-15(f) promulgated under the Securities Exchange Act of 1934, as amended. The Company's internal control over financial reporting was designed to provide reasonable assurance to management and the Board of Directors regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles.

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.

Management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting as of December 31, 2010 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, 2010.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2010 has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in its report which appears on page 61 herein.

Disclosure Controls and Procedures

The certificates of the Chief Executive Officer and Chief Financial Officer that are required by Secton 302 of the Sarbanes–Oxley Act of 2002 are included as exhibits to Hawaiian Electric Industries, Inc.'s 2010 Annual Report on Form 10-K.

Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheet as of December 31, 2010 and the related consolidated statements of income, changes in shareholders' equity and cash flows for the year then ended present fairly, in all material respects, the financial position of Hawaiian Electric Industries, Inc. and its subsidiaries (the "Company") at December 31, 2010, and the results of their operations and their cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2010, based on criteria established in *Internal Control - Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements, 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 opinions on these financial statements and on the Company's internal control over financial reporting based on our integrated 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 the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audit of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting 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.

As discussed in Note 1 to the consolidated financial statements, the Company changed the manner in which it accounts for variable interest entities as of January 1, 2010.

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 (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) 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 (iii) 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.

PricewaterhouseCoopers LLP

Los Angeles, California
February 18, 2011

Report of Independent Registered Public Accounting Firm

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

We have audited the accompanying consolidated balance sheet of Hawaiian Electric Industries, Inc. and subsidiaries as of December 31, 2009, and the related consolidated statements of income, changes in shareholders' equity, and cash flows for each of the years in the two-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 the results of their operations and their cash flows for each of the years in the two-year period ended December 31, 2009, in conformity with U.S. generally accepted accounting principles.

KPMG LLP

Honolulu, Hawaii
February 19, 2010

Consolidated Statements of Income

Hawaiian Electric Industries, Inc. and Subsidiaries

Years ended December 31 (in thousands, except per share amounts)	2010	2009	2008
Revenues			
Electric utility	$ 2,382,366	$ 2,035,009	$ 2,860,350
Bank	282,693	274,719	358,553
Other	(77)	(138)	17
	2,664,982	2,309,590	3,218,920
Expenses			
Electric utility	2,203,978	1,865,338	2,668,991
Bank	190,105	242,955	331,601
Other	14,688	13,633	14,171
	2,408,771	2,121,926	3,014,763
Operating income (loss)			
Electric utility	178,388	169,671	191,359
Bank	92,588	31,764	26,952
Other	(14,765)	(13,771)	(14,154)
	256,211	187,664	204,157
Interest expense – other than on deposit liabilities and other bank borrowings	(81,538)	(76,330)	(76,142)
Allowance for borrowed funds used during construction	2,558	5,268	3,741
Allowance for equity funds used during construction	6,016	12,222	9,390
Income before income taxes	183,247	128,824	141,146
Income taxes	67,822	43,923	48,978
Net income	115,425	84,901	92,168
Preferred stock dividends of subsidiaries	1,890	1,890	1,890
Net income for common stock	$ 113,535	$ 83,011	$ 90,278
Basic earnings per common share	$ 1.22	$ 0.91	$ 1.07
Diluted earnings per common share	$ 1.21	$ 0.91	$ 1.07
Dividends per common share	$ 1.24	$ 1.24	$ 1.24
Weighted-average number of common shares outstanding	93,421	91,396	84,631
Dilutive effect of share-based compensation	272	120	89
Adjusted weighted-average shares	93,693	91,516	84,720

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

Consolidated Balance Sheets

Hawaiian Electric Industries, Inc. and Subsidiaries

December 31		2010		2009
(dollars in thousands)				
ASSETS				
Cash and cash equivalents		$ 330,651		$ 503,922
Accounts receivable and unbilled revenues, net		266,996		241,116
Available-for-sale investment and mortgage-related securities		678,152		432,881
Investment in stock of Federal Home Loan Bank of Seattle		97,764		97,764
Loans receivable held for investment, net		3,489,880		3,645,578
Loans held for sale, at lower of cost or fair value		7,849		24,915
Property, plant and equipment, net				
Land	$ 66,002		$ 67,381	
Plant and equipment	5,034,211		4,832,740	
Construction in progress	103,303		133,972	
	5,203,516		5,034,093	
Less – accumulated depreciation	(2,037,598)	3,165,918	(1,945,482)	3,088,611
Regulatory assets		478,330		426,862
Other		487,614		381,163
Goodwill		82,190		82,190
Total assets		$ 9,085,344		$ 8,925,002
LIABILITIES AND SHAREHOLDERS' EQUITY				
Liabilities				
Accounts payable		$ 202,446		$ 159,044
Interest and dividends payable		27,814		27,950
Deposit liabilities		3,975,372		4,058,760
Short-term borrowings—other than bank		24,923		41,989
Other bank borrowings		237,319		297,628
Long-term debt, net—other than bank		1,364,942		1,364,815
Deferred income taxes		278,958		188,875
Regulatory liabilities		296,797		288,214
Contributions in aid of construction		335,364		321,544
Other		823,479		700,242
Total liabilities		7,567,414		7,449,061
Preferred stock of subsidiaries - not subject to mandatory redemption		34,293		34,293
Shareholders' equity				
Preferred stock, no par value, authorized 10,000,000 shares; issued: none		–		–
Common stock, no par value, authorized 200,000,000 shares; issued and outstanding: 94,690,932 shares and 92,520,638 shares in 2010 and 2009, respectively		1,314,199		1,265,157
Retained earnings		181,910		184,213
Accumulated other comprehensive income (loss), net of taxes				
Net unrealized gains on securities	$ 3,532		$ 4,728	
Unrealized losses on derivatives	(1,169)		–	
Retirement benefit plans	(14,835)	(12,472)	(12,450)	(7,722)
Total shareholders' equity		1,483,637		1,441,648
Total liabilities and shareholders' equity		$ 9,085,344		$ 8,925,002

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

Consolidated Statements of Changes in Shareholders' Equity

Hawaiian Electric Industries, Inc. and Subsidiaries

(in thousands, except per share amounts)	Common stock Shares	Common stock Amount	Retained earnings	Accumulated other comprehensive income (loss)	Total
Balance, December 31, 2007	83,432	1,072,101	225,168	(21,842)	1,275,427
Comprehensive income:					
Net income for common stock	–	–	90,278	–	90,278
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 assets, net of tax benefits of $96,975	–	–	–	152,256	152,256
Other comprehensive loss				(31,173)	
Comprehensive income					59,105
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)
Balance, December 31, 2008	90,516	1,231,629	210,840	(53,015)	1,389,454
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 for common stock	–	–	83,011	–	83,011
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 assets, net of taxes of $48,251	–	–	–	(75,756)	(75,756)
Other comprehensive income				49,074	
Comprehensive income					132,085
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)
Balance, December 31, 2009	92,521	1,265,157	184,213	(7,722)	1,441,648
Comprehensive income:					
Net income for common stock	–	–	113,535	–	113,535
Net unrealized losses on securities:					
Net unrealized losses on securities arising during the period, net of tax benefits of $789	–	–	–	(1,196)	(1,196)
Unrealized losses on derivatives qualified as cash flow hedges:					
Net unrealized holding losses arising during the period, net of tax benefits of $745				(1,169)	(1,169)
Retirement benefit plans:					
Prior service credit arising during the period, net of taxes of $3,001	–	–	–	4,712	4,712
Net losses arising during the period, net of tax benefits of $28,431	–	–	–	(44,626)	(44,626)
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 $2,566	–	–	–	4,030	4,030
Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory assets, net of tax benefits of $21,336	–	–	–	33,499	33,499
Other comprehensive loss				(4,750)	
Comprehensive income					108,785
Issuance of common stock: Dividend reinvestment and stock purchase plan	1,685	37,296	–	–	37,296
Retirement savings and other plans	485	8,934	–	–	8,934
Expenses and other, net	–	2,812	–	–	2,812
Common stock dividends ($1.24 per share)	–	–	(115,838)	–	(115,838)
Balance, December 31, 2010	94,691	1,314,199	181,910	(12,472)	1,483,637

As of December 31, 2010, HEI had reserved a total of 18,816,260 shares of common stock for future issuance under the HEI Dividend Reinvestment and Stock Purchase Plan (DRIP), the Hawaiian Electric Industries Retirement Savings Plan (HEIRSP), the 1987 Stock Option and Incentive Plan, the HEI 1990 Nonemployee Director Stock Plan, the ASB 401(k) Plan and the 2010 Executive Incentive Plan.

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

Consolidated Statements of Cash Flows

Hawaiian Electric Industries, Inc. and Subsidiaries

Years ended December 31	2010	2009	2008
(in thousands)			
Cash flows from operating activities			
Net income	$ 115,425	$ 84,901	$ 92,168
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation of property, plant and equipment	154,523	151,282	150,977
Other amortization	4,605	5,389	5,085
Provision for loan losses	20,894	32,000	10,334
Gain on pension curtailment	–	–	(472)
Loans receivable originated and purchased, held for sale	(360,527)	(443,843)	(204,457)
Proceeds from sale of loans receivable, held for sale	392,406	471,194	185,291
Net losses on sale of investment and mortgage-related securities	–	32,034	17,376
Other-than-temporary impairment on available-for-sale mortgage-related securities	–	15,444	7,764
Changes in deferred income taxes	97,791	12,787	5,134
Changes in excess tax benefits from share-based payment arrangements	45	310	(405)
Allowance for equity funds used during construction	(6,016)	(12,222)	(9,390)
Decrease in cash overdraft	(141)	–	–
Changes in assets and liabilities			
Decrease (increase) in accounts receivable and unbilled revenues, net	(25,880)	59,550	(6,219)
Decrease (increase) in fuel oil stock	(74,044)	(946)	14,157
Increase (decrease) in accounts, interest and dividends payable	43,266	3,410	(18,715)
Changes in prepaid and accrued income taxes and utility revenue taxes	(5,252)	(61,977)	16,466
Changes in other assets and liabilities	(16,378)	(64,845)	(5,280)
Net cash provided by operating activities	340,717	284,468	259,814
Cash flows from investing activities			
Available-for-sale investment and mortgage-related securities purchased	(714,552)	(297,864)	(489,264)
Principal repayments on available-for-sale investment and mortgage-related securities	465,437	357,233	610,521
Proceeds from sale of available-for-sale investment and mortgage-related securities	–	185,134	1,311,596
Proceeds from sale of other investments	–	–	17
Net decrease (increase) in loans held for investment	118,892	484,960	(92,241)
Proceeds from sale of real estate acquired in settlement of loans	5,967	1,555	–
Capital expenditures	(182,125)	(304,761)	(282,051)
Contributions in aid of construction	22,555	14,170	17,319
Other	5,092	1,199	1,116
Net cash provided by (used in) investing activities	(278,734)	441,626	1,077,013
Cash flows from financing activities			
Net decrease in deposit liabilities	(83,388)	(121,415)	(167,085)
Net increase (decrease) in short-term borrowings with original maturities of three months or less	(17,066)	41,989	(91,780)
Net decrease in retail repurchase agreements	(60,308)	(3,829)	(37,142)
Proceeds from other bank borrowings	–	310,000	2,592,635
Repayments of other bank borrowings	–	(689,517)	(3,682,119)
Proceeds from issuance of long-term debt	–	153,186	19,275
Repayment of long-term debt	–	–	(50,000)
Changes in excess tax benefits from share-based payment arrangements	(45)	(310)	405
Net proceeds from issuance of common stock	22,706	15,329	136,443
Common stock dividends	(93,034)	(96,843)	(83,604)
Preferred stock dividends of subsidiaries	(1,890)	(1,890)	(1,890)
Increase (decrease) in cash overdraft	–	(9,545)	1,265
Other	(2,229)	(2,762)	350
Net cash used in financing activities	(235,254)	(405,607)	(1,363,247)
Net increase (decrease) in cash and cash equivalents	(173,271)	320,487	(26,420)
Cash and cash equivalents, January 1	503,922	183,435	209,855
Cash and cash equivalents, December 31	$ 330,651	$ 503,922	$ 183,435

The accompanying notes are an integral part of these 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; 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 variable interest entities (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 cash equivalents. The Company considers cash on hand, deposits in banks, deposits with the Federal Home Loan Bank (FHLB) of Seattle, federal funds sold (excess funds that American Savings Bank, F.S.B. (ASB) loans to other banks overnight at the federal funds rate), 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 cash equivalents.

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 must 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 is 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 securities are accreted or amortized over the remaining lives of the securities, adjusted for actual portfolio prepayments, using the interest method. Discounts and premiums on mortgage-related securities are accreted or amortized over the remaining lives of the securities, adjusted based on changes in anticipated 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.

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 in accordance with rate-making. Electric utility plant has lives ranging from 20 to 69 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 3.5% in 2010, 3.8% in 2009 and 3.8% in 2008.

Leases. HEI, HECO and its subsidiaries and ASB have entered into lease agreements for the use of equipment and office space. The provisions of some of the lease agreements contain renewal options.

Operating lease expense was $13 million, $16 million and $16 million in 2010, 2009 and 2008, respectively. Future minimum lease payments are $13 million, $12 million, $11 million, $9 million, $7 million and $28 million for 2011, 2012, 2013, 2014, 2015 and thereafter, respectively.

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 the 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 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), 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. 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 shareholders' equity.

HEI uses the straight-line 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.

Under the two-class method, EPS was comprised as follows for both unvested restricted stock awards and unrestricted common stock:

	2010		2009	2008
	Basic	Diluted	Basic and diluted	Basic and diluted
Distributed earnings	$ 1.24	$ 1.24	$ 1.24	$ 1.24
Undistributed earnings (loss)	(0.02)	(0.03)	(0.33)	(0.17)
	$ 1.22	$ 1.21	$ 0.91	$ 1.07

As of December 31, 2010 and 2009, the antidilutive effect of stock appreciation rights (SARs) on 450,000 and 480,000 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 10.

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.

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.

In April 2010, management evaluated the impact of Accounting Standards Update (ASU) 2009-04, "Accounting for Redeemable Equity Instruments," and the provisions of the utilities' $34 million of preferred stock that allowed preferred shareholders to potentially control the board if preferred dividends were not paid for four quarters, which could lead to the redemption of the preferred shares. This evaluation resulted in the movement of preferred stock of subsidiaries on the consolidated balance sheet from shareholders' equity to mezzanine equity and the removal of preferred stock of subsidiaries from the consolidated statement of changes in shareholders' equity for all prior periods presented, which changes were immaterial to the financial statements. There were no changes to previously reported operating income, net income, earnings per share and cash flows.

Variable interest entities. In June 2009, the FASB issued a standard that amends the guidance in FASB Accounting Standards CodificationTM (ASC) Topic 810 related to the consolidation of VIEs. The standard eliminates exceptions to consolidating qualifying special-purpose entities, 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 adopted this standard in the first quarter of 2010 and the adoption did not impact the Company's financial condition, results of operations or cash flows.

Allowance for Credit Losses. In July 2010, the FASB issued ASU No. 2010−20, "Disclosures about the Credit Quality of Financing Receivables and the Allowance for Credit Losses," which requires the Company to provide a greater level of disaggregated information about the credit quality of the Company's loans and leases and the Allowance for Loan and Lease Losses (the Allowance). This ASU also requires the Company to disclose additional information related to credit quality indicators, nonaccrual and past due information, and information related to impaired loans and loans modified in a troubled debt restructuring. See Note 4.

Reclassifications. Certain reclassifications have been made to prior years' financial statements to conform to the 2010 presentation, which did not affect previously reported results of operations.

Electric utility

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.

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.

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 2010, 2009 and 2008, HECO and its subsidiaries included approximately $211 million, $181 million and $252 million, respectively, of revenue taxes in "operating revenues" and in "taxes, other than income taxes" expense.

Power purchase agreements. If a power purchase agreement (PPA) falls within the scope of ASC Topic 840, "Leases," 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 lease.

The utilities evaluate PPAs to determine if the PPAs are VIEs, if the utilities are primary beneficiaries and if consolidation is required. See Note 5.

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 after assessing the causes of the delay and probability of recovery.

The weighted-average AFUDC rate was 8.1% in 2010, 2009 and 2008, 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. Under ASC Topic 860, "Transfers and Servicing," 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, 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. For loans secured by real estate that are classified as troubled debt restructured loans, the present value of the expected future cash flows of the loans may also be 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. 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 collectability. 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 principal and interest payments has resumed and collectability is reasonably assured, 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, all past due unsecured 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.

Loans modified in a troubled debt restructuring. Loans are considered to have been modified in a troubled debt restructuring (TDR) when, due to a borrower's financial difficulties, ASB makes certain concessions to the borrower that it would not otherwise consider. Modifications may include interest rate reductions, forbearance, and other actions intended to minimize economic loss and to provide alternatives to foreclosure or repossession of collateral. Generally, a nonaccrual loan that has been modified in a TDR remains on nonaccrual status until the borrower has demonstrated sustained repayment performance for a period of six consecutive months. However, performance prior to the modification, or significant events that coincide with the modification, are included in assessing whether the borrower can meet the new terms and may result in the loan being returned to accrual status at the time of loan modification or after a shorter performance period. If the borrower's ability to meet the revised payment schedule is uncertain, or there is reasonable doubt over the full collectability of principal and interest, the loan remains on nonaccrual status.

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, 2010 and 2009, ASB had $4.3 million and $4.0 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, "Intangibles—Goodwill and other."

Goodwill. At December 2010 and 2009, 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, 2010, there has been no impairment of goodwill. The fair value of ASB was estimated 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 $8 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 fair value using the market approach also included a 20% control premium. 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 10.4%. As of September 30, 2010, the estimated fair value of ASB exceeded its book value by approximately 35%.

Amortized intangible assets.

December 31	2010		2009	
(in thousands)	Gross carrying amount	Accumulated amortization	Gross carrying amount	Accumulated Amortization
Mortgage servicing assets	$18,483	$11,656	$15,205	$10,804

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

(in thousands)	2010	2009	2008
Valuation allowance, January 1	$201	$268	$189
Provision (recovery)	(12)	166	278
Other-than-temporary impairment	(61)	(233)	(199)
Valuation allowance, December 31	$128	$201	$268

In 2010, 2009 and 2008, aggregate amortization expenses were $0.9 million, $0.8 million and $0.4 million, respectively.

The estimated aggregate amortization expenses for mortgage servicing assets for 2011, 2012, 2013, 2014 and 2015 are $1.0 million, $0.8 million, $0.7 million, $0.6 million and $0.5 million, respectively.

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, 2010 and 2009, the mortgage servicing assets had a net carrying value of $6.7 million and $4.2 million, respectively. In 2010, 2009 and 2008, mortgage servicing assets acquired through the sale or securitization of loans held for sale were $3.3 million, $3.3 million and $0.6 million, respectively. Amortization expenses for ASB's mortgage servicing assets amounted to $0.9 million, $0.8 million and $0.4 million for 2010, 2009 and 2008, 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, rent 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. (UBC), 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) (whose functions are to be transferred to the Office of the Comptroller of the Currency) 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
2010				
Revenues from external customers	$2,382,211	$ 282,693	$ 78	$2,664,982
Intersegment revenues (eliminations)	155	–	(155)	–
Revenues	2,382,366	282,693	(77)	2,664,982
Depreciation and amortization	157,432	749	947	159,128
Interest expense	61,510	20,349	20,028	101,887
Income (loss) before income taxes	125,452	92,512	(34,717)	183,247
Income taxes (benefit)	46,868	34,056	(13,102)	67,822
Net income (loss)	78,584	58,456	(21,615)	115,425
Preferred stock dividends of subsidiaries	1,995	–	(105)	1,890
Net income (loss) for common stock	76,589	58,456	(21,510)	113,535
Capital expenditures	174,344	7,709	72	182,125
Tangible assets (at December 31, 2010)	4,285,680	4,707,870	2,905	8,996,455
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
Income (loss) before income taxes	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
Preferred stock dividends of 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
Tangible assets (at December 31, 2009)	3,978,392	4,854,595	5,625	8,838,612
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
Income (loss) before income taxes	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
Preferred stock dividends of 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
Tangible assets (at December 31, 2008)	3,856,109	5,353,053	1,853	9,211,015

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	2010	2009	2008
(in thousands)			
Revenues			
Operating revenues	$2,367,441	$2,026,672	$2,853,639
Other – nonregulated	14,925	8,337	6,711
	2,382,366	2,035,009	2,860,350
Expenses			
Fuel oil	900,408	671,970	1,229,193
Purchased power	548,800	499,804	689,828
Other operation	251,027	248,515	243,249
Maintenance	127,487	107,531	101,624
Depreciation	149,708	144,533	141,678
Taxes, other than income taxes	222,117	191,699	261,823
Other – nonregulated	4,431	1,286	1,596
	2,203,978	1,865,338	2,668,991
Operating income from regulated and nonregulated activities	178,388	169,671	191,359
Allowance for equity funds used during construction	6,016	12,222	9,390
Interest expense and other charges	(61,510)	(57,944)	(54,757)
Allowance for borrowed funds used during construction	2,558	5,268	3,741
Income before income taxes	125,452	129,217	149,733
Income taxes	46,868	47,776	55,763
Net income	78,584	81,441	93,970
Preferred stock dividends of subsidiaries	915	915	915
Net income attributable to HECO	77,669	80,526	93,055
Preferred stock dividends of HECO	1,080	1,080	1,080
Net income for common stock	$ 76,589	$ 79,446	$ 91,975

Consolidated Balance Sheet Data

December 31	2010	2009
(in thousands, except share data)		
Assets		
Utility plant, at cost		
Property, plant and equipment	$ 4,948,338	$ 4,748,787
Less accumulated depreciation	(1,941,059)	(1,848,416)
Construction in progress	101,562	132,980
Net utility plant	3,108,841	3,033,351
Regulatory assets	478,330	426,862
Other	698,509	518,179
	$ 4,285,680	$ 3,978,392
Capitalization and liabilities		
Common stock ($6 2/3 par value, authorized 50,000,000 shares, outstanding 13,830,823 shares and 13,786,959 shares in 2010 and 2009, respectively)	$ 92,224	$ 91,931
Premium on common stock	389,609	385,659
Retained earnings	854,856	827,036
Accumulated other comprehensive income, net of income taxes	709	1,782
Common stock equity	1,337,398	1,306,408
Cumulative preferred stock – not subject to mandatory redemption (authorized 5,000,000 shares, $20 par value (1,114,657 shares outstanding), and 7,000,000 shares, $100 par value (120,000 shares outstanding); dividend rates of 4.25-7.625%)	34,293	34,293
Long-term debt, net	1,057,942	1,057,815
Total capitalization	2,429,633	2,398,516
Deferred income taxes	269,286	180,603
Regulatory liabilities	296,797	288,214
Contributions in aid of construction	335,364	321,544
Other	954,600	789,515
	$ 4,285,680	$ 3,978,392

Regulatory assets and liabilities. In accordance with ASC Topic 980, “Regulated Operations,” 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 immediately. 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 or if regulatory liabilities are required to be refunded to ratepayers immediately.

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 certain regulatory assets and to include certain regulatory assets in rate base. 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. Generally, HECO and its subsidiaries include regulatory liabilities in rate base or are required to apply interest to certain regulatory liabilities. Noted in parentheses are the original PUC authorized amortization or recovery periods and the remaining amortization or recovery periods as of December 31, 2010, if different.

Regulatory assets were as follows:

December 31 (in thousands)	2010	2009
Retirement benefit plans (9 years; 5 years remaining for HELCO's $2 million prepaid pension regulatory asset; 5 years, 4 years remaining for HECO's $7 million pension tracking mechanism; 5 years remaining for HELCO's $6 million and MECO's $3 million pension and OPEB tracking mechanisms; indeterminate for remainder)	$356,591	$303,927
Income taxes, net (1 to 36 years)	82,615	82,046
Unamortized expense and premiums on retired debt and equity issuances (5 to 30 years; 1 to 18 years remaining)	13,589	14,878
Vacation earned, but not yet taken (1 year)	7,349	6,849
Postretirement benefits other than pensions (18 years; 2 years remaining)	3,579	5,369
Other (1 to 50 years; 1 to 49 years remaining)	14,607	13,793
	$478,330	$426,862

Regulatory liabilities were as follows:

December 31 (in thousands)	2010	2009
Cost of removal in excess of salvage value (1 to 60 years)	$277,341	$280,674
Retirement benefit plans (5 years beginning with respective utility's next rate case; 4 years remaining for HECO's $4 million regulatory liability; 5 years remaining for HELCO's $0.8 million and MECO's $0.4 million regulatory liability)	18,617	5,193
Other (1 to 5 years)	839	2,347
	$296,797	$288,214

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 9).

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 10%, or $242 million, $199 million and $295 million, of their operating revenues from the sale of electricity to various federal government agencies in 2010, 2009 and 2008, respectively.

Commitments and contingencies.

Fuel contracts. HECO and its subsidiaries have contractual agreements to purchase minimum quantities of fuel oil, diesel fuel and biodiesel for multi-year periods, some through December 31, 2014. Fossil fuel prices are tied to the market prices of crude oil and petroleum products in the Far East and U.S. West Coast and the biodiesel price is tied to the market prices of animal fat feedstocks in the U.S. Midwest. Based on the average price per barrel as of December 31, 2010, the estimated cost of minimum purchases under the fuel supply contracts is $1.0 billion in each of 2011 and 2012 and a total of $0.8 billion in 2013 and $0.7 billion in 2014. The actual cost of purchases in 2011 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 $1.0 billion, $0.7 billion and $1.2 billion of fuel under contractual agreements in 2010, 2009 and 2008, 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. HECO is awaiting a final D&O from the PUC.

On May 5, 2010, HECO and Tesoro Hawaii Corporation (Tesoro) executed a second amendment to their existing LSFO supply contract (LSFO contract), subject to PUC approval. The amendment modified the pricing formula, which could result in higher prices. It also reduced the minimum fuel volumes HECO is obligated to buy under the LSFO contract and reduced the maximum volumes Tesoro is obligated to sell HECO under the LSFO contract. The term of the amended agreement runs through April 30, 2013 and may automatically renew for annual terms thereafter unless earlier terminated by either party. On June 7, 2010, HECO submitted an application for PUC approval of the second amendment, such that the changes in fuel prices under the amendment would be included in HECO's ECAC.

The utilities pay market-related prices for fuel supplies purchased under the Chevron and Tesoro agreements.

HECO and Renewable Energy Group Marketing & Logistics Group LLC (REG) entered into a supply contract dated December 21, 2009 and expiring in 2012 for biodiesel to be consumed in the operation of the Campbell Industrial Park combustion turbine. On June 4, 2010, the PUC approved the biodiesel supply contract and allowed HECO to include the costs in its ECAC, to the extent such costs are not recovered through HECO's base rates. HECO's price for biodiesel purchased under this agreement reflects market-related prices for animal fat and other process feedstocks.

In January 2011, HELCO signed a 20-year contract with Aina Koa Pono-Ka'u LLC to supply 16 million gallons of biodiesel per year from a biorefinery to be constructed by Aina Koa Pono-Ka'u LLC on the island of Hawaii, with initial consumption at HELCO's Keahole Power Plant to begin by 2015. The utilities filed an application with the PUC requesting approval of, among other things, the contract and the establishment of a Biofuel Surcharge Provision that will pass through the differential between the cost of the biofuel and the cost of the petroleum fuel that the biofuel is replacing, in the event the cost of the biofuel is higher, over the customer base of the utilities based on KWH usage. The effectiveness of the contract is contingent upon PUC approval of, among other items, the proposed methodology for spreading the cost differential between the price of biodiesel and petroleum diesel being replaced over the customers base of all three utilities and the recovery of the contract costs in the utilities' respective ECACs to the extent not included in base rates.

Power purchase agreements. As of December 31, 2010, 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 \$0.5 billion, \$0.5 billion and \$0.7 billion for 2010, 2009 and 2008, 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 2011 through 2015 and a total of \$0.7 billion in the period from 2016 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. 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.

The energy charge for energy purchased from Kalaeloa under HECO's PPA with Kalaeloa is based, in part, on the price Kalaeloa pays Tesoro for fuel oil under a Facility Fuel Supply Contract (fuel contract) between them. Kalaeloa and Tesoro have negotiated a proposed amendment to the pricing formula in their fuel contract. The amendment could result in higher fuel prices for Kalaeloa. In September 2010, HECO submitted a request for PUC approval to include the costs incurred under the PPA as a result of the amendment in HECO's ECAC.

Purchase power adjustment clause. The final decision and order (D&O) for the HECO 2009 test year rate case approved a purchased power adjustment clause (PPAC). Purchased power capacity, O&M and other non-energy costs previously recovered through base rates will be recovered in the PPAC, and subject to approval by the PUC, such costs resulting from new purchased power agreements can be added to the PPAC outside of a rate case. The PPAC will be adjusted monthly and reconciled quarterly and will implement a provision in the Energy Agreement that called for surcharge recovery of these costs. Purchased energy costs will continue to be recovered through the ECAC to the extent they are not recovered through base rates. Upon approval of the final rates in the HECO 2009 test year rate case, HECO will implement the PPAC.

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

Among the major provisions of the Energy Agreement are the following: (a) pursuing an overall goal of providing 70% of Hawaii's electricity and ground transportation energy needs from clean energy sources by 2030; (b) developing a feed-in tariff system with standardized purchase prices for renewable energy; (c) replacing system-wide caps on net energy metering (NEM) with per circuit thresholds that require a further study before a proposed interconnection that would take the circuit over the threshold may proceed; (d) adopting a regulatory rate-making model under which the utilities' revenues would be decoupled from kilowatthour (KWH) sales; (e) continuing the existing ECACs, subject to periodic review by the PUC; (f) establishing a surcharge to allow the utilities to pass through all reasonably incurred purchased power costs; (g) supporting the development and use of renewable biofuels; (h) promoting greater use of renewable energy, including wind power and solar energy; (i) 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; (j) improving and expanding "load management" and "demand response" programs that allow the utilities to control customer loads to improve grid reliability and cost management; (k) 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; (l) supporting prudent and cost effective investments in smart grid technologies; (m) delinking prices paid under all new renewable energy contracts from oil prices; and (n) exploring establishment of lifeline rates for low income customers.

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

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

Interim increases. As of December 31, 2010, HECO and its subsidiaries had recognized $4 million of revenues with respect to interim orders related to general rate increase requests. Revenue amounts recorded pursuant to interim orders are subject to refund, with interest, if they exceed amounts allowed in a final order.

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

Campbell Industrial Park combustion turbine No. 1 and transmission line. HECO built a 110 MW simple cycle combustion turbine generating unit and added an additional 138 kilovolt (kV) transmission line to transmit power from generating units at Campbell Industrial Park (CIP) to the rest of the Oahu electric grid (collectively, the Project).

In a second interim D&O to HECO's 2009 test year rate case issued in February 2010, the PUC granted HECO an increase of $12.7 million in annual revenues to recover $163 million of the costs of the Project. As of December 31, 2010, HECO's cost estimate for the Project was $195 million (of which $195 million had been incurred, including $9 million of AFUDC). In its 2011 test year rate case, HECO is seeking to recover actual project costs in excess of the $163 million estimate included in its 2009 test year rate case. Management believes no adjustment to project costs is required as of December 31, 2010.

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

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

As of December 31, 2010, the accumulated costs recorded for the EOTP amounted to $61 million ($59 million for Phase 1 and $2 million for Phase 2), including (i) $12 million of planning and permitting costs incurred prior to the 2002 denial of the permit, (ii) $25 million of planning, permitting and construction costs incurred after the denial of the permit and (iii) $24 million for AFUDC. Management believes no adjustment to project costs is required as of December 31, 2010.

HELCO generating units. In 1991, HELCO began planning to meet increased forecast demand for electricity. 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 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."

After numerous delays due to environmental and other permitting challenges, CT-4 and CT-5 became operational in mid-2004 and the costs of CT-4 and CT-5 (less a previously agreed to $12 million write-off) were included in HELCO's 2006 test year rate case interim and final rate increases.

On June 22, 2009, ST-7 was placed into service. As of December 31, 2010, HELCO's cost estimate, and incurred costs, for ST-7 were both $92 million. The costs of ST-7 were included in HELCO's 2010 test year rate case interim increase.

Management believes that no further adjustment to project costs is required at December 31, 2010.

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

HECO signed a contract with a software company in March 2006 with a transition to the new CIS originally scheduled to occur in February 2008, which transition did not occur. Disputes over the parties' contractual obligations resulted in litigation, which subsequently was settled. HECO subsequently contracted with a new CIS software vendor and a new system integrator. The CIS Project is proceeding with the implementation of the new software system. As of December 31, 2010, HECO's total deferred and capital cost estimate for the CIS was $57 million (of which $22 million was recorded). Management believes no adjustment to project costs is required as of December 31, 2010.

Environmental regulation. HECO and its subsidiaries are subject to environmental laws and regulations that regulate the operation of existing facilities, the construction and operation of new facilities and the proper cleanup and disposal of hazardous waste and toxic substances. In recent years, legislative and regulatory activity related to the environment, including proposals and rulemaking under the Clean Air Act (CAA) and Clean Water Act, has increased significantly and management anticipates that such activity will continue. Depending upon the final outcome of the legislative and regulatory activity (including under the Clean Water Act with respect to cooling water intake controls and changes in effluent standards and the Clean Air Act with respect to hazardous air pollutant emissions, tightening of the National Ambient Air Quality Standards, and the Regional Haze rule), HECO and its subsidiaries may be required to incur material capital expenditures and other compliance costs.

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 cash flows.

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

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

As of December 31, 2010, HECO's remaining accrual for its estimated share of environmental costs for the Iwilei unit was $1.4 million. Because (1) the full scope of work remains to be determined, (2) the final cost allocation method among the Participating Parties has not yet been established and (3) management cannot estimate the costs to be incurred (if any) for the sites other than the Iwilei unit (such as its Honolulu power plant located in the Downtown unit), the cost estimate may be subject to significant change and additional material costs may be incurred.

Global climate change and greenhouse gas (GHG) emissions reduction. National and international concern about climate change and the contribution of GHG emissions to global warming have led to action by the State and to 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. The electric utilities are participating in a Task Force established under Act 234, which is charged with developing a work plan and regulatory approach to reduce GHG emissions, as well as in initiatives aimed at reducing their GHG emissions, such as those to be undertaken under the Energy Agreement. A Task Force consultant prepared a work plan, which was submitted to the Hawaii Legislature in December 2009. 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, but compliance costs could be significant.

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 periodically to 83% by 2050. 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, which also includes cap and trade provisions. 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.

On September 22, 2009, the federal Environmental Protection Agency (EPA) issued the Final Mandatory Reporting of Greenhouse Gases Rule, which requires that sources emitting GHGs above certain threshold levels monitor and report GHG emissions beginning in 2010. The utilities' GHG emissions reports for 2010 are due on March 31, 2011. In December 2009, the EPA made the finding that motor vehicle GHG emissions endanger public health or welfare. Management believes the EPA will make the same or similar endangerment finding regarding GHG emissions from stationary sources like the utilities' generating units.

In addition, the Prevention of Significant Deterioration (PSD) permit program of the CAA applies to designated air pollutants from new or modified stationary sources, such as utility electrical generation units. In June 2010, the EPA issued its "Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule" (GHG Tailoring Rule) that created new thresholds for GHG emissions from new and existing facilities. States may need to increase fees to cover the increased level of activity caused by this rule. The GHG Tailoring

Rule requires 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. The EPA has stated that the PSD program applies to GHG emissions effective January 2, 2011 because that is the date the federal GHG emission standards for motor vehicles (Tailpipe Rule) take effect. Accordingly, permitting of new or modified stationary sources that have the potential to emit GHGs in greater quantities than the thresholds in the GHG Tailoring Rule will entail GHG emissions evaluation, analysis, and potentially control requirements. On January 12, 2011, the EPA issued a notice that it plans to defer, for three years, GHG permitting requirements for carbon dioxide (CO2) emissions from biomass-fired and other biogenic sources. The utilities are evaluating the impact of this deferral on their generation units that are or will be fired on biofuels.

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

While the timing, extent and ultimate effects of climate change cannot be determined with any certainty, climate change is predicted to result in sea level rise, which could potentially impact coastal and other low-lying areas (where much of the utilities' electric infrastructure is sited), and could cause erosion of beaches, saltwater intrusion into aquifers and surface ecosystems, higher water tables and increased flooding and storm damage due to heavy rainfall. The effects of climate change on the weather (for example, floods or hurricanes), sea levels, and water availability and quality have the potential to materially adversely affect the results of operations, financial condition and cash flows of the 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 utilities in the planning, design, construction, operation and maintenance of their facilities. To ensure the reliability of each island's grid, the utilities design and construct their electric generation systems with greater levels of redundancy than is typical for U.S. mainland, interconnected systems. Although a major natural disaster could have severe financial implications, such risks have existed since the Company's inception and the Company makes a concerted effort to prepare for a fast response in the event of an emergency.

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

BlueEarth Biofuels LLC. BlueEarth Maui Biodiesel LLC (BlueEarth Maui), a joint venture to pursue biodiesel development, was formed in early 2008 between BlueEarth Biofuels LLC (BlueEarth) and Uluwehiokama Biofuels Corp. (UBC), a non-regulated subsidiary of HECO. UBC invested $400,000 in BlueEarth Maui for a minority ownership interest. MECO began negotiating with BlueEarth Maui for a biodiesel fuel purchase contract, however, negotiations stalled. In October 2008, BlueEarth filed a civil action in federal district court 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. Trial has been scheduled for April 2012. The project was terminated because the litigation was filed 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 PPA for As-Available Energy (the RAC) dated October 13, 2004 between HELCO and Apollo Energy Corporation (Apollo), later assigned to Apollo's affiliate, Tawhiri Power LLC (Tawhiri). The maximum allowed output of the wind farm is 20.5 MW.

In June 2010, HELCO and Tawhiri participated in an arbitration relating to disputes surrounding HELCO's ownership and possessory interest in the switching station and reimbursement of certain interconnection costs. In December 2010, the arbitration panel issued its final award and order finding in favor of HELCO. Thus, Tawhiri transferred title to the switching station and rights to the land to HELCO and paid HELCO $0.6 million (which included reimbursement of certain interconnection costs, prejudgment interest and HELCO's attorneys' fees and costs). Tawhiri's appeal from the PUC's decision not to hear the issues presented to the arbitration panel remains pending before the Hawaii Intermediate Court of Appeals.

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

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

(in thousands)	2010	2009
Balance, January 1	$ 23,746	$ 286
Accretion expense	2,519	21
Liabilities incurred	11,949	23,479
Liabilities settled	(725)	(40)
Revisions in estimated cash flows	11,141	–
Balance, December 31	$ 48,630	$ 23,746

Collective bargaining agreements. As of December 31, 2010, approximately 54% 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 collective bargaining and benefit agreements with HECO, HELCO and MECO. The 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. The agreements had been extended to January 31, 2011. On January 31, 2011, a tentative settlement agreement was reached, subject to ratification by the utilities' union members.

Selected financial information

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

Consolidated Statements of Income Data

Years ended December 31 (in thousands)	2010	2009	2008
Interest and dividend income			
Interest and fees on loans	$195,192	$217,838	$247,210
Interest and dividends on investment and mortgage-related securities	14,946	26,977	65,208
	210,138	244,815	312,418
Interest expense			
Interest on deposit liabilities	14,696	34,046	61,483
Interest on other borrowings	5,653	9,497	43,941
	20,349	43,543	105,424
Net interest income	189,789	201,272	206,994
Provision for loan losses	20,894	32,000	10,334
Net interest income after provision for loan losses	168,895	169,272	196,660
Noninterest income			
Fee income on deposit liabilities	26,369	30,713	28,332
Fees from other financial services	27,280	25,267	24,846
Fee income on other financial products	6,487	5,833	6,683
Net losses on sale of securities	–	(32,034)	(17,376)
Net 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	12,419	15,569	11,414
	72,555	29,904	46,135
Noninterest expense			
Compensation and employee benefits	71,476	73,990	77,858
Occupancy	16,548	22,057	21,890
Data processing	13,213	14,382	10,678
Services	6,594	11,189	16,706
Equipment	6,620	8,849	12,544
Office supplies, printing and postage	3,928	3,758	4,243
Marketing	2,418	2,134	4,007
Communication	2,221	2,446	3,241
Loss on early extinguishment of debt	–	760	39,843
Other expense	25,920	27,906	24,994
	148,938	167,471	216,004
Income before income taxes	92,512	31,705	26,791
Income taxes	34,056	9,938	8,964
Net income	$ 58,456	$ 21,767	$ 17,827

Consolidated Balance Sheet Data

December 31 (in thousands)	2010	2009
Assets		
Cash and cash equivalents	$ 204,397	$ 425,896
Federal funds sold	1,721	1,479
Available-for-sale investment and mortgage-related securities	678,152	432,881
Investment in stock of Federal Home Loan Bank of Seattle	97,764	97,764
Loans receivable held for investment, net	3,489,880	3,645,578
Loans held for sale, at lower of cost or fair value	7,849	24,915
Other	234,806	230,282
Goodwill	82,190	82,190
	$4,796,759	$4,940,985
Liabilities and shareholder's equity		
Deposit liabilities–noninterest-bearing	$ 865,642	$ 808,474
Deposit liabilities–interest-bearing	3,109,730	3,250,286
Other borrowings	237,319	297,628
Other	90,683	92,129
	4,303,374	4,448,517
Common stock	330,562	329,439
Retained earnings	169,111	172,655
Accumulated other comprehensive loss, net of tax benefits	(6,288)	(9,626)
	493,385	492,468
	$4,796,759	$4,940,985

Other assets

December 31 (in thousands)	2010	2009
Bank-owned life insurance	$117,565	$113,433
Premises and equipment, net	56,495	54,428
Prepaid expenses	18,608	24,353
Accrued interest receivable	14,887	15,247
Mortgage-servicing rights	6,699	4,200
Real estate acquired in settlement of loans, net	4,292	3,959
Other	16,260	14,662
	$234,806	$230,282

Other liabilities

December 31 (in thousands)	2010	2009
Accrued expenses	$16,426	$ 17,270
Federal and state income taxes payable	28,372	19,141
Cashier's checks	22,396	26,877
Advance payments by borrowers	10,216	10,989
Other	13,273	17,852
	$ 90,683	$ 92,129

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 was comprised of: (1) realized losses on the sale of mortgage-related securities and agency notes of $19.3 million included in "Noninterest income-Net 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.

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 pretax included in "Noninterest income-Net 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 pretax) related to this early extinguishment of debt. Over time, ASB used the remaining proceeds from the sale of the PMRS to pay down high cost liabilities (maturing certificates of deposit and wholesale borrowings), to fund loan growth and to reinvest in securities with low credit risk and high liquidity, such as government or agency notes and mortgage-related securities.

As of December 31, 2010, ASB's investment portfolio distribution was 47% mortgage-related securities issued by FNMA, FHLMC or GNMA, 47% federal agency obligations and 6% 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, 2010

					Gross unrealized losses			
		Gross	Gross	Estimated	Less than 12 months		12 months or longer	
(dollars in thousands)	Amortized cost	unrealized gains	unrealized losses	fair value	Fair value	Amount	Fair value	Amount
Available-for-sale								
Federal agency obligations	$317,945	$ 171	$(2,220)	$315,896	$205,316	$(2,220)	$ –	$ –
Mortgage-related securities- FNMA, FHLMC and GNMA	310,711	9,570	(311)	319,970	30,986	(311)	–	–
Municipal bonds	43,632	7	(1,353)	42,286	41,479	(1,353)	–	–
	$672,288	$9,748	$(3,884)	$678,152	$277,781	$(3,884)	$ –	$ –

December 31, 2009

(dollars in thousands)	Amortized cost	Gross unrealized gains	Gross unrealized losses	Estimated fair value	Gross unrealized losses Less than 12 months Fair value	Amount	12 months or longer Fair value	Amount
Available-for-sale								
Federal agency obligations	$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)	$ –	$ –

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).

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

(in thousands)	Amortized Cost	Fair value
Due in one year or less	$ 20,800	$ 20,834
Due after one year through five years	274,338	272,730
Due after five years through ten years	55,955	54,581
Due after ten years	10,484	10,037
	361,577	358,182
Mortgage-related securities-FNMA,FHLMC and GNMA	310,711	319,970
Total available-for-sale securities	$672,288	$678,152

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 2010, 2009 and 2008, proceeds from sales of available-for-sale mortgage-related securities were nil, $185.1 million and $1.2 billion, resulting in gross realized gains of nil, $0.8 million and $0.6 million and gross realized losses of nil, $32.9 million and $19.8 million, respectively.

ASB pledged mortgage-related securities and federal agency obligations with a carrying value of approximately $60.8 million and $33.5 million as of December 31, 2010 and 2009, respectively, as collateral to secure public funds deposits, automated clearinghouse transactions with Bank of Hawaii, and deposits in ASB's bankruptcy and treasury, tax, and loan accounts with the Federal Reserve Bank of San Francisco. As of December 31, 2010 and 2009, mortgage-related securities and federal agency obligations with a carrying value of $204.8 million and $270.1 million, respectively, were pledged as collateral for securities sold under agreements to repurchase.

FHLB of Seattle stock. As of December 31, 2010 and 2009, 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, 2010, consistent with its accounting policy. ASB did not recognize an OTTI loss for 2010 based on its evaluation of the underlying investment (including the net income recorded by the FHLB of Seattle in the first nine months of 2010; 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 accounting 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 accounting 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. ASB did not recognize OTTI for 2010.

(in thousands)	Twelve months ended December 31, 2010	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	$ –	$ –

Loans receivable.

December 31	2010	2009
(in thousands)		
Real estate loans:		
Residential 1-4 family	$2,087,813	$2,332,763
Commercial real estate	300,689	255,716
Home equity line of credit	416,453	326,896
Residential land	65,599	96,515
Commercial construction	38,079	68,174
Residential construction	5,602	16,705
Total real estate loans	2,914,235	3,096,769
Commercial loans	551,683	545,622
Consumer loans	80,138	64,360
Total loans	3,546,056	3,706,751
Deferred loan fees, net and unamortized discounts	(15,530)	(19,494)
Allowance for loan losses	(40,646)	(41,679)
Total loans, net	$3,489,880	$3,645,578

As of December 31, 2010 and 2009, ASB's commitments to originate loans, including the undisbursed portion of loans in process, approximated $77.6 million and $51.7 million, respectively. The increase was primarily due to a $12 million increase in residential and home equity line of credit loan commitments and construction loans in process and $14 million increase in 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, 2010 and 2009, ASB had commitments to sell residential loans of $21.9 million and $18.6 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, 2010 and 2009, ASB had rate lock commitments on outstanding loans totaling $15.1 million and $13.8 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, 2010 and 2009, the notional amounts for forward sales contracts were $21.9 million and $18.6 million, respectively. Valuation models are applied using current market information to estimate fair value. In 2010, there was no gain or loss on derivatives. 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, 2010 and 2009, ASB had commitments to sell education loans of nil and $20.5 million, respectively.

As of December 31, 2010 and 2009, standby, commercial and banker's acceptance letters of credit totaled $16.3 million and $19.5 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, 2010 and 2009, undrawn consumer lines of credit, including credit cards, totaled $856.7 million and $801.1 million, respectively, and undrawn commercial loans including lines of credit totaled $263.4 million and $315.1 million, respectively.

ASB services real estate loans for investors ($0.8 billion, $0.6 billion and $0.3 billion as of December 31, 2010, 2009 and 2008, 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, 2010 and 2009, ASB had pledged loans with an amortized cost of approximately $1.4 billion and $1.6 billion, respectively, as collateral to secure advances from the FHLB of Seattle.

As of December 31, 2010 and 2009, 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 $60.9 million and $79.3 million, respectively. The $18.4 million decrease in such loans in 2010 was attributed to closed lines of credit and repayments of $57.5 million, offset by loans and lines of credit to new and existing directors and executive officers of $39.1 million. As of December 31, 2010 and

2009, $52.5 million and $65.4 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. As discussed in Note 1, ASB must maintain an allowance for loan losses that is adequate to absorb estimated probable credit losses associated with its loan portfolio. The allowance for loan losses consists of an allocated portion, which estimates credit losses for specifically identified loans and pools of loans, and an unallocated portion.

Segmentation. ASB segments its loan portfolio by three levels. In the first level, the loan portfolio is separated into homogeneous and non-homogeneous loan portfolios. Residential, consumer and credit scored business loans are considered homogeneous loans. These are loans that are typically underwritten based on common, uniform standards, and are generally classified as to the level of loss exposure based on delinquency status. Commercial loans and commercial real estate (CRE) loans are defined as non-homogeneous loans and ASB utilitizes a uniform ten–point risk rating system for evaluating the credit quality of the loans. These are loans where the underwriting criteria are not uniform and the risk rating classification is based upon considerations broader than just delinquency performance.

In the second level of segmentation, the loan portfolios are further stratified into individual products with common risk characteristics. For residential loans, the loan portfolio is segmented by loan categories and geographic location first within the State of Hawaii (Oahu vs. the neighbor islands) and second collectively outside of the state. The consumer loan portfolio is segmented into various unsecured loan product types. The credit scored business loan portfolio is segmented by loans under lines of credit or term loans, and corporate credit cards. For commercial loans, the portfolio is differentiated by separating Commercial & Industrial (C&I) loans and C&I loans guaranteed by Small Business Administration programs while CRE loans are grouped by owner-occupied loans, investor loans, construction loans, and vacant land loans.

For the third and last level of segmentation, loans are categorized into the regulatory asset quality classifications – Pass, Substandard, and Loss for homogeneous loans based primarily on delinquency status, and Pass (Risk Rating 1 to 6), Special Mention (Risk Rating 7), Substandard (Risk Rating 8), Doubtful (Risk Rating 9), and Loss (Risk Rating 10) for non-homogeneous loans based on credit quality.

Specific allocation.

Residential real estate. All residential real estate loans that are 180 days delinquent, or where ASB has initiated foreclosure action or have been modified in a TDR are reviewed for impairment based on the fair value of the collateral, net of costs to sell. Generally, impairment amounts derived under this method are immediately charged off.

Consumer. The consumer loan portfolio specific allocation is determined based on delinquency; unsecured consumer loans are generally charged-off based on delinquency status varying from 120 to 180 days.

Commercial and CRE. A specific allocation is determined for impaired commercial and CRE loans. See further discussion in Note 1.

Pooled allocation.

Residential real estate and consumer. Pooled allocation for non-impaired residential real estate and consumer loans are determined using a historical loss rate analysis and qualitative factor considerations.

Commercial and CRE. Pooled allocation for pass, special mention, substandard, and doubtful grade commercial and CRE loans that share common risk characteristics and properties are determined using a historical loss rate analysis and qualitative factor considerations.

Qualitative adjustments. Qualitative adjustments to historical loss rates or other static sources may be necessary since these rates may not be an accurate guide to assessing losses inherent in the current portfolio. To estimate the level of adjustments, management considers factors including levels and trends in problem loans, volume and term of loans, changes in risk from changes in lending policies and practices, management expertise, economic conditions, industry trends, and the effect of credit concentrations.

Unallocated allowance. ASB's allowance incorporates an unallocated portion to cover risk factors and events that may have occurred as of the evaluation date that have not been reflected in the risk measures due to inherent limitations to the precision of the estimation process. These risk factors, in addition to micro- and macro- economic factors, past, current and anticipated events based on facts at the balance sheet date, and realistic courses of action that management expects to take, are assessed in determining the level of unallocated allowance.

At December 31, 2010, the allowance for loan losses was comprised of the following:

(in thousands)	Residential 1-4 family	Commercial real estate	Home equity line of credit	Residential land	Commercial construction	Residential construction	Commercial loans	Consumer loans	Unallocated	Total
Allowance for loan losses:										
Beginning balance	$5,522	$ 861	$ 4,679	$4,252	$ 3,068	$ 19	$19,498	$2,590	$1,190	$41,679
Charge-offs	6,142	–	2,517	6,487	–	–	6,261	3,408	–	24,815
Recoveries	744	–	63	63	–	–	1,537	481	–	2,888
Provision	6,373	$613	2,044	8,583	(1,354)	(12)	1,241	$3,662	(256)	20,894
Ending balance	$6,497	$1,474	$ 4,269	$6,411	$ 1,714	$ 7	$16,015	$3,325	$ 934	$40,646
Ending balance: individually evaluated for impairment	$230	$ –	$ –	$1,642	$ –	$ –	$ 1,588	$ –		$ 3,460
Ending balance: collectively evaluated for impairment	$6,267	$1,474	$4,269	$4,769	$1,714	$ 7	$ 14,427	$3,325	$934	$37,186
Ending balance: loans acquired with deteriorated credit quality	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –		$ –
Financing Receivables:										
Ending balance	$2,087,813	$300,689	$416,453	$65,599	$38,079	$5,602	$551,683	$80,138		$3,546,056
Ending balance: individually evaluated for impairment	$34,615	$12,156	$827	$39,631	$ –	$ –	$28,886	$76		$116,191
Ending balance: collectively evaluated for impairment	$2,053,198	$288,533	$415,626	$25,968	$38,079	$5,602	$522,797	$80,062		$3,429,865
Ending balance: loans acquired with deteriorated credit quality	$ –	$ –	$ –	$ –	$ –	$ –	$ –	$ –		$ –

Changes in the allowance for loan losses were as follows:

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

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

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

The loan grade categories are:

1- Substantially risk free	6- Acceptable risk
2- Minimal risk	7- Special mention
3- Modest risk	8- Substandard
4- Better than average risk	9- Doubtful
5- Average risk	10- Loss

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

The credit risk profile by internally assigned grade for loans at December 31, 2010 was as follows:

(in thousands)	Commercial real estate	Commercial construction	Commercial
Grade:			
Pass	$285,624	$ 38,079	$ 462,078
Special mention	526	–	44,759
Substandard	14,539	–	44,259
Doubtful	–	–	556
Loss	–	–	31
Total	$300,689	$ 38,079	$ 551,683

The credit risk profile based on payment activity for loans at December 31, 2010 was as follows:

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

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

	Nonaccrual loans		Accruing loans 90 days or more past due		Trouble debt restructured loans	
December 31	2010	2009	2010	2009	2010	2009
(in thousands)						
Real estate loans:						
Residential 1-4 family	$36,420	$31,848	$ –	$ –	$ 5,150	$ 1,986
Commercial real estate	–	344	–	–	1,963	513
Home equity line of credit	1,659	2,755	–	–	–	–
Residential land	15,479	25,164	581	–	27,689	15,665
Commercial construction	–	–	–	–	–	–
Residential construction	–	326	–	–	–	–
Commercial loans	4,956	4,171	64	–	4,035	2,904
Consumer loans	341	715	320	–	–	–
Total	$58,855	$65,323	$965	$ –	$38,837	$ 21,068

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

December 31	2010					2009				
(in thousands)	Recorded investment	Unpaid principal balance	Related Allow-ance	Average recorded investment	Interest income recognized	Recorded investment	Unpaid principal balance	Related allow-ance	Average recorded investment	Interest income recognized
With no related allowance recorded										
Real estate loans:										
Residential 1-4 family	$ 18,205	$ 24,692	$ –	$14,609	$ 278	$ 2,412	$ 2,412	$ –	$ 1,891	$ 91
Commercial real estate	12,156	12,156	–	14,276	979	15,212	15,212	–	14,522	882
Home equity line of credit	–	–	–	–	–	–	–	–	–	–
Residential land	33,777	40,802	–	29,914	1,499	16,552	16,552	–	7,934	589
Commercial construction	–	–	–	–	–	–	–	–	–	–
Residential construction	–	–	–	–	–	–	–	–	–	–
Commercial loans	22,041	22,041	–	29,636	1,846	27,082	27,082	–	29,908	1,412
Consumer loans	–	–	–	–	–	–	–	–	–	–
	86,179	99,691	–	88,435	4,602	61,258	61,258	–	54,255	2,974
With an allowance recorded										
Real estate loans:										
Residential 1-4 family	3,917	3,917	230	2,807	175	–	–	–	–	–
Commercial real estate	–	–	–	–	–	–	–	–	–	–
Home equity line of credit	–	–	–	–	–	–	–	–	–	–
Residential land	5,041	5,090	1,642	3,753	327	–	–	–	–	–
Commercial construction	–	–	–	–	–	–	–	–	–	–
Residential construction	–	–	–	–	–	–	–	–	–	–
Commercial loans	6,845	6,845	1,588	2,796	182	4,505	4,505	1,635	3,937	236
Consumer loans	–	–	–	–	–	–	–	–	–	–
	15,803	15,852	3,460	9,356	684	4,505	4,505	1,635	3,937	236
Total										
Real estate loans:										
Residential 1-4 family	22,122	28,609	230	17,416	453	2,412	2,412	–	1,891	91
Commercial real estate	12,156	12,156	–	14,276	979	15,212	15,212	–	14,522	882
Home equity line of credit	–	–	–	–	–	–	–	–	–	–
Residential land	38,818	45,892	1,642	33,667	1,826	16,552	16,552	–	7,934	589
Commercial construction	–	–	–	–	–	–	–	–	–	–
Residential construction	–	–	–	–	–	–	–	–	–	–
Commercial loans	28,886	28,886	1,588	32,432	2,028	31,587	31,587	1,635	33,845	1,648
Consumer loans	–	–	–	–	–	–	–	–	–	–
	$101,982	$115,543	$3,460	$97,791	$5,286	$65,763	$65,763	$1,635	$58,192	$3,210

Deposit liabilities.

December 31	2010		2009	
(dollars in thousands)	Weighted-average stated rate	Amount	Weighted-average stated rate	Amount
Savings	0.12%	$1,623,211	0.19%	$1,592,739
Other checking				
Interest-bearing	0.05	589,228	0.09	580,737
Noninterest-bearing	–	473,297	–	427,585
Commercial checking	–	392,345	–	380,889
Money market	0.28	230,990	0.43	202,115
Term certificates	1.25	666,301	1.65	874,695
	0.28%	$3,975,372	0.46%	$4,058,760

As of December 31, 2010 and 2009, certificate accounts of $100,000 or more totaled $153 million and $208 million, respectively.

The approximate amounts of term certificates outstanding as of December 31, 2010 with scheduled maturities for 2011 through 2015 were $436 million in 2011, $72 million in 2012, $43 million in 2013, $40 million in 2014, $60 million in 2015 and $15 million thereafter.

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

(in thousands)	2010	2009	2008
Term certificates	$11,221	$27,369	$49,530
Savings	2,262	4,952	8,577
Money market	884	886	1,793
Interest-bearing checking	329	839	1,583
	$14,696	$34,046	$61,483

Other borrowings.

Securities sold under agreements to repurchase.

December 31, 2010 Maturity (dollars in thousands)	Repurchase liability	Weighted-average interest rate	Collateralized by mortgage-related securities and federal agency obligations– fair value plus accrued interest
Overnight	$122,022	0.45%	$141,733
1 to 29 days	–	–	–
30 to 90 days	–	–	–
Over 90 days	50,297	4.75	63,691
	$172,319	1.71%	$205,424

At December 31, 2010, $50 million of securities sold under agreements to repurchase with a 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)	2010	2009	2008
Amount outstanding as of December 31	$172	$233	$241
Average amount outstanding during the year	$201	$230	$507
Maximum amount outstanding as of any month-end	$238	$241	$817
Weighted-average interest rate as of December 31	1.71%	1.38%	1.86%
Weighted-average interest rate during the year	1.53%	1.55%	2.98%
Weighted-average remaining days to maturity as of December 31	628	544	601

Advances from Federal Home Loan Bank.

December 31, 2010	Weighted-average stated rate	Amount
(dollars in thousands)		
Due in		
2011	2.64%	$15,000
2012	–	–
2013	–	–
2014	–	–
2015	–	–
Thereafter	4.28	50,000
	3.90%	$65,000

At December 31, 2010, $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, 2010 and 2009.

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, 2010, 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, 2010, ASB was in compliance with the minimum capital requirements under OTS regulations.

In 2010, ASB paid dividends of $62 million to HEI, compared to $50.1 million in 2009. The OTS must approve ASB's dividends.

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 a judgment and loss sharing agreement with Visa in order to apportion financial responsibilities arising from any potential adverse judgment or negotiated settlements related to indemnified litigation involving Visa. As of December 31, 2010, ASB had accrued

$1.1 million related to the agreement. 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 restoration plan. Under the Federal Deposit Insurance Reform Act of 2005 (the Reform Act), the Federal Deposit Insurance Corporation (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, by 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 a 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. For the years ended December 31, 2010 and 2009, ASB's assessment rate was 14 basis points of deposits, or $5.7 million and $5.8 million, respectively.

In November 2010, the FDIC proposed a change to its assessment base from total domestic deposits to average total assets minus average tangible equity, as required in the Dodd-Frank Act. The proposal would also lower the assessment rate schedule since the new base is larger than the current base. Assessment rates would be reduced to a range of 2.5 to 9 basis points on the new assessment base for financial institutions in the lowest risk category. Financial institutions in the highest risk category will have assessment rates of 30 to 45 basis points. Based on the proposed changes to the assessment base and rates, ASB anticipates a reduction in its annual FDIC assessment by approximately $2 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. In July 2010, the Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) permanently raised the current standard maximum deposit insurance amount to $250,000. Previously, the standard maximum deposit insurance amount of $100,000 had been temporarily raised to $250,000 through December 31, 2013. The Dodd-Frank Act also redefines the assessment base as average total consolidated assets less average tangible equity (previously the assessment base was based on deposits).

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 VIEs. Trust III's balance sheet as of December 31, 2010 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 2010 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, 2010, HECO and its subsidiaries had six PPAs totaling 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), none of which are currently required to be consolidated as VIEs. 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 2010 totaled $549 million with purchases from AES Hawaii, Kalaeloa, HEP and HPOWER totaling $143 million, $225 million, $57 million and $44 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 2010, 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 • Interest rate swap agreements

In June 2010, HEI entered into multiple Forward Starting Swaps (FSS) with notional amounts totaling $125 million to hedge against interest rate fluctuations on a portion of the $150 million of medium-term notes expected to be issued by HEI in 2011, thereby enabling HEI to better forecast its future interest expense. The FSS terminate in January and June 2011 and entitle HEI to receive/(pay) the present value of the positive/(negative) difference between three-month LIBOR and a fixed rate at termination applied to the notional amount over a five-year period. The FSS are designated and accounted for as cash flow hedges and have a negative fair value of $2.8 million as of December 31, 2010 (recorded in "Other" liabilities on the consolidated balance sheet). Changes in fair value are recognized (1) in other comprehensive income to the extent that they are considered effective, and (2) in net income for any portion considered ineffective. The balance in accumulated other comprehensive income/(loss) (AOCI) at the dates of the anticipated medium-term note issuances will be accreted/amortized into interest expense over the lives of the new notes based on the effective interest method. For 2010, the ineffective portion of the change in fair value, or $0.8 million ($0.5 million, net of tax benefits), was recorded as a derivative loss in "Interest expense—other than on deposit liabilities and other bank borrowings" and the effective portion, or $2.0 million ($1.2 million, net of tax benefits), was recorded as a net loss in AOCI. Of the $1.2 million net loss in AOCI, a net $0.2 million is expected to be reclassified to earnings during the next 12 months.

In January 2011, HEI settled FSS with notional amounts totaling $50 million and a negative fair value of $1.3 million as of December 31, 2010 for a payment of $1.0 million.

7 • Short-term borrowings

As of December 31, 2010 and December 31, 2009, HEI had $25 million and $42 million of outstanding commercial paper, respectively, with a weighted-average interest rate of 0.9% and 0.6%, respectively, and HECO had no commercial paper outstanding.

As of December 31, 2010, HEI and HECO maintained syndicated credit facilities which totaled $125 million and $175 million, respectively. As of December 31, 2009, HEI and HECO maintained syndicated credit facilities which totaled $100 million and $175 million, respectively. HEI had no borrowings under its facility during 2010 and 2009. HECO had no borrowings under its facilities during 2010. HECO drew on its facility in June and July 2009; all such borrowings were repaid in August 2009. None of the facilities are collateralized.

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

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

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

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

8 • Long-term debt

December 31	2010	2009
(dollars in thousands)		
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
5.65-5.75%, 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	150,000
	1,007,900	1,007,900
Less unamortized discount	(1,504)	(1,631)
	1,006,396	1,006,269
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
	$1,364,942	$1,364,815

As of December 31, 2010, the aggregate principal payments required on long-term debt for 2011 through 2015 are $150 million in 2011, $65 million in 2012, $50 million in 2013, $111 million in 2014 and nil in 2015.

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, noncontributory 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.

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 of 2009, the Company amended the executive life benefit plan to limit it to current participants and to freeze the executive life benefits at current levels. In November 2010, August 2010 and August 2009, HELCO, MECO and HECO, respectively, eliminated the electric discount benefit for merit employees and retirees, and the electric discount benefit for bargaining unit employees and retirees was eliminated on January 31, 2011. The Company's cost for OPEB has been adjusted to reflect the plan amendment, which reduced benefits. The elimination of the 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% 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. Employers must recognize on their balance sheets the funded status of defined benefit pension and other postretirement benefit plans with an offset to AOCI in shareholders' equity (using the projected benefit obligation (PBO), to calculate the funded status).

The PUC allowed the utilities to adopt pension and OPEB tracking mechanisms in recent rate cases. 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 $1.6 million in 2010) 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. 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 $55 million pretax and $(124) million pretax at December 31, 2010 and 2009, respectively).

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.

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, 2010, MECO did not have any remaining pension asset, and HECO's pension asset had been reduced to $3 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.

Retirement benefits expense for the electric utilities for 2010, 2009 and 2008 was $39 million, $32 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 2010 and 2009 and the funded status of these plans and amounts related to these plans reflected in the Company's consolidated balance sheet as of December 31, 2010 and 2009 were as follows:

	2010		2009	
(in thousands)	Pension benefits	Other benefits	Pension benefits	Other benefits
Benefit obligation, January 1	$1,014,287	$170,572	$ 964,388	$180,656
Service cost	28,801	4,739	25,688	4,846
Interest cost	64,527	10,378	61,988	10,981
Amendments	–	(7,713)	109	(13,198)
Actuarial (gains) losses	121,898	11,817	14,323	(3,907)
Benefits paid and expenses	(54,979)	(9,461)	(52,209)	(8,806)
Benefit obligation, December 31	1,174,534	180,332	1,014,287	170,572
Fair value of plan assets, January 1	738,971	134,608	619,134	106,415
Actual return on plan assets	119,446	21,271	154,942	27,386
Employer contribution	27,803	3,989	15,883	9,471
Benefits paid and expenses	(53,864)	(8,751)	(50,988)	(8,664)
Fair value of plan assets, December 31	832,356	151,117	738,971	134,608
Accrued benefit liability, December 31	(342,178)	(29,215)	(275,316)	(35,964)
AOCI, January 1 (excluding impact of PUC D&Os)	302,147	14,693	400,875	52,433
Recognized during year – net recognized transition obligation	(2)	–	(2)	(1,831)
Recognized during year – prior service (cost)/credit	388	396	387	79
Recognized during year – net actuarial gains (losses)	(7,392)	14	(15,847)	(401)
Occurring during year – prior service cost	–	(7,714)	109	(2,476)
Occurring during year – net actuarial losses (gains)	71,411	1,647	(83,375)	(22,390)
Other adjustments	–	–	–	(10,721)
	366,552	9,036	302,147	14,693
Cumulative impact of PUC D&Os	(340,187)	(10,880)	(278,582)	(17,650)
AOCI, December 31	26,365	(1,844)	23,565	(2,957)
Net actuarial loss	367,456	18,633	303,437	16,972
Prior service gain	(907)	(9,597)	(1,295)	(2,279)
Net transition obligation	3	–	5	–
	366,552	9,036	302,147	14,693
Cumulative impact of PUC D&Os	(340,187)	(10,880)	(278,582)	(17,650)
AOCI, December 31	26,365	(1,844)	23,565	(2,957)
Income taxes	(10,403)	718	(9,309)	1,151
AOCI, net of taxes, December 31	$ 15,962	$ (1,126)	$ 14,256	$ (1,806)

The Company does not expect any plan assets to be returned to the Company during calendar year 2011.

The dates used to determine retirement benefit measurements for the defined benefit plans were December 31 of 2010, 2009 and 2008.

The defined benefit pension plans with accumulated benefit obligations (ABOs), which do not consider projected pay increases (unlike the PBOs shown in the table above), in excess of plan assets as of December 31, 2010 and 2009, had aggregate ABOs of $990 million and $858 million, respectively, and plan assets of $758 million and $673 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. If the plans fall below these thresholds, then, to avoid adverse consequences, funds in excess of the minimum required contribution may be contributed to the plan trust. 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 2011 is $64 million.

The Company estimates that the cash funding for the qualified defined benefit pension plans in 2011 and 2012 will be $60 million and $125 million, respectively, which should fully satisfy the minimum required contributions to those plans, including requirements of the utilities pension tracking mechanisms and the Plan's funding policy.

As of December 31, 2010, the benefits expected to be paid under the retirement benefit plans in 2011, 2012, 2013, 2014, 2015 and 2016 through 2020 amounted to $66 million, $69 million, $72 million, $75 million, $79 million and $452 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	2010	2009	Target	Range	2010	2009	Target	Range
Asset category								
Equity securities	71%	68%	70%	65-75%	70%	67%	70%	65-75%
Fixed income	29	32	30	25-35%	30	33	30	25-35%
	100%	100%	100%		100%	100%	100%	

See Note 15 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	2010	2009	2008	2010	2009	2008
Benefit obligation						
Discount rate	5.68%	6.50%	6.625%	5.60%	6.50%	6.50%
Rate of compensation increase	3.5	3.5	3.5	NA	NA	3.5
Net periodic benefit cost (years ended)						
Discount rate	6.50	6.625	6.125	6.50	6.50	6.125
Expected return on plan assets	8.25	8.25	8.50	8.25	8.25	8.50
Rate of compensation increase	3.5	3.5	4.2	NA	3.5	4.2

NA Not applicable

The Company based its selection of an assumed discount rate for 2011 net periodic benefit cost and December 31, 2010 disclosure on a cash flow matching analysis that utilized bond information provided by Bloomberg for all non-callable, high quality bonds (i.e., rated AA- or better) as of December 31, 2010. In selecting the expected rate of return on plan assets of 8% for 2011 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 matching of bond income to anticipated benefit cash flows was refined for 2010 but the basic methods of selecting the assumed discount rate and expected return on plan assets at December 31, 2010 did not change from December 31 2009.

As of December 31, 2010, the assumed health care trend rates for 2011 and future years were as follows: medical, 9%, grading down to 5% for 2019 and thereafter; dental, 5%; and vision, 4%. 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%.

The components of net periodic benefit cost were as follows:

	Pension benefits			Other benefits		
(in thousands)	2010	2009	2008	2010	2009	2008
Service cost	$ 28,801	$ 25,688	$ 28,356	$ 4,739	$ 4,846	$ 4,777
Interest cost	64,527	61,988	59,765	10,378	10,981	11,008
Expected return on plan assets	(68,959)	(57,244)	(73,172)	(11,101)	(8,902)	(10,970)
Amortization of net transition obligation	2	2	2	–	1,831	3,138
Amortization of net prior service cost (gain)	(388)	(387)	(421)	(396)	(79)	13
Amortization of net actuarial loss (gain)	7,392	15,847	6,765	(14)	401	–
Net periodic benefit cost	31,375	45,894	21,295	3,606	9,078	7,966
Impact of PUC D&Os	10,207	(10,570)	5,859	5,400	(132)	1,038
Net periodic benefit cost (adjusted for impact of PUC D&Os)	$ 41,582	$ 35,324	$ 27,154	$ 9,006	$ 8,946	$ 9,004

The estimated prior service credit, net actuarial loss and net transition obligation for defined benefit pension plans that will be amortized from AOCI or regulatory assets into net periodic pension benefit cost during 2011 are $(0.3) million, $17.4 million and de minimis, respectively. The estimated prior service cost (gain), net actuarial loss and net transitional obligation for other benefit plans that will be amortized from AOCI or regulatory assets into net periodic other than pension benefit cost during 2011 are $(0.9) million, de minimis and nil, respectively.

The Company recorded pension expense of $32 million, $27 million and $20 million and OPEB expense of $7 million, $7 million and $7 million in 2010, 2009 and 2008, respectively, and charged the remaining amounts primarily to electric utility plant.

All pension plans and other benefits plans, with the exception of the ASB Retirement Plan, had accumulated benefit obligations exceeding plan assets as of December 31, 2010 and December 31, 2009.

The health care cost trend rate assumptions can have a significant effect on the amounts reported for other benefits. As of December 31, 2010, a one-percentage-point increase in the assumed health care cost trend rates would have increased the total service and interest cost by $0.2 million and the PBO by $3 million, and a one-percentage-point decrease would have reduced the total service and interest cost by $0.2 million and the PBO by $3 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. On March 17, 2010, ASB contributed $1.9 million to fund AmeriShare for the 2009 plan year. This contribution equaled to 3.6% of eligible pay for eligible participants. ASB has accrued $1.9 million and $1.5 million in 2010 and 2009, respectively, for its anticipated Amerishare contributions in early 2011 and 2010, respectively. For 2010 and 2009, ASB's total expense for its employees participating in the HEI retirement savings plan and the new ASB 401(k) Plan combined was $3.6 million and $3.3 million, respectively, and cash contributions were $3.6 million and $3.9 million, respectively.

10 • Share-based compensation

The 2010 Equity and Incentive Plan (EIP) was approved by shareholders in May 2010 and allows HEI to issue an aggregate of 4 million shares of common stock as incentive compensation to selected employees in the form of stock options, stock appreciation rights, restricted shares, restricted stock units, performance shares and other share-based and cash-based awards. The term “deferred shares” in the EIP was replaced by amendment to the EIP with the term “restricted stock units,” which is the term historically used by the Company to refer to a form of award equivalent to deferred shares. Through December 31, 2010, grants under the EIP consisted of 18,009 restricted shares and 77,500 restricted stock units.

Under the 1987 Stock Option and Incentive Plan, as amended (SOIP), grants and awards of an estimated 1.1 million shares of common stock (based on various assumptions, including long-term incentive plan (LTIP) awards at maximum levels and the use of the December 31, 2010 market price of shares as the price on the exercise/payment dates) were outstanding as of December 31, 2010 to selected employees in the form of nonqualified stock options (NQSOs), stock appreciation rights (SARs), restricted stock units, LTIP performance and other shares and dividend equivalents. As of May 11, 2010, no new awards may be granted under the SOIP. After the shares of common stock for the outstanding SOIP grants and awards are issued or such grants and awards expire, the remaining shares registered under the SOIP will be deregistered and delisted.

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 generally became exercisable in installments of 25% each year for four years, and expire if not exercised ten years from the date of the grant. 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.

The restricted shares that have been issued under the EIP become unrestricted in four equal annual increments on the anniversaries of the grant date and are forfeited to the extent they have not become unrestricted for terminations of employment during the vesting period, except accelerated vesting is provided for terminations by reason of death, disability and termination without cause. Restricted stock awards under the SOIP generally become unrestricted four 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 shares and restricted stock awards compensation expense has been recognized in accordance with the fair-value-based measurement method of accounting. Dividends on restricted shares and restricted stock awards are paid quarterly in cash.

Restricted stock units awarded under the SOIP and EIP in 2010 and prior years 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 are accrued quarterly and are paid in cash at the end of the restriction period when the restricted stock units vest.

Stock performance awards granted under the 2009-2011 and 2010-2012 LTIPs entitle the grantee to shares of common stock with dividend equivalent rights once service conditions and performance conditions are satisfied at the end of the three-year performance period. LTIP awards are forfeited for terminations of employment during the performance period, except that pro-rata participation 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 stock performance awards portion of the

LTIP 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 are as follows:

(in millions)	2010	2009	2008
Share-based compensation expense [1]	$2.7	$1.1	$0.8
Income tax benefit	0.9	0.3	0.1

[1] The Company has not capitalized any share-based compensation cost.

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

	2010		2009		2008	
	Shares	(1)	Shares	(1)	Shares	(1)
Outstanding, January 1	374,500	$19.73	375,500	$19.73	603,800	$19.68
Granted	–	–	–	–	–	–
Exercised	(157,000)	18.32	–	–	(220,300)	19.62
Forfeited	–	–	–	–	–	–
Expired	(2,000)	20.49	(1,000)	17.61	(8,000)	19.23
Outstanding, December 31	215,500	$20.76	374,500	$19.73	375,500	$19.73
Exercisable, December 31	215,500	$20.76	374,500	$19.73	375,500	$19.73

(1) Weighted-average exercise price

December 31, 2010		Outstanding & Exercisable (Vested)		
Year of Grant	Range of exercise prices	Number of options	Weighted-average remaining contractual life	Weighted-average exercise price
2001	$ 17.96	16,000	0.3	$17.96
2002	21.68	82,000	1.1	21.68
2003	20.49	117,500	2.0	20.49
	$17.96 – 21.68	215,500	1.5	$20.76

As of December 31, 2010, all NQSOs outstanding were exercisable and had an aggregate intrinsic value (including dividend equivalents) of $1.0 million.

NQSO activity and statistics are summarized as follows:

($ in thousands, except prices)	2010	2009	2008
Cash received from exercise	$2,876	–	$4,323
Intrinsic value of shares exercised [1]	$1,355	–	$2,235
Tax benefit realized for the deduction of exercises	$278	–	$705
Dividend equivalent shares distributed under Section 409A	–	–	6,125
Weighted-average Section 409A distribution price	–	–	$22.38
Intrinsic value of shares distributed under Section 409A	–	–	$137
Tax benefit realized for Section 409A distributions	–	–	$53

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

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

	2010		2009		2008	
	Shares	(1)	Shares	(1)	Shares	(1)
Outstanding, January 1	480,000	$26.13	791,000	$26.12	857,000	$26.12
Granted	–	–	–	–	–	–
Exercised	–	–	–	–	(36,000)	26.05
Forfeited	–	–	(6,000)	26.18	(30,000)	26.18
Expired	(30,000)	26.18	(305,000)	26.10	–	–
Outstanding, December 31	450,000	$26.13	480,000	$26.13	791,000	$26.12
Exercisable, December 31	450,000	$26.13	480,000	$26.13	557,000	$26.10

(1) Weighted-average exercise price

(2) December 31, 2010		Outstanding & Exercisable (Vested)		
Year of Grant	Range of exercise prices	Number of shares underlying SARs	Weighted-average remaining contractual life	Weighted-average exercise price
2004	$ 26.02	150,000	2.1	$26.02
2005	26.18	300,000	2.8	26.18
	$26.02 –26.18	450,000	2.6	$26.13

As of December 31, 2010, all SARs outstanding were exercisable and had no intrinsic value.

SARs activity and statistics are summarized as follows:

($ in thousands, except prices)	2010	2009	2008
Shares vested	–	228,000	129,000
Aggregate fair value of vested shares	–	$1,354	$733
Intrinsic value of shares exercised [1]	–	–	$127
Tax benefit realized for the deduction of exercises	–	–	$49
Dividend equivalent shares distributed under Section 409A	–	3,143	–
Weighted-average Section 409A distribution price	–	$13.64	–
Intrinsic value of shares distributed under Section 409A	–	$43	–
Tax benefit realized for Section 409A distributions	–	$17	–

[1] Intrinsic value is the amount by which the fair market value of the underlying stock and the related dividend equivalents exceeds the exercise price of the right.

Section 409A. As a result of the changes enacted in Section 409A of the Internal Revenue Code of 1986, as amended (Section 409A), in 2009 and 2008, a total of 3,143 and 6,125 dividend equivalent shares, respectively, for NQSO and SAR grants were distributed to SOIP participants. Section 409A, which amended the federal income tax rules governing 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 was made in 2010. No further dividend equivalents are intended to be paid in accordance with this Section 409A modified distribution.

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

	2010		2009		2008	
	Shares	(1)	Shares	(1)	Shares	(1)
Outstanding, January 1	129,000	$25.50	160,500	$25.51	146,000	$25.82
Granted	18,009(2)	22.21	–	–	45,000(3)	24.71
Vested	(43,565)	26.29	(3,851)	24.52	(6,170)	25.44
Forfeited	(13,735)	24.35	(27,649)	25.67	(24,330)	25.90
Outstanding, December 31	89,709	$24.64	129,000	$25.50	160,500	$25.51

(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.
(2) Total weighted-average grant-date fair value of $0.4 million.
(3) Total weighted-average grant-date fair value of $1.1 million.

As of December 31, 2010, 18,009 restricted shares were outstanding under the EIP and 71,700 shares of restricted stock were outstanding under the SOIP.

For 2010, 2009 and 2008, total restricted stock vested had a fair value of $1.1 million, $0.1 million and $0.2 million, respectively, and the tax benefits realized for the tax deductions related to restricted stock awards were $0.3 million for 2010, $0.1 million for 2009 and $0.2 million for 2008.

As of December 31, 2010, there was $0.6 million of total unrecognized compensation cost related to nonvested restricted shares and restricted stock awards. The cost is expected to be recognized over a weighted-average period of 2.6 years.

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

	2010		2009	
	Shares	(1)	Shares	(1)
Outstanding, January 1	70,500	$16.99	–	–
Granted	77,500(2)	22.30	70,500(3)	$16.99
Vested	(250)	16.99	–	–
Forfeited	(1,250)	16.99	–	–
Outstanding, December 31	146,500	$19.80	70,500	$16.99

(1) Weighted-average grant-date fair value per share. The grant date fair value of the restricted stock units was the average price of HEI common stock on the date of grant.
(2) Total weighted-average grant-date fair value of $1.7 million.
(3) Total weighted-average grant-date fair value of $1.2 million.

As of December 31, 2010, 77,500 restricted stock units were outstanding under the EIP and 69,000 restricted stock units were outstanding under the SOIP.

As of December 31, 2010, there was $1.8 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 2.9 years.

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

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

	2010		2009	
Awards	Shares	(1)	Shares	(1)
Outstanding, January 1	36,198	$14.85	–	–
Granted	97,191	22.45	36,198(2)	$14.85
Vested	–	–	–	–
Forfeited	(6,607)	21.53	–	–
Outstanding, December 31	126,782	$20.33	36,198	$14.85

(1) Weighted-average grant-date fair value per share determined using a Monte Carlo simulation model.
(2) Total weighted-average grant-date fair value of $0.5 million.

On February 8, 2010, LTIP grants (under the 2010-2012 LTIP) were made payable in 97,191 shares of HEI common stock (based on the grant date price of $18.95 and target TRS performance levels), with a weighted-average grant date fair value of $2.2 million based on the weighted-average grant date fair value per share of $22.45.

The grant date fair values of the shares were determined using a Monte Carlo simulation model utilizing actual information for the common shares of HEI and its peers for the period from the beginning of the performance period to the grant date and estimated future stock volatility and dividends of HEI and its peers over the remaining three-year performance period. 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 LTIP linked to TRS and the resulting fair value of LTIP granted:

	2010	2009
Risk-free interest rate	1.30%	1.30%
Expected life in years	3	3
Expected volatility	27.9%	23.7%
Dividend yield	6.55%	4.53%
Range of expected volatility for Peer Group	22.3% to 52.3%	20.8% to 46.9%
Grant date fair value (per share)	$22.45	$14.85

As of December 31, 2010, there was $1.5 million of total unrecognized compensation cost related to the nonvested performance awards payable in shares linked to TRS. The cost is expected to be recognized over a weighted-average period of 1.7 years

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

	2010		2009	
	Shares	(1)	Shares	(1)
Outstanding, January 1	24,131	$16.99	–	–
Granted	160,939	18.95	24,131(2)	$16.99
Vested	–	–	–	–
Forfeited	(23,760)	18.90	–	–
Outstanding, December 31	161,310	$18.66	24,131	$16.99

(1) Weighted-average grant-date fair value per share based on the average price of HEI common stock on the date of grant.
(2) Total weighted-average grant-date fair value of $0.4 million.

On February 8, 2010, LTIP grants (under the 2010-2012 LTIP) were made payable in 160,939 shares of HEI common stock (based on the grant date price of $18.95 and target performance levels relating to performance goals other than TRS), with a weighted-average grant date fair value of $3.0 million based on the weighted-average grant date fair value per share of $18.95.

As of December 31, 2010, there was $2.3 million of total unrecognized compensation cost related to the nonvested shares linked to performance conditions other than TRS. The cost is expected to be recognized over a weighted-average period of 1.9 years.

11 • Income taxes

The components of income taxes attributable to net income for common stock were as follows:

Years ended December 31	2010	2009	2008
(in thousands)			
Federal			
Current	$(25,446)	$25,691	$38,041
Deferred	85,268	14,161	7,045
Deferred tax credits, net	(901)	(593)	(1,094)
	58,921	39,259	43,992
State			
Current	(7,392)	6,930	4,409
Deferred	13,425	(783)	(815)
Deferred tax credits, net	2,868	(1,483)	1,392
	8,901	4,664	4,986
Total	$ 67,822	$43,923	$48,978

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	2010	2009	2008
(in thousands)			
Amount at the federal statutory income tax rate	$64,136	$45,088	$48,740
Increase (decrease) resulting from:			
State income taxes, net of effect on federal income taxes	5,786	3,033	3,241
Other, net	(2,100)	(4,198)	(3,003)
Total	$67,822	$43,923	$48,978
Effective income tax rate	37.0%	34.1%	35.2%

The tax effects of book and tax basis differences that give rise to deferred tax assets and liabilities were as follows:

December 31	2010	2009
(in thousands)		
Deferred tax assets		
Cost of removal in excess of salvage value	$107,913	$109,210
Contributions in aid of construction and customer advances	78,958	77,766
Allowance for loan losses	16,461	16,869
Retirement benefits (AOCI)	9,685	8,269
Other	35,878	39,533
	248,895	251,647
Deferred tax liabilities		
Property, plant and equipment	375,361	336,569
Retirement benefits	12,164	6,367
Goodwill	20,130	18,233
Regulatory assets, excluding amounts attributable to property, plant and equipment	32,074	31,947
FHLB stock dividend	20,552	20,552
Change in accounting method related to repairs	46,702	–
Change in accounting method related to contributions in aid of construction	–	8,010
Other	20,870	18,844
	527,853	440,522
Net deferred income tax liability	$278,958	$188,875

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 2010, the significant increase in the net deferred income tax liability was primarily due to accelerated tax deductions taken for bonus depreciation (resulting from the Small Business Jobs Act and the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act) and the change in accounting method for repairs deductions for tax purposes. In 2010, $2.0 million of deferred tax assets were written off due to the expiration of the capital loss carryforward period for losses on an investment in China, which the IRS maintains is a capital loss while HEI asserts the loss is an ordinary deduction.

In 2010, interest income on income tax refunds was reflected in “Revenues—Electric utility” in the amount of $9.7 million, which resulted from the settlement with the IRS of appealed issues for the tax years 1996 to 2006 and was due in large part to a change in the method of allocating overhead costs to self-constructed assets. In 2010, 2009 and 2008, interest expense (and adjustments to expense) on income taxes was reflected in “Interest expense – other than on deposit liabilities and bank borrowings” in the amount of $(0.9) million, $0.7 million and $0.2 million, respectively. As of December 31, 2010 and 2009, the total amount of accrued interest related to uncertain tax positions and recognized on the balance sheet in “Interest and dividends payable” was $2.7 million and $3.6 million, respectively.

As of December 31, 2010, the total amount of liability for uncertain tax positions was $12.2 million and, of this amount, $1.2 million, if recognized, would affect the Company’s effective tax rate. Management concluded that no significant changes to the liability for uncertain tax positions will occur within the next 12 months.

The changes in total unrecognized tax benefits were as follows:

Years ended December 31	2010	2009
(in millions)		
Unrecognized tax benefits, January 1	$ 26.5	$ 27.9
Additions based on tax positions taken during the year	11.0	–
Reductions based on tax positions taken during the year	–	–
Additions for tax positions of prior years	2.2	0.4
Reductions for tax positions of prior years	(18.2)	(1.8)
Decreases due to tax positions taken	–	–
Settlements	(6.1)	–
Lapses of statute of limitations	–	–
Unrecognized tax benefits, December 31	$ 15.4	$ 26.5

In addition to the liability for uncertain tax positions, the Company’s unrecognized tax benefits include $1.4 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 2005 to 2009 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 2005 to 2007.

As of December 31, 2010, 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 cash flows.

12 • Cash flows

Supplemental disclosures of cash flow information. In 2010, 2009 and 2008, the Company paid interest to non-affiliates amounting to $95 million, $106 million and $182 million, respectively.

In 2010, 2009 and 2008, the Company paid income taxes amounting to $6 million, $21 million and $91 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 $23 million, $17 million and $21 million in 2010, 2009 and 2008, respectively. HEI satisfied the requirements of the HEI DRIP and the HEIRSP (from April 16, 2009 through September 3, 2009) and the ASB 401(k) Plan (from its inception on May 7, 2009 through September 3, 2009) by acquiring for cash its common shares through open market purchases rather than by issuing additional shares. During all other periods in 2009, and for all of 2008 and 2010, HEI satisfied the requirements of the HEI DRIP, HEIRSP and ASB 401(k) Plan through the issuance of additional shares of common stock.

In each of 2010, 2009 and 2008, other noncash increases in common stock issued under director and officer compensatory plans were $4 million, $2 million and $2 million, respectively.

In 2010, 2009 and 2008, HECO and its subsidiaries capitalized as part of the cost of electric utility plant an allowance for equity funds used during construction amounting to $6 million, $12 million and $9 million, respectively.

In 2010, 2009 and 2008, the estimated fair value of noncash contributions in aid of construction amounted to $7 million, $12 million and $10 million, respectively.

In 2010, 2009 and 2008, real estate acquired in settlement of loans in noncash transactions amounted to $7 million, $5 million and $1 million, respectively.

13 • Regulatory restrictions on net assets

As of December 31, 2010, 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, 2010, ASB could transfer approximately $132 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.

14 • 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.

15 • Fair value measurements

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

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

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

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

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

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

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

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

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

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

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

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

December 31	2010		2009	
(in thousands)	Carrying or notional amount	Estimated fair value	Carrying or notional amount	Estimated fair value
Financial assets				
Cash and cash equivalents, excluding money market accounts	$ 329,553	$ 329,553	$ 501,773	$ 501,773
Money market accounts	1,098	1,098	2,149	2,149
Available-for-sale investment and mortgage-related securities	678,152	678,152	432,881	432,881
Investment in stock of Federal Home Loan Bank of Seattle	97,764	97,764	97,764	97,764
Loans receivable, net	3,497,729	3,639,983	3,670,493	3,760,954
Financial liabilities				
Deposit liabilities	3,975,372	3,979,027	4,058,760	4,063,888
Short-term borrowings—other than bank	24,923	24,923	41,989	41,989
Other bank borrowings	237,319	251,822	297,628	307,154
Long-term debt, net—other than bank	1,364,942	1,345,770	1,364,815	1,336,250
Forward starting swaps	2,762	2,762	–	–
Off-balance sheet items				
HECO-obligated preferred securities of trust subsidiary	50,000	52,500	50,000	48,480

As of December 31, 2010 and 2009, 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 $0.4 million and $0.2 million, respectively. As of December 31, 2010 and 2009, loans serviced by ASB for others had notional amounts of $817.7 million and $577.5 million and the estimated fair value of the servicing rights for such loans was $8.8 million and $5.6 million, respectively.

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

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

	Fair value measurements using		
(in thousands)	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
December 31, 2010			
Money market accounts (“other” segment)	$ –	$ 1,098	$ –
Available-for-sale securities (bank segment)			
Mortgage-related securities-FNMA, FHLMC and GNMA	$ –	$319,970	$ –
Federal agency obligations	–	315,896	–
Municipal bonds	–	42,286	–
	$ –	$678,152	$ –
Forward starting swaps (“other” segment)	$ –	$ (2,762)	$ –
December 31, 2009			
Money market accounts (“other” segment)	$ –	$ 2,149	$ –
Available-for-sale securities (bank segment)			
Mortgage-related securities-FNMA, FHLMC and GNMA	$ –	$327,521	$ –
Federal agency obligations	–	104,044	–
Municipal bonds	–	1,316	–
	$ –	$432,881	$ –

Fair value measurements on a nonrecurring basis. From time to time, the Company may be required to measure certain assets at fair value on a nonrecurring basis in accordance with U. S. generally accepted accounting principles (GAAP). These adjustments to fair value usually result from the write-downs of individual assets. ASB does not record loans at fair value on a recurring basis. However, from time to time, ASB records nonrecurring fair value adjustments to loans to reflect specific reserves on loans based on the current appraised value of the collateral or unobservable market assumption. Unobservable assumptions reflect ASB’s own estimate of the fair value of collateral used in valuing the loan. 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 2010 and 2009, goodwill was not measured at fair value. As of December 31, 2009, there were no adjustments to fair value for assets measured at fair value on a nonrecurring basis in accordance with GAAP.

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

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

(in millions)	Balance	Fair value measurements using: Quoted prices in active markets for identical assets (Level 1)	Significant other Observable inputs (Level 2)	Significant Unobservable inputs (Level 3)
Loans				
December 31, 2010	$35	$ –	$26	$ 9
December 31, 2009	17	–	14	3

Specific reserves as of December 31, 2010 and 2009 were $3.5 million and $1.6 million, respectively, and were included in loans receivable held for investment, net. For 2010 and 2009, 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 were as follows:

	Pension benefits				Other benefits			
		Fair value measurements using				Fair value measurements using		
(in millions)	December 31, 2010	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)	December 31, 2010	Quoted prices in active markets for identical assets (Level 1)	Significant other observable inputs (Level 2)	Significant unobservable inputs (Level 3)
Equity securities	$453	$453	$ –	$ –	$ 80	$ 80	$ –	$ –
Equity index funds	80	80	–	–	14	14	–	–
Fixed income securities	238	55	183	–	8	2	6	–
Pooled and mutual funds	78	9	69	–	49	39	10	–
Total	849	$597	$252	$ –	151	$135	$ 16	$ –
Receivables and payables, net	(17)				–			
Fair value of plan assets	$832				$151			

	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	$486	$207	$67	135	$114	$ 7	$14
Receivables and payables, net	(21)				–			
Fair value of plan assets	$739				$135			

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 ASU 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, 2010 and 2009.

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, equity securities, pooled securities and mutual funds (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 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.

Other (Level 3). 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 2010 and 2009, the changes in Level 3 assets were as follows:

	2010		2009	
(in thousands)	Pension benefits	Other benefits	Pension benefits	Other benefits
Balance, January 1	$ 67,420	$ 13,703	$49,641	$12,713
Realized and unrealized gains	6,650	1,445	15,132	3,301
Purchases and settlements, net	(317)	(3,854)	2,647	(2,311)
Transfer in or out of Level 3	(73,612)	(11,289)	–	–
Balance, December 31	$ 141	$ 5	$67,420	$13,703

16 • Quarterly information (unaudited)

Selected quarterly information was as follows:

(in thousands, except per share amounts)	Quarters ended March 31	June 30	Sept. 30	Dec. 31	Years ended December 31
2010					
Revenues	$619,040	$655,664	$694,541	$695,737	$2,664,982
Operating income	60,707	63,631	72,631	59,242	256,211
Net income for common stock [1]	27,126	29,262	32,449	24,698	113,535
Basic earnings per common share [2]	0.29	0.31	0.35	0.26	1.22
Diluted earnings per common share [3]	0.29	0.31	0.35	0.26	1.21
Dividends per common share	0.31	0.31	0.31	0.31	1.24
Market price per common share [4]					
High	23.01	24.04	24.99	23.41	24.99
Low	18.63	21.07	22.04	21.77	18.63
2009					
Revenues	$543,797	$525,901	$620,313	$619,579	$2,309,590
Operating income	44,658	35,055	68,639	39,312	187,664
Net income for common stock [5]	20,395	15,479	33,483	13,654	83,011
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

[1] The fourth quarter of 2010 includes $6 million of interest income (net of taxes) at the utilities due to a federal tax settlement and $2 million of taxes for the write-off of a deferred tax asset due to the expiration of a capital loss carryforward period.

[2] The quarterly basic earnings per common share are based upon the weighted-average number of shares of common stock outstanding in each quarter.

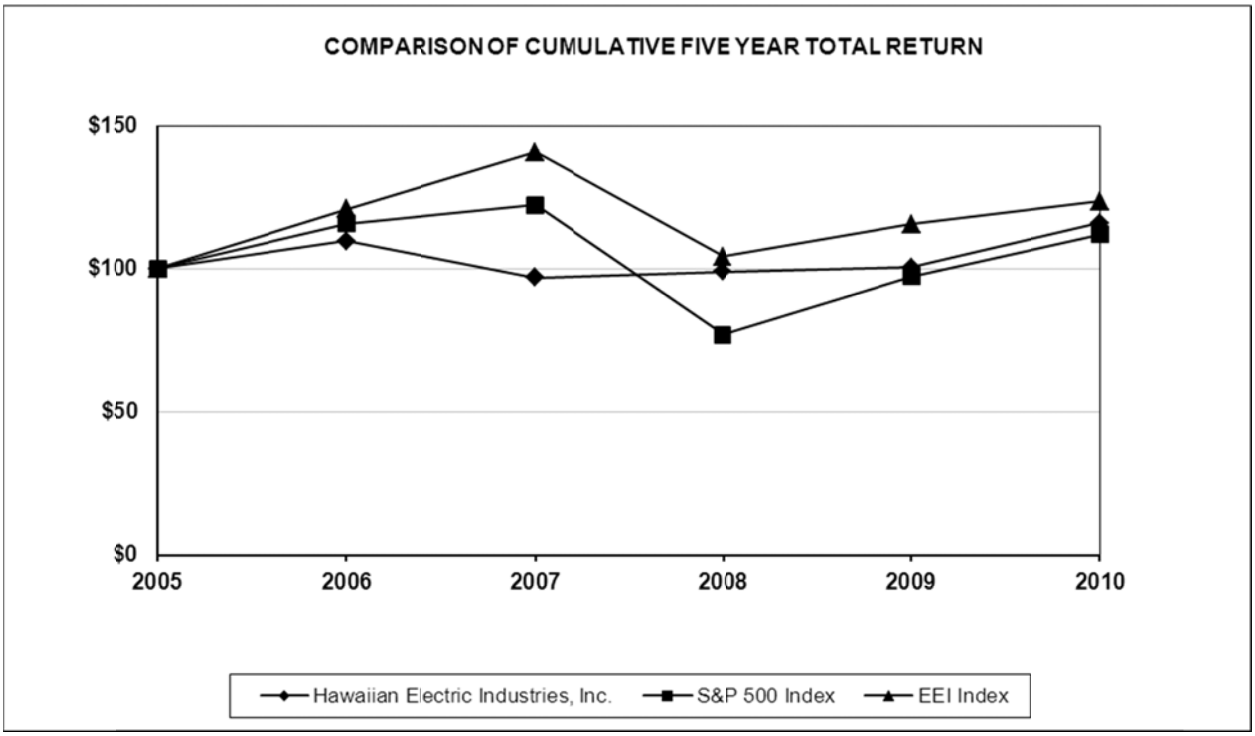
[3] The quarterly diluted earnings per common share are based upon the weighted-average number of shares of common stock outstanding in each quarter plus the dilutive incremental shares at quarter end.

[4] Market prices of HEI common stock (symbol HE) shown are as reported on the NYSE Composite Tape for the indicated date.

[5] 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.

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 (57 companies were included as of December 31, 2010). 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, 2005 in HEI Common Stock and the common stock of all companies in the indexes and that dividends were reinvested.



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Shareholder Information

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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 2010 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 10, 2011, 9:30 a.m.
American Savings Bank Tower
1001 Bishop Street
8th Floor, Room 805
Honolulu, Hawaii 96813

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Transfer Agents
Common stock and utility company preferred stock:
Shareholder Services

Common stock only:
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Facsimile: 212-509-5150

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 2 and 3 of the enclosed 2010 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.

HEI

HAWAIIAN ELECTRIC INDUSTRIES, INC.

To minimize our environmental impact, the Hawaiian Electric Industries 2010 Annual Report to Shareholders was printed on papers containing fibers from products from socially and environmentally responsible forestry.