# Hawaiian Electric Industries, Inc.

## 2008 Annual Report to Shareholders

## Appendix A

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Contents

## Forward-Looking Statements

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

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

- the effects of international, national and local economic conditions, including the state of the Hawaii tourist and construction industries, the strength or weakness of the Hawaii and continental U.S. real estate markets (including the fair value and/or the actual performance of collateral underlying loans and mortgage-related securities held by American Savings Bank, F.S.B. (ASB)), decisions concerning the extent of the presence of the federal government and military in Hawaii, and the implications and potential impacts of current capital and credit market conditions and federal and state responses to those conditions, such as the Emergency Economic Stabilization Act of 2008 (plan for a $700 billion bailout of the financial industry) and American Economic Recovery and Reinvestment Act of 2009 (economic stimulus package);
- the effects of weather and natural disasters, such as hurricanes, earthquakes, tsunamis, lightning strikes and the potential effects of global warming;
- global developments, including the effects of terrorist acts, the war on terrorism, continuing U.S. presence in Iraq and Afghanistan, potential conflict or crisis with North Korea and in the Middle East, Iran's nuclear activities and potential avian flu pandemic;
- the timing and extent of changes in interest rates and the shape of the yield curve;
- the ability of the Company to access credit markets to obtain commercial paper and other short-term and long-term debt financing and to access capital markets to issue preferred stock or hybrid securities (the electric utilities) and common stock (HEI) under volatile and challenging market conditions;
- the risks inherent in changes in the value of and market for securities available for sale and in the value of pension and other retirement plan assets;
- changes in laws, regulations, market conditions and other factors that result in changes in assumptions used to calculate retirement benefits costs and funding requirements and the fair value of ASB used to test goodwill for impairment;
- increasing competition in the electric utility and banking industries (e.g., increased self-generation of electricity may have an adverse impact on HECO's revenues and increased price competition for deposits, or an outflow of deposits to alternative investments, may have an adverse impact on ASB's cost of funds);
- the effects of the implementation of the Energy Agreement with the State of Hawaii and Consumer Advocate (Energy Agreement) setting forth the goals and objectives of a Hawaii Clean Energy Initiative (HCEI), the fulfillment by the utilities of their commitments under the Energy Agreement and revenue decoupling;
- capacity and supply constraints or difficulties, especially if generating units (utility-owned or independent power producer (IPP)-owned) fail or measures such as demand-side management (DSM), distributed generation (DG), combined heat and power (CHP) or other firm capacity supply-side resources fall short of achieving their forecasted benefits or are otherwise insufficient to reduce or meet peak demand;
- increased risk to generation reliability as generation peak reserve margins on Oahu continue to be strained;
- fuel oil price changes, performance by suppliers of their fuel oil delivery obligations and the continued availability to the electric utilities of their energy cost adjustment clauses (ECACs);
- the risks associated with increasing reliance on renewable energy, as contemplated under the Energy Agreement, including the availability of non-fossil fuel supplies for renewable generation and the operational impacts of adding intermittent sources of renewable energy to the electric grid;
- the ability of IPPs to deliver the firm capacity anticipated in their power purchase agreements (PPAs);
- the ability of the electric utilities to negotiate, periodically, favorable fuel supply and collective bargaining agreements;
- new technological developments that could affect the operations and prospects of HEI and its subsidiaries (including HECO and its subsidiaries and ASB and its subsidiaries) or their competitors;
- federal, state, county and international governmental and regulatory actions, such as changes in laws, rules and regulations applicable to HEI, HECO, ASB and their subsidiaries (including changes in taxation, regulatory changes resulting from the HCEI, environmental laws and regulations, the potential regulation of greenhouse gas emissions (GHG) and governmental fees and assessments); decisions by the Public Utilities Commission of the State of Hawaii (PUC) in rate cases (including decisions on ECACs) and other proceedings and by other agencies and courts on land use, environmental and other permitting issues (such as required corrective actions, restrictions and penalties that may arise, for example with respect to environmental conditions or renewable portfolio standards (RPS)); enforcement actions by the Office of Thrift Supervision (OTS) and other governmental authorities (such as consent orders, required corrective actions, restrictions and penalties that may arise, for example, with respect to compliance deficiencies under the Bank Secrecy Act or other regulatory requirements or with respect to capital adequacy);

- increasing operation and maintenance expenses and investment in infrastructure for the electric utilities, resulting in the need for more frequent rate cases, and increasing noninterest expenses at ASB;
- the risks associated with the geographic concentration of HEI's businesses;
- the effects of changes in accounting principles applicable to HEI, HECO, ASB and their subsidiaries, including the adoption of International Financial Reporting Standards or new accounting principles, continued regulatory accounting under Statement of Financial Accounting Standards (SFAS) No. 71, "Accounting for the Effects of Certain Types of Regulation," and the possible effects of applying Financial Accounting Standards Board (FASB) Interpretation No. (FIN) 46R, "Consolidation of Variable Interest Entities," and Emerging Issues Task Force (EITF) Issue No. 01-8, "Determining Whether an Arrangement Contains a Lease," to PPAs with IPPs;
- the effects of changes by securities rating agencies in their ratings of the securities of HEI and HECO and the results of financing efforts;
- faster than expected loan prepayments that can cause an acceleration of the amortization of premiums on loans and investments and the impairment of mortgage servicing assets of ASB;
- changes in ASB's loan portfolio credit profile and asset quality which may increase or decrease the required level of allowance for loan losses;
- changes in ASB's deposit cost or mix which may have an adverse impact on ASB's cost of funds;
- the final outcome of tax positions taken by HEI, HECO, ASB and their subsidiaries;
- the risks of suffering losses and incurring liabilities that are uninsured; and
- other risks or uncertainties described elsewhere in this report and in other reports (e.g., "Item 1A. Risk Factors" in the Company's Annual Report on Form 10-K) previously and subsequently filed by HEI and/or HECO with the Securities and Exchange Commission (SEC).

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

## Selected Financial Data

| Hawaiian Electric Industries, Inc. and Subsidiaries<br>Years ended December 31 | 2008 | 2007 | 2006 | 2005 | 2004 |
|---|---|---|---|---|---|
| (dollars in thousands, except per share amounts) | | | | | |
| **Results of operations** | | | | | |
| Revenues | $ 3,218,920 | $ 2,536,418 | $ 2,460,904 | $ 2,215,564 | $ 1,924,057 |
| Net income (loss) | | | | | |
| Continuing operations | $ 90,278 | $ 84,779 | $ 108,001 | $ 127,444 | $ 107,739 |
| Discontinued operations | – | – | – | (755) | 1,913 |
| | $ 90,278 | $ 84,779 | $ 108,001 | $ 126,689 | $ 109,652 |
| Basic earnings (loss) per common share | | | | | |
| Continuing operations | $ 1.07 | $ 1.03 | $ 1.33 | $ 1.58 | $ 1.36 |
| Discontinued operations | – | – | – | (0.01) | 0.02 |
| | $ 1.07 | $ 1.03 | $ 1.33 | $ 1.57 | $ 1.38 |
| Diluted earnings per common share | $ 1.07 | $ 1.03 | $ 1.33 | $ 1.56 | $ 1.38 |
| Return on average common equity-continuing operations * | 6.8% | 7.2% | 9.3% | 10.5% | 9.4% |
| Return on average common equity | 6.8% | 7.2% | 9.3% | 10.4% | 9.5% |
| **Financial position **** | | | | | |
| Total assets | $ 9,295,082 | $ 10,293,916 | $ 9,891,209 | $ 9,951,577 | $ 9,719,257 |
| Deposit liabilities | 4,180,175 | 4,347,260 | 4,575,548 | 4,557,419 | 4,296,172 |
| Other bank borrowings | 680,973 | 1,810,669 | 1,568,585 | 1,622,294 | 1,799,669 |
| Long-term debt, net | 1,211,501 | 1,242,099 | 1,133,185 | 1,142,993 | 1,166,735 |
| Preferred stock of subsidiaries – not subject to mandatory redemption | 34,293 | 34,293 | 34,293 | 34,293 | 34,405 |
| Stockholders' equity | 1,389,454 | 1,275,427 | 1,095,240 | 1,216,630 | 1,210,945 |
| **Common stock** | | | | | |
| Book value per common share ** | $ 15.35 | $ 15.29 | $ 13.44 | $ 15.02 | $ 15.01 |
| Market price per common share | | | | | |
| High | 29.75 | 27.49 | 28.94 | 29.79 | 29.55 |
| Low | 20.95 | 20.25 | 25.69 | 24.60 | 22.96 |
| December 31 | 22.14 | 22.77 | 27.15 | 25.90 | 29.15 |
| Dividends per common share | 1.24 | 1.24 | 1.24 | 1.24 | 1.24 |
| Dividend payout ratio | 116% | 120% | 93% | 79% | 90% |
| Dividend payout ratio-continuing operations | 116% | 120% | 93% | 78% | 91% |
| Market price to book value per common share ** | 144% | 149% | 202% | 172% | 194% |
| Price earnings ratio *** | 20.7x | 22.1x | 20.4x | 16.4x | 21.4x |
| Common shares outstanding (thousands) ** | 90,516 | 83,432 | 81,461 | 80,983 | 80,687 |
| Weighted-average | 84,631 | 82,215 | 81,145 | 80,828 | 79,562 |
| Shareholders **** | 33,588 | 34,281 | 35,021 | 35,645 | 35,292 |
| Employees ** | 3,560 | 3,520 | 3,447 | 3,383 | 3,354 |

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

** At December 31. (Note: Stockholders' equity and book value per common share since December 31, 2006 includes a charge to accumulated other comprehensive income (AOCI) relating to retirement benefits pursuant to SFAS No. 158, as adjusted by the impact of decisions of the PUC. See Note 8, "Retirement benefits," of HEI's "Notes to Consolidated Financial Statements.")

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

**** At December 31. Registered shareholders plus participants in the HEI Dividend Reinvestment and Stock Purchase Plan who are not registered shareholders. As of February 13, 2009, HEI had 33,536 registered shareholders and participants.

The Company discontinued its international power operations in 2001. Also see "Commitments and contingencies" in Note 3 and "Balance sheet restructure" 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 April 20, 2004, the HEI Board of Directors approved a 2-for-1 stock split in the form of a 100% stock dividend with a record date of May 10, 2004 and a distribution date of June 10, 2004. All share and per share information has been adjusted to reflect the stock split for all periods presented.

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).

## 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's two strategic objectives are to efficiently operate the electric utility and bank subsidiaries for long-term earnings growth and increase HEI's financial flexibility by strengthening its balance sheet and maintaining its credit ratings.

HEI, through 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 and its subsidiaries (collectively, the Company) also provide a wide array of banking and other financial services to consumers and businesses through its bank subsidiary, American Savings Bank, F.S.B. (ASB), one of Hawaii's largest financial institutions based on total assets as of December 31, 2008.

In 2008, net income was $90 million, compared to $85 million in 2007. Basic earnings per share were $1.07 per share in 2008, up 4% from $1.03 per share in 2007 due to higher earnings for the electric utility segment and slightly lower losses for the "other" segment, partly offset by lower earnings for the bank segment due primarily to a $35.6 million, net of tax benefits, charge related to a balance sheet restructuring and the effects of the higher weighted average number of shares outstanding.

Electric utility net income in 2008 ($92 million) increased 76% over the prior year due primarily to interim rate relief ($41 million, net of taxes) and two items recorded in 2007--a refund accrual for a portion of HECO's 2005 test year interim rate increase ($9 million, net of tax benefits) and a write-off of plant in service costs associated with generating units at Keahole as part of a settlement in HELCO's rate case ($7 million, net of tax benefits). Key to results for 2009 will be interim rate relief in HECO's 2009 test-year rate case and the impacts of actions taken under the Hawaii Clean Energy Initiative (HCEI), including the steps taken toward the integration of approximately 1,100 megawatts (MW) of new generation from a variety of renewable energy sources into the utility systems and adopting a new regulatory rate-making model that decouples revenues from kilowatthour (KWH) sales.

The bank's earnings in 2008 included a $35.6 million net charge related to a balance sheet restructuring to strengthen future profitability ratios and enhance future net interest margin. Also in 2008, the bank recorded a $4.7 million net charge for other-than-temporary impairments of securities. In 2007, ASB recorded a pension curtailment net gain of $5.3 million due to retirement benefit plan changes. Excluding the impact of the balance sheet restructuring, ASB's 2008 net income would have been flat compared to 2007, in spite of the difficult interest rate and economic environment, due to the improved net interest margin resulting in part from the balance sheet restructure and lower consulting, contract services and legal expenses. Management has been focused on reducing costs. ASB's future financial results will continue to be impacted by the interest rate environment, the quality of ASB's assets and its success in operating as a community bank and curtailing costs.

The "other" segment's $20 million loss in 2008 was comparable to the loss in 2007 and included no income from leveraged leases, which were all sold by the end of 2007. The 2008 net loss included lower consulting and interest expenses, partly offset by higher employee expenses and charitable contributions.

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 (adjusted for a 2-for-1 stock split in 2004). The indicated dividend yield as of December 31, 2008 was 5.6%. The dividend payout ratios based on net income for 2008, 2007 and 2006 were 116%, 120% and 93%, respectively. Excluding the $35.6 million net charge related to ASB's balance sheet restructuring (and disregarding other adjustments to net income that would be necessary to more fully reflect the impact on net income if the restructuring had not occurred), the payout ratio for 2008 would have been 83%. HEI currently expects to maintain the dividend at its present level; however, the HEI Board of Directors evaluates the dividend quarterly and considers many factors, 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; Department of Labor and Industrial Relations; Honolulu Board of Realtors; Blue Chip Financial Forecasts; Bloomberg and local newspapers).*

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

In the fourth quarter of 2008 the Hawaii economy declined rapidly due to the pressures created by the volatile capital markets and depressed national economy. State economists agree that Hawaii is in a recession. Hawaii economic growth as measured by the change in real personal income is expected to be lower by 0.2% in 2008 compared to 2007 and by 0.7% in 2009 compared to 2008. Growth is expected to resume in 2010 at a rate of 1.8% over 2009.

Weakness is most notable in one of the state's largest industries, tourism. The closure of Aloha and ATA Airlines, departure of two Norwegian Cruise Line cruise ships from Hawaii, record-high oil prices and downturn in the national economy have impacted the visitor industry. Visitor arrivals by air were down 14% in the fourth quarter of 2008 compared with the fourth quarter of 2007. For 2008, arrivals were down 11% from 2007 and 2008 was the first time since 2004 that annual arrivals were below seven million. Arrivals in 2009 are expected to be down 6% and growth is expected to resume at a 7% rate in 2010.

Visitor expenditures were down 15% for the fourth quarter of 2008 compared to the same period in 2007. Visitor expenditures were $11 billion for 2008, down 10% compared with expenditures for 2007. Annual visitor expenditures set a record of $12 billion in 2006.

Hotel occupancies, another indicator of tourism sector health, are down, especially on Maui and the Big Island. Statewide figures show December 2008 occupancy rates at 61% compared with 70% for December 2007. December 2008 occupancy rates on Oahu were the highest in the state at 68%, a five percentage point decline from December 2007. December 2008 occupancy rates for Maui and the Big Island were 57% and 48%, respectively, representing percentage point declines from December 2007 of 14 and 13, respectively.

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

At 5.5%, seasonally-adjusted Hawaii unemployment at the end of December 2008 remains below the national average of 7.2%. There was a sharp increase in unemployment in 2008 compared to 2007 when unemployment figures ranged between 2.4% and 3.1%. Declines in tourism and in consumer spending are expected to cause job losses in 2009. The Hawaii unemployment rate is expected to be 5.8% and 5.9% in 2009 and 2010, respectively.

Oahu homes retained their value during the fourth quarter of 2008 with December median prices above $600,000. For 2008, Oahu median home prices were $624,000, a decrease of 3% compared to 2007.

Permitted construction (nongovernment) continues to slow due to increased costs and tighter credit conditions. However, slowing continues to be considerably more moderate than in many U.S. mainland markets. Private new residential construction in Hawaii declined 18.9% in 2008 and is expected to further decline in 2009 before stabilizing in 2010. A new Disney resort development on Oahu should contribute to permitted construction. Military projects and state infrastructure projects will also provide stability to the overall construction industry in Hawaii.

On a national level, the Blue Chip economic consensus dated February 1, 2009 predicts real gross domestic product (GDP) to decline at 3.7% and 1.2% for the first and second quarters of 2009, respectively. Recovery is expected to resume in the second half of 2009. Consumer confidence has been adversely affected and credit is tight, which in turn has and will continue to negatively impact consumer spending.

The price of a barrel of crude oil has fallen sharply, with prices dropping from a peak of $145.29 per barrel on July 3, 2008 and closing at $34.62 per barrel on February 18, 2009.

Last year was characterized by a series of Federal Reserve easing and generally falling interest rates as the economy continued to worsen throughout the year. Interest rates fell dramatically during the fourth quarter of 2008 as the FOMC dropped the fed funds target rate from 2.0% at the beginning of the quarter to a 0% - 0.25% range by year-end. Additionally, the Treasury department announced a program to purchase agency mortgage-backed securities and agency debt, with the intent of driving down mortgage rates. Mortgage rates declined in response.

Overall, the Hawaii economy declined rapidly in the fourth quarter of 2008 as a result of weak national economic conditions and relief is not expected until late 2009 at the earliest.

**Emergency Economic Stabilization Act of 2008 and American Economic Recovery and Reinvestment Act of 2009**

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

The American Economic Recovery and Reinvestment Act of 2009 (the 2009 Act) was signed into law on February 17, 2009. The 2009 Act is intended to provide a stimulus to the U.S. economy in the midst of the global financial crisis and includes more than $42 billion in energy-related provisions. The 2009 Act includes: (1) a 30% tax credit of up to $1,500 for the purchase of highly efficient residential air conditioners, heat pumps or furnaces, (2) $0.3 billion in rebates for purchases of efficient appliances, (3) $20 billion for "green" jobs to make wind turbines, solar panels and improve energy efficiency in schools and federal buildings, (4) $6 billion in loan guarantees for renewable energy projects, (5) $5 billion to help low-income homeowners make energy improvements, (6) $11 billion to modernize and expand the U.S. electric power grid and (7) $2 billion for research into batteries for future electric cars. For the Company, major tax incentives in the 2009 Act are the extension of the 50% bonus depreciation for qualifying property placed into service in 2009 and the extension and broadening of renewable energy credits. The Company will analyze the 2009 Act for its impacts on results of operations, financial condition and liquidity and for the opportunities it presents.

## Results of operations

| (dollars in millions, except per share amounts) | | 2008 | % change | | 2007 | % change | | 2006 |
|---|---|---|---|---|---|---|---|---|
| Revenues | $ | 3,219 | 27 | $ | 2,536 | 3 | $ | 2,461 |
| Operating income | | 204 | – | | 204 | (15) | | 239 |
| Net income | | 90 | 6 | | 85 | (22) | | 108 |
| Electric utility | $ | 92 | 76 | $ | 52 | (30) | $ | 75 |
| Bank | | 18 | (66) | | 53 | (5) | | 56 |
| Other | | (20) | NM | | (20) | NM | | (23) |
| Net income | $ | 90 | 6 | $ | 85 | (22) | $ | 108 |
| Basic earnings per share | $ | 1.07 | 4 | $ | 1.03 | (23) | $ | 1.33 |
| Dividends per share | $ | 1.24 | – | $ | 1.24 | – | $ | 1.24 |
| Weighted-average number of common shares outstanding (millions) | | 84.6 | 3 | | 82.2 | 1 | | 81.1 |
| Dividend payout ratio | | 116% | | | 120% | | | 93% |

NM Not meaningful.

***Retirement benefits.*** The Company's reported costs of providing retirement benefits are dependent upon numerous factors resulting from actual plan experience and assumptions about future experience. For example, retirement benefits costs are impacted by actual employee demographics (including age and compensation levels), the level of contributions to the plans, plus earnings and realized and unrealized gains and losses on plan assets, and changes made to the provisions of the plans. (See Note 8 of HEI's "Notes to Consolidated Financial Statements" for a listing of plans that have been frozen. No other changes were made to the retirement benefit plans' provisions in 2008, 2007 and 2006 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 accounts for retirement benefits in accordance with Statement of Financial Accounting Standards (SFAS) No. 87, "Employers' Accounting for Pensions," SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions" and SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)," as adjusted by 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 2008, the Company's retirement benefit plans' assets generated a loss, including investment management fees, of 28.4%, resulting in net losses and realized and unrealized losses of $287 million, compared to earnings and gains of $87 million for 2007 and $122 million for 2006. The market value of the retirement benefit plans' assets as of December 31, 2008 was $726 million. See "Liquidity and Capital Resources" below for the Company's cash contributions to the retirement benefit plans.

Because of the significant decline in the value of plan assets in 2008, the Company expects that the minimum required contribution to the qualified retirement plans (after consideration of a $45 million credit balance) calculated in accordance with the Pension Protection Act of 2006 and the expected timing of the cash requirement based on the value of plan assets as of December 31, 2008 will be as follows for plan years 2009 and 2010. The minimum required contribution may differ from the cash funding for each plan year because the rules under the Internal Revenue Code allow the Company to make its last installment contribution as late as September of the following year. In addition, the Company is allowed to elect to apply any credit balance against the minimum required contribution. Further, pension tracking mechanisms generally require the electric utilities to fund only the minimum level required under the law until the existing pension assets are reduced to zero, at which time the electric utilities would make contributions to the pension trust in the amount of the actuarially calculated net periodic pension costs, except when limited by the Employee Retirement Income Security Act of 1974, as amended (ERISA), minimum contribution requirements or the maximum contribution limitation on deductible contributions imposed by the Internal Revenue Code. The "Cash funding requirement" in the following table considers the utilities' funding commitment (based on various assumptions in Note 8 of HEI's "Notes to Consolidated Financial Statements").

| (in millions) | 2009 | 2010 |
|---|---|---|
| **Pension Protection Act minimum required contribution:** | | |
| (net of applied credit balances) | | |
| **Based on plan assets as of December 31, 2008** | | |
| Consolidated HECO | $31 | Range of $76-136 |
| Consolidated HEI | $31 | Range of $78-140 |
| | | |
| **Cash funding to satisfy the Pension Protection Act minimum required contribution:** | | |
| **Based on plan assets as of December 31, 2008** | | |
| Consolidated HECO | $20 | $63 |
| Consolidated HEI | $21 | $64 |

The Pension Protection Act provides that more conservative assumptions be used to value obligations if a pension plan's funded status falls below certain levels. Depending on the funded status of the plans and whether funding relief is provided through legislation, the Company's projected contribution level for the 2010 plan year could fall in a range between $78 million and $140 million. Other factors could cause required contribution levels to fall outside this estimated range. Further, if the funded status of the pension plans continue to decline, restrictions on participant benefit accruals may be placed on the plans.

The credit rating agencies consider many factors when assigning their ratings. The distress in the worldwide financial market has significantly increased the unfunded status of the Company's pension plans, and may be a factor considered by the credit rating agencies in their evaluations. The associated increase in pension plan funding requirements will negatively impact certain financial metrics utilized by the credit rating agencies in determining the Company's credit ratings and could result in a reduction of the Company's credit ratings from their current levels.

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

| | AOCI balance, net of tax benefits, related to retirement benefits liability | | Retirement benefits expense, net of tax benefits | | | | Retirement benefits paid and plan expenses | | |
|---|---|---|---|---|---|---|---|---|---|
| | December 31 | | Years ended December 31 | | | | Years ended December 31 | | |
| (in millions) | 2008 [1] | 2007 [1] | (Estimated) 2009 [1, 2] | 2008 [1] | 2007 [1] | 2006 | 2008 | 2007 | 2006 |
| Consolidated HEI | $(20) | $(4) | $18 | $17 | $20 | $17 | $59 | $57 | $55 |
| Consolidated HECO | 2 | 1 | 17 | 17 | 16 | 13 | 55 | 53 | 51 |
| ASB | (15) | – | – | (1) | 2 | 3 | 2 | 2 | 2 |

1 Includes impact of 2007 decisions by the PUC.

2 Forward-looking statements subject to risks and uncertainties, including the impact of plan changes during the year, if any, and the impact of actual information when received (e.g., actual participant demographics as of January 1, 2009).

The following table reflects the sensitivities of the projected benefit obligation (PBO) and accumulated postretirement benefit obligation (APBO) as of December 31, 2008, 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 | $(55)/$61 |
| **Other benefits** | | |
| Discount rate | +/– 50 | (10)/11 |
| Health care cost trend rate | +/– 100 | 3/(3) |

Baseline assumptions: 6.625% discount rate for pension benefits; 6.50% discount rate for other benefits; 8.25% asset return rate; 10% medical trend rate for 2009, grading down to 5% for 2014 and thereafter; 5% dental trend rate; and 4% vision trend rate.

The impact on 2009 net income for changes in actuarial assumptions should be immaterial based on the adoption by the electric utilities of pension and postretirement benefits other than pensions (OPEB) tracking mechanisms approved by the PUC on an interim basis. See Note 8 of HEI's "Notes to Consolidated Financial Statements" for further retirement benefits information.

### *"Other" segment*

| (dollars in millions) | 2008 | % change | 2007 | % change | 2006 |
|---|---|---|---|---|---|
| Revenues [1] | $ – | (100) | $ 5 | NM | $ (2) |
| Operating income (loss) | (14) | NM | (11) | NM | (16) |
| Net loss | (20) | NM | (20) | NM | (23) |

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

NM Not meaningful.

The "other" business segment includes results of operations of HEI and HEI Diversified, Inc. (HEIDI), holding companies; HEI Investments, Inc. (HEIII), a company previously holding investments in leveraged leases; Pacific Energy Conservation Services, Inc. (PECS), a contract services company primarily providing windfarm operational and maintenance services to an affiliated electric utility; HEI Properties, Inc. (HEIPI), a company holding passive, venture capital investments; The Old Oahu Tug Service, Inc. (TOOTS), a maritime freight transportation company that ceased operations in 1999; and eliminations of intercompany transactions.

In 2008, HEIII recorded net income of $0.6 million, primarily for intercompany interest income, which is eliminated in consolidation. HEIII recorded net income of $4.8 million in 2007, including intercompany interest income, income from leveraged lease investments and a net after-tax gain of $1.3 million on the sale of leveraged lease investments (the last of which was sold in November 2007). HEIII recorded net income of $3.5 million in 2006, including intercompany interest income and income from leveraged leases. HEIII has filed articles of dissolution and is winding up its affairs.

HEIPI recorded net losses of $0.1 million in 2008, net income of $1.0 million in 2007 and net losses of $1.8 million in 2006, which amounts include income and losses from and/or writedowns of venture capital investments. In 2006, HEIPI recognized $2.6 million in unrealized and realized losses ($1.6 million after-tax) on its investment in Hoku Scientific, Inc. (Hoku), a materials science company focused on clean energy technologies. In January 2007, HEIPI sold its remaining investment in Hoku for a net after-tax gain of $0.9 million. As of December 31, 2008, HEIPI's venture capital investments amounted to $1.5 million.

HEI corporate operating, general and administrative expenses (including labor, employee benefits, incentive compensation, charitable contributions, legal fees, consulting, rent, supplies and insurance) were $12.7 million in 2008, compared to $14.0 million in 2007 and $12.1 million in 2006. In 2008, consulting expenses were lower, but labor expenses and funding of the HEI Charitable Foundation were higher. In 2007 consulting expenses were higher, but funding of the HEI Charitable Foundation was lower. HEI, HEIDI, PECS and TOOTS' net loss was $20.0 million in 2008, $26.2 million in 2007 and $24.5 million in 2006, the majority of which is comprised of financing costs.

The "other" segment's interest expenses were $21.4 million in 2008, $25.3 million in 2007 and $23.1 million in 2006. In 2008, financing costs were lower, primarily due to lower interest rates, including the use of lower-costing short-term commercial paper borrowings to replace maturing medium-term notes. In 2007, financing costs increased primarily due to higher medium-term note interest.

## Effects of inflation

U.S. inflation, as measured by the U.S. Consumer Price Index (CPI), averaged 0.1% in 2008, 4.1% in 2007 and 2.5% in 2006. Hawaii inflation, as measured by the Honolulu CPI, was 4.8% in 2007 and 5.9% in 2006. The Department of Business, Economic Development and Tourism estimates average Honolulu CPI to have been 4.2% in 2008 and forecasts it to be 2.6% for 2009.

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."

## 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, 2008 | Payment due by period | | | | |
|---|---|---|---|---|---|
| (in millions) | 1 year or less | 2-3 years | 4-5 years | More than 5 years | Total |
| **Contractual obligations** | | | | | |
| Deposit liabilities | | | | | |
| Commercial checking | $ 328 | $ – | $ – | $ – | $ 328 |
| Other checking | 932 | – | – | – | 932 |
| Savings | 1,383 | – | – | – | 1,383 |
| Money market | 148 | – | – | – | 148 |
| Term certificates | 1,142 | 219 | 13 | 15 | 1,389 |
| Total deposit liabilities | 3,933 | 219 | 13 | 15 | 4,180 |
| Other bank borrowings | 481 | 85 | 15 | 100 | 681 |
| Long-term debt, net | – | 150 | 115 | 951 | 1,216 |
| Operating leases, service bureau contract and maintenance agreements | 20 | 25 | 14 | 35 | 94 |
| Open purchase order obligations | 120 | 13 | – | – | 133 |
| Fuel oil purchase obligations (estimate based on January 1, 2008 fuel oil prices) | 435 | 870 | 870 | 435 | 2,610 |
| Power purchase obligations– minimum fixed capacity charges | 119 | 234 | 237 | 897 | 1,487 |
| Liabilities for uncertain tax positions (FIN 48 liability) | 7 | 2 | – | – | 9 |
| Total (estimated) | $5,115 | $1,598 | $1,264 | $2,433 | $10,410 |

| December 31, 2008 | |
|---|---|
| (in millions) | |
| **Other commercial commitments to ASB customers** | |
| Loan commitments (primarily expiring in 2009) | $ 21 |
| Loans in process | 64 |
| Unused lines and letters of credit | 1,147 |
| Total | $ 1,232 |

The tables above do not include other categories of obligations and commitments, such as deferred taxes, interest (on deposit liabilities, other bank borrowings, long-term debt and uncertain tax positions), trade payables, amounts that will become payable in future periods under collective bargaining and other employment agreements and employee benefit plans, obligations that may arise under indemnities provided to purchasers of discontinued operations and potential refunds of amounts collected under interim decision and orders (D&Os) of the PUC. As of December 31, 2008, the fair value of the assets held in trusts to satisfy the obligations of the qualified pension plans did not exceed the pension plans' benefit obligation. Minimum funding requirements for retirement benefit plans have not been included in the tables above; however, see "Retirement benefits" above for estimated minimum required contributions for 2009 and 2010.

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

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

The Company's total assets were $9.3 billion as of December 31, 2008 and $10.3 billion as of December 31, 2007. The decline in assets was primarily due to ASB's balance sheet restructuring in 2008.

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

| December 31 | 2008 | | 2007 | |
|---|---|---|---|---|
| (dollars in millions) | | | | |
| Short-term borrowings—other than bank | $ – | – % | $ 92 | 4% |
| Long-term debt, net—other than bank | 1,212 | 46 | 1,242 | 47 |
| Preferred stock of subsidiaries | 34 | 1 | 34 | 1 |
| Common stock equity | 1,389 | 53 | 1,275 | 48 |
| | $2,635 | 100% | $2,643 | 100% |

As of February 18, 2009, the Standard & Poor's (S&P) and Moody's Investors Service's (Moody's) ratings of HEI securities were as follows:

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

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

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

The rating agencies use a combination of qualitative measures (i.e., assessment of business risk that incorporates an analysis of the qualitative factors such as management, competitive positioning, operations, markets and regulation) as well as quantitative measures (e.g., cash flow, debt, interest coverage and liquidity ratios) in determining the ratings of HEI securities. In November 2008, S&P affirmed its corporate credit ratings and "stable" outlook for HEI. S&P's ratings outlook "assesses the potential direction of a long-term credit rating over the intermediate term (typically six months to two years)." S&P stated:

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

challenges, higher ratings are not foreseen during the outlook horizon and would need to be accompanied by sustained and improved financial performance.

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

S&P's financial risk designations are "minimal," "modest," "intermediate," "aggressive" and "highly leveraged." In November 2008, S&P indicated that "[t]he consolidated financial profile is 'aggressive,' reflecting in part the very heavy debt imputation we apply to the three utilities for power purchase agreements (PPA)."

In June 2008, Moody's issued an Issuer Comment regarding ASB's balance sheet restructuring. Moody's viewed the Company's announcement that ASB had substantially completed the balance sheet restructuring "as being positive to HEI's credit quality, but not material enough to warrant a rating change or a change in the company's stable outlook." In September 2008, Moody's affirmed its credit ratings and "stable" outlook for HEI. Moody's stated, "[t]he rating could be downgraded should weaker than expected economic growth and regulatory support emerge at HECO which ultimately causes earnings and sustainable cash flows to suffer over an extended period." Consequently, Moody's indicated that a shift in its expectations regarding the company's future sustainable levels of consolidated financial ratios such as Funds From Operations (net cash flow from operations less net changes in working capital items) to Adjusted Debt below 16% (16% as of June 30, 2008 – latest reported by Moody's) or Funds From Operations to Adjusted Interest of less than 3.5x (3.9x as of June 30, 2008 – latest reported by Moody's) could result in a lowering of the Company's rating.

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

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

| (in millions) | Year ended December 31, 2008 Average balance | Year ended December 31, 2008 End-of-period balance | December 31, 2007 |
|---|---|---|---|
| **Short-term borrowings** | | | |
| HEI commercial paper | $ 71 | $ – | $ 63 |
| HEI line of credit draws | 11 | – | – |
| HECO commercial paper | 76 | – | 29 |
| | $158 | $ – | $92 |
| **Line of credit facility (expiring March 31, 2011)** [1] | | $100 | $100 |
| Undrawn capacity under HEI's line of credit facility [2] | | 100 | 100 |

1 See Note 6 in HEI's "Notes to Consolidated Financial Statements" for a description of the line of credit facility. In the future, Company may seek to enter into new lines of credit and may also seek to increase the amount of credit available under such lines as management deems appropriate.

2 At February 18, 2009, there was no outstanding commercial paper balance and the line of credit facility was undrawn.

HEI utilizes short-term debt, typically commercial paper, to support normal operations, to refinance commercial paper, to retire long-term debt and for other temporary requirements. HEI also periodically makes short-term loans to HECO to meet HECO's cash requirements, including the funding of loans by HECO to HELCO and MECO. Due to the credit market conditions in the latter half of 2008 that resulted in a tightening commercial paper market, limited maturity options and escalating commercial paper rates, HEI began drawing on its $100 million syndicated line of credit facility in September 2008, rather than issuing commercial paper. HEI maintained an outstanding balance of up to $61 million on the syndicated line of credit facility through mid-December 2008 and maintained very limited outstanding commercial paper balances. All amounts drawn on the syndicated line of credit facility and all commercial paper borrowings were repaid by the end of the year.

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 a public offering of 5,000,000 shares of its common stock at $23 per share for gross proceeds of $115 million. HEI used the net proceeds of approximately $110 million, after deduction of underwriting discounts and commissions and estimated HEI expenses, to repay its outstanding short-term indebtedness, make loans to HECO and for working capital and other general corporate purposes. An over-allotment option granted to the underwriters was not exercised.

Operating activities provided net cash of $258 million in 2008, $217 million in 2007 and $286 million in 2006. Investing activities provided (used) net cash of $1.1 billion in 2008, ($222) million in 2007 and ($141) million in 2006. In 2008, net cash provided by investing activities was primarily due to proceeds from the sale of investment and mortgage-related securities from ASB's balance sheet restructuring and repayments of investment and mortgage-related securities owned by ASB, partly offset by purchases of investment and mortgage-related securities, HECO's consolidated capital expenditures (net of contributions in aid of construction) and net increases in loans held for investment. Financing activities used net cash of $1.4 billion in 2008, $43 million in 2007 and $105 million in 2006. In 2008, net cash used in financing activities was affected by several factors, including net decreases in other bank borrowings (largely due to the paydown of approximately $1.2 billion of costing liabilities as part of ASB's balance sheet restructuring), deposits, short-term borrowings and long-term debt and payment of common stock dividends, partly offset by proceeds from the issuance of common stock.

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% (56% at December 31, 2008), and restricts HECO from making distributions to HEI to the extent it would result in that ratio being less than 35%. In the absence of an unexpected material adverse change in the financial condition of the electric utilities or ASB, such restrictions are not expected to significantly affect the operations of HEI, its ability to pay dividends on its common stock or its ability to meet its debt or other cash obligations. See Note 12 of HEI's "Notes to Consolidated Financial Statements."

Forecasted HEI consolidated "net cash used in investing activities" (excluding "investing" cash flows from ASB) for 2009 through 2011 consists primarily of the net capital expenditures of HECO and its subsidiaries. In addition to the funds required for the electric utilities' construction program (see "Electric utility—Liquidity and capital resources"), approximately $150 million will be required in 2011 to repay maturing HEI medium-term notes, which are expected to be repaid with the proceeds from the issuance of commercial paper, and/or common stock issued under Company plans, and/or dividends from subsidiaries. Additional debt and/or equity financing may be utilized to pay down commercial paper or other short-term borrowings or may be required to fund unanticipated expenditures not included in the 2009 through 2011 forecast, such as increases in the costs of or an acceleration of the construction of capital projects of the utilities, utility capital expenditures that may be required by the HCEI or new environmental laws and regulations, unbudgeted acquisitions or investments in new businesses, significant increases in retirement benefit funding requirements and higher tax payments that would result if certain tax positions taken by the Company do not prevail. In addition, existing debt may be refinanced prior to maturity (potentially at more favorable rates) with additional debt or equity financing (or both).

As further explained in "Retirement benefits" above and Notes 1 and 8 of HEI's "Notes to Consolidated Financial Statements," the Company maintains pension and other postretirement benefit plans. The Company was not required to make any contributions to the qualified pension plans to meet minimum funding requirements pursuant to ERISA for 2008, 2007 and 2006, but the Company made voluntary contributions in those years. Contributions to the retirement benefit plans totaled $15 million in 2008 (comprised of $14 million made by the utilities, $1 million by HEI and nil by ASB), $13 million in both 2007 and 2006 and are expected to total $32 million in 2009 ($31 million by the utilities, $1 million by HEI and nil by ASB). In addition, the Company paid directly $1 million of benefits in each of 2008, 2007 and 2006 and expects to pay $1 million of benefits in 2009. Depending on the performance of the assets held in the plans' trusts and numerous other factors, additional contributions may be required in the future to meet the minimum funding requirements of ERISA or to pay benefits to plan participants. The Company believes it will have adequate access to capital resources to support any necessary funding requirements.

In the fourth quarter of 2008, HECO and its electric utility subsidiaries filed an application with the PUC for approval of one or more special purpose revenue bond financings (with the first such financing anticipated to be in 2009 if the PUC approves the application and market conditions are satisfactory.

## 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 on the construction and real estate industries and by the impact of world conditions (e.g., war in Iraq) on federal government spending in Hawaii. The two largest components of Hawaii's economy are tourism and the federal government (including the military).

The current turmoil in the financial markets and declines in the national and global economies are having a negative effect on the Hawaii economy. Declines in the Hawaii, U.S. and Asian economies, have led to declines in KWH sales in 2008 and an increase in uncollected billings of HECO and its subsidiaries, higher delinquencies in ASB's loan portfolio and other adverse effects on HEI's businesses. A similar downward trend is expected in 2009, which is expected to adversely impact the utilities', the bank's and consolidated HEI's 2009 results of operations. Given the current recessionary economic conditions and the associated uncertainty of U.S. and global financial markets, the Company's and consolidated HECO's earnings may decline and ratings may be threatened. If S&P or Moody's were to downgrade HEI's or HECO's long-term debt ratings because of these adverse effects, 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 with resulting reductions in HEI's consolidated net income in future periods. Further, if HEI's or HECO's commercial paper ratings were to be downgraded, HEI and HECO might not be able to sell commercial paper and might be required to draw on more expensive bank lines of credit or to defer capital or other expenditures.

Changes in the U.S. capital markets can also have significant effects on the Company. For example, pension funding requirements, as further explained in "Retirement benefits" above and Notes 1 and 8 of HEI's "Notes to Consolidated Financial Statements," are affected by the market performance of the assets in the master pension trust maintained for pension plans, and by the discount rate used to estimate the service and interest cost components of net periodic pension cost and value obligations. The electric utilities' pension tracking mechanisms help moderate pension expense; however, the recent significant decline in the value of the Company's defined benefit pension plan assets, in addition to continuing challenging market conditions in the beginning of 2009, has resulted in a substantial gap between the projected benefit obligations under the plans and the value of plan assets, resulting in sizable increases in expected funding requirements absent legislative or regulatory relief. However, potential laws and regulations may provide funding relief in the near term.

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. 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 2008, 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 2008 and continued volatility in the financial markets could further impact the fair value of this portfolio, which will have an adverse impact on ASB's and HEI's financial condition.

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

***Environmental matters***. HEI and its subsidiaries are subject to environmental laws and regulations that regulate the operation of existing facilities, the construction and operation of new facilities and the proper cleanup and disposal of hazardous waste and toxic substances. These laws and regulations, among other things, may require that certain environmental permits be obtained and maintained as a condition to constructing or operating certain facilities. Obtaining such permits can entail significant expense and cause substantial construction delays. Also, these laws and regulations may be amended from time to time, including amendments that increase the burden and expense of compliance.

## Material estimates and critical accounting policies

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

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

In accordance with SEC Release No. 33-8040, "Cautionary Advice Regarding Disclosure About Critical Accounting Policies," management has identified accounting policies it believes to be the most critical to the Company's financial statements—that is, management believes that the policies 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.*** Pension and other postretirement benefits (collectively, retirement benefits) costs are material estimates accounted for in accordance with SFAS No. 87, "Employers' Accounting for Pensions," SFAS No. 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions" and SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of Financial Accounting Standards Board (FASB) Statements No. 87, 88, 106, and 132(R)." For a discussion of retirement benefits (including costs, major assumptions, plan assets, other factors affecting costs, AOCI charges and sensitivity analyses), see "Retirement benefits (pension and other postretirement benefits)" in "Consolidated—Results of operations" above and Notes 1 and 8 of HEI's "Notes to Consolidated Financial Statements."

***Contingencies and litigation.*** The Company is subject to proceedings, lawsuits and other claims, including proceedings under laws and government regulations related to environmental matters. Management assesses the likelihood of any adverse judgments in or outcomes to 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 at enacted 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 in the evaluation required pursuant to FASB Interpretation No. (FIN) 48. 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 tax experts. Management believes that the Company's provision for tax contingencies is reasonable. However, the ultimate resolution of tax treatments disputed by governmental authorities may adversely affect the Company's current and deferred income tax amounts. See disclosure in Note 1 of HEI's "Notes to Consolidated Financial Statements" regarding the impact of changes made to estimating the impact of uncertain tax positions under FIN 48, which was adopted on January 1, 2007. Also, see Note 10, "Income taxes," of HEI's "Notes to Consolidated Financial Statements."

*Following are discussions of the electric utility and bank segments. Additional segment information is shown in Note 2 of HEI's "Notes to Consolidated Financial Statements."*

## Electric utility

### Executive overview and strategy

The electric utilities are vertically integrated and regulated by the PUC. The separate island utility systems have not been 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 options and technology opportunities (such as CHP and distributed generation (DG)) and taking the necessary steps to secure regulatory support for their plans.

Reliability projects, including projects to increase generation reserves to meet growing peak demand, remain a priority for HECO and its subsidiaries. On Oahu, HECO is making progress in building a new generating unit, which is projected to be placed in service in 2009, and in constructing the East Oahu Transmission Project (EOTP), a needed alternative route to move power from the west side of the island. HECO installed a new Energy Management System in 2006 and completed a new Outage Management System in 2007. On the island of Hawaii, after years of delay, the two 20 MW combustion turbines (CTs) at Keahole are operating and construction is underway to add an 18 MW heat recovery steam generator in 2009 to complete a dual-train combined-cycle unit. On the island of Maui, an 18 MW steam turbine at the Maalaea power plant site was installed in 2006. Further, the utilities have demand-side management (DSM) rebate programs and are considering additional utility-dispatchable DG as another measure to potentially help meet growth in demand.

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 and evaluate community concerns early in the process.

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

In November 2004, HECO filed a request with the PUC to increase base rates and interim rate relief was granted in September 2005. The PUC issued a bifurcation order separating HECO's requests for approval and/or modification of its existing and proposed DSM programs from the rate case proceeding into a new docket (EE DSM Docket). The DSM programs, with certain modifications, were approved in February 2007. See "Most recent rate requests—HECO" and "Other regulatory matters—Demand-side management programs."

In May 2006, December 2006 and February 2007, HELCO, HECO and MECO filed requests with the PUC to increase base rates and, in April, October and December of 2007, the PUC granted annual interim rate relief of $24.6 million, $70.0 million and $13.2 million, respectively. 2008 and 2007 revenues of the utilities included $73 million and $32 million of revenues, respectively, resulting from these interim increases. In July 2008, HECO filed a request to increase base rates based on a 2009 test year. See "Most recent rate requests."

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 agreement). The agreement provides that the parties pursue a wide range of actions, many of which will require PUC approval, with the purpose of decreasing the State of Hawaii's dependence on imported fossil fuels through substantial increases in the use of renewable energy and implementation of new programs intended to secure greater energy efficiency and conservation. A few of the major provisions of the agreement directly affecting HECO and its subsidiaries, which may affect future results and financial condition and require various PUC approvals, are: (1) pursuing an overall goal of providing 70% of Hawaii's electricity and ground transportation energy needs from clean energy sources; (2) establishing a Clean Energy Infrastructure Surcharge

(CEIS) designed to expedite cost recovery for infrastructure that supports greater use of renewable energy or grid efficiency within the utility systems; (3) pursuing the integration of approximately 1,100 MW from a variety of renewable energy sources into the utility systems, including the integration of 400 MW of wind power into the Oahu grid through a yet-to-be constructed undersea transmission cable system from wind farms proposed by developers to be built on the islands of Lanai and/or Molokai; (4) developing a feed-in tariff system with standardized purchase prices for renewable energy; and (5) adopting a new regulatory rate-making model, which employs a revenue adjustment mechanism that tracks the difference between the amount of revenues allowed in the last rate case and the sum of the current costs of providing electric service and a reasonable return on, and return of, additional capital investment in the electric system. See "Hawaii Clean Energy Initiative (HCEI)" in Note 3 of HEI's "Notes to Consolidated Financial Statements" for a more detailed discussion of the agreement.

Net income for HECO and its subsidiaries was $92 million in 2008 compared to $52 million in 2007 and $75 million in 2006. The increase in 2008 was primarily due to interim rate relief and the effects on 2007 earnings of a write-off of plant at Keahole and a reserve for a refund at the utilities in 2007, partly offset by lower sales. The decrease in 2007 was primarily due to increased operation and maintenance expenses (including more extensive maintenance on generating units, which are aging and are being run harder to meet the higher demand for electricity, and higher retirement benefits expense), higher depreciation expense due to investments in capital projects, a write-off of plant in service costs associated with the CT-4 and CT-5 generating units at Keahole as part of a settlement in HELCO's rate case, a reserve accrued for the potential refund of a portion of HECO's 2005 test year interim rate increase, and the discontinuation of DSM lost margin and shareholder incentives, partly offset by the impact of interim rate increases, proceeds from the sale of non-electric utility property and the accrual of a new HECO DSM utility incentive for meeting customer demand reduction goals.

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

In its June 27, 2008 filing with the PUC, HECO reported a consolidated RPS of 16.1% in 2007. This was accomplished through a combination of municipal solid waste, geothermal, wind, biomass, hydro, photovoltaic and biodiesel renewable generation resources; renewable energy displacement technologies; and energy savings from efficiency technologies.

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

In January 2007, HECO and MECO agreed to form a venture with BlueEarth Biofuels LLC (BlueEarth) to develop a biodiesel production facility on MECO property in Wa'ena on the island of Maui. BlueEarth Maui Biofuels LLC (BlueEarth Maui), a joint venture to pursue biodiesel development, was formed in early 2008 between BlueEarth and Uluwehiokama Biofuels Corp. (UBC), a non-regulated subsidiary of HECO. In February 2008, an Operating Agreement and an Investment Agreement were executed between BlueEarth and UBC, under which UBC invested $400,000 in BlueEarth Maui in exchange for a minority ownership interest. All of UBC's profits from the project are intended to be directed into a biofuels public trust to be created for the purpose of funding biofuels development in Hawaii. MECO intended to lease to BlueEarth Maui a portion of the land owned by MECO for its future Waena generation station as the site for the biodiesel plant, with lease proceeds intended to be credited to MECO ratepayers. MECO had been negotiating with BlueEarth Maui for a fuel purchase contract for biodiesel to be used in existing diesel-fired units at MECO's Maalaea plant. Both the land lease agreement and biodiesel fuel contract would require PUC approval. BlueEarth Maui has announced plans to prepare an environmental assessment and/or environmental impact statement for the project. HECO, working closely with the Natural Resources Defense Council, developed an environmental policy, which focuses on sustainable palm oil and locally-grown feedstocks, to ensure that the project would procure biofuel and biofuel feedstocks only from sustainable sources. However, BlueEarth's and MECO's negotiations for the biodiesel supply contract stalled based on inability to reach agreement on various financial and risk allocation issues. In October 2008, BlueEarth filed an action in federal district court in Texas against MECO, HECO and others alleging claims based on the parties' failure to have reached agreement on the biodiesel supply and land agreements. The lawsuit seeks damages and equitable relief. HECO and MECO have filed motions to dismiss the complaint, or, in the alternative, transfer venue of the action to Hawaii. The motions are pending.

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

In September 2007, HECO issued a Solicitation of Interest for its planned Renewable Energy Request for Proposals (RFP) for combined renewable energy projects up to 100 MW on Oahu. In June 2008, the PUC approved HECO's Oahu Renewable Energy RFP and HECO issued the RFP shortly thereafter. HECO received bids representing a variety of renewable technologies and a short list of bids proceeding to the Interconnection Requirements Study phase has been identified. Included in the bids received were proposals for large scale neighbor island wind projects. In accordance with the Energy Agreement, the plan is for these proposals for large scale neighbor island wind projects (Big Wind projects) to be bifurcated from the Oahu Renewable Energy RFP. This bifurcated RFP process to evaluate and select the most appropriate Big Wind project or projects will be led by HECO with support from the State of Hawaii. The process to bifurcate the RFP is currently being developed by HECO with the assistance of outside consultants and will be conducted in general conformance with the competitive bidding framework approved by the PUC. HECO plans to review this process with the PUC.

HECO's unregulated subsidiary, Renewable Hawaii, Inc. (RHI), is seeking to stimulate renewable energy initiatives by prospecting for new projects and sites and taking a passive, minority interest in selected third-party renewable energy projects. Since 2003, RHI has actively pursued a number of solicited and unsolicited projects, particularly those utilizing wind, landfill gas, and ocean energy. RHI will generally make project investments only after developers secure the necessary approvals and permits and independently execute a PUC-approved PPA with HECO, HELCO or MECO. While RHI has executed some memoranda of understanding and conditional investment agreements with project developers, no investments have been made to date.

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

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

For a description of some of the major provisions of the Energy Agreement most directly affecting HECO and its subsidiaries and their commitments relating to renewable energy and energy efficiency, see "Hawaii Clean Energy Initiative" in Note 3 of HEI's "Notes to Consolidated Financial Statements."

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

**Results of operations**

| (dollars in millions, except per barrel amounts) | 2008 | % change | 2007 | % change | 2006 |
|---|---|---|---|---|---|
| Revenues [1] | $ 2,860 | 36 | $ 2,106 | 3 | $ 2,055 |
| Expenses | | | | | |
| Fuel oil | 1,229 | 59 | 774 | (1) | 782 |
| Purchased power | 690 | 28 | 537 | 6 | 507 |
| Other | 750 | 13 | 664 | 11 | 599 |
| Operating income | 191 | 47 | 131 | (22) | 167 |
| Allowance for funds used during construction | 13 | 69 | 8 | (16) | 9 |
| Net income | 92 | 76 | 52 | (30) | 75 |
| Return on average common equity | 8.0% | | 5.0% | | 7.5% |
| Average fuel oil cost per barrel [1] | $ 114.50 | 66 | $ 69.08 | 1 | $ 68.13 |
| Kilowatthour sales (millions) | 9,936 | (2) | 10,118 | – | 10,116 |
| Cooling degree days (Oahu) | 4,946 | 2 | 4,835 | 7 | 4,520 |
| Number of employees (at December 31) | 2,203 | 3 | 2,145 | 3 | 2,085 |

[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.

- In 2008, the electric utilities' revenues increased by 36%, or $754 million, from 2007 primarily due to higher fuel prices ($695 million); interim rate relief granted by the PUC to HECO (2007 test year), HELCO (2006 test year) and MECO (2007 test year) in October 2007, April 2007 and December 2007, respectively ($73 million) (see "Most recent rate requests" below); 2007 accrual of a reserve for a refund of a portion of HECO's 2005 test year rate increase ($16 million), and higher DSM program recovery revenues ($12 million); partly offset by lower KWH sales ($44 million). KWH sales for 2008 were 1.8% lower when compared to 2007, due largely to customer conservation efforts, partially offset by new load growth (i.e., increase in number of customers) and the impact of warmer weather. Cooling degree days for Oahu were 2.3% higher in 2008 compared to 2007. The electric utilities are currently estimating KWH sales for 2009 to decrease from the prior year by 1.0% and remain flat in 2010, primarily due to the impact of slowing economic activity, continued customer conservation efforts and ongoing DSM activities, partially offset in 2010 by the expected impacts of improvements in tourism on HELCO and MECO sales.

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

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

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

• In 2007, the electric utilities' revenues increased by 2.5%, or $51 million, from 2006 primarily due to higher fuel prices ($21 million); interim rate relief granted by the PUC to HECO (2007 test year), HELCO (2006 test year) and MECO (2007 test year) in October 2007, April 2007 and December 2007, respectively ($32 million) (see "Most recent rate requests" below); higher DSM program recovery revenues ($7 million); a gain from the sale of non-electric utility property (see Note 3 in HEI's "Notes to Consolidated Financial Statements") and the accrual of utility incentives ($4 million) (see "Other Regulatory Matters – Demand-side management programs" below); partly offset by a reserve accrued for the potential refund of a portion of HECO's 2005 test year interim rate increase ($16 million) and lower shareholder incentives and lost margins ($7 million). KWH sales for 2007 were basically flat when compared to 2006, with only 0.02% growth, primarily due to new load growth (i.e., increase in number of customers) and the impact of warmer weather, largely offset by the impact of commercial (including large light and power) customer conservation efforts. Cooling degree days for Oahu were 7% higher in 2007 compared to 2006.

Operating income in 2007 was $36 million lower than in 2006 due primarily to higher other expenses, including a $12 million ($7 million, net of tax benefits) write-off of plant in service costs associated with the CT-4 and CT-5 generating units at Keahole as part of a settlement in HELCO's rate case, higher maintenance and retirement benefit expenses, a reserve accrued for the potential refund of a portion of HECO's 2005 test year interim rate increase and the discontinuation of the recovery of DSM lost margins and shareholder incentives, partly offset by the impact of interim rate increases for HECO, HELCO and MECO, proceeds from the sale of non-electric utility property and the accrual of a new HECO DSM utility incentive for meeting customer demand reduction goals.

Fuel oil expense in 2007 decreased by 1% due primarily to lower KWHs generated, mostly offset by higher fuel costs. Purchased power expenses in 2007 increased by 6% due primarily to higher KWHs purchased, higher purchased energy costs, and higher capacity and non-fuel charges. Higher fuel costs are generally passed on to customers.

Other expenses increased 11% in 2007 due to a 15% (or $28 million) increase in "other operation" expense; a 17% (or $15 million) increase in maintenance expense; a 5% (or $7 million) increase in depreciation expense; and a 2% (or $4 million) increase in taxes, other than income taxes, primarily due to the increase in revenues. "Other operation" expenses increased by $28 million in 2007 when compared to 2006 due primarily to higher administrative and general expense, including employee benefits expense ($6 million, of which $5 million was higher retirement benefits expense), DSM expenses that are generally passed on to customers through a surcharge ($7 million) and increased staffing and other costs to ensure reliable operation. Retirement benefits expenses for the electric utilities increased $5 million over 2006 due in part to the adoption of a 50 basis points lower asset return rate as of December 31, 2006 and expenses related to the adoption of the pension and OPEB tracking mechanisms, including the amortization of HELCO's prepaid pension asset (approved on an interim basis by the PUC; see "Most recent rate requests"). Maintenance expenses increased 17%, or $16 million over 2006, due to $12 million higher production maintenance expense (primarily due to generating plant maintenance and the greater scope and number of generating unit overhauls) and $4 million higher transmission and distribution maintenance expense (including higher substation maintenance, vegetation management, storm repairs and distribution line maintenance expenses). Higher depreciation expense was attributable to $268 million of additions to plant in service in 2006 (including HECO's new Dispatch Center and Energy Management System and Ford Island Substation, and MECO's M18 generating unit).

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

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

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

As of February 18, 2009, the ROACE found by the PUC to be reasonable in the most recent final rate decision for each utility was 10.7% for HECO (D&O issued on May 1, 2008, based on a 2005 test year), 11.5% for HELCO (D&O issued on February 8, 2001, based on a 2000 test year) and 10.94% for MECO (amended D&O issued on April 6, 1999, based on a 1999 test year). The ROACEs used by the PUC in the interim rate increases in HECO, HELCO and MECO rate cases based on 2007, 2006 and 2007 test years and issued in October, April and December 2007, respectively, were 10.7%.

For 2008, the actual ROACEs (calculated under the ratemaking 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 8.07%, 9.39% and 8.54%, respectively. HECO's and MECO's actual ROACEs were 263 and 216 basis points, respectively, lower than their authorized ROACEs primarily due to lower KWH sales and increased O&M expenses, which are expected to continue. HELCO's actual ROACE was 131 basis points lower than its authorized ROACE due in part to lower KWH sales. The interim rate relief granted to the utilities by the PUC (see below) in their most recent cases was based in part on increased costs of operating and maintaining their systems, and the gap between allowed and actual ROACEs has been narrowing as interim rate relief has become effective.

As of February 18, 2009, the ROR found by the PUC to be reasonable in the most recent final rate decision for each utility was 8.66% for HECO, 9.14% for HELCO and 8.83% for MECO (D&Os noted above). The RORs used by the PUC for purposes of the interim D&Os in the HECO, HELCO and MECO rate cases based on 2007, 2006 and 2007 test years were 8.62%, 8.33% and 8.67%, respectively. For 2008, the actual RORs (calculated under the ratemaking method, which excludes the effects of items not included in determining electric utility rates, and reported to the PUC) for HECO, HELCO and MECO were 7.05%, 7.21% and 7.03%, respectively.

In 2007, HECO, HELCO and MECO received interim D&Os in their most recent rate cases, which included the reclassification to a regulatory asset of the charge for retirement benefits that would otherwise be recorded in AOCI. See Note 3 of HEI's "Notes to Consolidated Financial Statements."

For a description of some of the rate-making changes that the parties have agreed to pursue under the Energy Agreement, see "Hawaii Clean Energy Initiative" in Note 3 of HEI's "Notes to Consolidated Financial Statements."

**HECO.**

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

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

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

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

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

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

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

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

HECO's application requested a return on HECO's pension assets (i.e., accumulated contributions in excess of accumulated net periodic pension costs) by including such assets (net of deferred taxes) in rate base. In a separate

AOCI proceeding, the electric utilities had earlier requested PUC approval to record as a regulatory asset for financial reporting purposes, the amounts that would otherwise be charged to AOCI in stockholders' equity as a result of adopting SFAS No. 158, but that request was denied. HECO thus proposed in the 2007 test year rate case to restore to book equity for ratemaking purposes the amounts charged to AOCI as a result of adopting SFAS No. 158. The authorized ROACE found to be fair in a rate case is applied to the equity balance in determining the utility's weighted cost of capital, which is the rate of return applied to the rate base in determining the utility's revenue requirements. HECO's position was that, if the reduction in equity balance resulting from the AOCI charges is not restored for ratemaking purposes, a higher ROACE will be required.

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

In a June 2007 update to its direct testimonies, HECO proposed pension and OPEB tracking mechanisms, similar to the mechanisms that were agreed to by HELCO and the Consumer Advocate and approved on an interim basis by the PUC in the HELCO 2006 test year rate case (discussed below). A pension funding study (required by the PUC in the AOCI proceeding) was filed in the HECO rate case in May 2007. The conclusions in the study were consistent with the funding practice proposed with the pension tracking mechanism. For a discussion of this mechanism and related pension issues, see Note 8, "Retirement Benefits" of HEI's "Notes to Consolidated Financial Statements."

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

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

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

On October 22, 2007, the PUC issued, and HECO implemented, an interim D&O granting HECO an increase of $70 million in annual revenues over rates effective at the time of the interim D&O, subject to refund with interest. The interim increase was based on the settlement agreement described above and did not include in rate base the HECO pension asset. The interim D&O also approved, on an interim basis, the adoption of the pension tracking mechanism and a tracking mechanism for OPEB. See "Interim increases" in Note 3 and Note 8, "Retirement benefits," of HEI's "Notes to Consolidated Financial Statements."

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

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

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

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

The requested rate increase was based on anticipated plant additions estimated at the time of filing of $375 million in 2008 and 2009 (including $162 million for the new Campbell Industrial Park generating unit and related transmission line) to maintain and improve system reliability, higher operation and maintenance costs required for HECO's electrical system, and higher depreciation expenses since the last rate case. As in its 2007 test year rate case, HECO requests continuation of its ECAC in its present form. The request excludes incremental DSM costs from the test year revenue requirement due to the transition of HECO's DSM programs to a third-party program administrator in 2009 as ordered by the PUC.

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

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

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

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

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

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

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

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

On April 4, 2007, the PUC issued an interim D&O, which was implemented by tariff changes made effective on April 5, 2007, granting HELCO an increase of 7.58%, or $24.6 million in annual revenues, over revenues at present rates for a normalized 2006 test year. The interim increase reflects the settlement of the revenue requirement issues reached between HELCO and the Consumer Advocate and is based on an average rate base of $357 million (which reflects the write-off of a portion of CT-4 and CT-5 costs) and an ROR of 8.33% (incorporating an ROACE of 10.7%). In the interim D&O, the PUC also approved on an interim basis the adoption of pension and OPEB tracking mechanisms (see Note 8 of HEI's "Notes to Consolidated Financial Statements").

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

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

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

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

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

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

In the interim D&O, the PUC also approved on an interim basis the adoption of pension and OPEB tracking mechanisms (see Note 8 of HEI's "Notes to Consolidated Financial Statements").

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

**Anticipated HELCO and MECO 2009 test year rate cases.** In order to implement the decoupling mechanism committed to by the parties in the Energy Agreement, the parties agreed that HELCO and MECO will each file a 2009 test year rate case.

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

On October 24, 2008, the PUC opened an investigative proceeding to examine implementing a decoupling mechanism for the utilities. In addition to the utilities and the Consumer Advocate, there are six other parties in the proceeding. The utilities and the Consumer Advocate submitted separate proposals for consideration by the parties in January 2009. The schedule for the proceeding includes technical workshops on the proposals, final position statements of the parties to be submitted in May 2009, and panel hearings during the week of June 29, 2009.

***Other regulatory matters.*** In addition to the items below, also see "Hawaii Clean Energy Initiative" and "Major projects" in Note 3 of HEI's "Notes to Consolidated Financial Statements" for a number of actions committed to in the Energy Agreement that will require PUC approval in either pending or new PUC proceedings.

**Demand-side management programs.** On February 13, 2007, the PUC issued its D&O in the EE DSM Docket that had been opened by the PUC to bifurcate the EE DSM issues originally raised in the HECO 2005 test year rate case. In the D&O, the PUC required that the administration of all EE DSM programs be turned over to a non-utility, third-party administrator, with the transition to the administrator, funded through a public benefits fund (PBF) surcharge. The PUC opened a new docket to select a third-party administrator and to refine details of the new market structure in an order issued in September 2007. In the order, the PUC stated that "[u]pon selection of the PBF Administrator, the PUC intends, in this docket, to determine whether the electric utilities will be allowed to compete for the implementation of the Energy Efficiency DSM programs." In July 2008, the PUC issued an Order to Initiate the Collection of Funds for the PBF Administrator of Energy Efficiency Programs, which authorized the electric utilities to expense $50,000 per quarter beginning July 1, 2008 for the initial start-up costs associated with the PBF Administrator and recover the cost in the DSM surcharge; confirmed that the load management, SolarSaver Pilot (SSP) and Residential Customer Energy Awareness programs shall remain with the electric utilities; and directed the electric utilities to continue to operate the DSM programs through June 30, 2009, after which transition period the electric utilities can compete for implementation of DSM programs as a subcontractor. The PUC issued its RFP for the PBF Administrator and proposals were received.

In December 2008, the PUC notified Science Applications International Corporation (SAIC) that it had been selected to continue negotiations with the PUC to become the PBF Administrator. The utilities had worked with SAIC to develop the PBF Administrator proposal selected by the PUC that included continued delivery of the existing energy efficiency programs by the utilities as subcontractor to SAIC. In the PBF Administrator RFP, the contract start date for the PBF Administrator is scheduled for approximately February 25, 2009.

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

The utilities filed new DSM program budgets and goals in January 2009.

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

On December 31, 2008, the utilities filed proposed modifications to expand the SSP Program from 600 solar water heating system installations over three years to 2,500 installations per year.

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

In 2007, HECO recorded incentives of $4 million. HELCO and MECO proposed goals for their programs, based on the goals established for HECO's programs, but recorded no incentives in 2007. On May 21, 2007, the PUC clarified the 2007 and 2008 energy efficiency goals and the calculation of the DSM utility incentive, and granted HECO the ability to request program modifications and budget increases by letter request. Since that time, the PUC has approved budget increases and program modifications for various DSM programs. In October 2007, the PUC approved an increase in the 2007 program budget for a residential coupon redemption program for compact fluorescent lamps and Energy Star™ appliances, and at the end of December 2007, HECO requested another increase, based on the estimate of the coupons to be submitted for 2007 customer purchases under the program. In June 2008, the PUC issued an order approving MECO's proposed cumulative energy and demand savings goals for 2007 and 2008, but set MECO's annual incentive cap at $320,000. Thus, in the second quarter of 2008, MECO recorded an incentive of $320,000 related to 2007. The PUC also issued an order approving HELCO's proposed cumulative energy and demand savings goals for 2007 and 2008, and an annual incentive cap of $200,000. However, HELCO did not achieve those goals and, therefore, no incentives were earned by HELCO. The utilities' DSM incentives for 2007 and 2008 were subject to adjustment based on the results of impact evaluation studies.

In December 2008, the results of the impact evaluation studies became available. The impact evaluation reduced actual DSM energy and demand savings for 2005 through 2007. As a result of the reduced savings, the utilities' Lost Margin and Shareholder Incentives earned in 2005 and 2006 were reduced. In addition, MECO no longer met its 2007 goals for DSM utility incentives. As a result of these changes, the utilities accrued a refund to its customers of $1.4 million, including interest, in December 2008, and will refund such amounts over 12 months after they file their annual DSM Accomplishments and Surcharge Report on or about March 31, 2009.

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

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

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

**Avoided cost generic docket.** In May 1992, the PUC instituted a generic investigation to examine the proxy method and formula used by the electric utilities to calculate their avoided energy costs and Schedule Q rates. In general, Schedule Q rates are available to customers with cogeneration and/or small power production facilities with a capacity of 100 kW or less who buy power from or sell power to the electric utility. The parties to the proceeding agreed that avoided fuel costs, except for Lanai and Molokai, would be determined using a computer production simulation model and agreed on certain parameters that would be used to calculate avoided costs. In March 2008, the PUC ordered that the new avoided energy cost rates and Schedule Q rates would go into effect on August 1, 2008. HECO, HELCO and MECO filed new avoided energy costs rates and Schedule Q rates, which were determined using the new differential revenue requirements "resource-in / resource-out" methodology instead of the proxy method. These rates were effective from August 1 through December 31, 2008, and the fuel component of the rates was adjusted monthly for changes in fuel prices.

On April 18, 2008, the PUC initiated a docket to examine the methodology for calculating Schedule Q electricity payment rates in the State of Hawaii. The proceeding was intended to examine new methodologies for calculating Schedule Q payment rates, with the intent of removing or reducing any linkages between the price of fossil fuels and the rate for non-fossil fuel generated electricity. The parties to the Energy Agreement agreed that all new renewable energy contracts are to be delinked from fossil fuel and that the utilities would seek to renegotiate existing PPAs with independent power producers (IPPs) that are based on fossil fuel prices to delink their energy payment rates from oil costs. Based on this understanding, the parties agreed to request that the PUC suspend the pending Schedule Q proceeding for a period of 12 months with a view to reviewing the necessity of the docket. On November 28, 2008, the PUC granted the request to suspend the Schedule Q proceeding for 12 months. On December 31, 2008, HECO, HELCO and MECO filed avoided energy costs rates and Schedule Q rates to be effective for 2009, subject to monthly adjustment of the fuel component of the rates for changes in fuel prices.

**Integrated resource planning, requirements for additional generating capacity and adequacy of supply.** The PUC issued an order in 1992 requiring the energy utilities in Hawaii to develop integrated resource plans (IRPs), which may be approved, rejected or modified by the PUC. The goal of integrated resource planning is the identification of demand- and supply-side resources and the integration of these resources for meeting near- and long-term consumer energy needs in an efficient and reliable manner at the lowest reasonable cost. The utilities' proposed IRPs are planning strategies, rather than fixed courses of action, and the resources ultimately added to their systems may differ from those included in their 20-year plans. Under the PUC's IRP framework, the utilities are required to submit annual evaluations of their plans (including a revised five-year program implementation schedule) and to submit new plans on a three-year cycle, subject to changes approved by the PUC. Prior to proceeding with the DSM programs, separate PUC approval proceedings must be completed.

The utilities were to be entitled to recover all appropriate and reasonable integrated resource planning and implementation costs, including the costs of DSM programs, either through a surcharge or through their base rates. Under procedural schedules for the IRP cost proceedings, the utilities were able to recover their incremental IRP costs in the month following the filing of their actual costs incurred for the year, subject to refund with interest pending the PUC's final D&O approving recovery in the docket for each year's costs. HELCO (since February 2001), HECO (since September 2005) and MECO (since December 2007) now recover IRP costs (which are included in O&M) through base rates. Previously, HECO, HELCO and MECO recovered their costs through a surcharge. The Consumer Advocate has objected to the recovery of $1.2 million (before interest) of the $4.0 million of incremental IRP costs incurred by the utilities during the 2002-2007 period, and the PUC's decisions on the recovery of these costs are pending. Also, see Note 3 in HEI's "Notes to Consolidated Financial Statements" and "Demand-side management programs" above.

The parties to the Energy Agreement agreed to seek to replace the IRP process with a new Clean Energy Scenario Planning (CESP) process, described in the Energy Agreement, intended to be used to determine future investments in transmission, distribution and generation that will be necessary to facilitate high levels of renewable energy production. Requests by the parties to the Energy Agreement to move to the CESP process were filed with the PUC on November 6, 2008, and the PUC acted on those requests as described below. The parties committed to supporting reasonable and prudent investment in the ongoing maintenance and upgrade of the existing generation, transmission and distribution systems, unless the CESP process determines otherwise.

*HECO's IRP.* On September 30, 2008, HECO filed its fourth IRP (IRP-4) covering a 20-year (2009-2028) planning horizon, subject to PUC approval. The IRP-4 preferred plan called for all future generation to be renewable. In addition, it called for conversion of a number of existing HECO-owned generating units to utilize biofuels and for continued aggressive implementation of DSM programs. In addition to the 110 MW biofueled CT scheduled for installation by HECO at its Campbell Industrial Park generating station in 2009, HECO plans to pursue the installation of a 100 MW biofueled CT at the same station in the 2011-2012 timeframe and plans to submit to the PUC a request for a waiver from the competitive bidding process to install this increment of additional firm capacity. The addition of two simple-cycle CTs will add to the system additional fast starting and ramping capability, which will facilitate integration of as-available generation (such as wind and solar) to the system. HECO also plans to remove Waiau Unit 3, a 46 MW oil-fired cycling unit, from service after the second CT is in service, and will later determine whether to place the unit in emergency reserve status or to retire the unit. When the necessary test biofuels are obtained, HECO plans to conduct a test on Kahe Unit 3 to evaluate the use of Low Sulfur Fuel Oil/biofuel blends in existing oil-fired steam units. Other renewable generation will be acquired via three renewable energy projects "grandfathered" from competitive bidding and from projects that are selected from proposals submitted in response to HECO's 100 MW RFP for Non-Firm Energy (see "Competitive bidding proceeding" below).

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

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

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

*MECO's IRP*. In April 2007, MECO filed its third IRP, which proposes multiple solutions to meet future energy needs on the islands of Maui, Lanai and Molokai, including renewable energy resources (such as photovoltaics, additional wind, biomass and waste-to-energy), energy efficiency (continuation of existing and addition of new DSM programs), technology (such as CHP and DG) and competitive bidding for generation or blocks of generation on Maui for 20 MW in each of 2011 and 2013 and 18 MW in 2024 which, under the utility parallel plan, could be located at its Waena site. In July 2008, the PUC approved MECO's IRP-3 and directed MECO to submit evaluation reports by December 31, 2008 and December 31, 2009, to make various improvements to the IRP process and to submit its IRP-4 by April 30, 2010.

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

**HECO's 2009 Campbell Industrial Park generating unit**. See "Campbell Industrial Park (CIP) generating unit" in Note 3 in HEI's "Notes to Consolidated Financial Statements."

**Adequacy of supply**.

*HECO*. HECO's 2008 Adequacy of Supply (AOS) letter, filed in January 2008, indicated that HECO's analysis estimates its reserve capacity shortfall to be approximately 80 MW in the 2008 to 2009 period (before the addition of the Campbell Industrial Park CT planned to be installed in 2009). The availability rates for HECO units have generally declined since 2002 and, based on this experience, the manner in which the units must be operated when there is a reserve capacity shortfall, and the increasing ages of the units, HECO expects availability rates to remain suppressed in the near-term. Although the availability rates for generating units on Oahu continue to be better than those of comparable units on the U.S. mainland, HECO generating units may continue to be entirely or partially unavailable to serve load during scheduled overhaul periods and other planned maintenance outages, or when they "trip" or are taken out of operation or their output is "de-rated" due to equipment failure or other causes.

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

After the planned 2009 addition of the Campbell Industrial Park generating unit, and in recognition of the uncertainty underlying key forecasts, HECO reported in its 2008 AOS letter that it anticipates the potential for continued reserve capacity shortfalls could range between 20 MW to 80 MW in 2010, up to a range of 70 MW to 130 MW in 2014, and may seek, under the guidance of the Competitive Bidding Framework issued by the PUC in December 2006, a firm, dispatchable resource (with a strong preference for a renewable resource) to meet this need, while continuing contingency planning activities. On September 30, 2008, HECO's IRP-4 included a new short-term sales and peak forecast, developed in March 2008, which indicated that the reserve capacity shortfall could range from 0 MW to 20 MW in 2011 and from 50 MW to 80 MW in 2014. As noted under "HECO's IRP" above, to address this projected shortfall HECO plans to pursue the installation of a second biofueled CT (100 MW) at its Campbell Industrial Park generating station in the 2011-2012 timeframe, at which time it would remove a 46 MW oil-fired cycling unit from service (and later determine whether to place the unit in emergency reserve status or to retire the unit).

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

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

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

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

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

**October 2006 outages.** In October 2006, two earthquakes centered on the island of Hawaii with magnitudes of 6.7 and 6.0 triggered power outages throughout most of the state and disrupted air traffic on all major islands. On Oahu, following the impact of the earthquakes, a series of protective actions and automatic systems operated to successively shut down all generators to protect them from potential damage. As a result, no significant damage to any of HECO's generators, or to its transmission and distribution systems, occurred. Following the island-wide outage, HECO restored power to customers in a careful, methodical manner to further protect its system, and as a result power was restored to over 99% of its customers within a period of time ranging from approximately 4½ to 18 hours. Management believes the shutdown and methodical restoration of power were necessary to prevent severe damage to HECO's generating equipment and power grid and to avoid a more prolonged blackout. HELCO's and MECO's smaller electric systems also experienced sustained outages from the earthquakes; however, their systems were, for the most part, back online by mid to late afternoon.

HECO immediately committed to investigating the outage caused by the earthquakes, and brought in an outside industry expert to help identify any potential improvements to procedures or systems, and also committed to cooperate fully with any other reviews conducted by its regulators.

Following requests by members of a state Senate energy subcommittee and the Consumer Advocate that the PUC investigate the power failure, to which investigation HECO stated it did not object, the PUC issued an order on October 27, 2006 opening an investigative proceeding on the outages at HECO, HELCO and MECO. The questions the PUC asked to be addressed in the proceeding include (1) aside from the earthquake, are there any underlying causes that contributed or may have contributed to the power outages, (2) were the actions of the electric utilities prior to and during the power outages reasonable and in the public interest, and were the power restoration processes and communication regarding the outages reasonable and timely under the circumstances, (3) could the island-wide power outages on Oahu and Maui have been avoided, and what are the necessary steps to minimize and improve the response to such occurrences in the future, and (4) what penalties, if any, should be imposed on the electric utilities.

Pursuant to the PUC's order, HECO's 2006 Outage Report was filed in December 2006, and the outage reports of HELCO and MECO were filed in March 2007. The investigation consultants retained by HECO, POWER Engineers, Inc., concluded that, "HECO's performance prior to and during the outage demonstrated reasonable actions in the public interest" in a "distinctly extraordinary event." POWER Engineers, Inc. also concluded that HELCO and MECO personnel responded in a "reasonable, responsible, and professional manner." The consultants also made a number of recommendations, mostly of a technical nature, regarding the operation of the electric system during such an incident. The Consumer Advocate submitted its findings in August 2007 and found the activities and performance of HECO, HELCO and MECO personnel prior to and during the outages were reasonable and in the public interest, and recommended no penalties for "these uncommon power outages." The Consumer Advocate also made several recommendations regarding training and potential electric system modifications. In October 2007, the electric utilities filed a final statement of position, which included proposed plans to address recommendations made by both POWER Engineers, Inc. and the Consumer Advocate.

On December 19, 2008, the PUC issued a D&O in this investigative proceeding. The PUC determined that the activities and performance of HECO, HELCO and MECO prior to and during the power outages were reasonable and in the public interest, and imposed no penalties. The PUC required HECO to file annual reports beginning on April 1, 2009 and for the next three years thereafter regarding the progress in implementing POWER Engineers, Inc.'s recommendations and any other additional measures taken to respond to similar future outage occurrences.

Management currently believes the financial impacts of property damage and other claims resulting from the earthquakes and outages are not material.

**December 2008 outage.** On December 26, 2008, an island-wide outage occurred on the island of Oahu that resulted in a loss of electric service to HECO customers ranging from approximately 7 to 20 hours. Based on HECO's preliminary analysis, the power outage was likely the result of a severe air-to-ground lightning storm, which is generally rare for Hawaii, with possible direct lightning strikes to HECO's 138-kilovolt transmission lines that created instability between system generation and load, causing HECO's generating units and those of IPPs to trip off line as a protective action.

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

HECO is engaging experts to assist in an internal investigation of the power outage, and will provide its report to the PUC upon completion. Management cannot at this time predict the outcome of its internal investigation, the PUC investigation or their impact on HECO.

**Intra-governmental wheeling of electricity.** In June 2007, the PUC initiated a docket to examine the feasibility of implementing intra-governmental wheeling of electricity in the State of Hawaii. The issues in the proceeding adopted by the PUC include (1) identifying what impact, if any, wheeling will have on Hawaii's electric industry, (2) addressing interconnection matters, (3) identifying the costs to utilities, (4) identifying any rate design and cost allocation issues, (5) considering the financial cost and impact on non-wheeling customers, (6) identifying any power back-up issues, (7) addressing how rates would be set, (8) identifying the environmental impacts, (9) identifying and evaluating the various forms of intra-governmental wheeling and (10) identifying and evaluating the resulting impact to any and all governmental entities, including but not limited to economic, feasibility and liability impacts. Parties to this proceeding include HECO, HELCO, MECO, Kauai Island Utility Cooperative and the Consumer Advocate, as well as governmental agencies (the DOD, the Department of Business, Economic Development and Tourism, the City and County of Honolulu and the Counties of Hawaii, Maui and Kauai), an environmental group, and two renewable energy developers. Two renewable energy contractors and a renewable energy developer also have been granted more limited participant status.

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

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

***Collective bargaining agreements.*** See "Collective bargaining agreements" in Note 3 of HEI's "Notes to Consolidated Financial Statements."

***Legislation and regulation.*** Congress and the Hawaii legislature periodically consider legislation that could have positive or negative effects on the utilities and their customers. Also see "Hawaii Clean Energy Initiative" and "Environmental regulation" in Note 3 of HEI's "Notes to Consolidated Financial Statements" and "Emergency Economic Stabilization Act of 2008 and the pending American Economic Recovery and Reinvestment Act of 2009" above.

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

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

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

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

The Renewable Energy Infrastructure Program proposed by HECO in the RPS docket consists of two components: (1) renewable energy infrastructure projects that facilitate third-party development of renewable energy resources, maintain existing renewable energy resources and/or enhance energy choices for customers, and (2) the creation and implementation of a temporary renewable energy infrastructure surcharge to recover the capital costs, deferred costs for software development and licenses, and/or other relevant costs approved by the PUC. These costs would be removed from the surcharge and included in base rates in the utility's next rate case. In July 2008, statements of position were filed with the PUC, in which the Consumer Advocate recommended approval of, HREA supported, and the environmental organization did not oppose the REIP proposed by HECO. In October 2008, pursuant to the PUC's request, the parties to the docket informed the PUC, among other things, that the parties (1) have reached an agreement on all of the issues in the docket, (2) agree that it is appropriate that the PUC approve the utilities' proposed REIP and related REIP surcharge, (3) agree that the record in the proceeding is complete and ready for PUC decision-making, and (4) waive an evidentiary hearing. In February 2009, the PUC issued to the parties information requests prepared by its consultant.

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

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

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

Management cannot predict the outcome of these proceedings and processes.

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

In 2005, the Legislature amended the net energy metering law by, among other revisions, authorizing the PUC, by rule or order, to increase the maximum size of the eligible net metered systems and to increase the total rated generating capacity available for net energy metering. In April 2006, the PUC initiated an investigative proceeding on whether the PUC should increase (1) the maximum capacity of eligible customer-generators to more than 50 kW and (2) the total rated generating capacity produced by eligible customer-generators to an amount above 0.5% of an electric utility's system peak demand. The parties to the proceeding include HECO, HELCO, MECO, Kauai Island Utility Cooperative (KIUC), the Consumer Advocate, a renewable energy organization and a solar vendor organization. In March 2008, the PUC approved a stipulated agreement filed by the parties (except for KIUC, which has its own stipulated agreement) to increase the maximum size of the eligible customer-generators from 50 kW to 100 kW and the system cap from 0.5% to 1.0% of system peak demand, to reserve a certain percentage of the 1.0% system peak demand for generators 10 kW or less and to consider in the IRP process any further increases in the maximum capacity of customer-generators and the system cap. The PUC further required the utilities: (1) to consider specific items relating to net energy metering in their respective IRP processes, (2) to evaluate the economic effects of net energy metering in future rate case proceedings and (3) to design and propose a net energy metering pilot program for the PUC's review and approval that will allow, on a trial basis, the use of a limited number of larger generating units (i.e., at least 100 kW to 500 kW, and may allow for larger units) for net energy metering purposes.

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

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

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

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

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

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

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

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

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

On July 11, 2008, the EPA issued its advance notice of proposed rulemaking (ANPR) inviting public comment on the benefits and ramifications of regulating GHGs under the CAA. The U.S. Supreme Court found that the CAA authorizes the EPA to regulate motor vehicle GHG emissions if the EPA determines they cause or contribute to air pollution that may reasonably be anticipated to endanger public health or welfare. Because the CAA language authorizing regulation of motor vehicle emissions is virtually identical to the Act's language regarding stationary source emissions, such as those emitted from the electric utilities' facilities, the utilities have begun their review of the ANPR in order to determine its potential impacts.

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

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

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

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

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

For a discussion of environmental legislation and regulations, see "Certain factors that may affect future results and financial condition—Environmental matters" below.

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

***Other developments***

**Advanced meter infrastructure (AMI).** After two years of pilot testing on Oahu, HECO executed a 15-year agreement with Sensus Metering Systems (Sensus) to provide AMI meters and network services for HECO, HELCO, and MECO. On December 1, 2008, the utilities' filed an AMI Project Application with the PUC for approval to implement AMI, covering approximately 451,000 meters (293,000 on Oahu, 92,000 on the island of Hawaii and 66,000 on Maui). The application embodies the goals of the HCEI which is further described in Note 3 of HEI's "Notes to Consolidated Financial Statements." The Sensus agreement is subject to PUC approval. Throughout 2008, HECO continued to operate a Sensus AMI network, now consisting of 7,700 advanced meters at both residential and commercial customer sites and began pilot investigations of Meter Data Management software that will ultimately capture the increased data volume from advanced meters and will serve as the data warehouse and knowledge store for current and future utility applications.

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

## Liquidity and capital resources

Despite the recent unprecedented deterioration in the capital markets and tightening of credit, HECO believes that its ability, and that of its subsidiaries, to generate cash, both internally from operations and externally from issuances of equity and debt securities, commercial paper and lines of credit, is adequate to maintain sufficient liquidity to fund their capital expenditures and investments and to cover debt, retirement benefits and other cash requirements in the foreseeable future.

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

| December 31 | 2008 | | 2007 | |
|---|---|---|---|---|
| (dollars in millions) | | | | |
| Short-term borrowings | $ 42 | 2% | $ 29 | 1% |
| Long-term debt, net | 905 | 42 | 885 | 43 |
| Preferred stock | 34 | 1 | 34 | 2 |
| Common stock equity | 1,189 | 55 | 1,110 | 54 |
| | $2,170 | 100% | $2,058 | 100% |

As of February 18, 2009, the S&P and Moody's ratings of HECO securities were as follows:

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

The above ratings reflect only the view of the applicable rating agency at the time the ratings are issued, from whom an explanation of the significance of such ratings may be obtained. Such ratings are not recommendations to buy, sell or hold any securities; such ratings may be subject to revision or withdrawal at any time by the rating agencies; and each rating should be evaluated independently of any other rating. HECO's overall S&P corporate credit rating is BBB/Stable/A-2. HECO's issuer rating by Moody's is Baa1 and Moody's outlook for HECO is stable.

* As a result of downgrades, Financial Guaranty Insurance Company's (FGIC's), MBIA Insurance Corporation's (MBIA's) and Syncora Guarantee Inc.'s (Syncora's)(formerly XL Capital Assurance Inc.'s) current financial strength ratings by S&P are CCC, BBB+ and CC, respectively, and their insurance financial strength ratings by Moody's are Caa1, B3 and Caa1, respectively. The revenue bonds insured by FGIC and Syncora referenced in the table above reflect a rating which corresponds to HECO's senior unsecured debt rating by S&P, and HECO's issuer rating by Moody's, because those ratings are higher than those of the applicable bond insurer. The bonds insured by MBIA also reflect HECO's issuer rating by Moody's, because the rating is higher than MBIA's financial strength rating by Moody's of B3.

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 HECO securities. In November 2008, S&P affirmed its corporate credit ratings and "stable" outlook for HECO. S&P's rating outlook "assesses the potential direction of a long-term credit rating over the intermediate term (typically six months to two years)." In November 2008, S&P stated:

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

environment, but decoupling or other measures are not expected to be available to the company before late 2009 or early 2010. Given these challenges, higher ratings are not foreseen during the outlook horizon and would need to be accompanied by sustained and improved financial performance.

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

S&P's financial risk designations are "minimal," "modest," "intermediate," "aggressive" and "highly leveraged." In November 2008, S&P indicated that "[t]he consolidated financial profile is 'aggressive,' reflecting in part the very heavy debt imputation Standard & Poor's Rating Services applies to HECO for its long-term power purchase agreements (PPAs)."

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

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

| | Year ended December 31, 2008 | | |
|---|---|---|---|
| (in millions) | Average balance | End-of-period balance | December 31, 2007 |
| **Short-term borrowings** | | | |
| Commercial paper | $ 76 | $ – | $29 |
| Borrowings from affiliates | 1 | 42 | – |
| **Line of credit facilities** [1] | | | |
| Undrawn capacity under line of credit facility expiring March 31, 2011 [2] | | 175 | 175 |
| Undrawn capacity under line of credit facility expiring September 8, 2009 [2] | | 75 | – |
| **Special purpose revenue bonds available for issue** | | | |
| 2005 legislative authorization (expiring June 30, 2010)-HELCO | | $ 20 | $ 20 |
| 2007 legislative authorization (expiring June 30, 2012) | | | |
| HECO | | 260 | 260 |
| HELCO | | 115 | 115 |
| MECO | | 25 | 25 |
| Total special purpose revenue bonds available for issue | | $420 | $420 |

1 See Note 6 in HEI's "Notes to Consolidated Financial Statements" for a description of the line of credit facilities. In the future, HECO may seek to modify the credit facility in accordance with the expedited approval process approved by the PUC, including to increase the amount of credit available under the agreement, and/or to enter into new lines of credit, as management deems appropriate.

2 At February 18, 2009, there was no outstanding commercial paper balance and the line of credit facilities were undrawn.

HECO utilizes short-term debt, principally commercial paper, to support normal operations and for other temporary requirements. HECO also periodically borrows short-term from HEI for itself and on behalf of HELCO and MECO, and HECO may borrow from or loan to HELCO and MECO short-term. The intercompany borrowings among the utilities, but not the borrowings from HEI, are eliminated in the consolidation of HECO's financial statements. At December 31, 2008, HECO had $41.6 million and $12.0 million of short-term borrowings from HEI and MECO, respectively, and HELCO had $62.0 million of short-term borrowings from HECO. HECO had an average outstanding balance of commercial paper for 2008 of $75.6 million and had no commercial paper outstanding at December 31, 2008. Management believes that, if HECO's commercial paper ratings were to be downgraded or if credit markets further tighten, it would be more difficult and expensive to sell commercial paper or it might not be able to sell commercial paper in the future.

Revenue bonds are issued by the Department of Budget and Finance of the State of Hawaii to finance capital improvement projects of HECO and its subsidiaries, but the source of their repayment are the unsecured obligations of HECO and its subsidiaries under loan agreements and notes issued to the Department, including HECO's guarantees of its subsidiaries' obligations. The payment of principal and interest due on all revenue bonds currently outstanding are insured either by Ambac Assurance Corporation (Ambac), Financial Guaranty Insurance Company (FGIC), MBIA Insurance Corporation (MBIA) or Syncora Guarantee Inc. (Syncora) (formerly XL Capital Assurance Inc.). The currently outstanding revenue bonds were initially issued with S&P and Moody's ratings of AAA and Aaa, respectively, based on the ratings at the time of issuance of the applicable bond insurer. Beginning in 2008, however, ratings of Ambac, MBIA, FGIC and XLCA (now Syncora) were downgraded 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. S&P and/or Moody's ratings of Ambac, FGIC, MBIA and Syncora are reported to be on watch, review, developing and/or negative outlook. Management believes that if HECO's ratings were to be downgraded, or if credit markets further tighten, it could be more difficult and/or expensive to sell bonds in the future.

Operating activities provided $244 million in net cash during 2008. Investing activities used net cash of $260 million, primarily for capital expenditures, net of contributions in aid of construction. Financing activities provided net cash of $18 million, including a $19 million net increase in long-term debt, $13 million net increase in short-term borrowings, partly offset by $15 million for the payment of common and preferred stock dividends. In order to strengthen HECO's balance sheet and support its investment in its reliability program, HECO did not pay any dividends to HEI after the first quarter of 2008.

For the five-year period 2009 through 2013, the utilities forecast $1.6 billion of gross capital expenditures, approximately 57% of which is for transmission and distribution projects and 39% for generation projects, with the remaining 4% for general plant and other projects. These estimates do not include expenditures, which could be material, that would be required to comply with final cooling water intake structure regulations that the EPA will be required to develop in response to a Supreme Court decision that is currently pending, the July 1999 Regional Haze Rule amendments or pending Maximum Achievable Control Technology (see "Environmental regulation" in Note 3 of HEI's "Notes to Consolidated Financial Statements") or for significant renewable energy infrastructure projects. The electric utilities' net capital expenditures (which exclude AFUDC and capital expenditures funded by third-party contributions in aid of construction) for 2009 through 2013 are currently estimated to total approximately $1.4 billion. HECO's consolidated cash flows from operating activities (net income, adjusted for non-cash income and expense items such as depreciation, amortization and deferred taxes), after the payment of common stock and preferred stock dividends, are currently not expected to provide sufficient cash to cover the forecast net capital expenditures and to reduce the level of short-term borrowings, which level is expected to fluctuate during this forecast period. Long-term debt and equity financing is expected to be required to fund this estimated shortfall as well as any unanticipated expenditures not included in the 2009 through 2013 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 drawdown of proceeds from revenue bonds, cash flows from operating activities and temporary increases in short-term borrowings are expected to provide the forecast $293 million needed for the net capital expenditures in 2009. For 2009, gross capital expenditures are estimated to be $343 million, including approximately $170 million for transmission and distribution projects, approximately $159 million for generation projects and approximately $14 million for general plant and other projects. Consolidated net capital expenditures for HECO and subsidiaries for 2008, 2007 and 2006 were $257 million, $186 million and $171 million, respectively.

The PUC must approve issuances, if any, of equity and long-term debt securities by HECO, HELCO and MECO. In October 2008, HECO, MECO and HELCO filed with the PUC an application for approval of one or more special purpose revenue bond financings under the 2007 legislative authorization identified above, with the first such financing anticipated to be in 2009 if the PUC approves the application and market conditions are satisfactory.

For a discussion of funding for the electric utilities' retirement benefits plans, see Note 1 and Note 8 of HEI's "Notes to Consolidated Financial Statements" and "Retirement benefits" above. Although the electric utilities were not required to make any contributions to the qualified pension plans to meet minimum funding requirements pursuant to ERISA for 2008, 2007 and 2006, they made voluntary contributions in 2008 and 2007. Contributions by the electric utilities to the retirement benefit plans for 2008, 2007 and 2006 totaled $14 million, $12 million and $10 million, respectively, and are expected to total $31 million in 2009. In addition, the electric utilities paid directly less than $1 million of benefits in each of 2008, 2007 and 2006 and expect to pay less than $1 million of benefits in 2009. Additional contributions to the retirement benefit plans may be required, or may be made even if not required, and such contributions could be in amounts substantially in excess of the amounts currently included in the electric utilities forecast of their consolidated financing requirements for the period 2009 through 2013. SFAS No. 158, which was adopted on December 31, 2006, does not impact the calculations of retirement benefit costs.

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

## Certain factors that may affect future results and financial condition

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

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

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

***Regulation of electric utility rates.*** The rates the electric utilities are allowed to charge for their services, and the timeliness of permitted rate increases, are among the most important items influencing their financial condition, results of operations and liquidity. The PUC has broad discretion over the rates the electric utilities charge and other matters. Any adverse decision by the PUC concerning the level or method of determining electric utility rates, the items and amounts permitted to be included in rate base, the authorized returns on equity or rate base found to be reasonable, the potential consequences of exceeding or not meeting such returns, or any prolonged delay in rendering a decision in a rate or other proceeding could have a material adverse affect on the Company's and HECO's consolidated results of operations, financial condition and liquidity. Upon a showing of probable entitlement, the PUC is required to issue an interim D&O in a rate case within 10 months from the date of filing a completed application if the evidentiary hearing is completed (subject to extension for 30 days if the evidentiary hearing is not completed). There is no time limit for rendering a final D&O. Interim rate increases are subject to refund with interest, pending the final outcome of the case. Through December 31, 2008, HECO and its subsidiaries had recognized $145 million of revenues with respect to interim orders ($5 million related to interim orders regarding certain integrated resource planning costs and $140 million related to interim orders regarding general rate increase requests), which revenues are subject to refund, with interest, if and to the extent they exceed the amounts allowed in final orders. The Consumer Advocate has objected to the recovery of $1.5 million (before interest) of the $4.3 million of incremental IRP costs incurred by the utilities during the 2000-2006 period, and the PUC's decision is pending on these costs.

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

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

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

***Fuel oil and purchased power.*** The electric utilities rely on fuel oil suppliers and IPPs to deliver fuel oil and power, respectively. See "Fuel contracts" and "Power purchase agreements" in Note 3 of HEI's "Notes to Consolidated Financial Statements." The Company estimates that 76.0% of the net energy generated and purchased by HECO and its subsidiaries in 2009 will be generated from the burning of oil. Purchased KWHs provided approximately 40.4% of the total net energy generated and purchased in 2008 compared to 39.5% in 2007 and 38.2% in 2006.

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

***Other operation and maintenance expenses.*** Other operation and maintenance expenses increased 8%, 16% and 8% for 2008, 2007 and 2006, respectively, when compared to the prior year. This trend of increased operation and maintenance expenses is expected to continue in 2009 as the electric utilities expect higher production expenses (primarily to support the level of demand that has occurred over the past five years), higher costs for material and contract services and higher transmission and distribution expense to maintain system reliability. The timing and amount of these expenses can vary as circumstances change. For example, recent overhauls have been more expensive than in the past due to the larger scope of work necessary to maintain aging equipment, which has experienced heavier usage as demand has increased to current levels. Also, the cost of overhauls can be higher than originally planned after full assessments of the repair work are performed. Increased operation and maintenance expenses were among the reasons HECO, HELCO and MECO filed requests with the PUC in recent years to increase base rates. In addition, the costs of environmental compliance continue to increase with more stringent regulatory requirements.

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

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

In 1996, the PUC issued an order instituting a proceeding to identify and examine the issues surrounding electric competition and to determine the impact of competition on the electric utility infrastructure in Hawaii. In October 2003, the PUC opened investigative proceedings on two specific issues (competitive bidding and DG) to move toward a more competitive electric industry environment under cost-based regulation. For a description of some of the regulatory changes that will be pursued as part of the Energy Agreement, see "Hawaii Clean Energy Initiative" in Note 3 of HEI's "Notes to Consolidated Financial Statements."

**Competitive bidding proceeding.** The stated purpose of this proceeding, commenced in 2003, was to evaluate competitive bidding as a mechanism for acquiring or building new generating capacity in Hawaii. In December 2006, the PUC issued a decision that included a final competitive bidding framework, which became effective immediately. The final framework states, among other things, that under the framework: (1) a utility is required to use competitive bidding to acquire a future generation resource or a block of generation resources unless the PUC finds bidding to be unsuitable; (2) the determination of whether to use competitive bidding for a future generation resource or a block of generation resources will be made by the PUC during its review of the utility's IRP; (3) the framework does not apply to two certain pending projects, specifically identified offers to sell energy on an as-available basis or to sell firm energy and/or capacity by non-fossil fuel producers and certain other situations identified in the framework; (4) waivers from competitive bidding for certain circumstances will be considered by the PUC; (5) for each project that is subject to competitive bidding, the utility is required to submit a report on the cost of parallel planning upon the PUC's request; (6) the utility is required to consider the effects on competitive bidding of not allowing bidders access to utility-owned or controlled sites, and to present reasons to the PUC for not allowing site access to bidders when the utility has not chosen to offer a site to a third party; (7) the utility is required to select an independent observer from a list approved by the PUC whenever the utility or its affiliate seeks to advance a project proposal (i.e., in competition with those offered by bidders); (8) the utility may consider its own self-bid proposals in response to generation needs identified in its RFP; (9) the evaluation of the utility's bid should account for the possibility that the capital or running costs actually incurred, and recovered from ratepayers, over the plant's lifetime, will vary from the levels assumed in the utility's bid; and (10) for any resource to which competitive bidding does not apply (due to waiver or exemption), the utility retains its traditional obligation to offer to purchase capacity and energy from a Qualifying Facility (QF) at avoided cost upon reasonable terms and conditions approved by the PUC.

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

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

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

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

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

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

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

In January 2006, the PUC issued its D&O indicating that its policy is to promote the development of a market structure that assures DG is available at the lowest feasible cost, DG that is economical and reliable has an opportunity to come to fruition and DG that is not cost-effective does not enter the system. The D&O affirmed the ability of the utilities to procure and operate DG for utility purposes at utility sites. The PUC also indicated its desire to promote the development of a competitive market for customer-sited DG. The PUC found that the "disadvantages outweigh the advantages" of allowing a utility to provide DG services on a customer's site. However, the PUC also found that the utility "is the most informed potential provider of DG" and it would not be in the public interest to exclude the utilities from providing DG services at this early stage of DG market development. Therefore, the D&O allows the utility to provide DG services on a customer-owned site as a regulated service when (1) the DG resolves a legitimate system need, (2) the DG is the lowest cost alternative to meet that need, and (3) it can be shown that, in an open and competitive process acceptable to the PUC, the customer operator was unable to find another entity ready and able to supply the proposed DG service at a price and quality comparable to the utility's offering.

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

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

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

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

In February 2008, MECO received PUC approval of an agreement for the installation of a CHP system at a hotel site on the island of Lanai. Final engineering is in progress and initial site construction activities commenced in December 2008. The CHP system is planned to be placed in service in mid-2009.

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

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

Under the Energy Agreement, the utilities will conduct a review of the modified DG interconnection tariffs by June 30, 2009, to evaluate whether the tariffs are effective in supporting non-utility DG and distributed energy storage by improving the process and procedure for interconnection.

**DG and distributed energy storage under the Energy Agreement.** Under the Energy Agreement, the utilities committed to facilitate planning for distributed energy resources through a new Clean Energy Scenario Planning process. Under this process, Locational Value Maps will be developed by December 31, 2009 to identify areas where DG and DES would provide utility system benefits and can be reasonably accommodated.

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

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

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

The Energy Agreement also provides that to the degree that transmission and distribution automation and other smart grid technology investments are needed to facilitate distributed energy resource utilization, those investments will be recovered through a Clean Energy Infrastructure Surcharge and later placed in rate base in the next rate case proceeding.

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

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

Pending environmental matters that may adversely affect the Company's future operating results and financial condition include the ongoing Honolulu Harbor environmental investigation, the July 1999 Regional Haze Rule amendments, section 112 of the Clean Air Act and section 316(b) of the federal Clean Water Act, which are discussed under "Environmental regulation" in Note 3 of HEI's "Notes to Consolidated Financial Statements" and "Greenhouse gas emissions reduction" discussed above under "Legislation and regulation." 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.

***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 Emerging Issues Task Force (EITF) Issue No. 01-8, "Determining Whether an Arrangement Contains a Lease," to their new PPAs, PPA amendments and other arrangements they enter into. A possible outcome of the evaluation is that an arrangement falls within the scope of EITF 01-8 and results in its classification as a capital lease, which could have a material effect on HECO's consolidated balance sheet if a significant amount of capital assets and lease obligations needed to be recorded.

Management believes that the PUC will allow recovery of property, plant and equipment in its electric rates. If the PUC does not allow recovery of any such costs, the electric utility would be required to write off the disallowed costs at that time. See the discussion in Note 3 of HEI's "Notes to Consolidated Financial Statements" concerning costs recorded for CT-4 and CT-5 at Keahole and the East Oahu Transmission Project.

***Regulatory assets and liabilities.*** The electric utilities are regulated by the PUC. In accordance with SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," 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, 2008, regulatory liabilities and regulatory assets amounted to $289 million and $531 million, 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, 2008 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 SFAS No. 71 criteria. If events or circumstances should change so that those criteria are no longer satisfied, the electric utilities expect that the regulatory assets would be charged to expense and the regulatory liabilities would be credited to income or refunded to ratepayers. In the event of unforeseen regulatory actions or other circumstances, however, management believes that a material adverse effect on the Company's results of operations and financial position may result if regulatory assets have to be charged to expense without an offsetting credit for regulatory liabilities or if regulatory liabilities are required to be refunded to ratepayers.

***Revenues.*** Electric utility revenues are based on rates authorized by the PUC and include revenues applicable to energy consumed in the accounting period but not yet billed to customers. As of December 31, 2008, revenues applicable to energy consumed, but not yet billed to customers, amounted to $107 million.

Revenue amounts recorded pursuant to a PUC interim order are subject to refund, with interest, pending a final order. As of December 31, 2008, HECO and its subsidiaries had recognized $145 million of such revenues with respect to interim orders. Also, the rate schedules of the electric utilities include ECACs under which electric rates are adjusted for changes in the weighted-average price paid for fuel oil and certain components of purchased power, and the relative amounts of company-generated power and purchased power. See "Regulation of electric utility rates" above.

***Consolidation of VIEs.*** In December 2003, the FASB issued revised FIN No. 46 (FIN 46R), "Consolidation of Variable Interest Entities," which addresses how a business enterprise should evaluate whether it has a controlling financial interest in an entity through means other than voting rights and accordingly should consolidate the entity. The Company evaluates the impact of applying FIN 46R to its relationships with IPPs with whom the electric utilities execute new PPAs or execute amendments of existing PPAs. A possible outcome of the analysis is that HECO (or its subsidiaries, as applicable) may be found to meet the definition of a primary beneficiary of a VIE (the IPP) which finding may result in the consolidation of the IPP in HECO's consolidated financial statements. The consolidation of IPPs could have a material effect on HECO's consolidated financial statements, including the recognition of a significant amount of assets and liabilities, and, if such a consolidated IPP were operating at a loss and had insufficient equity, the potential recognition of such losses. The electric utilities do not know how the consolidation of IPPs would be treated for regulatory or credit ratings purposes. See Note 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 since 1988 and ended 2008 with assets of $5.4 billion and net income of $18 million, compared to assets of $6.9 billion as of December 31, 2007 and net income of $53 million in 2007. The significant change in assets and net income from 2007 to 2008 was primarily due to a balance sheet restructuring that ASB undertook and substantially completed in June 2008. The restructuring resulted in a net charge to net income of $35.6 million in the second quarter of 2008 and shrinking of ASB's total assets and total liabilities. The restructuring allowed ASB to free up capital, which was largely distributed to HEI, and positioned ASB to strengthen future profitability ratios and enhance future net interest margin, while remaining "well-capitalized." Net income for 2008 was $18 million (or $53 million excluding the restructuring charge).

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

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

ASB continues to face a challenging interest rate environment that has pressured its net interest margin as the Federal Reserve cut the Federal Funds Rate seven times in 2008. Competitive factors and the level of interest rates have made it difficult to retain deposits and control funding costs and have held down asset yields. The potential for compression of ASB's margin continues to be a 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 deposits, which enables ASB to replace other borrowings and reduce funding costs;
(2) diversifying its loan portfolio with higher-spread, shorter-maturity loans or variable rate loans such as commercial, commercial real estate and consumer loans, which also creates a more diversified income stream for the bank;
(3) investing in mortgage-related securities with short average lives; and
(4) managing costing liabilities to optimize cost of funds and manage interest rate sensitivity.

ASB had good loan quality in 2008 despite the weakening economy and slowing real estate market. Although new home purchase and home resale transaction volumes in Hawaii have fallen off, the Hawaii residential real estate market has not experienced the same level of decline in values seen in many mainland U.S. markets. However, the slowdown in the economy, both nationally and locally, has caused increased levels of financial stress on the part of ASB's customers, resulting in higher levels of loan delinquencies and losses. As a result, ASB's provision for loan losses has increased, following several years of historically low loan losses and loan loss allowances. The consensus outlook for the Hawaii economy is for continued decline in 2009 following the decline in 2008, which was preceded by several years of strong growth. Continued financial stress on ASB's customers or falling home prices may result in higher levels of loan delinquencies and losses.

Pressure from the national economic slowdown and declines in the national housing market impacted securities in ASB's investment portfolio. The rating agencies downgraded the ratings on a significant number of mortgage-related securities in the fourth quarter of 2008, including several mortgage-related securities held in ASB's portfolio. Five mortgage-related securities in ASB's portfolio were downgraded to below-investment grade ratings. Additionally, ASB determined the impairment on two private-issue mortgage-related securities to be other than temporary, adjusted the carrying values to market value, and recognized a noncash impairment charge of $7.8 million in the fourth quarter of 2008.

## Results of operations

| (dollars in millions) | | 2008 | % change | | 2007 | % change | | 2006 |
|---|---|---|---|---|---|---|---|---|
| Revenues | $ | 359 | (16) | $ | 425 | 4 | $ | 408 |
| Net interest income | | 207 | 5 | | 197 | (3) | | 203 |
| Operating income | | 27 | (68) | | 84 | (5) | | 89 |
| Net income | | 18 | (66) | | 53 | (5) | | 56 |
| Return on average common equity [1] | | 3.2% | | | 9.4% | | | 10.1% |
| Earning assets | | | | | | | | |
| Average balance [1] | $ | 5,722 | (12) | $ | 6,473 | – | $ | 6,470 |
| Weighted-average yield | | 5.46% | (1) | | 5.52% | 2 | | 5.39% |
| Costing liabilities | | | | | | | | |
| Average balance [1] | $ | 4,754 | (14) | $ | 5,515 | – | $ | 5,533 |
| Weighted-average rate | | 2.22% | (23) | | 2.90% | 10 | | 2.64% |
| Net interest margin [2] | | 3.62% | 19 | | 3.05% | (3) | | 3.13% |

1 Calculated using the average daily balances.

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

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

Loan originations and purchases of loans and mortgage-related securities are ASB's primary sources of earning assets. ASB's loan volumes and yields are affected by market interest rates, competition, demand for financing, availability of funds and management's responses to these factors. As of December 31, 2008, ASB's loan portfolio mix, net, consisted of 70% residential loans, 14% commercial loans, 9% consumer loans and 7% commercial real estate loans. As of December 31, 2007, ASB's loan portfolio mix, net, consisted of 75% residential loans, 11% commercial loans, 7% consumer loans and 7% commercial real estate loans.

Deposits continue to be the largest source of funds for ASB and are affected by market interest rates, competition and management's responses to these factors. Competition for deposits and the level of short-term interest rates have made it difficult to retain deposits and control funding costs, and deposit retention and growth will remain challenges in the current environment. Advances from the Federal Home Loan Bank (FHLB) of Seattle and securities sold under agreements to repurchase continue to be significant sources of funds. As of December 31, 2008, ASB's costing liabilities consisted of 86% deposits and 14% other borrowings. As of December 31, 2007, ASB's costing liabilities consisted of 71% deposits and 29% other borrowings. The decrease in the relative level of other borrowings and corresponding increase in the level of deposits was due to the early extinguishment of certain borrowings through the restructuring of ASB's balance sheet. (See "Balance sheet restructure" in Note 4 of HEI's Notes to Consolidated Financial Statements.)

As of December 31, 2008, the bank's investment portfolio consisted of 9% federal agency obligations, 46% mortgage-related securities issued by Federal National Mortgage Association (FNMA), Federal Home Loan Mortgage Corporation (FHLMC) or Government National Mortgage Association (GNMA), and 45% private-issue mortgage-related securities. As of December 31, 2007, the bank's investment portfolio consisted of 3% federal agency obligations, 72% mortgage-related securities issued by FNMA, FHLMC or GNMA and 25% private-issue mortgage-related securities. The increase in the percentage of federal agency obligations and private-issue mortgage-related securities was a result of the reduction in the size of the investment portfolio associated with the balance sheet restructuring, as opposed to growth in that sector of the portfolio.

Principal and interest on mortgage-related securities issued by FNMA, FHLMC and GNMA are guaranteed by the issuer, and the securities carry implied AAA ratings. Private-issue mortgage-related securities carry a risk of loss due to delinquencies, foreclosures, and losses in the mortgage loans collateralizing the securities. The continued deterioration in the housing market, as seen in the declines in values of residential real estate and increases in the level of delinquencies on residential mortgage loans, has caused the nationally recognized statistical rating agencies, such as Moody's or S&P, to undertake a thorough re-evaluation of their rated private-issue mortgage-related securities using current delinquency data and more severe home price depreciation and loss severity assumptions. These reviews have led them to downgrade the ratings on a large number of securities in 2008. The majority of securities downgraded were collateralized by residential mortgage loans underwritten in 2006 and 2007. Underwriting standards for loans underwritten in 2006 and 2007 were thought to be most troublesome, and delinquency rates for loans of these vintages has been higher than delinquency rates for loans originated in prior years. Additionally, the rating agencies have also applied higher loss assumptions when analyzing securities collateralized by loans originated in 2006 and 2007 due to the fact that home prices peaked in 2006 and 2007. Several of the private-issued mortgage-related securities owned by the bank were downgraded by at least one rating agency in the fourth quarter of 2008. Within those downgrades, five securities were downgraded to non-investment grade ratings. (See "Investment and mortgage-related securities" in Note 4 of HEI's Notes to Consolidated Financial Statements for a table summarizing the private-issue mortgage-related securities by rating and vintage.)

Private-issue mortgage-related securities that are held in the portfolio are collateralized instruments backed by whole mortgages. Securities issued in 2003 and after are mainly backed by prime 30 and 15 year first lien fixed-rate mortgages (97% of private-issue mortgage-related securities). Exceptions to these positions are two pools collateralized by Alt-A 30 year fixed-rate first lien mortgages (8% of private-issue mortgage-related securities). All positions purchased during this period are Collateralized Mortgage Obligations which are current pay front-end sequentials or Planned Amortization Classes. These structures were selected because of their shorter average life and higher subordination or credit support. Typical of all jumbo pools issued during this period, most exhibit the following characteristics: significant geographic concentration in California, significant percentage of low documentation loans and some exposure to investor owned properties. Despite all positions originally being rated AAA by at least one of the agencies, recent vintages have not performed well relative to original expectations at time of purchase.

Private-issue mortgage-related securities that are held in the portfolio that were issued in 2002 and prior are backed by a mix of fixed and floating rate whole loans or securities backed by whole loans in a Resecuritization of Real Estate Mortgage Investment Conduit structure (3% of private-issue mortgage-related securities). Many of these positions are well seasoned with significant credit support subordinating ASB's tranche. Exceptions to these positions are those backed by subprime collateral (1% of private-issue mortgage-related securities). While all of the subprime positions were originated in 1999, lower amortized balances and increasing median housing prices during this period has not broadly benefited these positions as loss severities are much higher than comparable prime collateral.

ASB uses internal analysis/modeling and multiple third-party services in its assessment of private-issue mortgage-backed positions held in the investment securities portfolio. ASB's monitoring process includes a periodic review of all private-issue residential mortgage-related securities including a review of collateral performance and credit support. This monitoring process considers position level metrics which include but are not limited to delinquency trends, loss severities and position credit support. Relevant third-party research, credit rating agency information and historical position performance are used to benchmark and assess position performance. Bonds that are of non-investment grade credit rating or show signs of credit deterioration are further analyzed. Final assessment of impairment is based on a number of inputs including ASB's internal analysis, results from third-party analyses, as well as other information. Internal analysis includes a more detailed review of collateral characteristics and performance, deal structure as well as projections of future cash flows based on management's expectations of factors such as prepayments, defaults and loss severity. Based upon management's expectation of future performance, two bonds were determined to be other than temporarily impaired as of December 31, 2008 and marked the carrying value on those securities down to the current fair value, resulting in a $7.8 million charge. Most of the charge was associated with one security that had a pre-impairment book value of $19.7 million and current market value of $12.0 million. While this security is currently performing, recent increases in delinquency rates and cash flow projections in alternate scenarios led management to conclude that it is probable that the bank may be unable to collect all amounts due. Under current base-case estimates, projected future cash flows show an estimated loss of principal of $0.4 million, with the first loss projected in 2012. The second security had a pre-impairment book value of $0.3 million and current market value of $0.1 million. This security's underlying loan performance is good, but is projected to have an interest shortfall. Because of the small size of the security, the excess interest is not sufficient to cover fixed expenses, resulting in the expected interest shortfall. In both cases, as long as the underlying loans continue to perform, the difference between the expected loss and the impairment charge will be accreted to interest income over the remaining lives of the securities using the effective interest method.

"See "Investment and mortgage-related securities" in Note 4 of HEI's "Notes to Consolidated Financial Statements" for a discussion of four positions with material unrealized losses currently held in the securities portfolio.

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

Although higher long-term interest rates or other conditions in credit markets (such as the effects of the deteriorated subprime market) could reduce the market value of available-for-sale investment and mortgage-related securities and reduce stockholder's equity through a balance sheet charge to AOCI, this reduction in the market value of investments and mortgage-related securities would not result in a charge to net income in the absence of a sale of such securities (such as those that occurred in the balance sheet restructure) or an "other-than-temporary" impairment in the value of the securities (such as in the case of the two private-issue mortgage-related securities described above). As of December 31, 2008 and 2007, the net unrealized losses, net of tax benefits, on available-for-sale investments and mortgage-related securities (including securities pledged for repurchase agreements) in AOCI was $33 million and $18 million, respectively. The increase in net unrealized losses was largely due to lower prices on certain mortgage-related securities, resulting from significant spread widening in the fourth quarter of 2008. See "Quantitative and Qualitative Disclosures about Market Risk."

**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 2008, 2007 and 2006.

| | 2008 | | | 2007 | | |
|---|---|---|---|---|---|---|
| ($ in thousands) | Average balance | Interest | Average rate (%) | Average balance | Interest | Average rate (%) |
| Assets: | | | | | | |
| Other investments [1] | $ 123,819 | $ 1,542 | 1.25 | $ 196,504 | $ 5,581 | 2.84 |
| Investment and mortgage-related securities | 1,424,015 | 63,666 | 4.47 | 2,350,821 | 105,889 | 4.50 |
| Loans receivable [2] | 4,173,802 | 247,210 | 5.92 | 3,925,186 | 245,593 | 6.26 |
| Total interest-earning assets | 5,721,636 | 312,418 | 5.46 | 6,472,511 | 357,063 | 5.52 |
| Allowance for loan losses | (30,829) | | | (31,509) | | |
| Non-interest-earning assets | 415,822 | | | 376,655 | | |
| Total assets | $6,106,629 | | | $6,817,657 | | |
| Liabilities and Stockholder's Equity: | | | | | | |
| Interest-bearing demand and savings deposits | $2,094,396 | 11,953 | 0.57 | $2,168,672 | 16,805 | 0.77 |
| Time certificates | 1,478,427 | 49,530 | 3.35 | 1,633,871 | 65,074 | 3.98 |
| Total interest-bearing deposits | 3,572,823 | 61,483 | 1.72 | 3,802,543 | 81,879 | 2.15 |
| Other borrowings | 1,180,844 | 43,941 | 3.72 | 1,712,642 | 78,019 | 4.56 |
| Total interest-bearing liabilities | 4,753,667 | 105,424 | 2.22 | 5,515,185 | 159,898 | 2.90 |
| Non-interest bearing liabilities: | | | | | | |
| Deposits | 686,461 | | | 640,198 | | |
| Other | 104,539 | | | 96,461 | | |
| Stockholder's equity | 561,962 | | | 565,813 | | |
| Total Liabilities and Stockholder's Equity | $6,106,629 | | | $6,817,657 | | |
| Net interest income | | $206,994 | | | $197,165 | |
| Net interest margin (%) [3] | | | 3.62 | | | 3.05 |

| | 2006 | | |
|---|---|---|---|
| ($ in thousands) | Average balance | Interest | Average rate (%) |
| Assets: | | | |
| Other investments [1] | $ 172,146 | $ 3,757 | 2.18 |
| Investment and mortgage-related securities | 2,579,730 | 113,403 | 4.40 |
| Loans receivable [2] | 3,718,208 | 231,610 | 6.23 |
| Total interest-earning assets | 6,470,084 | 348,770 | 5.39 |
| Allowance for loan losses | (30,535) | | |
| Non-interest-earning assets | 361,299 | | |
| Total assets | $6,800,848 | | |
| Liabilities and Stockholder's Equity: | | | |
| Interest-bearing demand and savings deposits | $2,370,396 | 18,148 | 0.77 |
| Time certificates | 1,548,443 | 55,466 | 3.58 |
| Total interest-bearing deposits | 3,918,839 | 73,614 | 1.88 |
| Other borrowings | 1,613,667 | 72,482 | 4.49 |
| Total interest-bearing liabilities | 5,532,506 | 146,096 | 2.64 |
| Non-interest bearing liabilities: | | | |
| Deposits | 621,453 | | |
| Other | 92,303 | | |
| Stockholder's equity | 554,586 | | |
| Total Liabilities and Stockholder's Equity | $6,800,848 | | |
| Net interest income | | $202,674 | |
| Net interest margin (%) [3] | | | 3.13 |

1 Includes federal funds sold, interest bearing deposits and stock in the FHLB of Seattle ($98 million as of December 31, 2008).

2 Includes loan fees of $4.4 million, $4.5 million and $5.3 million for 2008, 2007 and 2006, respectively, together with interest accrued prior to suspension of interest accrual on nonaccrual loans.

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

***Financial results***

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

ASB had good loan quality during 2008 despite a weakening economy and slowing real estate market. A provision for loan losses of $10.3 million was recorded in 2008, primarily due to an increase in the classification of commercial loans and an increase in nonperforming residential lot loans. This compares with a provision for loan losses of $5.7 million in 2007 primarily due to specific reserves for one commercial borrower and the reclassification of certain commercial loans that had identified weaknesses. ASB's allowance as a percentage of average loans was 0.86% at the end of 2008, compared to 0.77% and 0.84% at the end of 2007 and 2006, respectively. The allowance is adjusted continuously through the provision for loan losses to reflect factors such as charge-offs; outstanding loan balances; loan grading; external factors affecting the national and Hawaii economy, specific industries and sectors and interest rates; and historical and projected loan losses. ASB's nonaccrual and renegotiated loans represented 0.7%, 0.2% and 0.2% of total loans outstanding as of December 31, 2008, 2007 and 2006, respectively.

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

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

In the fourth quarter of 2008, ASB's results were impacted by the sharp decline in the Hawaii economy, the depressed national economy and the volatility in the financial markets. Credit risk for ASB has risen--residential loan delinquencies started to trend upward resulting in the increased provision for loan losses and the value of mortgage-related securities became impaired resulting in the write-down of two securities to fair value. As the deteriorating economic and market conditions are expected to negatively impact 2009 results, management has been focused on positioning ASB for improved operating performance and financial flexibility. For example, management is reviewing service bureaus that can provide ASB's core processing functions in an efficient manner at a reasonable cost. A final decision is expected in the first quarter of 2009 and is expected to result in a reduction of future service bureau expenses. However, if a new service bureau is selected, conversion costs would also be incurred in 2009.

- Net interest income before provision for loan losses for 2007 decreased by $6 million or 2.7%, when compared to 2006 as the interest rate environment made it difficult to retain deposits and control funding costs. Net interest margin decreased from 3.13% in 2006 to 3.05% in 2007 as the impact of growth in the loan portfolio and higher yields on earning assets were more than offset by lower balances of investment and mortgage-related securities and increased funding costs. The increase in the average loan portfolio balance was due to the strength of the Hawaii economy and the stability of the Hawaii real estate market and loans purchased. The decrease in the investment and mortgage-related securities balances was due to the use of proceeds from repayments in the portfolio to fund loans. The shift in deposit mix from lower-cost savings and checking accounts to higher-cost certificates, along with the repricing of deposits and increased other borrowings, have contributed to increased funding costs.

ASB's asset quality remained high in 2007 due to the strength of the Hawaii economy and the stability of the Hawaii real estate market. A provision for loan losses of $5.7 million was recorded in 2007, primarily due to specific reserves for one commercial borrower and the reclassification of certain commercial loans that continue to be current on loan payments but have identified weaknesses. This compares with a provision for loan losses of $1.4 million in 2006 for the same commercial borrower. See Note 4 of HEI's "Notes to Consolidated Financial Statements."

Noninterest income for 2007 increased by $8.8 million over 2006 primarily due to higher fee income on deposit liabilities and other financial services.

Noninterest expense for 2007 increased by $3.6 million over 2006 primarily due to higher legal expenses, costs to strengthen ASB's risk management and compliance infrastructure, and higher occupancy expenses, partly offset by lower compensation and employee benefit expenses as a result of the recognition in 2007 of a pension curtailment gain of $8.8 million ($5.3 million, net of taxes).

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

***Legislation and regulation.*** ASB is subject to extensive regulation, principally by the Office of Thrift Supervision (OTS) and the Federal Deposit Insurance Corporation (FDIC). Depending on its level of regulatory capital and other considerations, these regulations could restrict the ability of ASB to compete with other institutions and to pay dividends to its shareholders. See the discussions below under "Liquidity and capital resources" and "Certain factors that may affect future results and financial condition." Also see "Regulatory compliance," "FDIC restoration plan," "Deposit insurance coverage" and "Capital Purchase Program" in Note 4 of HEI's "Notes to Consolidated Financial Statements."

***FHLB of Seattle dividends.*** In December 2008, the FHLB of Seattle announced that it would not pay a dividend on its stock in the fourth quarter of 2008 due to a net loss reported by the FHLB of Seattle for the third quarter of 2008. Also, in January 2009, the FHLB of Seattle announced that it will likely report a risk-based capital deficiency at December 31, 2008 and will not be able to repurchase capital stock or declare a dividend while a risk-based capital deficiency exists. ASB does not believe that the FHLB of Seattle's risk-based capital deficiency will affect the FHLB of Seattle's ability to meet ASB's liquidity and funding needs. ASB received cash dividends on its $98 million of FHLB of Seattle stock of $0.1 million in 2006, $0.6 million in 2007 and $0.9 million in 2008. Periodically and as conditions warrant, ASB reviews its investment in the stock of FHLB of Seattle for impairment and adjusts the carrying value if the investment is determined to be impaired.

## Liquidity and capital resources

| December 31<br>(dollars in millions) | 2008 | % change | 2007 | % change |
|---|---|---|---|---|
| Assets | $5,437 | (21) | $6,861 | 1 |
| Available-for-sale investment and mortgage-related securities | 658 | (69) | 2,141 | (10) |
| Investment in stock of Federal Home Loan Bank of Seattle | 98 | – | 98 | – |
| Loans receivable, net | 4,206 | 3 | 4,101 | 8 |
| Deposit liabilities | 4,180 | (4) | 4,347 | (5) |
| Other bank borrowings | 681 | (62) | 1,811 | 15 |

As of December 31, 2008, ASB was one of Hawaii's largest financial institutions based on assets of $5.4 billion and deposits of $4.2 billion. The significant decline in available-for-sale investment and mortgage-related securities and other bank borrowings was due to the balance sheet restructuring in June 2008 as ASB moved to strengthen future profitability ratios, enhance future net interest margin and also reduce its reliance on debt as a source of funds.

In March 2007, Moody's raised ASB's counterparty credit rating to A3 from Baa3 and, in August 2008, maintained the rating following its annual review of ASB. In April 2007, S&P raised ASB's long-term/short-term counterparty credit ratings to BBB/A-2 from BBB-/A-3 and in May 2008 maintained the rating following its annual review of ASB. These ratings reflect only the view, at the time the ratings are issued, of the applicable rating agency, from whom an explanation of the significance of such ratings may be obtained. Such ratings are not recommendations to buy, sell or hold any securities; such ratings may be subject to revision or withdrawal at any time by the rating agencies; and each rating should be evaluated independently of any other rating.

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, 2008 were $167 million lower than December 31, 2007. 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, 2008, FHLB borrowings totaled approximately $440 million, representing 8% 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, 2008, ASB's unused FHLB borrowing capacity was approximately $1.5 billion, a significant increase from the $1.1 billion as of December 31, 2007 due primarily to the balance sheet restructuring in June 2008. As of December 31, 2008, securities sold under agreements to repurchase totaled $241 million, representing 4% 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, 2008, 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, 2008 and 2007, ASB had $19.5 million and $3.2 million of loans on nonaccrual status, respectively, or 0.5% and 0.1% of net loans outstanding, respectively. As of December 31, 2008, ASB had $1.5 million of real estate acquired in settlement of loans compared to no real estate acquired in settlement of loans as of December 31, 2007.

In 2008, operating activities provided cash of $30 million. Net cash of $1.3 billion was provided by investing activities primarily due to proceeds from the sale of investment and mortgage-related securities from the balance sheet restructuring and repayments of investment and mortgage-related securities, partly offset by purchases of investment and mortgage-related securities, net increases in loans held for investment and capital expenditures. Financing activities used net cash of $1.4 billion due to net decreases in other borrowings and deposits and the payment of common stock dividends.

ASB believes that a satisfactory regulatory capital position provides a basis for public confidence, affords protection to depositors, helps to ensure continued access to capital markets on favorable terms and provides a foundation for growth. FDIC regulations restrict the ability of financial institutions that are not well-capitalized to compete on the same terms as well-capitalized institutions, such as by offering interest rates on deposits that are significantly higher than the rates offered by competing institutions. As of December 31, 2008, ASB was well-capitalized (see "Capital requirements" below for ASB's capital ratios).

**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, 2008, the fair value and carrying value of the investment and mortgage-related securities held by ASB were $0.7 billion.

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. Competitive factors and the level of short-term interest rates have made it difficult to retain deposits and control funding costs. If the current interest rate environment persists, the potential for compression of ASB's net interest margin will continue. ASB also manages the credit risk associated with its lending and securities portfolios, but a deep and prolonged recession led by a material decline in housing prices could materially impair the value of its portfolios. See "Net interest margin and other factors" above and "Quantitative and Qualitative Disclosures about Market Risk" below.

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

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

***Regulation.*** ASB is subject to examination and comprehensive regulation by the Department of Treasury, OTS and the FDIC, and is subject to reserve requirements established by the Board of Governors of the Federal Reserve System. Regulation by these agencies focuses in large measure on the adequacy of ASB's capital and the results of periodic "safety and soundness" examinations conducted by the OTS. ASB's insurance product sales activities are subject to regulation by the Hawaii Insurance Commissioner. See also "Legislation and regulation" above.

**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, 2008, 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, 2008 with a tangible capital ratio of 8.5% (1.5%), a core capital ratio of 8.5% (4.0%) and a total risk-based capital ratio of 12.8% (8.0%).
- ASB met the capital requirements to be generally considered "well-capitalized" (noted in parentheses) as of December 31, 2008 with a leverage ratio of 8.5% (5.0%), a Tier-1 risk-based capital ratio of 11.8% (6.0%) and a total risk-based capital ratio of 12.8% (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 HEIDI) 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. In January 2008, the OTS issued consent orders requiring, among other things, various actions by ASB to strengthen its Bank Secrecy Act and Anti-Money Laundering Program and its Compliance Management Program and assessing a civil money penalty of $37,730 related to non-compliance with certain laws and regulations requiring flood insurance in connection with certain loans (see "Regulatory compliance" in Note 4 of HEI's "Notes to Consolidated Financial Statements"). In December 2008, the OTS lifted the order.

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, 2008, 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, HEIDI 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, 2008, approximately 82% of its assets were qualified thrift investments.

**Federal Thrift Charter.** The Gramm-Leach-Bliley Act of 1998 (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, HEIDI 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.

**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, private-issue mortgage-related securities and mortgage-related securities issued by the FNMA, GNMA and FHLMC, all of which are classified as available-for-sale and reported at fair value, with unrealized gains and temporary losses excluded from earnings and reported in AOCI. Declines in value determined to be other than temporary are included in earnings and result in a new cost basis for the investment.

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. ASB assesses individual securities in its investment securities portfolio 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, ASB then determines whether this impairment is temporary or other than temporary. In estimating other-than-temporary impairment losses, management considers, among other things, (i) the severity and duration of the impairment, (ii) the ratings of the security, (iii) the overall deal structure (e.g., ASB's position within the structure), the overall, near term financial performance of the underlying collateral, delinquencies, defaults, loss severities, recoveries, prepayments, cumulative loss projections and discounted cash flows, and (iv) the intent and ability of ASB to retain its investment in the security for a period of time sufficient to allow for any anticipated recovery in fair value. Management initially considers whether an investment security is other-than-temporarily impaired under the guidance promulgated in FASB Staff Position (FSP) FAS 115-1 and FAS 124-1, "The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments" and the guidance from the SEC found in Staff Accounting Bulletin Topic 5M. If impairment is determined to be other than temporary, an impairment loss is recognized by reducing the amortized cost basis to fair value. Upon recognizing an impairment loss, ASB applies AICPA Statement of Position No. 03-3, "Accounting for Certain Loans or Debt Securities Acquired in a Transfer" for applicable securities in each subsequent reporting period.

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, 2008, ASB had investment and mortgage-related securities issued by FHLMC, GNMA and FNMA valued at $0.4 billion and private-issue mortgage-related securities valued at $0.3 billion.

***Allowance for loan losses.*** See Note 1 of HEI's "Notes to Consolidated Financial Statements" and the discussion above under "Net interest margin and other factors." As of December 31, 2008, ASB's allowance for loan losses was $35.8 million and ASB had $19.5 million of loans on nonaccrual status. In 2008, ASB recorded a provision for loan losses of $10.3 million. Although management believes the allowance for loan losses is adequate, the actual loan losses, provision for loan losses and allowance for loan losses may be materially different if conditions change (e.g., if there is a significant change in the Hawaii economy or real estate market), and material increases in those amounts could have a material adverse affect on the Company's results of operations and financial position.

## Quantitative and Qualitative Disclosures about Market Risk

The Company manages various market risks in the ordinary course of business, including credit risk and liquidity risk. The Company believes the electric utility and the "other" segment's exposures to these two risks are not material as of December 31, 2008.

Credit risk for ASB is the risk that borrowers or issuers of securities will not be able to repay their obligations to the bank. Credit risk associated with ASB's lending portfolios is controlled through its underwriting standards, loan rating of commercial and commercial real estate loans, on-going monitoring by loan officers, credit review and quality control functions in these lending areas and adequate allowance for loan losses. Credit risk associated with the securities portfolio is mitigated through investment portfolio limits, experienced staff working with analytical tools, monthly fair value analysis and on-going monitoring and reporting such as investment watch reports and loss sensitivity analysis. See "Net interest margin and other factors" and "Allowance for loan losses" above.

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

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

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

**Bank interest rate risk**

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

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

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

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

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

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

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

ASB's interest-rate risk sensitivity measures as of December 31, 2008 and 2007 constitute "forward-looking statements" and were as follows:

| December 31 | 2008 | | | 2007 | | |
|---|---|---|---|---|---|---|
| | Change in NII | NPV ratio | NPV ratio sensitivity* | Change in NII | NPV ratio | NPV ratio sensitivity* |
| Change in interest rates (basis points) | Gradual change | Instantaneous change | | Gradual change | Instantaneous change | |
| +300 | 1.2% | 6.94% | (379) | (2.2)% | 6.97% | (334) |
| +200 | 1.2 | 8.42 | (231) | (0.9) | 8.27 | (204) |
| +100 | 0.7 | 9.84 | (89) | (0.2) | 9.46 | (85) |
| Base | – | 10.73 | – | – | 10.31 | – |
| -100 | (1.6) | 10.43 | (30) | (0.5) | 10.40 | 9 |
| -200 | ** | ** | ** | (3.0) | 9.67 | (64) |
| -300 | ** | ** | ** | (6.9) | 8.68 | (163) |

* Change from base case in basis points.

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

Management believes that ASB's interest rate risk position as of December 31, 2008 represents a reasonable level of risk. Under the rising interest rate change scenarios, the December 31, 2008 NII profile is asset sensitive to increases in interest rates, and more liability sensitive to the -100 decrease in interest rates compared to the NII profile on December 31, 2007. These changes are primarily due to the low overall level of interest rates as of December 31, 2008 relative to December 31, 2007.

ASB's base NPV ratio as of December 31, 2008 was higher than on December 31, 2007. The change in NPV ratio was a result of differences in the mix of assets and liabilities, changes in the level and shape of the yield curve, and changes in pricing spreads.

ASB's NPV ratio sensitivity as of December 31, 2008 was more sensitive to the rising and -100 rate scenarios compared to December 31, 2007 due to changes in the mix and pricing of assets and liabilities.

The computation of the prospective effects of hypothetical interest rate changes on the NII sensitivity, NPV ratio, and NPV ratio sensitivity analyses is based on numerous assumptions, including relative levels of market interest rates, loan prepayments, balance changes and pricing strategies, and should not be relied upon as indicative of actual results. To the extent market conditions and other factors vary from the assumptions used in the simulation analysis, actual results may differ materially from the simulation results. Furthermore, NII sensitivity analysis measures the change in ASB's twelve-month, pre-tax NII in alternate interest rate scenarios, and is intended to help management identify potential exposures in ASB's current balance sheet and formulate appropriate strategies for managing interest rate risk. The simulation does not contemplate any actions that ASB management might undertake in response to changes in interest rates. Further, the changes in NII vary in the twelve-month simulation period and are not necessarily evenly distributed over the period. These analyses are for analytical purposes only and do not represent management's views of future market movements, the level of future earnings, or the timing of any changes in earnings within the twelve month analysis horizon. The actual impact of changes in interest rates on NII will depend on the magnitude and speed with which rates change, actual changes in ASB's balance sheet, and management's responses to the changes in interest rates.

**Other than bank interest rate risk**

The Company's general policy is to manage "other than bank" interest rate risk through use of a combination of short-term debt, long-term debt (currently fixed-rate debt) and preferred securities. As of December 31, 2008, management believes the Company is exposed to "other than bank" interest rate risk because of their periodic borrowing requirements, the impact of interest rates on the discount rate and the market value of plan assets used to determine retirement benefits expenses and obligations (see "Retirement benefits (pension and other postretirement benefits)" in "Management's discussion and analysis of financial condition and results of operations" and Note 8 of HEI's "Notes to Consolidated Financial Statements") and the possible effect of interest rates on the electric utilities' allowed rates of return (see "Electric utility—Certain factors that may affect future results and financial condition—Regulation of electric utility rates"). Other than these exposures, management believes its exposure to "other than bank" interest rate risk is not material. There was no short-term debt outstanding as of December 31, 2008 and the Company's longer-term debt, in the form of revenue bonds and Medium-Term Notes, is at fixed rates. Such rates are favorable (i.e., lower) compared to current market rates, and therefore, the estimated fair value of such debt is notably lower than the amount outstanding (see Note 14 of HEI's "Notes to Consolidated Financial Statements").

## Index to Consolidated Financial Statements

## Annual Report of Management on Internal Control Over Financial Reporting

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

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

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

Management conducted an evaluation of the effectiveness of the Company's internal control over financial reporting as of December 31, 2008 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, 2008.

KPMG LLP, an independent registered public accounting firm, has issued an audit report on the Company's internal control over financial reporting as of December 31, 2008. This report appears on page 65.

Constance H. Lau
President and
Chief Executive Officer

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

Curtis Y. Harada
Vice President, Controller and
Chief Accounting Officer;

February 20, 2009

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

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

We have audited Hawaiian Electric Industries, Inc.'s internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Hawaiian Electric Industries, Inc.'s management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying annual report of management on internal control over financial reporting. Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

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

In our opinion, Hawaiian Electric Industries, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control—Integrated Framework issued by the COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Hawaiian Electric Industries, Inc. and subsidiaries as of December 31, 2008 and 2007, and the related consolidated statements of income, changes in stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2008, and our report dated February 20, 2009 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Honolulu, Hawaii
February 20, 2009

## Report of Independent Registered Public Accounting Firm

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

We have audited the accompanying consolidated balance sheets of Hawaiian Electric Industries, Inc. and subsidiaries as of December 31, 2008 and 2007, and the related consolidated statements of income, changes in stockholders' equity, and cash flows for each of the years in the three-year period ended December 31, 2008. 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, 2008 and 2007, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2008, in conformity with U.S. generally accepted accounting principles.

As discussed in Notes 1 and 4 to the consolidated financial statements, the Company adopted the provisions of Statement of Financial Accounting Standards No. 157, *Fair Value Measurements*, as of January 1, 2008, for fair value measurements of financial assets and liabilities.

As discussed in Notes 1 and 10 to the consolidated financial statements, the Company adopted the provisions of FASB Interpretation No. 48, *Accounting for Uncertainty in Income Taxes*, as of January 1, 2007.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Hawaiian Electric Industries, Inc.'s internal control over financial reporting as of December 31, 2008, based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 20, 2009 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

KPMG LLP

Honolulu, Hawaii
February 20, 2009

## Consolidated Statements of Income

Hawaiian Electric Industries, Inc. and Subsidiaries

| Years ended December 31<br>(in thousands, except per share amounts) | 2008 | 2007 | 2006 |
|---|---|---|---|
| **Revenues** | | | |
| Electric utility | $ 2,860,350 | $ 2,106,314 | $ 2,054,890 |
| Bank | 358,553 | 425,495 | 408,365 |
| Other | 17 | 4,609 | (2,351) |
| | 3,218,920 | 2,536,418 | 2,460,904 |
| **Expenses** | | | |
| Electric utility | 2,668,991 | 1,975,729 | 1,888,172 |
| Bank | 331,601 | 341,485 | 319,807 |
| Other | 14,171 | 15,472 | 13,529 |
| | 3,014,763 | 2,332,686 | 2,221,508 |
| **Operating income (loss)** | | | |
| Electric utility | 191,359 | 130,585 | 166,718 |
| Bank | 26,952 | 84,010 | 88,558 |
| Other | (14,154) | (10,863) | (15,880) |
| | 204,157 | 203,732 | 239,396 |
| Interest expense – other than on deposit liabilities and other bank borrowing | (76,142) | (78,556) | (75,678) |
| Allowance for borrowed funds used during construction | 3,741 | 2,552 | 2,879 |
| Preferred stock dividends of subsidiaries | (1,890) | (1,890) | (1,890) |
| Allowance for equity funds used during construction | 9,390 | 5,219 | 6,348 |
| **Income before income taxes** | 139,256 | 131,057 | 171,055 |
| Income taxes | 48,978 | 46,278 | 63,054 |
| **Net income** | $ 90,278 | $ 84,779 | $ 108,001 |
| **Basic earnings per common share** | $ 1.07 | $ 1.03 | $ 1.33 |
| **Diluted earnings per common share** | $ 1.07 | $ 1.03 | $ 1.33 |
| **Dividends per common share** | $ 1.24 | $ 1.24 | $ 1.24 |
| **Weighted-average number of common shares outstanding** | 84,631 | 82,215 | 81,145 |
| Dilutive effect of stock-based compensation | 89 | 204 | 228 |
| **Adjusted weighted-average shares** | 84,720 | 82,419 | 81,373 |

See accompanying "Notes to Consolidated Financial Statements."

## Consolidated Balance Sheets

Hawaiian Electric Industries, Inc. and Subsidiaries

| December 31 (dollars in thousands) | | 2008 | | 2007 |
|---|---|---|---|---|
| **ASSETS** | | | | |
| Cash and equivalents | | $ 182,903 | | $ 145,855 |
| Federal funds sold | | 532 | | 64,000 |
| Accounts receivable and unbilled revenues, net | | 300,666 | | 294,447 |
| Available-for-sale investment and mortgage-related securities | | 657,717 | | 2,140,772 |
| Investment in stock of Federal Home Loan Bank of Seattle (estimated fair value $97,764) | | 97,764 | | 97,764 |
| Loans receivable, net | | 4,206,492 | | 4,101,193 |
| Property, plant and equipment, net | | | | |
| Land | $ 55,857 | | $ 51,477 | |
| Plant and equipment | 4,433,105 | | 4,285,189 | |
| Construction in progress | 270,227 | | 156,130 | |
| | 4,759,189 | | 4,492,796 | |
| Less – accumulated depreciation | (1,851,813) | 2,907,376 | (1,749,386) | 2,743,410 |
| Regulatory assets | | 530,619 | | 284,990 |
| Other | | 328,823 | | 338,405 |
| Goodwill, net | | 82,190 | | 83,080 |
| | | $ 9,295,082 | | $ 10,293,916 |
| **LIABILITIES AND STOCKHOLDERS' EQUITY** | | | | |
| **Liabilities** | | | | |
| Accounts payable | | $ 183,584 | | $ 202,299 |
| Deposit liabilities | | 4,180,175 | | 4,347,260 |
| Short-term borrowings—other than bank | | – | | 91,780 |
| Other bank borrowings | | 680,973 | | 1,810,669 |
| Long-term debt, net—other than bank | | 1,211,501 | | 1,242,099 |
| Deferred income taxes | | 143,308 | | 155,337 |
| Regulatory liabilities | | 288,602 | | 261,606 |
| Contributions in aid of construction | | 311,716 | | 299,737 |
| Other | | 871,476 | | 573,409 |
| | | 7,871,335 | | 8,984,196 |
| Minority interests | | | | |
| Preferred stock of subsidiaries – not subject to mandatory redemption | | 34,293 | | 34,293 |
| **Stockholders' 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: 90,515,573 shares and 83,431,513 shares | | 1,231,629 | | 1,072,101 |
| Retained earnings | | 210,840 | | 225,168 |
| Accumulated other comprehensive loss, net of income tax benefits | | | | |
| Net unrealized losses on securities | $(33,025) | | $(18,043) | |
| Retirement benefit plans | (19,990) | (53,015) | (3,799) | (21,842) |
| | | 1,389,454 | | 1,275,427 |
| | | $ 9,295,082 | | $ 10,293,916 |

See accompanying "Notes to Consolidated Financial Statements."

## Consolidated Statements of Changes in Stockholders' Equity

Hawaiian Electric Industries, Inc. and Subsidiaries

| (in thousands, except per share amounts) | Common stock Shares | Common stock Amount | Retained earnings | Accumulated other comprehensive income (loss) | Total |
|---|---|---|---|---|---|
| **Balance, December 31, 2005** | 80,983 | $1,018,966 | $235,394 | $ (37,730) | $1,216,630 |
| Comprehensive income: | | | | | |
| Net income | – | – | 108,001 | – | 108,001 |
| Net unrealized gains on securities: | | | | | |
| Net unrealized gains arising during the period, net of taxes of $1,361 | – | – | – | 2,059 | 2,059 |
| Less: reclassification adjustment for net realized gains included in net income, net of taxes of $690 | – | – | – | (1,045) | (1,045) |
| Minimum pension liability adjustment, net of taxes of $804 | – | – | – | 1,254 | 1,254 |
| Comprehensive income (loss) | – | – | 108,001 | 2,268 | 110,269 |
| Adjustment to initially apply SFAS No. 158, net of tax benefits of $89,394 | – | – | – | (140,066) | (140,066) |
| Issuance of common stock: Stock Option and Incentive Plan and other plans | 478 | 10,270 | – | – | 10,270 |
| Expenses and other, net | – | (1,135) | – | – | (1,135) |
| Common stock dividends ($1.24 per share) | – | – | (100,728) | – | (100,728) |
| **Balance, December 31, 2006** | **81,461** | **1,028,101** | **242,667** | **(175,528)** | **1,095,240** |
| Comprehensive income: | | | | | |
| Net income | – | – | 84,779 | – | 84,779 |
| Net unrealized gains on securities: | | | | | |
| Net unrealized gains arising during the period, net of taxes of $11,944 | – | – | – | 18,087 | 18,087 |
| Less: reclassification adjustment for net realized gains included in net income, net of taxes of $441 | – | – | – | (668) | (668) |
| Retirement benefit plans: | – | – | – | | |
| Prior service credit arising during the period, net of taxes of $6,990 | – | – | – | 10,584 | 10,584 |
| Net gains arising during the period, net of taxes of $11,400 | – | – | – | 17,825 | 17,825 |
| Less: amortization of transition obligation, prior service credit and net losses recognized during the period in net periodic benefit cost, net of tax benefits of $5,545 | – | – | – | 8,694 | 8,694 |
| Less: reclassification adjustment for impact of D&Os of the PUC included in regulatory asset, net of taxes of $11,007 | – | – | – | (17,282) | (17,282) |
| Less: reclassification adjustment for curtailment gain included in net income, net of taxes of $3,503 | – | – | – | (5,305) | (5,305) |
| Comprehensive income (loss) | – | – | 84,779 | 31,935 | 116,714 |
| Adjustment to initially apply PUC D&Os related to retirement benefit plans, net of taxes of $77,546 | – | – | – | 121,751 | 121,751 |
| Adjustment to initially apply FIN 48 | – | – | (228) | – | (228) |
| Issuance of common stock: Dividend reinvestment and stock purchase plan | 1,447 | 34,443 | – | – | 34,443 |
| Retirement savings and other plans | 524 | 10,804 | – | – | 10,804 |
| Expenses and other, net | – | (1,247) | – | – | (1,247) |
| Common stock dividends ($1.24 per share) | – | – | (102,050) | – | (102,050) |
| **Balance, December 31, 2007** | **83,432** | **1,072,101** | **225,168** | **(21,842)** | **1,275,427** |
| Comprehensive income: | | | | | |
| Net income | – | – | 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 asset, net of taxes of $96,975 | – | – | – | 152,256 | 152,256 |
| Comprehensive income (loss) | – | – | 90,278 | (31,173) | 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** |

As of December 31, 2008, HEI had reserved a total of 12,648,870 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 and the HEI 1990 Nonemployee Director Stock Plan.

See accompanying "Notes to Consolidated Financial Statements."

## Consolidated Statements of Cash Flows

Hawaiian Electric Industries, Inc. and Subsidiaries

| Years ended December 31 (in thousands) | 2008 | 2007 | 2006 |
|---|---|---|---|
| **Cash flows from operating activities** | | | |
| Net income | $ 90,278 | $ 84,779 | $ 108,001 |
| Adjustments to reconcile net income to net cash provided by operating activities | | | |
| Depreciation of property, plant and equipment | 150,977 | 147,881 | 141,184 |
| Other amortization | 5,085 | 11,878 | 10,778 |
| Provision for loan losses | 10,334 | 5,700 | 1,400 |
| Writedown of utility plant | – | 11,701 | – |
| Gain on pension curtailment | (472) | (8,809) | – |
| Net loss (gain) on sale of investment and mortgage-related securities | 17,376 | (1,109) | (1,735) |
| Loans receivable originated and purchased, held for sale | (204,457) | (39,688) | (23,767) |
| Proceeds from sale of loans receivable, held for sale | 185,291 | 33,876 | 26,150 |
| Other-than-temporary impairment on available-for-sale investment securities | 7,764 | – | – |
| Deferred income taxes | 5,134 | (34,624) | (12,946) |
| Excess tax benefits from share-based payment arrangements | (405) | (195) | (1,052) |
| Allowance for equity funds used during construction | (9,390) | (5,219) | (6,348) |
| Changes in assets and liabilities, net of effects from the disposal of businesses | | | |
| Decrease (increase) in accounts receivable and unbilled revenues, net | (6,219) | (45,808) | 834 |
| Decrease (increase) in fuel oil stock | 14,157 | (27,559) | 21,138 |
| Decrease in federal tax deposit | – | – | 30,000 |
| Increase (decrease) in accounts payable | (18,715) | 36,794 | (17,831) |
| Changes in prepaid and accrued income taxes and utility revenue taxes | 16,466 | 42,617 | (2,273) |
| Changes in other assets and liabilities | (5,280) | 5,126 | 12,519 |
| **Net cash provided by operating activities** | 257,924 | 217,341 | 286,052 |
| **Cash flows from investing activities** | | | |
| Available-for-sale investment and mortgage-related securities purchased | (489,264) | (402,071) | (343,927) |
| Principal repayments on available-for-sale investment and mortgage-related securities | 610,521 | 652,083 | 542,702 |
| Proceeds from sale of available-for-sale investment and mortgage-related securities | 1,311,596 | 1,109 | 61,131 |
| Proceeds from sale of other investments | 17 | 35,920 | – |
| Net increase in loans held for investment | (92,241) | (315,786) | (211,872) |
| Proceeds from sale of real estate acquired in settlement of loans | – | – | 403 |
| Capital expenditures | (282,051) | (218,297) | (210,529) |
| Contributions in aid of construction | 17,319 | 19,011 | 19,707 |
| Other | 1,116 | 5,902 | 1,708 |
| **Net cash provided by (used in) investing activities** | 1,077,013 | (222,129) | (140,677) |
| **Cash flows from financing activities** | | | |
| Net increase (decrease) in deposit liabilities | (167,085) | (228,288) | 18,129 |
| Net increase (decrease) in short-term borrowings with original maturities of three months or less | (91,780) | (84,492) | 35,213 |
| Proceeds from short-term borrowings with original maturities of greater than three months | – | – | 44,891 |
| Repayment of short-term borrowings with original maturities of greater than three months | – | – | (45,590) |
| Net increase (decrease) in retail repurchase agreements | (37,142) | 71,205 | 60,596 |
| Proceeds from other bank borrowings | 2,592,635 | 1,338,432 | 1,331,559 |
| Repayments of other bank borrowings | (3,682,119) | (1,166,112) | (1,446,995) |
| Proceeds from issuance of long-term debt | 19,275 | 242,539 | 100,000 |
| Repayment of long-term debt | (50,000) | (136,000) | (110,000) |
| Principal payments on nonrecourse debt | – | (17,242) | (3,387) |
| Excess tax benefits from share-based payment arrangements | 405 | 195 | 1,052 |
| Net proceeds from issuance of common stock | 136,443 | 21,072 | 5,481 |
| Common stock dividends | (83,604) | (81,489) | (100,673) |
| Increase (decrease) in cash overdraft | 1,265 | (3,545) | 4,631 |
| Other | 350 | 1,067 | 542 |
| **Net cash used in financing activities** | (1,361,357) | (42,658) | (104,551) |
| **Net cash provided by discontinued operations--operating activities** | – | – | 7,530 |
| Net increase (decrease) in cash and equivalents and federal funds sold | (26,420) | (47,446) | 48,354 |
| Cash and equivalents and federal funds sold, January 1 | 209,855 | 257,301 | 208,947 |
| **Cash and equivalents and federal funds sold, December 31** | $183,435 | $ 209,855 | $ 257,301 |

See accompanying "Notes to Consolidated Financial Statements."

## 1 • Summary of significant accounting policies

### General

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

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

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

***Consolidation.*** The consolidated financial statements include the accounts of HEI and its subsidiaries (collectively, the Company), but exclude subsidiaries which are variable-interest entities 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 the application of Financial Accounting Standards Board (FASB) Interpretation (FIN) No. 46(R).

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

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

For securities that are not trading securities, declines in value determined to be other than temporary are included in earnings and result in a new cost basis for the investment. To determine whether an impairment is other than temporary, the Company considers whether it has the ability and intent to hold the investment until a market price recovery and considers whether evidence indicating the cost of the investment is recoverable outweighs evidence to the contrary. Evidence considered in this assessment includes the magnitude of the impairment, the severity and duration of the impairment, changes in value subsequent to year-end and forecasted performance of the investment.

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

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

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

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

If a power purchase agreement (PPA) falls within the scope of Emerging Issues Task Force (EITF) Issue No. 01-8, "Determining Whether an Arrangement Contains a Lease" and results in the classification of the agreement as a capital lease, the electric utility would recognize a capital asset and a lease obligation.

***Depreciation.*** Depreciation is computed primarily using the straight-line method over the estimated lives of the assets being depreciated. Electric utility plant additions in the current year are depreciated beginning January 1 of the following year. Electric utility plant has lives ranging from 20 to 45 years for production plant, from 25 to 60 years for transmission and distribution plant and from 7 to 45 years for general plant. The electric utilities' composite annual depreciation rate, which includes a component for cost of removal, was 3.8% in 2008 and 2007 and 3.9% in 2006.

***Retirement benefits.*** Pension and other postretirement benefit costs are charged primarily to expense and electric utility plant. Funding for the Company's qualified pension plans (Plans) is based on actuarial assumptions adopted by the Pension Investment Committee administering the Plans on the advice of an enrolled actuary. The participating employers contribute amounts to a master pension trust for the Plans in accordance with the funding requirements of Employee Retirement Income Security Act of 1974, as amended (ERISA), including changes promulgated by the Pension Protection Act of 2006, and considering the deductibility of contributions under the Internal Revenue Code. The Company generally funds at least the net periodic pension cost as calculated using Statement of Financial Accounting Standards (SFAS) No. 87 during the fiscal year, subject to limits and targeted funded status as determined with the consulting actuary. Under a pension tracking mechanism approved by the Public Utilities Commission of the State of Hawaii (PUC) on an interim basis, Hawaiian Electric Company, Inc. (HECO) generally will make contributions to the pension fund at the minimum level required under the law, until its pension asset (existing at the time of the PUC decision and determined based on the cumulative fund contributions in excess of the cumulative net periodic pension cost recognized) is reduced to zero, at which time HECO would fund the pension cost as specified in the pension tracking mechanism. Hawaii Electric Light Company, Inc. (HELCO) and Maui Electric Company, Limited (MECO) will generally fund the net periodic pension cost. Future decisions in rate cases could further impact funding amounts.

Certain health care and/or life insurance benefits are provided to eligible retired employees and the employees' beneficiaries and covered dependents. The Company generally funds the net periodic postretirement benefit costs other than pensions as calculated using SFAS No. 106 and the amortization of the regulatory asset for postretirement benefits other than pensions (OPEB), while maximizing the use of the most tax advantaged funding vehicles, subject to cash flow requirements and reviews of the funded status with the consulting actuary. The electric utilities must fund OPEB costs as specified in the OPEB tracking mechanisms, which were approved by the PUC on an interim basis. Future decisions in rate cases could further impact funding amounts.

Effective December 31, 2006, the Company adopted SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)," and recognized on its balance sheet the funded status of its defined benefit pension and other postretirement benefit plans, as adjusted by the impact of decisions of the PUC.

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

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

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

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

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

***Income taxes.*** Deferred income tax assets and liabilities are established for the temporary differences between the financial reporting bases and the tax bases of the Company's assets and liabilities at 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.

Effective January 1, 2007, the Company adopted FIN 48, "Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109," and uses a "more-likely-than-not" recognition threshold and measurement attribute 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 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.

As of December 31, 2008 and 2007, the antidilutive effect of stock appreciation rights (SARs) on 791,000 and 857,000 shares of common stock (for which the SARs' exercise prices were greater than the closing market price of HEI's common stock), respectively, were not included in the computation of diluted EPS. As of December 31, 2006, the dilutive effect of all options, SARs and restricted stock were included in the computation of diluted EPS.

***Share-based compensation.*** For 2005, the Company applied the fair value based method of accounting prescribed by SFAS No. 123, "Accounting for Stock-Based Compensation," to account for its stock compensation. Since January 1, 2006, the Company applied the fair value based method of accounting prescribed by SFAS No. 123 (Revised 2004), "Share-Based Payment," to account for its stock compensation, including the use of a forfeiture assumption. See Note 9.

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

***Recent accounting pronouncements and interpretations***

**Business combinations.** In December 2007, the FASB issued SFAS No. 141R, "Business Combinations." SFAS No. 141R requires an acquiring entity to recognize all the assets acquired and liabilities assumed at the acquisition-date fair value with limited exceptions. Under SFAS No. 141R, acquisition costs will generally be expensed as incurred, noncontrolling interests will be valued at acquisition-date fair value, and acquired contingent liabilities will be recorded at acquisition-date fair value and subsequently measured at the higher of such amount or the amount determined under existing guidance for non-acquired contingencies. The Company must adopt SFAS No. 141R for all business combinations for which the acquisition date is on or after January 1, 2009. Because the impact of adopting SFAS No. 141R will be dependent on future acquisitions, if any, management cannot currently predict such impact.

**Noncontrolling interests.** In December 2007, the FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements." SFAS No. 160 requires the recognition of a noncontrolling interest (i.e., a minority interest) as equity in the consolidated financial statements, separate from the parent's equity, and requires the amount of consolidated net income attributable to the parent and to the noncontrolling interest be clearly identified and presented on the face of the income statement. Under SFAS No. 160, changes in the parent's ownership interest that leave control intact are accounted for as capital transactions (i.e., as increases or decreases in ownership), a gain or loss will be recognized when a subsidiary is deconsolidated based on the fair value of the noncontrolling equity investment (not carrying amount), and entities must provide sufficient disclosures that clearly identify and distinguish between the interests of the parent and of the noncontrolling owners. The Company adopted SFAS No. 160 prospectively on January 1, 2009, except for the presentation and disclosure requirements which must be applied retrospectively. Thus, beginning in the first quarter of 2009, "Preferred stock of subsidiaries--not subject to mandatory redemption" will be presented as a separate component of "Stockholders' equity" rather than as "Minority interests" in the mezzanine section between liabilities and equity on the balance sheet, dividends on preferred stock of subsidiaries will be deducted from net income to arrive at net income for common stock on the income statement, and a column for "Preferred stock of subsidiaries—not subject to mandatory redemption" will be added to the statement of changes in stockholders' equity.

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

**Written loan commitments.** In November 2007, the Securities and Exchange Commission (SEC) issued Staff Accounting Bulletin (SAB) No. 109, "Written Loan Commitments Recorded at Fair Value through Earnings," which supersedes SAB No. 105, "Application of Accounting Principles to Loan Commitments." SAB No. 109 states that the expected net future cash flows related to the associated servicing of the loan should be included in the measurement of all written loan commitments that are accounted for at fair value through earnings. Previously, SAB No. 105 stated that in measuring the fair value of a derivative loan commitment, a company should not incorporate the expected net future cash flows related to the associated servicing of the loan. SAB No. 109 is effective for loan commitments issued or modified in fiscal quarters beginning after December 15, 2007. ASB adopted SAB No. 109 in the first quarter of 2008 and the adoption had an immaterial impact on the Company's financial statements.

**The fair value option for financial assets and financial liabilities**. In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities, Including an amendment of FASB Statement No. 115." SFAS No. 159 permits entities to choose to measure many financial instruments and certain other items at fair value, which should improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. The Company adopted SFAS No. 159 on January 1, 2008 and the adoption had no impact on the Company's financial statements as the Company did not choose to measure additional items at fair value.

**Fair value measurements**. In September 2006, the FASB issued SFAS No. 157, "Fair Value Measurements," which defines fair value, establishes a framework for measuring fair value under generally accepted accounting principles and expands disclosures about fair value measurements. SFAS No. 157 applies to fair value measurements that are already required or permitted under existing accounting pronouncements with some exceptions. SFAS No. 157 retains the exchange price notion in defining fair value and clarifies that the exchange price is the price that would be received upon sale of an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability. It emphasizes that fair value is a market-based, not an entity-specific, measurement based upon the assumptions that consider credit and nonperformance risk market participants would use in pricing an asset or liability. As a basis for considering assumptions in fair value measurements, SFAS No. 157 establishes a hierarchy that gives the highest priority to quoted prices (unadjusted) in active markets for identical assets or liabilities (Level 1) and the lowest priority to unobservable inputs (Level 3). SFAS No. 157 expands disclosures about the use of fair value, including disclosure of the level within the hierarchy in which the fair value measurements fall and the effect of the measurements on earnings (or changes in net assets) for the period. The Company adopted SFAS No. 157 on January 1, 2008. The adoption of SFAS No. 157 for fair value measures of financial assets and financial liabilities had no impact on the Company's financial results, but have impacted the Company's fair value measurement disclosures.

FSP FAS 157-2, "Effective Date of FASB Statement No. 157," delays the effective date of SFAS No. 157 until fiscal years beginning after November 15, 2008 for all nonfinancial assets and nonfinancial liabilities that are recognized or disclosed at fair value in the financial statements on a nonrecurring basis. In accordance with FSP FAS 157-2, the Company has not applied the provisions of SFAS No. 157 to goodwill.

On January 1, 2009, the Company will be required to apply the provisions of SFAS No. 157 to fair value measurements of nonfinancial assets and nonfinancial liabilities that are recognized or disclosed at fair value in the financial statements on a nonrecurring basis. The Company is in the process of evaluating the impact, if any, of applying these provisions on its financial position and results of operations.

In October 2008, the FASB issued FSP FAS 157-3, "Determining the Fair Value of a Financial Asset When the Market for That Asset is Not Active," which was effective immediately. FSP FAS 157-3 clarifies the application of SFAS No. 157 in cases where the market for a financial instrument is not active and provides an example to illustrate key considerations in determining fair value in those circumstances. The Company has considered the guidance provided by FSP FAS 157-3 in its determination of estimated fair values during 2008.

**Income tax benefits of dividends on share-based payment awards.** In June 2007, the FASB ratified the EITF consensus reached on EITF Issue No. 06-11, "Accounting for Income Tax Benefits of Dividends on Share-Based Payment Awards." The consensus applies to share-based payment arrangements in which the employee receives dividends on the award during the vesting period, the dividend payment results in a tax deduction, and the employer thereby realizes a tax benefit during the vesting period (e.g., restricted stock awards issued by the Company). Under SFAS No. 123R, dividends paid during the vesting period on share-based payments that are expected to vest are charged to retained earnings because the compensation cost already reflects the expected value of those dividends, which are included in the grant date fair value of the award, but dividends on awards that do not vest are recognized as additional compensation cost. The consensus requires the tax benefit received on dividends associated with share-based awards that are charged to retained earnings to be recorded in additional paid-in capital and included in the pool of excess tax benefits available to absorb potential future tax deficiencies on share-based payment awards. A tax benefit recognized from a dividend on an award that is subsequently forfeited or is no longer expected to vest (and that is therefore reclassified as additional compensation expense) would be reclassified to the income statement if sufficient excess tax benefits are available in the pool of excess tax benefits in additional paid-in capital on the date of the reclassification. The consensus is effective for the tax benefits of dividends declared in fiscal years beginning after December 15, 2007. The Company adopted this consensus on January 1, 2008 and the adoption had no impact on the Company's financial statements.

***Reclassifications.*** Certain reclassifications have been made to prior years' financial statements to conform to the 2008 presentation, which did not affect previously reported results of operations.

## Electric utility

***Regulation by the PUC.*** The electric utilities are regulated by the PUC and account for the effects of regulation under SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation." As a result, the actions of regulators can affect the timing of recognition of revenues, expenses, assets and liabilities. Management believes HECO and its subsidiaries' operations currently satisfy the SFAS No. 71 criteria. If events or circumstances should change so that those criteria are no longer satisfied, the electric utilities expect that the regulatory assets would be charged to expense and the regulatory liabilities would be credited to income or refunded to ratepayers. In the event of unforeseen regulatory actions or other circumstances, however, management believes that a material adverse effect on the Company's results of operations and financial position may result if regulatory assets have to be charged to expense without an offsetting credit for regulatory liabilities or if regulatory liabilities are required to be refunded to ratepayers.

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

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

***Electric utility revenues.*** Electric utility revenues are based on rates authorized by the PUC and include revenues applicable to energy consumed in the accounting period but not yet billed to the customers. Revenues related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. However, the determination of the energy sales to individual customers for billing purposes is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on the meter readings in the beginning of the following month, monthly generation volumes, estimated customer usage by account, line losses and applicable customer rates based on historical values and current rate schedules. As of December 31, 2008, customer accounts receivable include unbilled energy revenues of $107 million on a base of annual revenue of $2.9 billion. Revenue amounts recorded pursuant to a PUC interim order are subject to refund, with interest, pending a final order.

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

HECO and its subsidiaries' operating revenues include amounts for various revenue taxes. Revenue taxes are generally recorded as an expense in the year the related revenues are recognized. HECO and its subsidiaries' payments to the taxing authorities are based on the prior years' revenues. For 2008, 2007 and 2006, HECO and its subsidiaries included approximately $252 million, $185 million and $182 million, respectively, of revenue taxes in "operating revenues" and in "taxes, other than income taxes" expense.

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

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

The weighted-average AFUDC rate was 8.1%, 8.1% and 8.4% in 2008, 2007 and 2006, respectively, 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. Effective January 1, 2007, ASB adopted SFAS No. 156, "Accounting for Servicing of Financial Assets – an amendment of FASB Statement No. 140." SFAS No. 156 requires that mortgage servicing assets or liabilities resulting from the sale or securitization of loans be initially measured at fair value at the date of transfer, and permits a class-by-class election between fair value and the lower of amortized cost or fair value for subsequent measurements of mortgage servicing asset classes. Mortgage servicing assets or liabilities are included as a component of gain on sale of loans. Upon adoption of SFAS No. 156, 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. 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. 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. For all loans secured by real estate, ASB measures impairment by utilizing the fair value of the collateral; for other loans, discounted cash flows are used to measure impairment. Losses from impairment are charged to the provision for loan losses and included in the allowance for loan losses.

For the residential, consumer and homogeneous commercial loans receivable portfolios, the allowance for loan loss allocations are based on historical loss ratio analyses.

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

Management believes its allowance for loan losses is adequate. While management utilizes available information to recognize losses on loans, future adjustments may be required from time to time to the allowance for loan losses (e.g. due to changes in economic conditions, particularly in the State of Hawaii) and actual results could differ from management's estimates, and these adjustments and differences could be material.

***Real estate acquired in settlement of loans.*** ASB records real estate acquired in settlement of loans at the lower of cost or fair value, less estimated selling expenses. ASB obtains appraisals based on recent comparable sales to assist management in estimating the fair value of real estate acquired in settlement of loans. Subsequent declines in value are charged to expense through a valuation allowance. Costs related to holding real estate are charged to operations as incurred. As of December 31, 2008, ASB had $1.5 million of real estate acquired in settlement of loans. As of December 31, 2007, ASB had no 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 SFAS No. 144.

**Goodwill.** At December 2008 and 2007, the amount of goodwill was $82.2 million and $83.1 million, which is the Company's only intangible asset with an indefinite useful life, 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, 2008, there has been no impairment of goodwill. The fair value of ASB is estimated by an unrelated third party using a valuation method based on a market approach, which takes into consideration market values of comparable companies, which are publicly traded, recent transactions of companies in the industry and discounted cash flows.

**Amortized intangible assets.**

| December 31 | 2008 | | 2007 | |
|---|---|---|---|---|
| (in thousands) | Gross carrying amount | Accumulated amortization | Gross carrying amount | Accumulated amortization |
| Core deposit intangibles | $20,276 | $20,276 | $20,276 | $20,276 |
| Mortgage servicing assets | 12,150 | 10,005 | 11,754 | 9,560 |
| | $32,426 | $30,281 | $32,030 | $29,836 |

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

| (in thousands) | 2008 | 2007 | 2006 |
|---|---|---|---|
| Valuation allowance, January 1 | $189 | $119 | $207 |
| Provision (reversal of allowance) | 278 | 92 | (74) |
| Other-than-temporary impairment | (199) | (22) | (14) |
| Valuation allowance, December 31 | $268 | $189 | $119 |

In 2008, 2007 and 2006, aggregate amortization expenses were $0.4 million, $2.0 million and $2.2 million, respectively.

The estimated aggregate amortization expenses for mortgage servicing assets for 2009, 2010, 2011, 2012 and 2013 are $0.4 million, $0.4 million, $0.3 million, $0.2 million and $0.2 million, respectively.

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

ASB capitalizes mortgage servicing assets acquired through either the purchase or origination of mortgage loans for sale or the securitization of mortgage loans with servicing rights retained. Changes in mortgage interest rates impact the value of ASB's mortgage servicing assets. Rising interest rates typically result in slower prepayment speeds in the loans being serviced for others which increases the value of mortgage servicing assets, whereas declining interest rates typically result in faster prepayment speeds which decrease the value of mortgage servicing assets and increase the amortization of the mortgage servicing assets. As of December 31, 2008 and 2007, the mortgage servicing assets had a net carrying value of $1.9 million and $2.0 million, respectively. In 2008, 2007 and 2006, mortgage servicing assets acquired through the sale or securitization of loans held for sale was $0.6 million, $0.1 million and $0.1 million, respectively. Amortization expenses for ASB's mortgage servicing assets amounted to $0.4 million, $0.4 million, and $0.5 million for 2008, 2007 and 2006, respectively, and are recorded as a reduction in revenues on the consolidated statements of income.

## 2 • Segment financial information

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

### Electric utility

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

### Bank

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

### Other

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

HEI Properties, Inc. (HEIPI) held shares of Hoku Scientific, Inc. (Hoku), a company focused on clean energy technologies. Shares of Hoku began trading on the Nasdaq Stock Market on August 5, 2005 and since then HEIPI had classified its Hoku shares as trading securities, carried at fair value with changes in fair value recorded in earnings. HEIPI began selling Hoku stock in February 2006 when HEIPI's lock-up agreement expired. In 2006 and 2005, HEIPI recognized a $1.6 million loss (unrealized and realized, net of taxes) and a $2.9 million gain (unrealized, net of taxes), respectively, on the Hoku shares. In 2007, HEIPI sold its remaining investment in Hoku for a net after-tax gain of $0.9 million.

Segment financial information was as follows:

| (in thousands) | Electric utility | Bank | Other | Total |
|---|---|---|---|---|
| **2008** | | | | |
| Revenues from external customers | $2,860,177 | $ 358,553 | $ 190 | $3,218,920 |
| Intersegment revenues (eliminations) | 173 | – | (173) | – |
| Revenues | 2,860,350 | 358,553 | 17 | 3,218,920 |
| Depreciation and amortization | 150,297 | 4,884 | 881 | 156,062 |
| Interest expense | 54,757 | 105,424 | 21,385 | 181,566 |
| Profit (loss)* | 147,738 | 26,791 | (35,273) | 139,256 |
| Income taxes (benefit) | 55,763 | 8,964 | (15,749) | 48,978 |
| Net income (loss) | 91,975 | 17,827 | (19,524) | 90,278 |
| Capital expenditures | 278,476 | 3,499 | 76 | 282,051 |
| Assets (at December 31, 2008) | 3,856,109 | 5,437,120 | 1,853 | 9,295,082 |
| **2007** | | | | |
| Revenues from external customers | $2,106,096 | $ 425,495 | $ 4,827 | $2,536,418 |
| Intersegment revenues (eliminations) | 218 | – | (218) | – |
| Revenues | 2,106,314 | 425,495 | 4,609 | 2,536,418 |
| Depreciation and amortization | 145,311 | 13,574 | 874 | 159,759 |
| Interest expense | 53,268 | 159,898 | 25,288 | 238,454 |
| Profit (loss)* | 83,093 | 83,989 | (36,025) | 131,057 |
| Income taxes (benefit) | 30,937 | 30,882 | (15,541) | 46,278 |
| Net income (loss) | 52,156 | 53,107 | (20,484) | 84,779 |
| Capital expenditures | 209,821 | 7,866 | 610 | 218,297 |
| Assets (at December 31, 2007) | 3,423,888 | 6,861,493 | 8,535 | 10,293,916 |
| **2006** | | | | |
| Revenues from external customers | $2,054,616 | $ 408,365 | $ (2,077) | $2,460,904 |
| Intersegment revenues (eliminations) | 274 | – | (274) | – |
| Revenues | 2,054,890 | 408,365 | (2,351) | 2,460,904 |
| Depreciation and amortization | 138,096 | 13,175 | 691 | 151,962 |
| Interest expense | 52,563 | 146,096 | 23,115 | 221,774 |
| Profit (loss)* | 121,387 | 88,558 | (38,890) | 171,055 |
| Income taxes (benefit) | 46,440 | 32,776 | (16,162) | 63,054 |
| Net income (loss) | 74,947 | 55,782 | (22,728) | 108,001 |
| Capital expenditures | 195,072 | 14,927 | 530 | 210,529 |
| Assets (at December 31, 2006 **) | 3,063,134 | 6,808,499 | 19,576 | 9,891,209 |

* Income (loss) before income taxes.

** Includes net assets of discontinued operations.

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

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.

## Selected financial information

Hawaiian Electric Company, Inc. and Subsidiaries

### Consolidated Statements of Income Data

| Years ended December 31 | 2008 | 2007 | 2006 |
|---|---|---|---|
| (in thousands) | | | |
| **Revenues** | | | |
| Operating revenues | $2,853,639 | $2,096,958 | $2,050,412 |
| Other – nonregulated | 6,711 | 9,356 | 4,478 |
| | 2,860,350 | 2,106,314 | 2,054,890 |
| **Expenses** | | | |
| Fuel oil | 1,229,193 | 774,119 | 781,740 |
| Purchased power | 689,828 | 536,960 | 506,893 |
| Other operation | 243,249 | 214,047 | 186,449 |
| Maintenance | 101,624 | 105,743 | 90,217 |
| Depreciation | 141,678 | 137,081 | 130,164 |
| Taxes, other than income taxes | 261,823 | 194,607 | 190,413 |
| Other – nonregulated | 1,596 | 13,172 | 2,296 |
| | 2,668,991 | 1,975,729 | 1,888,172 |
| Operating income from regulated and nonregulated activities | 191,359 | 130,585 | 166,718 |
| Allowance for equity funds used during construction | 9,390 | 5,219 | 6,348 |
| Interest and other charges | (55,672) | (54,183) | (53,478) |
| Allowance for borrowed funds used during construction | 3,741 | 2,552 | 2,879 |
| Income before income taxes and preferred stock dividends of HECO | 148,818 | 84,173 | 122,467 |
| Income taxes | 55,763 | 30,937 | 46,440 |
| Income before preferred stock dividends of HECO | 93,055 | 53,236 | 76,027 |
| Preferred stock dividends of HECO | 1,080 | 1,080 | 1,080 |
| Net income for common stock | $ 91,975 | $ 52,156 | $ 74,947 |

## Consolidated Balance Sheet Data

| December 31 | 2008 | 2007 |
|---|---|---|
| (in thousands) | | |
| **Assets** | | |
| Utility plant, at cost | | |
| Property, plant and equipment | $ 4,320,040 | $ 4,169,428 |
| Less accumulated depreciation | (1,741,453) | (1,647,113) |
| Construction in progress | 266,628 | 151,179 |
| Net utility plant | 2,845,215 | 2,673,494 |
| Regulatory assets | 530,619 | 284,990 |
| Other | 480,275 | 465,404 |
| | $ 3,856,109 | $ 3,423,888 |
| **Capitalization and liabilities** | | |
| Common stock ($6 2/3 par value, authorized 50,000,000 shares. outstanding: 12,805,843 shares) | $ 85,387 | $ 85,387 |
| Premium on common stock | 299,214 | 299,214 |
| Retained earnings | 802,590 | 724,704 |
| Accumulated other comprehensive income | 1,651 | 1,157 |
| Common stock equity | 1,188,842 | 1,110,462 |
| 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 | 904,501 | 885,099 |
| Total capitalization | 2,127,636 | 2,029,854 |
| Short-term borrowings from nonaffiliates and affiliates | 41,550 | 28,791 |
| Deferred income taxes | 166,310 | 162,113 |
| Regulatory liabilities | 288,602 | 261,606 |
| Contributions in aid of construction | 311,716 | 299,737 |
| Other | 920,295 | 641,787 |
| | $ 3,856,109 | $ 3,423,888 |

***Regulatory assets and liabilities.*** In accordance with SFAS No. 71, HECO and its subsidiaries' financial statements reflect assets, liabilities, revenues and expenses based on current cost-based rate-making regulations. Their continued accounting under SFAS No. 71 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 SFAS No. 71 criteria. If events or circumstances should change so that those criteria are no longer satisfied, the electric utilities expect that the regulatory assets would be charged to expense and the regulatory liabilities would be credited to income or refunded to ratepayers. In the event of unforeseen regulatory actions or other circumstances, management believes that a material adverse effect on the Company's results of operations and financial position may result if regulatory assets have to be charged to expense without an offsetting credit for regulatory liabilities or if regulatory liabilities are required to be refunded to ratepayers.

Regulatory assets represent deferred costs expected to be fully recovered through rates over PUC-authorized periods. Generally, HECO and its subsidiaries do not earn a return on their regulatory assets; however, they have been allowed to recover interest on their regulatory assets for demand-side management (DSM) program costs. Regulatory liabilities represent amounts included in rates and collected from ratepayers for costs expected to be incurred in the future. For example, the regulatory liability for cost of removal in excess of salvage value represents amounts that have been collected from ratepayers for costs that are expected to be incurred in the future to retire utility plant. Noted in parentheses are the original PUC authorized amortization or recovery periods and the remaining amortization or recovery periods as of December 31, 2008, if different.

Regulatory assets were as follows:

| December 31<br>(in thousands) | 2008 | 2007 |
|---|---|---|
| Retirement benefit plans (5 years; 3 years for HELCO's $8 million prepaid pension regulatory asset, indeterminate for remainder) | $416,680 | $169,814 |
| Income taxes, net (1 to 36 years) | 77,660 | 74,605 |
| Postretirement benefits other than pensions (18 years; 4 years) | 7,159 | 8,949 |
| Unamortized expense and premiums on retired debt and equity issuances (14 to 30 years; 1 to 20 years) | 16,191 | 17,510 |
| Demand-side management program costs, net (1 year) | 2,571 | 4,113 |
| Vacation earned, but not yet taken (1 year) | 6,654 | 5,997 |
| Other (1 to 20 years) | 3,704 | 4,002 |
| | $530,619 | $284,990 |

Regulatory liabilities were as follows:

| December 31<br>(in thousands) | 2008 | 2007 |
|---|---|---|
| Cost of removal in excess of salvage value (1 to 60 years) | $282,400 | $259,765 |
| Retirement benefit plans (5 years beginning with respective utility's next rate case) | 4,718 | – |
| Other (5 years; 1 to 5 years) | 1,484 | 1,841 |
| | $288,602 | $261,606 |

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

***Cumulative preferred stock.*** The cumulative preferred stock of HECO and its subsidiaries is redeemable at the option of the respective company at a premium or par, but none is subject to mandatory redemption.

***Major customers.*** HECO and its subsidiaries received $295 million (10%), $194 million (9%) and $197 million (10%) of their operating revenues from the sale of electricity to various federal government agencies in 2008, 2007 and 2006, respectively.

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

***Commitments and contingencies***

**Fuel contracts.** HECO and its subsidiaries have contractual agreements to purchase minimum quantities of fuel oil and diesel fuel through December 31, 2014 (at prices tied to the market prices of petroleum products in Singapore and Los Angeles). Based on the average price per barrel as of January 1, 2009, the estimated cost of minimum purchases under the fuel supply contracts is $0.4 billion per year for 2009 through 2012 and a total of $0.9 billion for the period 2013 through 2014. The actual cost of purchases in 2009 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 $1.2 billion, $795 million and $755 million of fuel under contractual agreements in 2008, 2007 and 2006, respectively.

**Power purchase agreements.** As of December 31, 2008, 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 $690 million, $537 million and $507 million for 2008, 2007 and 2006, 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 2009 through 2013 and a total of $0.9 billion in the period from 2014 through 2030.

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

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

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

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

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

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

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

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

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

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

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

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

HECO and its subsidiaries will continue to negotiate with developers of currently proposed projects (identified in the Energy Agreement) to integrate approximately 1,100 MW from a variety of renewable energy sources, including solar, biomass, wind, ocean thermal energy conversion, wave, and others. This includes HECO's commitment to integrate, with the assistance of the State of Hawaii, up to 400 MW of wind power into the Oahu electrical grid that would be imported via a yet-to-be-built undersea transmission cable system from wind farms proposed by developers to be built on the islands of Lanai and/or Molokai. Utilizing technical resources such as the U.S. Department of Energy national laboratories, HECO, along with the other parties, have committed to work together to evaluate, assess and address the operational challenges for integrating such a large increment of wind into its grid system on Oahu. The State and HECO have agreed to work together to ensure the supporting infrastructure needed for the Oahu grid is in place to reliably accommodate this large increment of wind power, including appropriate additional storage capacity investments and any required utility system connections or interfaces with the cable and the wind farm facilities.

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

As another method of accelerating the acquisition of renewable energy by the utilities, the Energy Agreement includes support of the parties for the development of a feed-in tariff (FIT) system with standardized purchase prices for renewable energy. The PUC is requested to conclude an investigative proceeding by March 2009 to determine the best design for FIT that support the HCEI goals, considering such factors as categories of renewables, size or locational limits for projects qualifying for the FIT, what annual limits should apply to the amount of renewables allowed to utilize the FIT, what factors to incorporate into the prices set for FIT payments, and other terms and conditions. Based on these understandings, the Energy Agreement requires that the parties request the PUC to suspend the pending intra-governmental wheeling and avoided cost (Schedule Q) dockets for a period of 12 months. On October 24, 2008, the PUC opened an investigative proceeding to examine the implementation of FITs. The utilities and Consumer Advocate were named as initial parties to the proceeding and almost twenty other parties were granted intervention. The procedural schedule for the proceeding includes final position statements by the parties at the end of March 2009, and panel hearings during the week of April 13, 2009. On December 11, 2008, the PUC issued a scoping paper prepared by its consultant that specified certain issues and questions for the parties to address and for the utilities and the Consumer Advocate to consider in a joint FIT proposal. On December 23, 2008, the utilities and the Consumer Advocate filed a joint proposal on FITs that called for the establishment of simple, streamlined and broad standard payment rates, which can be offered to as many renewable technologies as feasible. It proposed that the initial FIT be focused on photovoltaics (PV), concentrated solar power (CSP), in-line hydropower and wind, with individual project sizes targeted to provide a greater likelihood of more straightforward interconnection, project implementation and use of standardized energy rates and power purchase contracting. The FIT would be regularly reviewed to update tariff pricing to applicable technologies, project sizes and annual targets. An FIT update would be conducted for all islands in the utilities' service territory not later than two years after initial implementation of the FIT and every three years thereafter. The proposed initial target project sizes are:

- PV systems up to and including 500 kilowatts (kW) on Oahu, PV systems up to and including 250 kW on Maui and the island of Hawaii and PV systems up to and including 100 kW on Lanai and Molokai.
- CSP systems up to and including 500 kW on Oahu, Maui, and the island of Hawaii and up to and including 100 kW on Lanai and Molokai.
- In-line hydropower systems up to and including 100 kW on Oahu, Maui, Lanai, Molokai and the island of Hawaii.
- Wind power systems up to and including 100 kW on Oahu, Maui, Lanai, Molokai and the island of Hawaii.

The FIT joint proposal also recommended that no applications for new net energy metering contracts be accepted once the FIT is formally made available to customers (although existing net energy metering systems under contract would be grandfathered), and no applications for new Schedule Q contracts would be accepted once an FIT is formally made available for the resource type. Schedule Q would continue as an option for qualifying projects of 100 kW and less for which an FIT is not available.

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

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

In recognition of the need to recover the infrastructure and other investments required to support significantly increased levels of renewable energy and to eliminate the potential conflict between encouraging energy efficiency and conservation and lower sales revenues, the parties agree that it is appropriate to adopt a regulatory rate-making model, which is subject to PUC approval, under which HECO, HELCO and MECO revenues would be decoupled from KWH sales. If approved by the PUC, the new regulatory model, which is similar to the regulatory models currently used in California, would employ a revenue adjustment mechanism to track on an ongoing basis the differences between the amount of revenues allowed in the last rate case and (a) the current costs of providing electric service and (b) a reasonable return on and return of additional capital investment in the electric system. On October 24, 2008, the PUC opened an investigative proceeding to examine implementing a decoupling mechanism for the utilities. In addition to the utilities and the Consumer Advocate, there are six other parties in the proceeding. The utilities and the Consumer Advocate submitted separate proposals for consideration by the parties in January 2009. The schedule for the proceeding includes technical workshops on the proposals, final position statements of the parties to be submitted in May 2009, and panel hearings during the week of June 29, 2009.

The utilities would also continue to use existing PUC-approved tracking mechanisms for pension and other post-retirement benefits. The utilities would also be allowed an automatic revenue adjustment mechanism to reflect changes in state or federal tax rates. The PUC will be requested to incorporate implementation of the new regulatory model in the PUC's future interim decision and order (D&O) in HECO's 2009 test year rate case. The Energy Agreement also contemplates that additional rate cases based on a 2009 test year will be filed by HELCO and MECO in order to provide their respective baselines for implementation of the new regulatory model.

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

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

The Energy Agreement includes a number of other undertakings intended to accomplish the purposes and goals of the HCEI, subject to PUC approval and including, but not limited to: (a) promoting through specifically proposed steps greater use of solar energy through solar water heating, commercial and residential photovoltaic energy installations and concentrated solar power generation; (b) providing for the retirement or placement on reserve standby status of older and less efficient fossil fuel fired generating units as new, renewable generation is installed; (c) improving and expanding "load management" and "demand response" programs that allow the utilities to control customer loads to improve grid reliability and cost management; (d) the filing of PUC applications this year for approval of the installation of Advanced Metering Infrastructure, coupled with time-of-use or dynamic rate options for customers; (e) supporting prudent and cost effective investments in smart grid technologies, which become even more important as wind and solar generation is added to the grid; (f) including 10% of the energy purchased under FITs in each utility's respective rate base through January 2015; and (g) delinking prices paid under all new renewable energy contracts from oil prices.

**Interim increases.** On April 4, 2007, the PUC issued an interim D&O in HELCO's 2006 test year rate case granting a general rate increase on the island of Hawaii of 7.58%, or $25 million, which was implemented on April 5, 2007.

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

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

As of December 31, 2008, HECO and its subsidiaries had recognized $145 million of revenues with respect to interim orders ($5 million related to interim orders regarding certain integrated resource planning costs and $140 million related to interim orders regarding general rate increase requests). Revenue amounts recorded pursuant to interim orders are subject to refund, with interest, pending a final order.

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

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

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

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

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

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

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

**Major projects.** Many public utility projects require PUC approval and various permits from other governmental agencies. Difficulties in obtaining, or the inability to obtain, the necessary approvals or permits can result in significantly increased project costs or even cancellation of projects. Further, completion of projects is subject to various risks, such as problems or disputes with vendors. In the event a project does not proceed, or if the PUC disallows cost recovery for all or part of the project, project costs may need to be written off in amounts that could result in significant reductions in HECO's consolidated net income. Significant projects (with capitalized and deferred costs accumulated through December 31, 2008 noted in parentheses) include generating unit in and transmission line to Campbell Industrial Park ($96 million), HECO's East Oahu Transmission Project ($38 million), HELCO's ST-7 ($55 million) and a Customer Information system ($20 million).

*Campbell Industrial Park (CIP) generating unit.* HECO is building a new 110 MW simple-cycle combustion turbine (CT) generating unit at CIP and plans to add an additional 138 kilovolt transmission line to transmit power from generating units at CIP (including the new unit) to the rest of the Oahu electric grid (collectively, the Project). Plans are for the CT to be run primarily as a "peaking" unit beginning in mid-2009, fueled by biodiesel. On December 15, 2005, HECO signed a contract with Siemens to purchase a 110 MW CT unit.

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

In a related application filed with the PUC in June 2005, HECO requested approval of community benefit measures to mitigate the impact of the new generating unit on communities near the proposed generating unit site. In June 2007, the PUC issued a D&O which (1) approved HECO's request to commit funds for HECO's project to use recycled instead of potable water for industrial water consumption at the Kahe power plant, (2) approved HECO's request to commit funds for the environmental monitoring programs and (3) denied HECO's request to provide a base electric rate discount for HECO's residential customers who live near the proposed generation site. The approved measures are estimated to cost $9 million (through the first 10 years of implementation).

As of December 31, 2008, HECO's cost estimate for the Project (exclusive of the costs of the community benefit measures described above) was $186 million (of which $96 million had been incurred, including $4 million of AFUDC) and outstanding commitments for materials, equipment and outside services totaled $43 million. Management believes no adjustment to project costs is required as of December 31, 2008. However, if it becomes probable that the PUC will disallow some or all of the incurred costs for rate-making purposes, HECO may be required to write off a material portion or all of the project costs incurred in its efforts to put the project into service whether or not it is completed.

In August 2007, HECO entered into a contract with Imperium Services, LLC (Imperium), to supply biodiesel for the planned generating unit, subject to PUC approval. Imperium agreed to comply with HECO's procurement policy requiring sustainable sources of biofuel and biofuel feedstocks. In October 2007, HECO filed an application with the PUC for approval of this biodiesel supply contract. An evidentiary hearing on the application was held in October 2008. Due to deteriorating market conditions in the biodiesel industry, Imperium requested that HECO enter into negotiations to amend the original contract terms in order for Imperium to supply the biodiesel. In January 2009, HECO filed an amended biofuel supply contract with the PUC. In February 2009, HECO filed with the PUC a related terminalling and trucking agreement with Aloha Petroleum, Ltd. to support the delivery and storage of biodiesel from

Imperium. In February 2009, the PUC approved modifications to the procedural schedule for this proceeding, calling for a re-opening of the evidentiary hearing in March 2009.

*East Oahu Transmission Project (EOTP).* HECO had planned a project (EOTP) to construct a part underground 138 kilovolt (kV) line in order to close the gap between the southern and northern transmission corridors on Oahu and provide a third transmission line to a major substation. However, in 2002, an application for a permit, which would have allowed construction in a route through conservation district lands, was denied.

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

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

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

As of December 31, 2008, the accumulated costs recorded for the EOTP amounted to $38 million, including (i) $12 million of planning and permitting costs incurred prior to 2003, (ii) $8 million of planning, permitting and construction costs incurred after 2002 and (iii) $18 million for AFUDC. Management believes no adjustment to project costs is required as of December 31, 2008. However, if it becomes probable that the PUC will disallow some or all of the incurred costs for rate-making purposes, HECO may be required to write off a material portion or all of the project costs incurred in its efforts to put the project into service whether or not it is completed.

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

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

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

HELCO has completed engineering and design activities and construction work for ST-7 is progressing towards completion in mid-2009. As of December 31, 2008, HELCO's cost estimate for ST-7 was $92 million (of which

$55 million had been incurred) and outstanding commitments for materials, equipment and outside services totaled $28 million, a substantial portion of which are subject to cancellation charges.

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

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

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

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

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

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

**Environmental regulation.** HEI and its subsidiaries are subject to environmental laws and regulations that regulate the operation of existing facilities, the construction and operation of new facilities and the proper cleanup and disposal of hazardous waste and toxic substances.

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

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

*Honolulu Harbor investigation.* HECO has been involved since 1995 in a work group with several other potentially responsible parties (PRPs) identified by the DOH, including oil companies, in investigating and responding to historical subsurface petroleum contamination in the Honolulu Harbor area. The U.S. Environmental Protection Agency (EPA) became involved in the investigation in June 2000. Some of the PRPs (the Participating Parties) entered into a joint defense agreement and ultimately entered an Enforceable Agreement with the DOH. The Participating Parties are funding the investigative and remediation work using an interim cost allocation method (subject to a final allocation) and have organized a limited liability company to perform the work. Although the Honolulu Harbor investigation involves four units—Iwilei, Downtown, Kapalama and Sand Island, to date all the investigative and remedial work has focused on the Iwilei Unit.

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

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

Through December 31, 2008, HECO has accrued a total of $3.3 million (including $0.4 million in the first quarter of 2008) for estimates of HECO's share of costs for continuing investigative work, remedial activities and monitoring for the Iwilei unit. As of December 31, 2008, the remaining accrual (amounts expensed less amounts expended) for the Iwilei unit was $1.8 million. Because (1) the full scope of work remains to be determined, (2) the final cost allocation method among the PRPs has not yet been established and (3) management cannot estimate the costs to be incurred (if any) for the sites other than the Iwilei unit (such as its Honolulu power plant located in the Downtown unit of the Honolulu Harbor site), the cost estimate may be subject to significant change and additional material costs may be incurred.

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

*Hazardous Air Pollutant (HAP) Control*. In February 2008, the federal Circuit Court of Appeals for the District of Columbia vacated the EPA's Delisting Rule, which had removed coal- and oil-fired electric generating units (EGUs) from the list of sources requiring control under Section 112 of the Clean Air Act. The EPA's request for a rehearing was denied. The EPA is thus required to develop Maximum Achievable Control Technology (MACT) standards for oil-fired EGU HAP emissions, including nickel compounds. Depending on the MACT standards developed (and the success of a potential challenge, after the MACT standards are issued, that the EPA inappropriately listed oil-fired EGUs initially), costs to comply with the standards could be significant. The Company is currently evaluating its options regarding potential MACT standards for applicable HECO steam units.

In October 2008, the EPA petitioned the U.S. Supreme Court to review the decision of the Circuit Court of Appeals for the District of Columbia vacating the EPA's Delisting Rule. Also, an industry group is seeking review of the Delisting Rule decision. On February 6, 2009, the EPA filed a motion with the Supreme Court to withdraw its petition for review. In the motion, the EPA indicated that it would begin rulemaking to establish MACT standards for EGUs. Management cannot predict if the Supreme Court will grant the industry petitioners' request for review and is evaluating options available regarding the rulemaking if the Supreme Court rejects industry petitioners' request for review or upholds the Court of Appeals decision.

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

In January 2007, the U.S. Circuit Court of Appeals for the Second Circuit issued a decision that remanded for further consideration and proceedings significant portions of the rule and found other portions to be impermissible. In July 2007, the EPA formally suspended the rule and provided guidance to federal and state permit writers that they should use their "best professional judgment" in determining permit conditions regarding cooling water intake requirements at existing power plants. HECO facilities are subject to permit renewal in mid-2009 and may be subject to new permit conditions to address cooling water intake requirements at that time. In April 2008, the U.S. Supreme

Court agreed to review the Court of Appeal's rejection of a cost-benefit test to determine compliance options. The Supreme Court heard the case in December 2008 and a decision is anticipated in the first half of 2009. If the Supreme Court affirms the Court of Appeal's decision, the compliance options available to HECO are reduced. Due to the uncertainties regarding the Court of Appeal's decision, management is unable to predict which compliance options, some of which could entail significant capital expenditures to implement, will be applicable to its facilities.

**Collective bargaining agreements.** As of December 31, 2008, approximately 57% of the electric utilities' employees were members of the International Brotherhood of Electrical Workers, AFL-CIO, Local 1260, Unit 8, which is the only union representing employees of the Company. On March 1, 2008, members of the union ratified new collective bargaining and benefit agreements with HECO, HELCO and MECO. The new agreements cover a three-year term, from November 1, 2007 to October 31, 2010, and provide for non-compounded wage increases of 3.5% effective November 1, 2007, 4% effective January 1, 2009 and 4.5% effective January 1, 2010.

**Limited insurance.** HECO and its subsidiaries purchase insurance to protect themselves against loss or damage to their properties against claims made by third-parties and employees. However, the protection provided by such insurance is limited in significant respects and, in some instances, there is no coverage. HECO, HELCO and MECO's overhead and underground transmission and distribution systems (with the exception of substation buildings and contents) have a replacement value roughly estimated at $4 billion and are uninsured. Similarly, HECO, HELCO and MECO have no business interruption insurance. If a hurricane or other uninsured catastrophic natural disaster were to occur, and if the PUC were not to allow the utilities to recover from ratepayers restoration costs and revenues lost from business interruption, their results of operations and financial condition could be materially adversely impacted. Also, certain insurance has substantial "deductibles", limits on the maximum amounts that may be recovered and exclusions or limitations of coverage for claims related to certain perils. If a series of losses occurred, such as from a series of lawsuits in the ordinary course of business, each of which were subject to the deductible amount, or if the maximum limit of the available insurance were substantially exceeded, HECO, HELCO and MECO could incur losses in amounts that would have a material adverse effect on its results of operations and financial condition.

## Selected financial information

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

### Consolidated Statements of Income Data

| Years ended December 31<br>(in thousands) | 2008 | 2007 | 2006 |
|---|---|---|---|
| **Interest and dividend income** | | | |
| Interest and fees on loans | $247,210 | $245,593 | $231,610 |
| Interest and dividends on investment and mortgage-related securities | 65,208 | 111,470 | 117,160 |
| | 312,418 | 357,063 | 348,770 |
| **Interest expense** | | | |
| Interest on deposit liabilities | 61,483 | 81,879 | 73,614 |
| Interest on other borrowings | 43,941 | 78,019 | 72,482 |
| | 105,424 | 159,898 | 146,096 |
| **Net interest income** | **206,994** | **197,165** | **202,674** |
| Provision for loan losses | 10,334 | 5,700 | 1,400 |
| **Net interest income after provision for loan losses** | **196,660** | **191,465** | **201,274** |
| **Noninterest income** | | | |
| Fees from other financial services | 24,846 | 27,916 | 26,385 |
| Fee income on deposit liabilities | 28,332 | 26,342 | 18,779 |
| Fee income on other financial products | 6,683 | 7,418 | 8,025 |
| Gain (loss) on sale of securities | (17,376) | 1,109 | 1,735 |
| Loss on investments | (7,764) | – | – |
| Other income | 11,414 | 5,647 | 4,671 |
| | 46,135 | 68,432 | 59,595 |
| **Noninterest expense** | | | |
| Compensation and employee benefits | 77,858 | 61,937 | 68,478 |
| Occupancy | 21,890 | 21,051 | 18,829 |
| Equipment | 12,544 | 14,417 | 14,700 |
| Services | 16,706 | 29,173 | 21,484 |
| Data processing | 10,678 | 10,458 | 10,164 |
| Marketing | 4,007 | 4,245 | 5,199 |
| Office supplies, printing and postage | 4,243 | 4,586 | 4,055 |
| Communication | 3,241 | 3,740 | 3,335 |
| Loss on early extinguishment of debt | 39,843 | – | – |
| Other expense | 24,994 | 26,301 | 26,067 |
| | 216,004 | 175,908 | 172,311 |
| **Income before income taxes** | **26,791** | **83,989** | **88,558** |
| Income taxes | 8,964 | 30,882 | 32,776 |
| **Net income** | **$ 17,827** | **$ 53,107** | **$ 55,782** |

## Consolidated Balance Sheet Data

| December 31 | 2008 | 2007 |
|---|---|---|
| (in thousands) | | |
| **Assets** | | |
| Cash and equivalents | $ 168,766 | $ 140,023 |
| Federal funds sold | 532 | 64,000 |
| Available-for-sale investment and mortgage-related securities | 657,717 | 2,140,772 |
| Investment in stock of Federal Home Loan Bank of Seattle | 97,764 | 97,764 |
| Loans receivable, net | 4,206,492 | 4,101,193 |
| Other | 223,659 | 234,661 |
| Goodwill, net | 82,190 | 83,080 |
| | $5,437,120 | $6,861,493 |
| **Liabilities and stockholder's equity** | | |
| Deposit liabilities–noninterest-bearing | $ 701,090 | $ 652,055 |
| Deposit liabilities–interest-bearing | 3,479,085 | 3,695,205 |
| Other borrowings | 680,973 | 1,810,669 |
| Other | 98,598 | 108,800 |
| | 4,959,746 | 6,266,729 |
| Common stock | 328,162 | 325,467 |
| Retained earnings | 197,235 | 287,710 |
| Accumulated other comprehensive loss, net of tax benefits | (48,023) | (18,413) |
| | 477,374 | 594,764 |
| | $5,437,120 | $6,861,493 |

***Balance sheet restructure.*** In June 2008, ASB undertook and substantially completed a restructuring of its balance sheet through the sale of mortgage-related securities and agency notes and the early extinguishment of certain borrowings to strengthen future profitability ratios and enhance future net interest margin, while remaining "well-capitalized" and without significantly impacting future net income and interest rate risk. On June 25, 2008, ASB completed a series of transactions which resulted in the sales to various broker/dealers of available-for-sale agency and private-issue mortgage-related securities and agency notes with a weighted average yield of 4.33% for approximately $1.3 billion. ASB used the proceeds from the sales of these mortgage-related securities and agency notes to retire debt with a weighted average cost of 4.70%, comprised of approximately $0.9 billion of FHLB advances and $0.3 billion of securities sold under agreements to repurchase. These transactions resulted in a charge to net income of $35.6 million in the second quarter of 2008. The $35.6 million is comprised of: (1) realized losses on the sale of mortgage-related securities and agency notes of $19.3 million included in "Noninterest income-Gain (loss) on sale of securities," (2) fees associated with the early retirement of other bank borrowings of $39.8 million included in "Noninterest expense-Loss on early extinguishment of debt" and (3) income tax benefits of $23.5 million included in "Income taxes." Although the sales of the mortgage-related securities and agency notes resulted in realized losses in the second quarter of 2008, a portion of the losses on these available-for-sale securities had been previously recognized as unrealized losses in ASB's equity as a result of mark-to-market charges to other comprehensive income in earlier periods.

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

As a result of this balance sheet restructuring, ASB freed up capital and planned to dividend up to approximately $75 million over the next several quarters in 2008 and 2009, subject to OTS approval. In the third quarter of 2008, ASB received OTS approval to pay and paid a dividend to HEI (through ASB's direct parent, HEI Diversified, Inc.) of $54.7 million. ASB represented to the OTS that the dividend would be paid only to the extent that its payment would not cause its Tier I leverage ratio to fall below 8%. 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), private-issue mortgage-related securities and mortgage-related securities issued by the Federal National Mortgage Association (FNMA), Federal Home Loan Mortgage Corporation (FHLMC) and Government National Mortgage Association (GNMA). As of December 31, 2008, ASB's available-for-sale federal agency obligations with a carrying value of $60 million had a contractual maturity date in 2009. 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.

As of December 31, 2008, ASB's investment portfolio distribution was 9% federal agency obligations, 46% mortgage-related securities issued by FNMA, FHLMC or GNMA, and 45% private-issue mortgage-related securities. The table below summarizes the private-issue mortgage-related securities by credit rating and year of issuance.

December 31, 2008

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

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

2 Includes one issue rated "Aa2" by Moody's, with a realized other-than-temporary impairment loss of $0.2 million based on ASB's third-party pricing source.

3 Includes one issue rated "B" by S&P, with a realized other-than-temporary impairment loss of $7.6 million based on ASB's third-party pricing source.

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.

A continued decline in housing prices, combined with a prolonged economic downturn, could erode credit support of private-issue mortgage-related securities and result in additional realized and unrealized losses in ASB's portfolio, and these losses could be material.

December 31, 2008

| | | | | | Gross unrealized losses | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Less than 12 months | | | 12 months or longer | | |
| (dollars in thousands) | Amortized cost | Gross unrealized gains | Gross unrealized losses | Estimated fair value | Count | Fair Value | Amount | Count | Fair Value | Amount |
| **Available-for-sale** | | | | | | | | | | |
| Investment securities-federal agency obligation | $ 59,939 | $ 61 | $ – | $ 60,000 | – | $ – | $ – | – | $ – | $ – |
| Mortgage-related securities: | | | | | | | | | | |
| FNMA, FHLMC and GNMA | 301,106 | 4,420 | 119 | 305,407 | 5 | 1,352 | (23) | 4 | 15,266 | (96) |
| Private issue | 351,504 | 20 | 59,214 | 292,310 | 12 | 66,947 | (24,227) | 35 | 224,662 | (34,987) |
| | $712,549 | $4,501 | $59,333 | $657,717 | 17 | $68,299 | $(24,250) | 39 | $239,928 | $(35,083) |

December 31, 2007

| | | | | | Gross unrealized losses | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Less than 12 months | | | 12 months or longer | | |
| (dollars in thousands) | Amortized cost | Gross unrealized gains | Gross unrealized losses | Estimated fair value | Count | Fair Value | Amount | Count | Fair Value | Amount |
| **Available-for-sale** | | | | | | | | | | |
| Investment securities-federal agency obligation | $ 59,990 | $ 45 | $ (7) | $ 60,028 | – | $ – | $ – | 1 | $ 24,983 | $ (7) |
| Mortgage-related securities: | | | | | | | | | | |
| FNMA, FHLMC and GNMA | 1,554,201 | 1,943 | (22,155) | 1,533,989 | 18 | 81,200 | (186) | 166 | 1,133,457 | (21,969) |
| Private issue | 556,537 | 593 | (10,375) | 546,755 | 23 | 227,411 | (3,513) | 29 | 267,498 | (6,862) |
| | $2,170,728 | $2,581 | $(32,537) | $2,140,772 | 41 | $308,611 | $(3,699) | 196 | $1,425,938 | $(28,838) |

December 31, 2006

| | | | | | Gross unrealized losses | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| | | | | | Less than 12 months | | | 12 months or longer | | |
| (dollars in thousands) | Amortized Cost | Gross unrealized gains | Gross unrealized losses | Estimated fair value | Count | Fair Value | Amount | Count | Fair Value | Amount |
| **Available-for-sale** | | | | | | | | | | |
| Investment securities-federal agency obligations | $ 149,978 | $ – | $ (654) | $ 149,324 | 5 | $ 124,842 | $(158) | 1 | $ 24,482 | $ (496) |
| Mortgage-related securities: | | | | | | | | | | |
| FNMA, FHLMC and GNMA | 1,754,154 | 505 | (51,854) | 1,702,805 | 4 | 4,534 | (22) | 206 | 1,654,550 | (51,832) |
| Private issue | 522,173 | 339 | (7,214) | 515,298 | 8 | 102,155 | (726) | 26 | 313,879 | (6,488) |
| | $2,426,305 | $844 | $(59,722) | $2,367,427 | 17 | $231,531 | $(906) | 233 | $1,992,911 | $(58,816) |

**Federal agency mortgage-related securities**. The unrealized losses on ASB's investment in federal agency mortgage-backed securities were primarily caused by higher interest rates. The higher interest rate environment coupled with wider spreads on all mortgage collateralized securities caused the market value of the securities held to fall below the carrying book value. All contractual cash flows of those investments are guaranteed by an agency of the U.S. government and accordingly it is expected that the securities would not be settled at a price less than the amortized cost of the investment. Because the decline in market value is attributable to changes in interest rates and not the credit quality and because ASB has the ability and intent to hold those investments until a recovery of fair value, which may be maturity, ASB does not consider those investments to be other-than-temporarily impaired at December 31, 2008.

**Private-issue mortgage-related securities**. The unrealized losses on ASB's investment in private-issue mortgage-related securities is due to multiple factors primarily related to continued deterioration in the residential housing market and spread widening for all credit sensitive sectors of the market. Increasing foreclosures coupled with recessionary employment pressures and declining housing prices have depressed the values of all private-issue mortgage collateralized securities as risks for this sector have increased. Changes in credit rating for issues originated in 2006 and 2007 have dramatically depressed valuations in this sector of the portfolio. While risks within this sector have increased, ASB believes that, based on its internal assessment of positions held in the portfolio, it is probable that ASB will be able to collect all scheduled cash flows due according to the contractual terms of the investment. Therefore, it is expected that the debentures would not be settled at a price less than the amortized cost of the investment. Because ASB has the ability and intent to hold this investment until a recovery of fair value, which may be at maturity, it does not consider investments held in this sector to be other-than-temporarily impaired at December 31, 2008.

Consistent with disclosure requirements outlined in FSP FAS 115-1 and 124-1, ASB has identified four positions with material unrealized losses currently held in the securities portfolio. All four positions are 2006 vintages and are backed by 30-year fixed collateral and the securities were individually determined to not be other than temporarily impaired. Management's determination of future cash flows includes, but is not limited to, the following:

- The first position has a book value of $15.7 million and an unrealized loss of $6.0 million. Collateral performance has not been favorable as delinquencies have increased to levels higher than that of similar type and vintage. Despite poor performance of the position to date, lower than average Loan to Values (LTV) ratios, high loan balances and the historical experience of the pool do not support loss severities which would result in probable loss expectations by management. Third-party analysis validates internal expectations of receipt of all scheduled cash flows expected at time of purchase.
- The second position has a book value of $14.3 million with an unrealized loss of $5.9 million. While collateral performance to date has been better than comparable vintages, because the position is backed by Alt-A mortgages absolute performance has been somewhat problematic. Despite the position's high concentration of low documentation loans, mitigating collateral characteristics such as lower LTVs, higher FICOs and overall loss performance supports more favorable performance expectations relative to other fixed Alt-A positions of similar vintages. Based upon management's assumptions, internal cash flow scenarios support continued expectations that ASB will receive all scheduled distributions.
- The third position has a book value of $16.5 million with an unrealized loss of $5.9 million. Collateral performance to date has been unfavorable as delinquencies are running ahead of comparable vintages and management's original expectations. Lower geographic exposure to California coupled with collateral characteristics similar to that of comparable vintages supports management's model assumptions. Using these assumptions, ASB's tranche's level of credit support is sufficient to cover any losses that management is expecting the position to experience.
- The fourth position has a book value of $17.3 million with an unrealized loss of $4.4 million. Delinquencies have been trending in line with comparable prime vintages. Lower LTVs and investment property percentages, and higher levels of full documentation loans support baseline assumptions which do not result in a loss. Based on this analysis, internal cash flows analysis supports management's assumption that ASB will receive all of the cash flows expected at the time of purchase.

As of December 31, 2008, 2007 and 2006, 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 stock of the FHLB of Seattle for impairment and adjusts the carrying value if the investment is determined to be impaired.

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 2008, 2007 and 2006, proceeds from sales of available-for-sale mortgage-related securities were $1.2 billion, nil and $61 million, resulting in gross realized gains of $0.6 million, nil and $1.8 million and gross realized losses of $19.8 million, nil and $0.1 million, respectively.

ASB pledged mortgage-related securities with a carrying value of approximately $221 million and $727 million as of December 31, 2008 and 2007, respectively, as collateral to secure advances from the FHLB, secure discount window borrowings from the Federal Reserve Bank of San Francisco, collateralize public funds deposits, collateralize automated clearinghouse (ACH) transactions with Bank of Hawaii, and collateralize deposits in the Bank's bankruptcy and treasury, tax, and loan accounts with the Federal Reserve Bank of San Francisco. As of December 31, 2008 and 2007, mortgage-related securities with a carrying value of $274 million and $900 million, respectively, were pledged as collateral for securities sold under agreements to repurchase.

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

***Loans receivable***

| December 31 | 2008 | 2007 |
|---|---|---|
| (in thousands) | | |
| Real estate loans | | |
| One-to-four unit residential and commercial | $3,200,339 | $3,337,237 |
| Construction and development | 152,446 | 137,451 |
| | 3,352,785 | 3,474,688 |
| Consumer loans | 344,305 | 265,989 |
| Commercial loans | 597,233 | 471,576 |
| | 4,294,323 | 4,212,253 |
| Undisbursed portion of loans in process | (64,189) | (71,272) |
| Deferred fees and discounts, including net purchase accounting discounts | (24,631) | (26,192) |
| Allowance for loan losses | (35,798) | (30,211) |
| Loans held for investment | 4,169,705 | 4,084,578 |
| Loans held for sale | 36,787 | 16,615 |
| | $4,206,492 | $4,101,193 |

As of December 31, 2008, ASB had impaired loans totaling $51.0 million, which consisted of $19.2 million of commercial real estate loans, $27.8 million of commercial loans and $4.0 million of residential real estate loans. As of December 31, 2007, ASB had impaired loans totaling $26.5 million, which consisted of $4.6 million of commercial real estate loans and $21.9 million of commercial loans. As of December 31, 2008 and 2007, impaired loans totaling $12.8 million and $0.1 million, respectively, had related allowances for loan losses of $4.4 million and $0.01 million, respectively. As of December 31, 2008 and 2007, ASB had $38.2 million and $26.4 million of impaired loans, respectively, for which there were no related allowances for loan losses. ASB realized $3.0 million, $2.0 million and $1.9 million of interest income on impaired loans in 2008, 2007 and 2006, respectively. The average balances of impaired loans during 2008, 2007 and 2006 were $45.0 million, $25.5 million and $22.0 million, respectively.

As of December 31, 2008 and 2007, ASB had nonaccrual and renegotiated loans of $28.1 million and $6.3 million, respectively.

ASB had no loans that were 90 days or more past due on which interest was being accrued as of December 31, 2008 and 2007.

As of December 31, 2008 and 2007, commitments not reflected in the consolidated balance sheets consisted of commitments to originate loans, other than the undisbursed portion of loans in process, of $21 million and $94 million, respectively. 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, 2008 and 2007, ASB had commitments to sell residential loans of $84 million and $11.3 million, respectively. The loans are included in loans 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, 2008 and 2007, rate lock commitments were made on loans totaling $65.1 million and $6.7 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, 2008 and 2007, the notional amounts for forward sales contracts were $84.0 million and $11.3 million, respectively. Valuation models are applied using current market information to estimate fair value. For 2008 and 2007, the net gain on derivatives was $0.3 million and the net loss on derivatives was $49,000, respectively.

As of December 31, 2008 and 2007, ASB had commitments to sell education loans of $18 million and $12 million, respectively.

As of December 31, 2008 and 2007, standby, commercial and banker's acceptance letters of credit totaled $19 million and $29 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, 2008 and 2007, unused lines of credit and undrawn commercial loans totaled $1.1 billion and $1.0 billion, respectively.

ASB services real estate loans owned by third parties ($0.3 billion as of December 31, 2008, 2007 and 2006), 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, 2008 and 2007, ASB had pledged loans with an amortized cost of approximately $1.9 billion and $1.7 billion, respectively, as collateral to secure advances from the FHLB of Seattle.

As of December 31, 2008 and 2007, 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 $88 million and $93 million, respectively. The $5 million decrease in such loans in 2008 was attributed to closed lines of credit and repayments of $66 million, offset by loans and lines of credit to new and existing directors and executive officers of $61 million. As of December 31, 2008 and 2007, $72 million and $69 million of the loan balances, respectively, were to related interests of individuals who are directors of ASB. All such loans were made at ASB's normal credit terms except that residential real estate loans and consumer loans to directors and executive officers of ASB were made at preferred employee interest rates. Management believes these loans do not represent more than a normal risk of collection.

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

| (dollars in thousands) | 2008 | 2007 | 2006 |
|---|---|---|---|
| Allowance for loan losses, January 1 | $30,211 | $31,228 | $30,595 |
| Provision for loan losses | 10,334 | 5,700 | 1,400 |
| **Charge-offs, net of recoveries** | | | |
| Real estate loans | 287 | (68) | (200) |
| Other loans | 4,460 | 6,785 | 967 |
| Net charge-offs | 4,747 | 6,717 | 767 |
| Allowance for loan losses, December 31 | $35,798 | $30,211 | $31,228 |
| Ratio of net charge-offs to average loans outstanding | 0.11% | 0.17% | 0.02% |

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

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

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

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

**Assets measured at fair value on a recurring basis**

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

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

| | | Fair value measurements using | | |
|---|---|---|---|---|
| (in millions) | December 31, 2008 | Quoted prices in active markets for identical assets (Level 1) | Significant other observable inputs (Level 2) | Significant unobservable inputs (Level 3) |
| Available-for-sale securities | $658 | $ – | $658 | $ – |

**Assets measured at fair value on a nonrecurring basis**

*Loans*. ASB does not record loans at fair value on a recurring basis. However, from time to time, ASB records nonrecurring fair value adjustments to loans to reflect specific reserves on loans based on the current appraised value of the collateral or unobservable market assumptions. These adjustments to fair value usually result from the application of lower-of-cost-or-market accounting or write-downs of individual loans. Unobservable assumptions reflect ASB's own estimate of the fair value of collateral used in valuing the loan.

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

| | | Fair value measurements using | | |
|---|---|---|---|---|
| (in millions) | December 31, 2008 | Quoted prices in active markets for identical assets (Level 1) | Significant other observable inputs (Level 2) | Significant unobservable inputs (Level 3) |
| Loans | $8.4 | $ – | $ 3.5 | $4.9 |

Specific reserves as of December 31, 2008 were $4.4 million and were included in loans receivable held for investment, net. For 2008, there were no adjustments to fair value for ASB's loans held for sale.

***Deposit liabilities***

| December 31 | 2008 | | 2007 | |
|---|---|---|---|---|
| (dollars in thousands) | Weighted-average stated rate | Amount | Weighted-average stated rate | Amount |
| Savings | 0.52% | $1,382,796 | 0.74% | $1,401,866 |
| Other checking | | | | |
| Interest-bearing | 0.66 | 558,629 | 0.36 | 514,179 |
| Noninterest-bearing | – | 373,513 | – | 345,515 |
| Commercial checking | – | 327,577 | – | 306,540 |
| Money market | 0.59 | 148,255 | 1.88 | 174,844 |
| Term certificates | 2.92 | 1,389,405 | 3.89 | 1,604,316 |
| | 1.25% | $4,180,175 | 1.79% | $4,347,260 |

As of December 31, 2008 and 2007, certificate accounts of $100,000 or more totaled $407 million and $524 million, respectively.

The approximate amounts of term certificates outstanding as of December 31, 2008 with scheduled maturities for 2009 through 2013 were $1,142 million in 2009, $172 million in 2010, $47 million in 2011, $7 million in 2012 and $6 million in 2013.

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

| (in thousands) | 2008 | 2007 | 2006 |
|---|---|---|---|
| Term certificates | $49,530 | $65,074 | $55,466 |
| Savings | 8,577 | 11,170 | 13,316 |
| Money market | 1,793 | 4,094 | 3,829 |
| Interest-bearing checking | 1,583 | 1,541 | 1,003 |
| | $61,483 | $81,879 | $73,614 |

*Other borrowings*

**Securities sold under agreements to repurchase.**

| December 31, 2008<br>Maturity | Repurchase liability | Weighted-average interest rate | Collateralized by mortgage-related securities–fair value plus accrued interest |
|---|---|---|---|
| (dollars in thousands) | | | |
| Overnight | $186,159 | 0.99% | $212,164 |
| 1 to 29 days | – | – | – |
| 30 to 90 days | 4,967 | 5.43 | 6,000 |
| Over 90 days | 50,297 | 4.75 | 56,728 |
| | $241,423 | 1.86% | $274,892 |

At December 31, 2008, $50 million of securities sold under agreement to repurchase with a weighted average rate of 4.75% and maturity date over 90 days is callable quarterly at par until maturity.

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

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

| (dollars in millions) | 2008 | 2007 | 2006 |
|---|---|---|---|
| Amount outstanding as of December 31 | $241 | $765 | $839 |
| Average amount outstanding during the year | $507 | $887 | $771 |
| Maximum amount outstanding as of any month-end | $817 | $979 | $839 |
| Weighted-average interest rate as of December 31 | 1.86% | 3.92% | 4.22% |
| Weighted-average interest rate during the year | 2.98% | 4.22% | 4.21% |
| Weighted-average remaining days to maturity as of December 31 | 601 | 1,318 | 1,047 |

**Advances from Federal Home Loan Bank.**

| December 31, 2008 | Weighted-average stated rate | Amount |
|---|---|---|
| (dollars in thousands) | | |
| Due in | | |
| 2009 | 2.20% | $289,550 |
| 2010 | 2.64 | 40,000 |
| 2011 | 2.38 | 45,000 |
| 2012 | 2.94 | 15,000 |
| 2013 | – | – |
| Thereafter | 4.28 | 50,000 |
| | 2.52% | $439,550 |

At December 31, 2008, $50 million of fixed rate FHLB advances with a rate of 4.28% is callable quarterly at par beginning in 2009 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, 2007 and 2006.

***Common stock equity.*** In 1988, HEI agreed with the OTS predecessor regulatory agency that it would contribute additional capital to ASB up to a maximum aggregate amount of approximately $65 million (Capital Maintenance Agreement). As of December 31, 2008, as a result of capital contributions in prior years, HEI's maximum obligation to contribute additional capital under the agreement had been reduced to approximately $28.3 million. As of December 31, 2008, ASB was in compliance with the minimum capital requirements under OTS regulations.

The $30 million increase in accumulated other comprehensive loss from December 31, 2007 to December 31, 2008 was primarily due to the decrease in the market value of the available-for-sale investment and mortgage-related securities and changes in ASB's defined benefit pension plan. Changes in the market value of investment or mortgage-related securities do not result in a charge to net income in the absence of an "other-than-temporary" impairment in the value of the securities.

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

***Regulatory compliance.*** ASB is subject to a range of bank regulatory compliance obligations. In connection with ASB's review of internal compliance processes and OTS examinations, certain compliance deficiencies were identified in prior years. ASB has and continues to take steps to remediate these deficiencies and to strengthen ASB's overall compliance programs. ASB agreed to a consent order (Order) issued by the OTS on January 23, 2008 as a result of issues relating to ASB's compliance with certain laws and regulations, including the Bank Secrecy Act and Anti-Money Laundering (BSA/AML). The Order did not impose restrictions on ASB's business activities; however it required, among other things, various actions by ASB to strengthen its BSA/AML Program and Compliance Management Program. ASB implemented several initiatives to enhance its BSA/AML Program and Compliance Management Program that address the requirements of the Order. In December 2008, the OTS lifted the Order.

ASB also consented to the concurrent issuance of an order by the OTS for the assessment of a civil money penalty of $37,730 related to non-compliance with certain flood insurance laws and regulations and paid the penalty in January 2008.

***FDIC restoration plan.*** Under the Federal Deposit Insurance Reform Act of 2005 (the Reform Act), the FDIC may set the designated reserve ratio within a range of 1.15% to 1.50%. The Reform Act requires that the FDIC's Board of Directors adopt a restoration plan when the Deposit Insurance Fund (DIF) reserve ratio falls below 1.15% or is expected to within six months. Recent financial institution failures have significantly increased the DIF's loss provisions, resulting in a decline in the reserve ratio. As of June 30, 2008, the reserve ratio had fallen 18 basis points since the previous quarter to 1.01%. To restore the reserve ratio to 1.15%, higher assessment rates are required. The FDIC is proposing changes to the assessment system to ensure that riskier institutions will bear a greater share of the proposed increase in assessments. Under the proposed rules, financial institutions in Risk Category I, the lowest risk group, will have an initial base assessment rate within the range of 10 to 14 basis points. After applying adjustments for unsecured debt, secured liabilities and brokered deposits, the total base assessment rate for financial institutions in Risk Category I would be within the range of 8 to 21 basis points. The FDIC recommends the proposed rates become effective April 1, 2009. The FDIC also recommends raising the current rates uniformly by seven basis points for the assessment for the quarter beginning January 1, 2009. ASB is classified in Risk Category I and anticipates its assessment rate to be 12.5 basis points for the quarter beginning January 1, 2009 decreasing to 10 to 11 basis points for the quarter beginning April 1, 2009. Currently, ASB's assessment is 5.5 basis points of deposits, or $0.6 million for the quarter ended December 31, 2008.

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

***Capital Purchase Program.*** On October 14, 2008, President Bush's Working Group on Financial Markets announced a voluntary Capital Purchase Program (CPP) to encourage U.S. financial institutions to build capital to increase the flow of financing to U.S. businesses and consumers and to support the U.S. economy.

Under the CPP, the U.S. Treasury (Treasury) will purchase non-voting senior preferred securities from qualifying U.S.-controlled banks and thrifts and bank and thrift holding companies. The senior preferred securities will pay cumulative dividends at a rate of 5% per annum for the first five years and a rate of 9% thereafter. In conjunction with the purchase of the senior preferred securities, the Treasury will receive 10-year warrants to purchase common stock of the qualifying institution with an aggregate market price equal to 15% of the amount of the senior preferred investment, with an exercise price equal to the market price of the issuer's common stock at the time of issuance, calculated on a 20 trading day trailing average. Financial institutions participating in the program must also adopt the Treasury's standards for executive compensation and corporate governance, for the period during which the Treasury holds equity issued under the program. Financial institutions must submit their application to participate in the program by November 14, 2008. ASB has applied to participate in the program.

***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 MECO and HELCO in the respective principal amounts of $10 million, (iii) making distributions on the trust securities and (iv) engaging in only those other activities necessary or incidental thereto. The 2004 Trust Preferred Securities are mandatorily redeemable at the maturity of the underlying debt on March 18, 2034, which maturity may be extended to no later than March 18, 2053; and are redeemable at the issuer's option without premium beginning on March 18, 2009. The 2004 Debentures, together with the obligations of HECO, HELCO and MECO under an expense agreement and HECO's obligations under its trust guarantee and its guarantee of the obligations of HELCO and MECO under their respective debentures, are the sole assets of Trust III. Trust III has at all times been an unconsolidated subsidiary of HECO. Since HECO, as the common security holder, does not absorb the majority of the variability of Trust III, HECO is not the primary beneficiary and does not consolidate Trust III in accordance with FIN 46R. Trust III's balance sheet as of December 31, 2008 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 2008 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, 2008, HECO and its subsidiaries had six PPAs for a total of 540 MW of firm capacity, and other PPAs with smaller IPPs and Schedule Q providers (i.e., customers with cogeneration and/or small power production facilities with a capacity of 100 kW or less who buy power from or sell power to the utilities) that supplied as-available energy. Approximately 91% of the 540 MW of firm capacity is under PPAs, entered into before December 31, 2003, with AES Hawaii, Inc. (AES Hawaii), Kalaeloa Partners, L.P. (Kalaeloa), Hamakua Energy Partners, L.P. (HEP) and HPOWER. Purchases from all IPPs for 2008 totaled $690 million, with purchases from AES Hawaii, Kalaeloa, HEP and HPOWER totaling $141 million, $273 million, $92 million and $60 million, respectively. The primary business activities of these IPPs are the generation and sale of power to HECO and its subsidiaries (and municipal waste disposal in the case of HPOWER). Current financial information about the size, including total assets and revenues, for many of these IPPs is not publicly available.

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

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

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

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

**Kalaeloa Partners, L.P.** In October 1988, HECO entered into a PPA with Kalaeloa, subsequently approved by the PUC, which provided that HECO would purchase 180 MW of firm capacity for a period of 25 years beginning in May 1991. In October 2004, HECO and Kalaeloa entered into amendments to the PPA, subsequently approved by the PUC, which together effectively increased the firm capacity from 180 MW to 208 MW. The energy payments that HECO makes to Kalaeloa include: 1) a fuel component, with a fuel price adjustment based on the cost of low sulfur fuel oil, 2) a fuel additives cost component, and 3) a non-fuel component, with an adjustment based on changes in the Gross National Product Implicit Price Deflator. The capacity payments that HECO makes to Kalaeloa are fixed in accordance with the PPA. Kalaeloa also has a steam delivery cogeneration contract with another customer, the term of which coincides with the PPA. The facility has been certified by the Federal Energy Regulatory Commission as a Qualifying Facility under the Public Utility Regulatory Policies Act of 1978.

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

No commercial paper was outstanding at December 31, 2008. As of December 31, 2007, commercial paper issued by HEI and HECO had a weighted-average interest rate of 5.64%.

As of December 31, 2008 and 2007, HEI maintained a syndicated credit facility which totaled $100 million while HECO maintained two syndicated credit facilities which totaled $250 million and $175 million, respectively. HEI borrowed under its facility in September and October 2008; all such borrowings were repaid in November and December 2008. HEI had no borrowings under its facility during 2007. HECO had no borrowings under its facilities during 2008 or 2007. None of the facilities are secured.

***Credit agreements.*** Effective April 3, 2006, HEI entered into a revolving unsecured credit agreement establishing a line of credit facility of $100 million, with a letter of credit sub-facility, expiring on March 31, 2011, with a syndicate of eight financial institutions. Any draws on the facility bear interest, at the option of HEI, at either the "Adjusted LIBO Rate" plus 50 basis points or the greater of (a) the "Prime Rate" and (b) the sum of the "Federal Funds Rate" plus 50 basis points, as defined in the agreement. The annual fee is 10 basis points on the undrawn commitment amount. The agreement contains provisions for revised pricing in the event of a ratings change. For example, a ratings downgrade of HEI's Senior Debt Rating (e.g., from BBB/Baa2 to BBB-/Baa3 by Standard & Poor's (S&P) and Moody's Investors Service's (Moody's), respectively) would result in a commitment fee increase of 2.5 basis points and an interest rate increase of 10 basis points on any drawn amounts. On the other hand, a ratings upgrade (e.g., from BBB/Baa2 to BBB+/Baa1 by S&P or Moody's, respectively) would result in a commitment fee decrease of 2 basis points and an interest rate decrease of 10 basis points on any drawn amounts. The agreement does not contain clauses that would affect access to the lines by reason of a ratings downgrade, nor does it have a broad "material adverse change" clause. However, the agreement does contain customary conditions which must be met in order to draw on it, such as the accuracy of certain of its representations at the time of a draw and compliance with its covenants (such as covenants preventing its subsidiaries from entering into agreements that restrict the ability of the subsidiaries to pay dividends to, or to repay borrowings from, HEI). In addition to customary defaults, HEI's failure to maintain its financial ratio, as defined in the agreement, or meet other requirements will result in an event of default. For example, under the agreement, it is an event of default if HEI fails to maintain a nonconsolidated "Capitalization Ratio" (funded debt) of 50% or less (ratio of 18% as of December 31, 2008, as calculated under the agreement) and "Consolidated Net Worth" of $850 million (Net Worth of $1.5 billion as of December 31, 2008, as calculated under the agreement), if there is a "Change in Control" of HEI, if any event or condition occurs that results in any "Material Indebtedness" of HEI being subject to acceleration prior to its scheduled maturity, if any "Material Subsidiary Indebtedness" actually becomes due prior to its scheduled maturity, or if ASB fails to remain well capitalized and to maintain specified minimum capital ratios.

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

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

Any draws on the facility bear interest, at the option of HECO, at either the "Adjusted LIBO Rate" plus 40 basis points or the greater of (a) the "Prime Rate" and (b) the sum of the "Federal Funds Rate" plus 50 basis points, as defined in the agreement. The annual fee is 8 basis points on the undrawn commitment amount. The agreement contains provisions for revised pricing in the event of a ratings change. For example, a ratings downgrade of HECO's Senior Debt Rating (e.g., from BBB+/Baa1 to BBB/Baa2 by S&P and Moody's, respectively) would result in a commitment fee increase of 2 basis points and an interest rate increase of 10 basis points on any drawn amounts. On the other hand, a ratings upgrade (e.g., from BBB+/Baa1 to A-/A3 by S&P or Moody's, respectively) would result in a commitment fee decrease of 1 basis point and an interest rate decrease of 10 basis points on any drawn amounts. The agreement does not contain clauses that would affect access to the lines by reason of a ratings downgrade, nor does it have a broad "material adverse change" clause. However, the agreement does contain customary conditions that must be met in order to draw on it, such as the accuracy of certain of its representations at the time of a draw and compliance with its covenants (such as covenants preventing its subsidiaries from entering into agreements that restrict the ability of the subsidiaries to pay dividends to, or to repay borrowings from, HECO, and restricting HECO's ability, as well as the ability of any of its subsidiaries, to guarantee indebtedness of the subsidiaries if such additional debt would cause the subsidiary's "Consolidated Subsidiary Funded Debt to Capitalization Ratio" to exceed 65% (ratios of 48% for HELCO and 44% for MECO as of December 31, 2008, as calculated under the agreement)). In addition to customary defaults, HECO's failure to maintain its financial ratios, as defined in its agreement, or meet other requirements will result in an event of default. For example, under the agreement, it is an event of default if HECO fails to maintain a "Consolidated Capitalization Ratio" (equity) of at least 35% (ratio of 55% as of December 31, 2008, as calculated under the agreement), if HECO fails to remain a wholly-owned subsidiary of HEI or if any event or condition occurs that results in any "Material Indebtedness" of HECO or any of its significant subsidiaries being subject to acceleration prior to its scheduled maturity. HECO's syndicated credit facility is maintained to support the issuance of commercial paper, but it may also be drawn for general corporate purposes and capital expenditures.

Effective December 8, 2008, HECO entered into a 9-month revolving unsecured credit agreement establishing a line of credit facility of $75 million, expiring on September 8, 2009, with Wells Fargo Bank National Association, as Administrative Agent and a lender, and U.S. Bank National Association, Bank of America, N.A. and Bank of Hawaii, as lenders. Similar to HECO's existing $175 million, 5-year revolving unsecured credit agreement, this agreement does not contain clauses that would affect access to the lines by reason of a ratings downgrade nor does it have a broad "material adverse change" clause. Major provisions of the credit agreement are substantially the same as provisions in HECO's existing $175 million credit agreement, except for pricing and prepayment requirements as noted below.

The annual fee is 25 basis points on the daily commitment amount. Any draws on the facility bear interest, at the option of HECO, at either the "Adjusted LIBO Rate" plus 175 basis points or the greatest of (a) the "Prime Rate", (b) the sum of the "Federal Funds Rate" plus 150 basis points, and (c) the "Adjusted LIBO Rate" for a one month Interest Period plus 150 basis points, as defined in the agreement. A ratings change would result in revised pricing. For example, a ratings downgrade of HECO's Issuer Ratings (e.g., from BBB+/Baa1 to BBB/Baa2 by S&P and Moody's, respectively) would result in a facility fee increase of 5 basis points, and an interest rate increase of 20 basis points on any drawn amounts. On the other hand, a ratings upgrade (e.g., from BBB+/Baa1 to A-/A3 by S&P or Moody's, respectively) would result in a facility fee decrease of 5 basis points, and an interest rate decrease of 20 basis points on any drawn amounts. This agreement includes a provision for mandatory prepayments and reductions in the commitment amount in the event of any Debt Issuance or Equity Capital Markets Transaction, as defined by the agreement, in the amount of 100% of the net cash proceeds received (provided, however, for purposes of the agreement, HECO's receipt of proceeds from special purpose revenue bond financings do not occur until such proceeds are disbursed to HECO by the construction fund trustee in accordance with the indenture pursuant to which the bonds are issued). This credit facility is maintained to provide back-up and liquidity for its commercial paper borrowings and to provide funding for its working capital needs, intercompany loans to its subsidiaries and general corporate purposes.

On May 23, 2007, S&P lowered the long-term corporate credit and unsecured debt ratings on HECO, HELCO and MECO to BBB from BBB+ and stated that the downgrade "is the result of sustained weak bondholder protection parameters compounded by the financial pressure that continuous need for regulatory relief, driven by heightened capital expenditure requirements, is creating for the next few years." The pricing for future borrowings under the line of credit facility did not change since the pricing level is "determined by the higher of the two" ratings by S&P and Moody's, and Moody's ratings did not change.

## 7 • Long-term debt

| December 31<br>(dollars in thousands) | 2008 | 2007 |
|---|---|---|
| 6.50% Junior Subordinated Deferrable Interest Debentures, Series 2004, due 2034 (see Note 5) | $ 51,546 | $ 51,546 |
| Obligations to the State of Hawaii for the repayment of special purpose revenue bonds issued on behalf of electric utility subsidiaries | | |
| 4.75-4.95%, due 2012-2025 | 118,500 | 118,500 |
| 5.00-5.50%, due 2014-2032 | 203,400 | 203,400 |
| 5.65-5.88%, due 2018-2027 | 216,000 | 216,000 |
| 6.15-6.20%, due 2020-2029 | 55,000 | 55,000 |
| 4.60-4.65%, due 2026-2037 | 265,000 | 265,000 |
| | 857,900 | 857,900 |
| Less funds on deposit with trustee | (3,186) | (22,461) |
| Less unamortized discount | (1,759) | (1,886) |
| | 852,955 | 833,553 |
| HEI medium-term note 4.00%, due 2008 | – | 50,000 |
| 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 |
| | $1,211,501 | $1,242,099 |

As of December 31, 2008, the aggregate principal payments required on long-term debt for 2009 through 2013 are nil in 2009 and 2010, $150 million in 2011, $65 million in 2012 and $50 million in 2013.

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

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

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

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

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

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

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

***SFAS No. 158.*** In September 2006, the FASB issued SFAS No. 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans, an amendment of FASB Statements No. 87, 88, 106, and 132(R)," which requires employers to recognize on their balance sheets the funded status of defined benefit pension and other postretirement benefit plans with an offset to AOCI in stockholders' equity (using the projected benefit obligation (PBO) rather than the accumulated benefit obligation (ABO); to calculate the funded status of pension plans).

By application filed on December 8, 2005 (AOCI Docket), the electric utilities requested the PUC to permit them to record, as a regulatory asset pursuant to SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," the amount that would otherwise be charged against stockholders' equity as a result of recording a minimum pension liability as prescribed by SFAS No. 87. The electric utilities updated their application in the AOCI Docket in November 2006 to take into account SFAS No. 158. On January 26, 2007, the PUC issued a D&O in the updated AOCI Docket, which denied the electric utilities' request to record a regulatory asset on the grounds that the electric utilities had not met their burden of proof to show that recording a regulatory asset was warranted, or that there would be adverse consequences if a regulatory asset was not recorded. The PUC also required HECO to submit a pension study (determining whether ratepayers are better off with a well-funded pension plan, a minimally-funded pension plan, or something in between) in its pending 2007 test year rate case, as proposed by the electric utilities in support of their request.

In HELCO's 2006, HECO's 2007 and MECO's 2007 test year rate cases, the utilities and the Consumer Advocate proposed adoption of pension and OPEB tracking mechanisms, which are intended to smooth the impact to ratepayers of potential fluctuations in pension and OPEB costs. Under the tracking mechanisms, any costs determined under SFAS Nos. 87 and 106, as amended, that are over/under amounts allowed in rates are charged/credited to a regulatory asset/liability. The regulatory asset/liability for each utility will be amortized over 5 years beginning with the respective utility's next rate case.

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

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

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

Under HELCO's interim order, a regulatory asset (representing HELCO's $12.8 million prepaid pension asset as of December 31, 2006 prior to the adoption of SFAS No. 158) was allowed to be recovered (and is being amortized) over a period of five years and was allowed to be included in HELCO's rate base, net of deferred income taxes. On October 25, 2007, however, the PUC issued an amended proposed final D&O for HECO's 2005 test year rate case, which reversed the portion of the interim D&O related to the inclusion of HECO's approximately $50 million pension asset, net of deferred income taxes, in rate base, and required a refund of revenues associated with that reversal, including interest, retroactive to September 28, 2005 (the date the interim increase became effective). In 2007, HECO accrued $16 million for the potential customer refunds, including interest, reducing 2007 net income by $9 million. The final D&O for HECO's 2005 test year rate case confirmed the refund. In the settlement agreement and interim PUC decision in HECO's 2007 test year rate case, HECO's pension asset was not included in HECO's rate base and amortization of the pension asset was not included as part of the pension tracking mechanism adopted in the proceeding on an interim basis. In HECO's rate increase application based on a 2009 test year, HECO's pension asset was not included in rate base and the amortization of the pension asset was not included in the revenue requirements. In the settlement agreement and interim PUC decision in MECO's 2007 test year rate case, MECO's pension asset ($1 million as of December 31, 2007) was not included in MECO's rate base and amortization of the pension asset was not included as part of the pension tracking mechanism adopted in the proceeding on an interim basis.

As a result of the 2007 interim orders, the electric utilities have reclassified to a regulatory asset charges for retirement benefits that would otherwise be recorded in AOCI pursuant to SFAS No. 158 (amounting to the elimination of a potential charge to AOCI of $249 million pre-tax and $171 million pre-tax at December 31, 2008 and at December 31, 2007, respectively, compared to a retirement benefits pre-tax charge of $207 million at December 31, 2006).

Retirement benefits expense for the electric utilities for 2008, 2007 and 2006 was $27 million, $27 million and $22 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 2008 and 2007 and the funded status of these plans and amounts related to these plans reflected in the Company's balance sheet as of December 31, 2008 and 2007 were as follows:

| | 2008 | | 2007 | |
|---|---|---|---|---|
| (in thousands) | Pension benefits | Other benefits | Pension benefits | Other benefits |
| Benefit obligation, January 1 | $998,610 | $187,099 | $985,562 | $191,222 |
| Service cost | 28,356 | 4,777 | 30,996 | 4,773 |
| Interest cost | 59,765 | 11,008 | 57,851 | 10,829 |
| Amendments | (2,105) | – | (17,574) | – |
| Actuarial gain | (70,974) | (12,949) | (10,350) | (10,313) |
| Benefits paid and expenses | (49,264) | (9,279) | (47,875) | (9,412) |
| Benefit obligation, December 31 | 964,388 | 180,656 | 998,610 | 187,099 |
| Fair value of plan assets, January 1 | 907,295 | 148,343 | 875,278 | 136,366 |
| Actual return on plan assets | (245,828) | (41,161) | 75,274 | 11,608 |
| Employer contribution | 6,039 | 8,496 | 3,728 | 9,396 |
| Benefits paid and expenses | (48,372) | (9,263) | (46,985) | (9,027) |
| Fair value of plan assets, December 31 | 619,134 | 106,415 | 907,295 | 148,343 |
| Accrued benefit liability, December 31 | (345,254) | (74,241) | (91,315) | (38,756) |
| AOCI, January 1 (excluding impact of PUC D&Os) | 160,828 | 16,403 | 197,924 | 31,536 |
| Recognized during year – net recognized transition obligation | (2) | (3,138) | (3) | (3,138) |
| Recognized during year – prior service (cost)/credit | 421 | (13) | 197 | (13) |
| Recognized during year – net actuarial losses | (6,765) | – | (11,282) | – |
| Occurring during year – prior service cost | (1,633) | – | (17,574) | – |
| Occurring during year – net actuarial losses (gains) | 248,026 | 39,181 | (17,243) | (11,982) |
| Other adjustments | – | – | 8,809 | – |
| | 400,875 | 52,433 | 160,828 | 16,403 |
| Cumulative impact of PUC D&Os | (365,874) | (54,365) | (152,888) | (18,120) |
| AOCI, December 31 | 35,001 | (1,932) | 7,940 | (1,717) |
| Net actuarial loss | 402,659 | 39,763 | 161,398 | 582 |
| Prior service cost (gain) | (1,792) | 118 | (580) | 131 |
| Net transition obligation | 8 | 12,552 | 10 | 15,690 |
| | 400,875 | 52,433 | 160,828 | 16,403 |
| Cumulative impact of PUC D&Os | (365,874) | (54,365) | (152,888) | (18,120) |
| AOCI, December 31 | 35,001 | (1,932) | 7,940 | (1,717) |
| Income tax benefits | (13,831) | 752 | (3,092) | 668 |
| AOCI, net of taxes, December 31 | $ 21,170 | $ (1,180) | $ 4,848 | $ (1,049) |

The Company does not expect any plan assets to be returned to the Company during calendar year 2009.

The dates used to determine retirement benefit measurements for the defined benefit plans were December 31 of 2008, 2007 and 2006.

The defined benefit pension plans' ABO, which do not consider projected pay increases (unlike the PBO shown in the table above), as of December 31, 2008 and 2007 were $872 million and $883 million, respectively.

The Company's current estimate of contributions to the retirement benefit plans in 2009 is $32 million. The Pension Protection Act provides that more conservative assumptions be used to value obligations if a pension plan's funded status falls below certain levels. Depending on the funded status of the plans and whether funding relief is provided through legislation, the Company's projected contribution level for the qualified pension plans for the 2010 plan year could fall in a range between $78 million and $140 million. Other factors could cause required contribution levels to fall outside this estimated range. Further, if the funded status of the pension plans continue to decline, restrictions on participant benefit accruals may be placed on the plans.

As of December 31, 2008, the benefits expected to be paid under the retirement benefit plans in 2009, 2010, 2011, 2012, 2013 and 2014 through 2018 amounted to $63 million, $65 million, $68 million, $70 million, $73 million and $418 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 retirement defined benefit plans was as follows:

| | Pension benefits | | | | Other benefits | | | |
|---|---|---|---|---|---|---|---|---|
| | | | Investment policy | | | | Investment policy | |
| December 31 | 2008 | 2007 | Target | Range | 2008 | 2007 | Target | Range |
| Asset category | | | | | | | | |
| Equity securities | 62% | 72% | 70% | 65-75% | 63% | 70% | 70% | 65-75% |
| Fixed income | 37 | 27 | 30 | 25-35% | 37 | 30 | 30 | 25-35% |
| Other [1] | 1 | 1 | – | – | – | – | – | – |
| | 100% | 100% | 100% | | 100% | 100% | 100% | |

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

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

| | Pension benefits | | | Other benefits | | |
|---|---|---|---|---|---|---|
| December 31 | 2008 | 2007 | 2006 | 2008 | 2007 | 2006 |
| Benefit obligation | | | | | | |
| Discount rate | 6.625% | 6.125% | 6.00% | 6.50% | 6.125% | 6.00% |
| Rate of compensation increase | 3.5 | 4.2 | 4.2 | 3.5 | 4.2 | 4.2 |
| Net periodic benefit cost (years ended) | | | | | | |
| Discount rate | 6.125 | 6.00 | 5.75 | 6.125 | 6.00 | 5.75 |
| Expected return on plan assets | 8.5 | 8.5 | 9.0 | 8.5 | 8.5 | 9.0 |
| Rate of compensation increase | 4.2 | 4.2 | 4.6 | 4.2 | 4.2 | 4.6 |

The Company based its selection of an assumed discount rate for 2009 net periodic cost and December 31, 2008 disclosure on a cash flow matching analysis that utilized bond information provided by Standard & Poor's for all non-callable, high quality bonds (i.e., rated AA- or better) as of December 31, 2008. In selecting the expected rate of return on plan assets of 8.25% for 2009 net periodic benefit cost, the Company considered economic forecasts for the types of investments held by the plans (primarily equity and fixed income investments), the plans' asset allocations and the past performance of the plans' assets. The methods of selecting the assumed discount rate and expected return on plan assets at December 31, 2008 did not change from December 31 2007.

As of December 31, 2008, the assumed health care trend rates for 2009 and future years were as follows: medical, 10.00%, grading down to 5.00% for 2014 and thereafter; dental, 5.00%; and vision, 4.00%. As of December 31, 2007, the assumed health care trend rates for 2008 and future years were as follows: medical, 10.00%, grading down to 5.00% for 2013 and thereafter; dental, 5.00%; and vision, 4.00%.

The components of net periodic benefit cost were as follows:

| (in thousands) | Pension benefits 2008 | 2007 | 2006 | Other benefits 2008 | 2007 | 2006 |
|---|---|---|---|---|---|---|
| Service cost | $ 28,356 | $ 30,996 | $ 32,486 | $ 4,777 | $ 4,773 | $ 5,099 |
| Interest cost | 59,765 | 57,851 | 54,200 | 11,008 | 10,829 | 10,620 |
| Expected return on plan assets | (73,172) | (68,381) | (71,684) | (10,970) | (9,939) | (9,918) |
| Amortization of net transition obligation | 2 | 3 | 5 | 3,138 | 3,138 | 3,138 |
| Amortization of net prior service cost (gain) | (421) | (197) | (205) | 13 | 13 | 13 |
| Amortization of net actuarial loss | 6,765 | 11,282 | 12,005 | – | – | 412 |
| Net periodic benefit cost | 21,295 | 31,554 | 26,807 | 7,966 | 8,814 | 9,364 |
| Impact of PUC D&Os | 5,859 | 1,195 | – | 1,038 | 187 | – |
| Net periodic benefit cost (adjusted for impact of PUC D&Os) | $ 27,154 | $ 32,749 | $ 26,807 | $ 9,004 | $9,001 | $ 9,364 |

The estimated prior service credit, net actuarial loss and net transition obligation for defined benefits pension plans that will be amortized from AOCI or regulatory asset into net periodic pension benefit cost over 2009 are $(0.4) million, $15.9 million and nil, respectively. The estimated prior service cost, net actuarial loss and net transitional obligation for other benefit plans that will be amortized from AOCI or regulatory asset into net periodic other than pension benefit cost over 2009 are nil, $0.5 million and $3.1 million, respectively.

The Company recorded pension expense of $20 million, $26 million and $21 million and OPEB expense of $7 million, $7 million and $7 million in 2008, 2007 and 2006, respectively, and charged the remaining amounts primarily to electric utility plant.

All pension plans had ABOs exceeding plan assets as of December 31, 2008. The PBO, ABO and fair value of plan assets for pension plans with an ABO in excess of plan assets were $19 million, $16 million and nil, respectively, as of December 31, 2007. All other benefits plans had APBOs exceeding plan assets as of December 31, 2008 and December 31, 2007.

The health care cost trend rate assumptions can have a significant effect on the amounts reported for other benefits. As of December 31, 2008, a one-percentage-point increase in the assumed health care cost trend rates would have increased the total service and interest cost by $0.1 million and the postretirement benefit obligation by $2.6 million, and a one-percentage-point decrease would have reduced the total service and interest cost by $0.2 million and the postretirement benefit obligation by $3.0 million.

**Defined contribution plan.** On January 1, 2008, ASB began providing employer matching contributions of 100% on the first 4% of eligible pay contributed by participants to HEI's retirement savings plan for its eligible employees. In addition, a new ASB 401(k) Plan was created to initially fund a discretionary employer profit sharing contribution for the 2008 plan year, with the intent to transfer over ASB employee accounts from the HEI retirement savings plan during 2009. The discretionary employer profit sharing contribution will be allocated pro-rata to accounts of all eligible participants based on a flat percent of eligible pay. This percentage will be determined annually after year-end, based on ASB's performance and achievement of financial goals. For 2008, ASB's total expense for its employees participating in the HEI retirement savings plan was $4.4 million and contributions were $1.7 million.

## 9 • Share-based compensation

Under the 1987 Stock Option and Incentive Plan, as amended (SOIP), HEI may issue an aggregate of 9.3 million shares of common stock (4,501,796 shares available for issuance under outstanding and future grants and awards as of December 31, 2008) to officers and key employees as incentive stock options, nonqualified stock options (NQSOs), restricted stock, stock appreciation rights (SARs), stock payments or dividend equivalents. HEI has issued new shares for NQSOs, restricted stock (nonvested stock), SARs and dividend equivalents under the SOIP. All information presented has been adjusted for the 2-for-1 stock split in June 2004.

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

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

The Company's share-based compensation expense and related income tax benefit (as limited by the deductibility of executive compensation) are as follows:

| ($ in millions) | 2008 | 2007 | 2006 |
|---|---|---|---|
| Share-based compensation expense [1] | 0.8 | 1.3 | 1.6 |
| Income tax benefit | 0.1 | 0.4 | 0.7 |

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

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

| | 2008 | | 2007 | | 2006 | |
|---|---|---|---|---|---|---|
| | Shares | (1) | Shares | (1) | Shares | (1) |
| Outstanding, January 1 | 603,800 | $19.68 | 660,000 | $19.68 | 929,000 | $19.88 |
| Granted | – | – | – | – | – | – |
| Exercised | (220,300) | $19.62 | (56,200) | $19.70 | (269,000) | $20.38 |
| Forfeited | – | – | – | – | – | – |
| Expired | (8,000) | $19.23 | – | – | – | – |
| Outstanding, December 31 | 375,500 | $19.73 | 603,800 | $19.68 | 660,000 | $19.68 |
| Options exercisable, December 31 | 375,500 | $19.73 | 603,800 | $19.68 | 581,000 | $19.57 |

(1) Weighted-average exercise price

| December 31, 2008 | | | Outstanding & Exercisable | |
|---|---|---|---|---|
| Year of grant | Range of exercise prices | Number of options | Weighted-average remaining contractual life | Weighted-average exercise price |
| 1999 | $ 17.61 | 1,000 | 0.3 | $17.61 |
| 2000 | 14.74 | 46,000 | 1.3 | 14.74 |
| 2001 | 17.96 | 65,000 | 2.3 | 17.96 |
| 2002 | 21.68 | 122,000 | 3.1 | 21.68 |
| 2003 | 20.49 | 141,500 | 3.8 | 20.49 |
| | $14.74 – 21.68 | 375,500 | 3.0 | $19.73 |

As of December 31, 2008, all NQSOs outstanding were exercisable and had an aggregate intrinsic value (including dividend equivalents) of $2.2 million.

NQSO activity and statistics are summarized as follows:

| ($ in thousands, except prices) | 2008 | 2007 | 2006 |
|---|---|---|---|
| Shares vested | – | 79,000 | 198,500 |
| Aggregate fair value of vested shares | – | $350 | $916 |
| Cash received from exercise | $4,323 | $1,107 | $5,481 |
| Intrinsic value of shares exercised [1] | $2,235 | $575 | $2,908 |
| Tax benefit realized for the deduction of exercises | $705 | $195 | $965 |
| Dividend equivalent shares distributed under Section 409A | 6,125 | 21,971 | 43,265 |
| Weighted-average Section 409A distribution price | $22.38 | $26.14 | $26.27 |
| Intrinsic value of shares distributed under Section 409A | $137 | $574 | $1,137 |
| Tax benefit realized for Section 409A distributions | $53 | $224 | $442 |

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

As of December 31, 2008, all NQSOs were vested.

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

| | 2008 | | 2007 | | 2006 | |
|---|---|---|---|---|---|---|
| | Shares | (1) | Shares | (1) | Shares | (1) |
| Outstanding, January 1 | 857,000 | $26.12 | 879,000 | $26.12 | 879,000 | $26.12 |
| Granted | – | – | – | – | – | – |
| Exercised | (36,000) | $26.05 | (4,000) | $26.18 | – | – |
| Forfeited | (30,000) | $26.18 | (18,000) | $26.18 | – | – |
| Expired | – | – | – | – | – | – |
| Outstanding, December 31 | 791,000 | $26.12 | 857,000 | $26.12 | 879,000 | $26.12 |
| Options exercisable, December 31 | 557,000 | $26.10 | 464,000 | $26.08 | 399,000 | $26.09 |

(1) Weighted-average exercise price

| December 31, 2008 | | Outstanding | | | Exercisable | | |
|---|---|---|---|---|---|---|---|
| Year of grant | Range of exercise prices | Number of shares underlying SARs | Weighted-average remaining contractual life | Weighted-average exercise price | Number of shares underlying SARs | Weighted-average remaining contractual life | Weighted-average exercise price |
| 2004 | $ 26.02 | 295,000 | 2.4 | $26.02 | 295,000 | 2.4 | $26.02 |
| 2005 | 26.18 | 496,000 | 3.6 | 26.18 | 262,000 | 1.3 | 26.18 |
| | $26.02 –26.18 | 791,000 | 3.2 | $26.12 | 557,000 | 1.8 | $26.10 |

As of December 31, 2008, the SARs outstanding and the SARs exercisable had no aggregate intrinsic value (including dividend equivalents).

SARs activity and statistics are summarized as follows:

| ($ in thousands, except prices) | 2008 | 2007 | 2006 |
|---|---|---|---|
| Shares vested | 129,000 | 69,000 | 317,750 |
| Aggregate fair value of vested shares | $733 | $341 | $1,773 |
| Cash received from exercise | – | – | – |
| Intrinsic value of shares exercised [1] | $127 | $3 | – |
| Tax benefit realized for the deduction of exercises | $49 | $1 | – |
| Dividend equivalent shares distributed under Section 409A | – | 23,760 | 28,600 |
| Weighted-average Section 409A distribution price | – | $26.15 | $26.37 |
| Intrinsic value of shares distributed under Section 409A | – | $621 | $754 |
| Tax benefit realized for Section 409A distributions | – | $242 | $293 |

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

As of December 31, 2008, there was $0.1 million of total unrecognized compensation cost related to SARs and that cost is expected to be recognized over a weighted average period of 0.3 years.

No SARs were granted in 2008, 2007 or 2006.

***Section 409A.*** As a result of the changes enacted in Section 409A of the Internal Revenue Code (Section 409A) for 2008, 2007 and 2006, a total of 6,125, 45,732 and 71,865 dividend equivalent shares (for NQSO and SAR grants) were distributed to SOIP participants, respectively. Section 409A, which amended the rules on deferred compensation, required the Company to change the way certain affected dividend equivalents are paid in order to avoid significant adverse tax consequences to the SOIP participants. Generally dividend equivalents subject to Section 409A will be paid within 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.

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

| | 2008 | | 2007 | | 2006 | |
|---|---|---|---|---|---|---|
| | Shares | (1) | Shares | (1) | Shares | (1) |
| Outstanding, January 1 | 146,000 | $25.82 | 91,800 | $23.68 | 41,000 | $23.50 |
| Granted | 45,000 | $24.71 | 75,700 | $23.50 | 60,800 | $26.32 |
| Restrictions ended | (6,170) | $25.44 | (16,000) | $23.48 | (10,000) | $20.65 |
| Forfeited | (24,330) | $25.90 | (5,500) | $26.04 | – | – |
| Outstanding, December 31 | 160,500 | $25.51 | 146,000 | $25.82 | 91,800 | $25.68 |

(1) Weighted-average price per share at grant date

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

In 2008, 2007 and 2006, total restricted stock granted had a grant date fair value of $1.1 million, $1.9 million and $1.6 million, respectively. In 2008, 2007 and 2006, total restricted stock vested had a grant date fair value of $0.2 million, $0.4 million and $0.2 million, respectively. The tax benefit realized for the tax deductions from restricted stock were $0.2 million for 2008, $0.2 million for 2007 and $0.1 million for 2006.

As of December 31, 2008, there was $1.9 million of total unrecognized compensation cost related to nonvested restricted stock. The cost is expected to be recognized over a weighted-average period of 2.6 years.

## 10 • Income taxes

In June 2006, the FASB issued FIN 48, "Accounting for Uncertainty in Income Taxes, an interpretation of FASB Statement No. 109," which prescribes a "more-likely-than-not" recognition threshold and measurement attribute (the largest amount of benefit that is greater than 50% likely of being realized upon ultimate resolution with tax authorities) for the financial statement recognition and measurement of an income tax position taken or expected to be taken in a tax return. The Company adopted FIN 48 in the first quarter of 2007.

As a result of the implementation of FIN 48, the Company reclassified certain deferred tax liabilities to a liability for uncertain tax positions (FIN 48 liability) and reduced retained earnings by $0.2 million as of January 1, 2007 for the cumulative effect of the adoption of FIN 48.

In general, prior to January 1, 2007, the Company (except for ASB) recorded known interest on income taxes in "Interest expense – other than bank" (in "Interest and other charges" in HECO's consolidated statements of income) and ASB recorded known interest on income taxes in "Expenses - Bank" (in "Other expense" in ASB's consolidated statements of income). Since the adoption of FIN 48, the electric utilities and ASB record all (potential and known) interest on income taxes in "Interest and other charges" and "Other expense," respectively, but the Company records such amounts in "Interest expense – other than on deposit liabilities and other bank borrowings." For 2006, interest income on income taxes was $0.3 million.

In 2008 and 2007, interest expense on income taxes was reflected in "Interest expense – other than on deposit liabilities and bank borrowings" in the amount of $0.2 million and $1.2 million, respectively. The Company will record associated penalties, if any, in the respective segment's expenses. As of December 31, 2008 and 2007, the total amount of accrued interest related to uncertain tax positions and recognized on the balance sheet was $2.9 million and $2.8 million, respectively.

As of December 31, 2008, the total amount of FIN 48 liability was $9.1 million and, of this amount, $1.8 million, if recognized, would affect the Company's effective tax rate. Management concluded that it is reasonably possible that the FIN 48 liability will significantly change within the next 12 months due to the resolution of issues under examination by the Internal Revenue Service and estimates the range of the reasonably possible change to be a decrease of between nil and $7.4 million in 2009.

The changes in total unrecognized tax benefits were as follows:

| Years ended December 31 | 2008 | 2007 |
|---|---|---|
| (in millions) | | |
| Unrecognized tax benefits, January 1 | $ 31.3 | $ 30.1 |
| Additions based on tax positions taken during the year | – | – |
| Reductions based on tax positions taken during the year | – | – |
| Additions for tax positions of prior years | 0.8 | 1.8 |
| Reductions for tax positions of prior years | (4.2) | (0.6) |
| Decreases due to tax positions taken | – | – |
| Settlements | – | – |
| Lapses of statute of limitations | – | – |
| Unrecognized tax benefits, December 31 | $ 27.9 | $ 31.3 |

In addition to the FIN 48 liability, the Company's unrecognized tax benefits include $18.8 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 FIN 48 liability was required to offset these potential benefits.

Tax years 2003 to 2007 currently remain subject to examination by the Internal Revenue Service and Department of Taxation of the State of Hawaii. HEI Investments, Inc., which owned leveraged lease investments in other states prior to 2008, is also subject to examination by those state tax authorities for tax years 2003 to 2007.

The Company's effective federal and state income tax rate for 2008 and 2007 was 35%.

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

| Years ended December 31 | 2008 | 2007 | 2006 |
|---|---|---|---|
| (in thousands) | | | |
| Federal | | | |
| Current | $38,041 | $71,028 | $65,501 |
| Deferred | 7,045 | (27,855) | (9,372) |
| Deferred tax credits, net | (1,094) | (1,154) | (1,259) |
| | 43,992 | 42,019 | 54,870 |
| State | | | |
| Current | 4,409 | 8,194 | 5,848 |
| Deferred | (815) | (5,615) | (1,468) |
| Deferred tax credits, net | 1,392 | 1,680 | 3,804 |
| | 4,986 | 4,259 | 8,184 |
| | $48,978 | $46,278 | $63,054 |

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 | 2008 | 2007 | 2006 |
|---|---|---|---|
| (in thousands) | | | |
| Amount at the federal statutory income tax rate | $48,740 | $45,870 | $59,869 |
| Increase (decrease) resulting from: | | | |
| State income taxes, net of effect on federal income taxes | 3,241 | 2,768 | 5,319 |
| Other, net | (3,003) | (2,360) | (2,134) |
| | $48,978 | $46,278 | $63,054 |

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

| December 31<br>(in thousands) | 2008 | 2007 |
|---|---|---|
| Deferred tax assets | | |
| Cost of removal in excess of salvage value | $109,882 | $101,075 |
| Contributions in aid of construction and customer advances | 78,834 | 76,342 |
| Allowance for loan losses | 14,020 | 13,816 |
| Net unrealized losses on available-for-sale investment and mortgage-related securities (AOCI) | 21,807 | 11,913 |
| Retirement benefits (AOCI) | 13,079 | 2,424 |
| Other | 34,313 | 42,511 |
| | 271,935 | 248,081 |
| Deferred tax liabilities | | |
| Property, plant and equipment | 311,027 | 285,608 |
| Retirement benefits | 8,546 | 18,546 |
| Goodwill | 16,335 | 14,438 |
| Regulatory assets, excluding amounts attributable to property, plant and equipment | 30,240 | 29,050 |
| FHLB stock dividend | 20,552 | 20,552 |
| Change in accounting method | 16,020 | 23,036 |
| Other | 12,523 | 12,188 |
| | 415,243 | 403,418 |
| Net deferred income tax liability | $143,308 | $155,337 |

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. 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.

As of December 31, 2008, the FIN 48 disclosures above present the Company's accrual for potential tax liabilities and related interest. Based on information currently available, the Company believes this accrual has adequately provided for potential income tax issues with federal and state tax authorities and related interest, and that the ultimate resolution of tax issues for all open tax periods will not have a material adverse effect on its results of operations, financial condition or liquidity.

## 11 • Cash flows

***Supplemental disclosures of cash flow information.*** In 2008, 2007 and 2006, the Company paid interest to non-affiliates amounting to $182 million, $233 million and $214 million, respectively.

In 2008, 2007 and 2006, the Company paid income taxes amounting to $91 million, $39 million and $69 million, respectively.

***Supplemental disclosures of noncash activities.*** Under the HEI Dividend Reinvestment and Stock Purchase Plan (DRIP), common stock dividends reinvested by shareholders in HEI common stock in noncash transactions amounted to $21 million in both 2008 and 2007. From March 23, 2004 to March 5, 2007, HEI satisfied the requirements of the HEI DRIP and the Hawaiian Electric Industries Retirement Savings Plan (HEIRSP) by acquiring for cash its common shares through open market purchases rather than the issuance of additional shares. On March 6, 2007, it began satisfying those requirements by the issuance of additional shares.

In 2008, 2007 and 2006, other noncash increases in common stock issued under director and officer compensatory plans were $2 million, $2 million and $3 million, respectively.

In 2008, 2007 and 2006, HECO and its subsidiaries capitalized as part of the cost of electric utility plant an allowance for equity funds used during construction amounting to $9 million, $5 million and $6 million, respectively.

In 2008, 2007 and 2006, the estimated fair value of noncash contributions in aid of construction amounted to $10 million, $18 million and $14 million, respectively.

In 2006, the Company completed the settlement of net taxes and interest due to the IRS for tax years 1994 through 2002. In a non-cash transaction in 2006, a $30 million deposit made by the Company in 2005 with the IRS was applied to the net liabilities of $10 million for tax years 1994 through 2002 and $18 million for tax year 2005 with an immaterial net income impact. The remaining $2 million of the 2005 deposit was refunded to the Company in 2006.

## 12 • Regulatory restrictions on net assets

As of December 31, 2008, HECO and its subsidiaries could not transfer approximately $506 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, 2008, ASB could transfer approximately $107 million of net assets to HEI in the form of dividends and still maintain its "well-capitalized" position.

HEI management expects that the regulatory restrictions will not materially affect the operations of the Company nor HEI's ability to pay common stock dividends.

## 13 • Significant group concentrations of credit risk

Most of the Company's business activity is with customers located in the State of Hawaii. Most of ASB's financial instruments are based in the State of Hawaii, except for the investment and mortgage-related securities it owns. Substantially all real estate loans receivable are secured by real estate in Hawaii. ASB's policy is to require mortgage insurance on all real estate loans with a loan to appraisal ratio in excess of 80% at origination. As of December 31, 2008, ASB's private-issue mortgage-related securities represented whole or participating interests in pools of mortgage loans collateralized by real estate in the U.S. As of December 31, 2008, various securities rating agencies rated the private-issue mortgage-related securities held by ASB. See "Investment and mortgage-related securities" in Note 4 for ratings of ASB's private-issued mortgage-related securities.

## 14 • Fair value of financial instruments

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

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

***Cash and equivalents and federal funds sold.*** The carrying amount approximated fair value because of the short maturity of these instruments.

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

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

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

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

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

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

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

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

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

| December 31 | 2008 | | 2007 | |
|---|---|---|---|---|
| (in thousands) | Carrying or notional amount | Estimated fair value | Carrying or notional amount | Estimated fair value |
| **Financial assets** | | | | |
| Cash and equivalents | $ 182,903 | $ 182,903 | $ 145,855 | $ 145,855 |
| Federal funds sold | 532 | 532 | 64,000 | 64,000 |
| Available-for-sale investment and mortgage-related securities | 657,717 | 657,717 | 2,140,772 | 2,140,772 |
| Investment in stock of Federal Home Loan Bank of Seattle | 97,764 | 97,764 | 97,764 | 97,764 |
| Loans receivable, net | 4,206,492 | 4,322,153 | 4,101,193 | 4,087,901 |
| **Financial liabilities** | | | | |
| Deposit liabilities | 4,180,175 | 4,197,429 | 4,347,260 | 4,345,397 |
| Other bank borrowings | 680,973 | 701,998 | 1,810,669 | 1,852,762 |
| Long-term debt | 1,211,501 | 949,170 | 1,242,099 | 1,264,606 |
| **Off-balance sheet items** | | | | |
| HECO-obligated preferred securities of trust subsidiary | 50,000 | 40,420 | 50,000 | 46,200 |

As of December 31, 2008 and 2007, loan commitments and unused lines and letters of credit had carrying amounts of $1.2 billion and the estimated fair value was $0.8 million and $0.2 million, respectively. As of December 31, 2008 and 2007, loans serviced for others had carrying amounts of $307.6 million and $282.2 million and the estimated fair value of the servicing rights for such loans was $2.6 million and $3.3 million, respectively.

## 15 • 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 |
|---|---|---|---|---|---|
| **2008** | | | | | |
| Revenues [1, 2] | $729,617 | $774,055 | $915,431 | $799,817 | $3,218,920 |
| Operating income [1, 2] | 70,746 | 21,602 | 74,129 | 37,680 | 204,157 |
| Net income (loss) [1, 2] | 33,967 | 5,136 | 37,281 | 13,894 | 90,278 |
| Basic earnings (loss) per common share [3] | 0.41 | 0.06 | 0.44 | 0.16 | 1.07 |
| Diluted earnings (loss) per common share [4] | 0.41 | 0.06 | 0.44 | 0.16 | 1.07 |
| Dividends per common share | 0.31 | 0.31 | 0.31 | 0.31 | 1.24 |
| Market price per common share [5] | | | | | |
| High | 23.95 | 27.16 | 29.75 | 29.06 | 29.75 |
| Low | 20.95 | 23.89 | 23.50 | 21.29 | 20.95 |
| **2007** | | | | | |
| Revenues [6, 7] | $554,023 | $600,763 | $673,461 | $708,171 | $2,536,418 |
| Operating income [6, 7] | 28,541 | 45,309 | 48,017 | 81,865 | 203,732 |
| Net income (loss) [6, 7] | 6,764 | 17,549 | 19,881 | 40,585 | 84,779 |
| Basic earnings (loss) per common share [3] | 0.08 | 0.21 | 0.24 | 0.49 | 1.03 |
| Diluted earnings (loss) per common share [4] | 0.08 | 0.21 | 0.24 | 0.49 | 1.03 |
| Dividends per common share | 0.31 | 0.31 | 0.31 | 0.31 | 1.24 |
| Market price per common share [5] | | | | | |
| High | 27.49 | 26.73 | 23.91 | 23.95 | 27.49 |
| Low | 25.10 | 22.81 | 20.25 | 20.92 | 20.25 |

1 For 2008, amounts include interim rate relief for HECO (2007 test year), HELCO (2006 test year) and MECO (2007 test year). The fourth quarter of 2008 includes a reduction of $1.3 million, net of taxes, of electric sales revenues related to prior periods and a $4.7 million, net of tax benefits, charge for other-than-temporary impairments of securities owned by ASB.

2 The second quarter of 2008 includes a $35.6 million, net of tax benefits, charge related to a balance sheet restructuring at ASB.

3 The quarterly basic earnings (loss) per common share are based upon the weighted-average number of shares of common stock outstanding in each quarter.

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

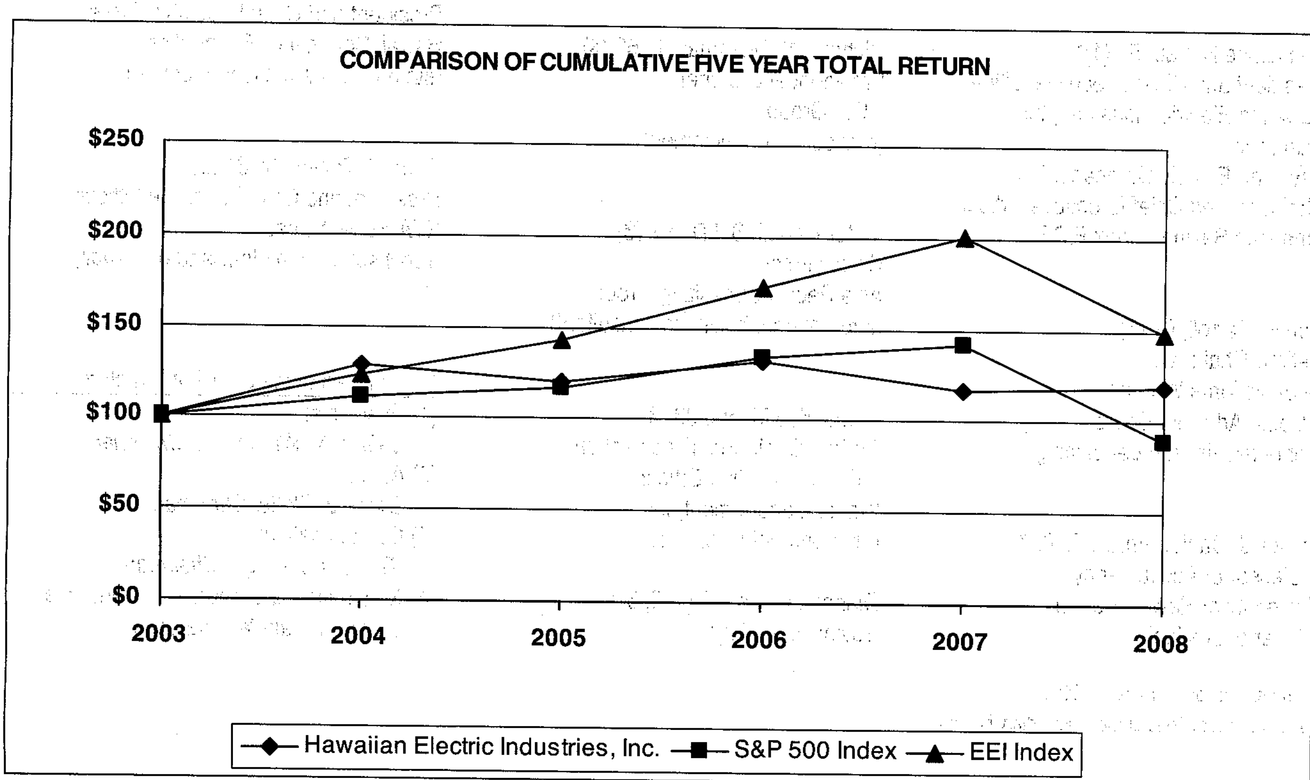
5 Market prices of HEI common stock (symbol HE) shown are as reported on the NYSE Composite Tape.

6 For 2007, amounts include interim rate relief for HECO (2005 test year; 2007 test year since October 22, 2007), HELCO (2006 test year since April 5, 2007) and MECO (2007 test year since December 21, 2007).

7 The first quarter of 2007 includes a $7 million, net of tax benefits, write-off of plant in service costs at HELCO as part of a settlement in HELCO's 2006 test year rate case. The third quarter of 2007 includes a $9 million, net of tax benefits, reserve accrued for the potential refund (with interest) of a portion of HECO's 2005 test year interim rate increase. Operating and net income for the fourth quarter of 2007 includes a $5 million, net of taxes, pension curtailment gain at 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 (59 companies were included as of December 31, 2008). 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, 2003 in HEI Common Stock and the common stock of all companies in the indexes and that dividends were reinvested.



## HEI Directors

Jeffrey N. Watanabe, 66 (1)*
Chairman
Hawaiian Electric Industries, Inc.
Honorary Of Counsel
Watanabe Ing LLP
(private law firm)

Constance H. Lau, 56 (1)*
President and Chief Executive Officer
Hawaiian Electric Industries, Inc.
Chairman
Hawaiian Electric Company, Inc.
Chairman and Chief Executive Officer
American Savings Bank F.S.B.

Don E. Carroll, 67 (3)*
Retired Chairman
Oceanic Time Warner
Cable Advisory Board
(cable television broadcasting)

Shirley J. Daniel, Ph.D., 55 (2)*
Professor of Accountancy
University of Hawaii-Manoa
(higher education)

Admiral Thomas B. Fargo,
USN (Retired), 60 (2, 3)*
President and Chief Executive Officer
Hawaii Superferry, Inc.
(inter-island passenger & vehicle ferry)

Richard W. Gushman, II, 63 (4)*
President and Owner
DGM Group
(real estate development)

Victor Hao Li, S.J.D., 67 (3)*
Co-chairman
Asia Pacific Consulting Group
(international business consultant)

A. Maurice Myers, 68 (3)
Retired Chairman, President and
Chief Executive Officer
Waste Management, Inc.
(environmental services)

Diane J. Plotts, 73 (1, 2, 3)*
Business Advisor

James K. Scott, Ed.D., 57 (2, 4)*
President
Punahou School
(private education)

Kelvin H. Taketa, 54 (4)*
President and Chief Executive Officer
Hawaii Community Foundation
(statewide charitable foundation)

Barry K. Taniguchi, 61 (2)*
President and Chief Executive Officer
KTA Super Stores
(retail super markets-island of Hawaii)

Committees of the Board of Directors

(1) Executive:
*Jeffrey N. Watanabe, Chairman*
(2) Audit:
*Diane J. Plotts, Chairman*
(3) Compensation:
*Thomas B. Fargo, Chairman*
(4) Nominating & Corporate Governance:
*Kelvin H. Taketa, Chairman*

Information as of February 20, 2009.
* Also member of one or more subsidiary boards.

## HEI Executive Officers and Subsidiary Presidents

Constance H. Lau, 56
President and Chief Executive Officer
Hawaiian Electric Industries, Inc.
Chairman
Hawaiian Electric Company, Inc.
Chairman and Chief Executive Officer
American Savings Bank, F.S.B.
1984

James A. Ajello, 55
Senior Financial Vice President,
Treasurer and Chief Financial Officer
2009

Curtis Y. Harada, 53
Vice President, Controller
Chief Accounting Officer
1989

Jay M. Ignacio, 49
President, Hawaii Electric Light
Company, Inc.
1990

Richard M. Rosenblum, 58
President and Chief Executive Officer
Hawaiian Electric Company, Inc.
2009

Edward L. Reinhardt, 56
President, Maui Electric Company, Limited
1986

Chester A. Richardson, 60
Senior Vice President–General Counsel
and Chief Administrative Officer
2007

Timothy K. Schools, 39
President, American Savings Bank, F.S.B.
2007

Information as of February 20, 2009.
Year denotes year of first employment by the company.

# Shareholder Information

## CORPORATE HEADQUARTERS

Hawaiian Electric Industries, Inc.
900 Richards Street,
Honolulu, Hawaii 96813
Telephone: 808-543-5662

Mailing address: P. O. Box 730
Honolulu, Hawaii 96808-0730

## NEW YORK STOCK EXCHANGE

Common stock symbol: HE
Trust preferred securities symbol: HEPrU (HECO)

## SHAREHOLDER SERVICES

P. O. Box 730
Honolulu, Hawaii 96808-0730
Telephone: 808-532-5841
Toll Free: 866-672-5841
Facsimile: 808-532-5868
E-mail: invest@hei.com
Office hours: 7:30 a.m. to 3:00 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 2008 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.

## 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 5, 2009, 9:30 a.m.
American Savings Bank Tower, 1001 Bishop Street
8th Floor, Room 805, Honolulu, Hawaii 96813

*Please direct inquiries to:*
Patricia U. Wong,
Vice President-Administration and Corporate Secretary
Telephone: 808-543-7900, Facsimile: 808-203-1183

## INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

KPMG LLP
Pauahi Tower, 1003 Bishop Street – Suite 2100
Honolulu, Hawaii 96813
Telephone: 808-540-2800

## INSTITUTIONAL INVESTOR AND SECURITIES ANALYST INQUIRIES

*Please direct inquiries to:*
Suzy P. Hollinger
Manager, Treasury and Investor Relations
Telephone: 808-543-7385
Facsimile: 808-203-1155
E-mail: shollinger@hei.com

## TRANSFER AGENTS

*Common stock and utility company preferred stock:*
Shareholder Services

*Common stock only:*
Continental Stock Transfer & Trust Company
17 Battery Place
New York, New York 10004
Telephone: 212-509-4000
Facsimile: 212-509-5150

*Trust preferred securities:*
Contact your investment broker for information on transfer procedures.

## OTHER INFORMATION

The Company has included in its 2008 Form 10-K annual report certifications pursuant to Section 13a-14 of the Securities Exchange Act of 1934 of the Chief Executive Officer (CEO) and the Chief Financial Officer of the Company as Exhibits 31.1 and 31.2, respectively. The Company has submitted to the New York Stock Exchange a certification, dated June 3, 2008, of the CEO certifying that she is not aware of any violation by the Company of the New York Stock Exchange corporate governance listing standards.