Hawaiian Electric Industries, Inc.

2007 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)) and decisions concerning the extent of the presence of the federal government and military in Hawaii;
- the effects of weather and natural disasters, such as hurricanes, earthquakes, tsunamis 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 the credit markets to obtain financing;
- 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 assumptions used to calculate retirement benefits costs and changes in funding requirements;
- 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);
- 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 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 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, environmental laws and regulations, the potential regulation of greenhouse gas emissions 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 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 new accounting principles (such as the effects of Statement of Financial Accounting Standards (SFAS) No. 158 regarding employers' accounting for defined benefit pension and other postretirement plans and Financial Accounting Standards Board (FASB) Interpretation No. (FIN) 48 regarding uncertainty in income taxes), continued regulatory accounting under SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation," and the possible effects of applying FIN 46R, "Consolidation of Variable Interest Entities," and Emerging Issues Task Force Issue No. 01-8, "Determining Whether an Arrangement Contains a Lease," to PPAs with independent power producers;
- 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 ability of consolidated HEI to generate capital gains and utilize capital loss carryforwards on future tax returns;
- the risks of suffering losses and incurring liabilities that are uninsured; and
- other risks or uncertainties described elsewhere in this report and in other periodic reports (e.g., "Item 1A. Risk Factors" in the Company's Annual Report on Form 10-K) previously and subsequently filed by HEI and/or HECO with the Securities and Exchange Commission (SEC).

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

Selected Financial Data

Hawaiian Electric Industries, Inc. and Subsidiaries Years ended December 31	2007	2006	2005	2004	2003
(dollars in thousands, except per share amounts)					
Results of operations					
Revenues	$ 2,536,418	$ 2,460,904	$ 2,215,564	$ 1,924,057	$ 1,781,316
Net income (loss)					
Continuing operations	$ 84,779	$ 108,001	$ 127,444	$ 107,739	$ 118,048
Discontinued operations	–	–	(755)	1,913	(3,870)
	$ 84,779	$ 108,001	$ 126,689	$ 109,652	$ 114,178
Basic earnings (loss) per common share					
Continuing operations	$ 1.03	$ 1.33	$ 1.58	$ 1.36	$ 1.58
Discontinued operations	–	–	(0.01)	0.02	(0.05)
	$ 1.03	$ 1.33	$ 1.57	$ 1.38	$ 1.53
Diluted earnings per common share	$ 1.03	$ 1.33	$ 1.56	$ 1.38	$ 1.52
Return on average common equity-continuing operations *	7.2%	9.3%	10.5%	9.4%	11.1%
Return on average common equity	7.2%	9.3%	10.4%	9.5%	10.7%
Financial position **					
Total assets	$ 10,293,916	$ 9,891,209	$ 9,951,577	$ 9,719,257	$ 9,307,700
Deposit liabilities	4,347,260	4,575,548	4,557,419	4,296,172	4,026,250
Other bank borrowings	1,810,669	1,568,585	1,622,294	1,799,669	1,848,388
Long-term debt, net	1,242,099	1,133,185	1,142,993	1,166,735	1,064,420
HEI- and HECO-obligated preferred securities of trust subsidiaries	–	–	–	–	200,000
Preferred stock of subsidiaries – not subject to mandatory redemption	34,293	34,293	34,293	34,405	34,406
Stockholders' equity	1,275,427	1,095,240	1,216,630	1,210,945	1,089,031
Common stock					
Book value per common share **	$ 15.29	$ 13.44	$ 15.02	$ 15.01	$ 14.36
Market price per common share					
High	27.49	28.94	29.79	29.55	24.00
Low	20.25	25.69	24.60	22.96	19.10
December 31	22.77	27.15	25.90	29.15	23.69
Dividends per common share	1.24	1.24	1.24	1.24	1.24
Dividend payout ratio	120%	93%	79%	90%	81%
Dividend payout ratio-continuing operations	120%	93%	78%	91%	78%
Market price to book value per common share **	149%	202%	172%	194%	165%
Price earnings ratio ***	22.1x	20.4x	16.4x	21.4x	15.0x
Common shares outstanding (thousands) **	83,432	81,461	80,983	80,687	75,838
Weighted-average	82,215	81,145	80,828	79,562	74,696
Shareholders ****	34,281	35,021	35,645	35,292	34,439
Employees **	3,520	3,447	3,383	3,354	3,197

* 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 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 14, 2008, HEI had 34,185 registered shareholders and participants.

The Company discontinued its international power operations in 2001. Also see "Commitments and contingencies" in Note 3 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.

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 three strategic objectives are to operate the electric utility and bank subsidiaries for long-term growth, maintain HEI's annual dividend 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), provide 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), Hawaii's third largest financial institution based on total assets.

In 2007, income from continuing operations was $85 million, compared to $108 million in 2006. Basic earnings per share from continuing operations were $1.03 per share in 2007, down 23% from $1.33 per share in 2006 due to lower earnings for the electric utility and bank segments, partly offset by slightly lower losses for the "other" segment.

The electric utilities' 2007 earnings were impacted by a refund accrual, a write-down of plant, and higher expenses, but benefited from interim rate relief and slightly higher kilowatthour (KWH) sales. Electric utility net income in 2007 declined 30% from the prior year due primarily to the $16 million ($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, higher other operation and maintenance (O&M) and depreciation expenses ($50 million), a first quarter 2007 $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, and the discontinuation of demand-side management (DSM) lost margin recovery and shareholder incentives, partly offset by new DSM utility incentives. Net income for the fourth quarter of 2007 was $28 million and included higher rate relief of $20 million ($11 million, net of taxes), compared to net income of $13 million for the fourth quarter of 2006.

The bank's earnings in 2007 were hurt by the challenging interest rate environment—a relatively flat yield curve throughout most of 2007, an increased provision for loan losses primarily for one commercial borrower, higher legal expenses, increased costs to strengthen ASB's risk management and compliance infrastructure and competitive factors impacting its ability to increase loans and attract deposits. Also in 2007, ASB recorded a pension curtailment gain of $5.3 million, net of taxes, due to retirement benefit plan changes. 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.

The "other" segment's $20 million loss in 2007 was less than the $23 million loss in 2006 primarily due to the gain on the sale of the remaining shares of a venture capital investment (compared to unrealized and realized losses on this investment in 2006), gains on the sales of leveraged lease investments, and lower funding of the HEI Charitable Foundation, partly offset by higher consulting and interest expenses.

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, 2007 was 5.4%. HEI's Board believes that HEI should have a payout ratio of 65% or lower on a sustainable basis and that cash flows should support an increase before it considers increasing the common stock dividend above its current level. The dividend payout ratios based on net income for 2007, 2006 and 2005 were 120%, 93% and 79%, respectively. The payout ratios for 2007 and 2006 were higher than in 2005 primarily due to lower net income in those years.

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 the 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 (DBEDT), U.S. Census Bureau and Bloomberg).

Because its core businesses provide local electric utility and banking services, the Company's operating results are influenced by the strength of Hawaii's economy.

In recent years, Hawaii's economy experienced strong growth fueled by increases in tourism, military spending by the federal government to expand and revitalize its facilities, strength in the housing market and increases in residential and commercial construction. Growth in 2004 and 2005 was 5.6% and 4.3%, respectively. In 2006, Hawaii started to see a moderating of the growth rate to 3.0% and the most recent outlook by local economists is for further slowing of the growth rate by 0.1% per year for 2007, 2008 and 2009. This growth translated into rising demand for electricity between 2000 and 2004 and a stabilization of demand at high levels through 2007.

Tourism saw record levels of growth in 2004 and 2005, but stabilized in 2006 and 2007. Visitor days in 2007 were slightly lower than in 2006 due to lower arrivals. Visitor expenditures were modestly higher due largely to increases in hotel room rates. State economists expect growth in 2008 with projected increases of 1% in visitor days and 4% in visitor expenditures. Historically, tourism has been affected by the health of the U.S and Japanese economies. The real gross domestic product (GDP) growth in the U.S. is estimated to have been 2.2% in 2007 and to be 2.2% in 2008. For Japan, real GDP is estimated to have been 1.8% in 2007 and to be 1.5% in 2008, compared to 2.4% in 2006 and 1.9% in 2005.

Hawaii's real estate market followed a pattern similar to tourism, showing record growth in 2004 and 2005 and slowing in 2006 and 2007. Values on Oahu, the most populous of the five major islands, have held with the average median price for a single-family home of $643,500, slightly higher than the median for 2006 of $630,000. Values on the Big Island, Maui, Molokai and Kauai have not held up as well. The strength of the Hawaii real estate market has supported historically low delinquency rates in the bank's loan portfolio. The slowing of the residential housing market has been accompanied by an increase in foreclosure activity, but not to levels seen in many mainland markets. According to a national real estate research firm, Hawaii had one of the lowest foreclosure rates in the nation in 2007, ranking 43rd among the 50 states.

The outlook for the construction industry in Hawaii remains positive. Construction activity, as measured by permitting activity, peaked in 2006 and stabilized in 2007. Residential construction activity declined in 2007, as rising costs met flattening demand. Military, industrial and commercial construction activity were stabilizing factors in 2007 as increased activity in those sectors helped offset the decline in residential construction. Local economists expect the overall level of construction activity to remain fairly stable, as military and industrial and commercial construction will continue to be stabilizing factors. Risks to this outlook include whether reduced market liquidity will impact funding of commercial construction projects in Hawaii and whether the Federal government will reduce spending on new military projects.

While the overall outlook for Hawaii is for continued moderate growth, factors such as a U.S. economic recession, inflation, and availability of credit could negatively impact the outlook for key industries such as tourism and construction. Although Hawaii unemployment remains low and well-below national averages, recent data indicates an upward trend. High energy costs also continue to contribute to inflation rates in Hawaii that are higher than the national inflation rate, which will in turn stress Hawaii consumers.

Management also monitors (1) oil prices because of their impact on the rates the utilities charge for electricity and the potential effect of increased electricity prices on usage, and (2) interest rates because of their potential impact on ASB's earnings, HEI's and HECO's cost of capital and pension costs, and HEI's stock price. Crude oil prices continued to push higher through the end of the year amid strong global demand and a weaker dollar. Crude oil traded at an average price of $74.21 per barrel during 2007 based on West Texas Intermediate markets, compared to an average price of $70.52 per barrel in 2006, and is expected to continue trading at a premium into 2008 due to continued geopolitical instability and tight refining capacity. The average fuel oil cost per barrel for the electric utilities, however, increased only 1% in 2007 compared to 2006.

Volatility in the interest rate environment during the second half of 2007 was primarily due to the credit issues arising from the subprime mortgage crisis and concerns about the health of the economy. Although the overall level of Treasury rates started to decline in the second half of 2007, ASB continued to face margin pressure as wholesale borrowing costs and deposit rates, which are generally correlated with the 3-month Libor rate, did not decline accordingly. As of December 31, 2007, the spread between the 3-month Treasury and 3-month Libor swap rate was 1.46%, compared to the December 31, 2006 spread of 0.34%.

Results of Operations

(dollars in millions, except per share amounts)	2007	% change	2006	% change	2005
Revenues	$ 2,536	3	$ 2,461	11	$ 2,216
Operating income	204	(15)	239	(12)	271
Income from continuing operations	$ 85	(22)	$ 108	(15)	$ 128
Loss from discontinued operations	–	NM	–	NM	(1)
Net income	$ 85	(22)	$ 108	(15)	$ 127
Electric utility	$ 52	(30)	$ 75	3	$ 73
Bank	53	(5)	56	(14)	65
Other	(20)	NM	(23)	NM	(10)
Income from continuing operations	$ 85	(22)	$ 108	(15)	$ 128
Basic earnings (loss) per share					
Continuing operations	$ 1.03	(23)	$ 1.33	(16)	$ 1.58
Discontinued operations	–	NM	–	NM	(0.01)
	$ 1.03	(23)	$ 1.33	(15)	$ 1.57
Dividends per share	$ 1.24	–	$ 1.24	–	$ 1.24
Weighted-average number of common shares outstanding (millions)	82.2	1	81.1	–	80.8
Dividend payout ratio	120%		93%		79%

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 description of ASB's retirement benefit plan changes that become effective on December 31, 2007. No other changes were made to the retirement benefit plans' provisions in 2007, 2006 and 2005 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), and thus, 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. The Company based its selection of an assumed discount rate for 2008 net periodic cost and December 31, 2007 disclosure on the plans' actuarial consultant's cashflow 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, 2007. In selecting an assumed rate of return on plan assets, the Company considers 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.

For 2007, the Company's retirement benefit plans' assets generated a total return, net of investment management fees, of 8.6%, resulting in earnings and realized and unrealized gains of $87 million, compared to $122 million for 2006 and $65 million for 2005. The market value of the retirement benefit plans' assets as of December 31, 2007 was $1.1 billion. See "Liquidity and Capital Resources" below for the Company's cash contributions to the retirement benefit plans.

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		Retirement benefits expense, net of tax benefits				Retirement benefits paid and plan expenses		
	December 31		Years ended December 31				Years ended December 31		
	2007 [1]	2006	(Estimated) 2008 [1, 2]	2007 [1]	2006	2005 [3]	2007	2006	2005
(in millions)									
Consolidated HEI	$(4)	$(140)	$17	$20	$17	$11	$57	$55	$51
Consolidated HECO	1	(127)	17	16	13	8	53	51	50
ASB	–	(8)	(1)	2	3	2	2	2	1

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, 2008).
3 Does not include impact of the Medicare Prescription Drug, Improvement and Modernization Act of 2003.

The following table reflects the sensitivities of the projected benefit obligation (PBO) and accumulated postretirement benefit obligation (APBO) as of December 31, 2007, 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	$(62)/$68
Other benefits		
Discount rate	+/– 50	(11)/12
Health care cost trend rate	+/– 100	3/(4)

Baseline assumptions: 6.125% discount rate; 8.5% asset return rate; 10% medical trend rate for 2008, grading down to 5% for 2013 and thereafter; 5% dental trend rate; and 4% vision trend rate.

The impact on 2008 net income for changes in actuarial assumptions should be immaterial based on the adoption by the electric utilities of pension and 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)	2007	% change	2006	% change	2005
Revenues [1]	$ 5	NM	$ (2)	NM	$ 21
Operating income (loss)	(11)	NM	(16)	NM	5
Net loss	(20)	NM	(23)	NM	(10)

[1] Including writedowns of and net gains and losses from investments.
NM Not meaningful.

The "other" business segment includes results of operations of HEI Investments, Inc. (HEIII), a company previously holding investments in leveraged leases; Pacific Energy Conservation Services, Inc., 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; HEI and HEI Diversified, Inc. (HEIDI), holding companies; and eliminations of intercompany transactions.

- 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 recorded net income of $16.2 million in 2005, including a gain of $14 million on the sale of its approximate 25% interest in a trust that is the owner/lessor of a 60% undivided interest in a coal-fired electric generating plant in Georgia. Most of the approximately $5 million of income taxes on the sale were recorded at HEI in accordance with the Company's tax allocation policy. Since HEIII has now sold substantially all of its investments, the Company currently plans to wind up HEIII's affairs during 2008.

- HEIPI recorded net income of $1.0 million in 2007, net losses of $1.8 million in 2006 and net income of $3.5 million in 2005, which amounts include income and losses from and/or writedowns of venture capital investments. In 2005, HEIPI recognized a $4.6 million unrealized gain ($2.9 million after-tax) on its investment in Hoku Scientific, Inc. (Hoku), a materials science company focused on clean energy technologies. HEIPI began selling Hoku stock in February 2006 when its lock-up agreement expired. In 2006, HEIPI recognized $2.6 million in unrealized and realized losses ($1.6 million after-tax) on its investment in Hoku. In January 2007, HEIPI sold its remaining investment in Hoku for a net after-tax gain of $0.9 million. As of December 31, 2007, HEIPI's venture capital investments amounted to $1.6 million.

- HEI Corporate operating, general and administrative expenses (including labor, employee benefits, incentive compensation, charitable contributions, legal fees, consulting, rent, supplies and insurance) were $14.0 million in 2007, compared to $12.1 million in 2006 and $14.8 million in 2005. In 2007 consulting expenses were higher, but funding of the HEI Charitable Foundation was lower. In 2006, incentive and share-based compensation was lower than in 2005. HEI Corporate and the other subsidiaries' net loss was $25.8 million in 2007, $24.5 million in 2006 and $30.0 million in 2005, the majority of which is comprised of financing costs. The results for 2005 include most of the $5 million of income taxes on the $14 million gain on sale by HEIII of the 25% interest in the trust described above.

- The "other" segment's interest expenses were $25.3 million in 2007, $23.1 million in 2006 and $25.9 million in 2005. In 2007, financing costs increased primarily due to higher medium-term note interest. In 2006, financing costs decreased due to the use of lower-costing short-term commercial paper borrowings to replace or temporarily refinance maturing medium-term notes.

Effects of inflation

U.S. inflation, as measured by the U.S. Consumer Price Index (CPI), averaged 4.1% in 2007, 2.5% in 2006 and 3.4% in 2005. Hawaii inflation, as measured by the Honolulu CPI, was 5.9% in 2006 and 3.8% in 2005. DBEDT estimates average Honolulu CPI to have been 4.5% in 2007 and forecasts it to be 3.8% for 2008. 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, 2007	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	$ 306	$ –	$ –	$ –	$ 306
Other checking	860	–	–	–	860
Savings	1,402	–	–	–	1,402
Money market	175	–	–	–	175
Term certificates	1,250	297	50	7	1,604
Total deposit liabilities	3,993	297	50	7	4,347
Other bank borrowings	578	543	340	350	1,811
Long-term debt, net	50	–	215	1,001	1,266
Operating leases, service bureau contract and maintenance agreements	26	34	16	33	109
Open purchase order obligations	86	29	1	–	116
Fuel oil purchase obligations (estimate based on January 1, 2008 fuel oil prices)	898	1,793	1,795	1,793	6,279
Power purchase obligations– minimum fixed capacity charges	119	237	234	1,015	1,605
Liabilities for uncertain tax positions (FIN 48 liability)	–	9	3	–	12
Total (estimated)	$5,750	$2,942	$2,654	$4,199	$15,545

December 31, 2007	
(in millions)	
Other commercial commitments to ASB customers	
Loan commitments (primarily expiring in 2008)	$ 94
Loans in process	71
Unused lines and letters of credit	1,053
Total	$ 1,218

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, 2007, the fair value of the assets held in trusts to satisfy the obligations of the qualified pension plans exceeded the pension plans' accumulated benefit obligation. Thus, no minimum funding requirements for retirement benefit plans have been included in the tables above. The funding requirements of the Pension Protection Act become effective in 2008, but the Company does not expect those requirements to cause an increase in its estimated qualified pension plans contribution in 2008.

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

The Company believes that its ability to generate cash, both internally from electric utility and banking operations and externally from issuances of equity and debt securities, commercial paper and bank borrowings, is adequate to maintain sufficient liquidity to fund its contractual obligations and commercial commitments in the tables above, 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 $10.3 billion as of December 31, 2007 and $9.9 billion as of December 31, 2006.

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

December 31	2007		2006	
(dollars in millions)				
Short-term borrowings—other than bank	$ 92	4%	$ 177	7%
Long-term debt, net—other than bank	1,242	47	1,133	47
Preferred stock of subsidiaries	34	1	34	1
Common stock equity [1]	1,275	48	1,095	45
	$2,643	100%	$2,439	100%

[1] Includes AOCI charge for retirement benefit plans in accordance with SFAS No. 158, as adjusted by the impact of decisions of the PUC in 2007.

As of February 14, 2008, 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
Medium-term notes	BBB	Baa2

The above 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.

The rating agencies use a combination of qualitative measures (i.e., assessment of business risk that incorporates an analysis of the qualitative factors such as management, competitive positioning, operations, markets and regulation) as well as quantitative measures (e.g., cash flow, debt, interest coverage and liquidity ratios) in determining the ratings of HEI securities. In May 2007, S&P affirmed its corporate credit ratings of HEI and lifted the outlook on HEI from "negative" to "stable" and in September 2007, S&P maintained its stable outlook. 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 also ranks business profiles from "1" (excellent) to "10" (vulnerable). In May 2007, S&P changed HEI's business profile rank from "6" to "5." In September 2007, S&P maintained HEI's rating and business profile rank of "5" and stated that HEI has somewhat weak financial measures. S&P indicated that unsupportive rate treatment that would result in the erosion of key financial parameters, especially cash flow coverage of debt, and a slump in the state economy could lead to downward rating pressure.

See the electric utilities' "Liquidity and capital resources" section below for the May 2007 downgrades by S&P of certain HECO, HELCO and MECO ratings.

In December 2007, Moody's confirmed its ratings and stable outlook for HEI. Moody's indicated that the rating could be downgraded should weaker than expected regulatory support emerge at HECO, which ultimately causes earnings and sustainable cash flow to suffer. Consequently, a shift in Moody's expectations regarding the Company's future sustainable levels of consolidated financial ratios such as Adjusted Cash Flow (net cash flow from operations less net changes in working capital items) to Adjusted Debt below 16% (16% as of September 30, 2007-latest reported by Moody's) or Adjusted Cash Flow to Adjusted Interest of less than 3.5x (4.0x as of September 30, 2007-latest reported by Moody's) could result in a lowering of the Company's ratings.

As of December 31, 2007, $96 million of debt, equity and/or other securities were available for offering by HEI under an omnibus shelf registration and an additional $50 million principal amount of Series D notes were available for offering by HEI under its registered medium-term note program. These registrations will expire to the extent the registered securities have not been issued by November 30, 2008.

HEI utilizes short-term debt, principally commercial paper, to support normal operations and for other temporary requirements. HEI also periodically makes short-term loans to HECO to meet HECO's cash requirements, including the funding of loans by HECO to HELCO and MECO. HEI had an average outstanding balance of commercial paper for 2007 of $67.6 million and had $63.0 million outstanding as of December 31, 2007. Management believes that if HEI's commercial paper ratings were to be downgraded, it might not be able to sell commercial paper under current market conditions.

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. Effective February 19, 2008, HEI entered into a short-term, unsecured credit agreement establishing a line of credit facility of $50 million, expiring on November 18, 2008, with William Street LLC, an affiliate of Goldman, Sachs & Co. See Note 6 of HEI's "Notes to Consolidated Financial Statements" for a description of the credit facilities. In the future, the Company may seek to enter into new lines of credit and may also seek to increase the amount of credit available under such lines as management deems appropriate.

Operating activities provided net cash of $217 million in 2007, $286 million in 2006 and $218 million in 2005. Investing activities used net cash of $222 million in 2007, $141 million in 2006 and $202 million in 2005. In 2007, net cash was used in investing activities primarily for HECO's consolidated capital expenditures, net of contributions in aid of construction, and net increases in loans held for investment, partly offset by repayments of investment and mortgage-related securities and sales of mortgage-related securities, net of purchases. Financing activities used net cash of $43 million in 2007 and $105 million in 2006 and provided net cash of $22 million in 2005. In 2007, net cash used in financing activities was affected by several factors, including payment of common stock dividends and net decreases in deposits and short-term borrowings, partly offset by net increases in other bank borrowings and long-term debt and 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 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% (55% at December 31, 2007), 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 2008 through 2010 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 $50 million will be required during 2008 through 2010 to repay maturing HEI medium-term notes, which are expected to be repaid with the issuance of commercial paper, and/or common stock 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 2008 through 2010 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 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 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 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 2007, 2006 and 2005, but the Company made voluntary contributions in those years. Contributions to the retirement benefit plans totaled $13 million in 2007 (comprised of $12 million made by the utilities and $1 million by ASB), $13 million in 2006 and $24 million in 2005 and are expected to total $14 million in 2008 ($14 million by the utilities and nil by ASB). In addition, the Company paid directly $1 million of benefits in each of 2007, 2006 and 2005 and expects to pay $1 million of benefits in 2008. 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.

<u>Off-balance sheet arrangements</u>

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 is 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.

<u>Certain factors that may affect future results and financial condition</u>

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" and "Certain factors that may affect future results and financial condition" in each of the electric utility and bank segment discussions below.

Economic conditions. Because its core businesses are providing local electric utility and banking services, HEI's operating results are influenced by the strength of 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. See "Economic conditions" above.

U.S. capital markets and credit and interest rate environment. Changes in the U.S. capital markets and credit and interest rate environment can have significant effects on the Company. For example, volatility in U.S. capital markets can affect the fair values of assets available to satisfy retirement benefits obligations. The Company estimates that consolidated retirement benefits expense, net of amounts capitalized and income taxes, will be $17 million in 2008 as compared to $20 million in 2007, partly as a result of the increase in the discount rate from 6% at December 31, 2006 to 6.125% at December 31, 2007. The access to credit markets and the interest rate environment affects the Company's cost of capital and has a significant impact on ASB's financial results. As of December 31, 2007, the Company had no floating-rate long-term debt outstanding. As of December 31, 2007, HEI and HECO, in the aggregate, had $92 million of commercial paper outstanding with a weighted-average interest rate of 5.64% and maturities ranging from 2 to 19 days.

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 Securities and Exchange Commission (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 below and the policies affecting just one segment are 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 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 island utility systems are not interconnected, which requires that additional reliability be built into the systems, 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 combined heat and power (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 megawatt (MW) combustion turbines at Keahole are operating and plans are 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 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 a critical component in achieving KWH sales and revenue growth over time. 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. See "Most recent rate requests." 2007 revenues of the utilities included $32 million of revenues resulting from these interim increases.

The electric utilities' long-term plan to meet Hawaii's future energy needs includes their support of a range of energy choices, including renewable energy and new power supply technologies such as DG. The PUC has issued a decision and framework in a competitive bidding proceeding and a decision in a DG proceeding (see "Certain factors that may affect future results and financial condition—Competition" below). HECO's subsidiary, Renewable Hawaii, Inc. (RHI), has initial approval from the HECO Board of Directors to fund investments by RHI of up to $10 million in selected renewable energy projects to help bring online commercially feasible renewable energy sources in Hawaii.

Net income for HECO and its subsidiaries was $52 million in 2007 compared to $75 million in 2006 and $73 million in 2005. 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 are taking actions intended to protect Hawaii's island ecology and counter global warming, while continuing to provide reliable power to customers. A three-pronged strategy supports attainment of the State of Hawaii renewable portfolio standards (RPS) and the Hawaii Global Warming Solutions Act of 2007 by: 1) the greening of existing assets, 2) the expansion of renewable energy generation and 3) the acceleration of energy efficiency and load management programs. Major initiatives are being pursued in each category.

In its December 19, 2007 filing with the PUC, HECO reported a consolidated RPS of 13.8% in 2006. This was accomplished through a combination of municipal solid waste (395 gigawatthours (GWh)), geothermal (212 GWh), wind (82 GWh), biomass (79 GWh), hydro (56 GWh), photovoltaic (3.4 GWh), and biodiesel (0.2 GWh) renewable generation resources; 95 GWh of renewable energy displacement technologies; and 476 GWh of energy savings from efficiency technologies.

The electric utilities are actively exploring the use of biofuels for all company-owned existing and planned 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, based upon economic and technical feasibility.

In February 2007, BlueEarth Biofuels LLC (BlueEarth) announced plans for a new biodiesel refining plant to be built on the island of Maui by early 2010. The biodiesel plant will be owned by BlueEarth Maui Biofuels LLC (BlueEarth Maui), a joint venture recently formed 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 $380,000 (with a commitment to invest an additional $20,000) in BlueEarth Maui in exchange for a minority ownership interest. All of UBC's profits from the project will be directed into a biofuels public trust to be created for the purpose of funding biofuels development in Hawaii. MECO intends to lease to UBC a portion of the land owned by MECO for its future Waena generation station as the site for the biodiesel plant, with lease proceeds to be credited to MECO ratepayers. In addition, MECO is negotiating a fuel purchase contract with BlueEarth Maui for biodiesel to be used in existing diesel-fired units at MECO's Maalaea plant. Both the land lease agreement and biodiesel fuel contract will require PUC approval. Although not required to do so, BlueEarth Maui has also announced plans to prepare an environmental impact study 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.

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 to be located at HECO's Archer substation. The contract is subject to PUC approval. On September 28, 2007, HECO issued a Solicitation of Interest for its planned Renewable Energy Request for Proposals for combined renewable energy projects up to 100 MW on Oahu. On February 11, 2008, HECO submitted its draft Renewable Energy Request for Proposals for renewable energy projects to 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 understandings with project developers, no investments have been made to date.

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

Energy efficiency and demand-side management 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.

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

Results of Operations

(dollars in millions, except per barrel amounts)	2007	% change	2006	% change	2005
Revenues [1]	$ 2,106	3	$ 2,055	14	$ 1,806
Expenses					
Fuel oil	774	(1)	782	22	640
Purchased power	537	6	507	11	458
Other	664	11	599	10	546
Operating income	131	(22)	167	3	162
Allowance for funds used during construction	8	(16)	9	30	7
Net income	52	(30)	75	3	73
Return on average common equity	5.0%		7.5%		7.1%
Average price per barrel of fuel oil [1]	$ 69.08	1	$ 68.13	20	$ 56.61
Kilowatthour sales (millions)	10,118	–	10,116	–	10,090
Cooling degree days (Oahu)	4,835	7	4,520	(9)	4,971
Number of employees (at December 31)	2,145	3	2,085	1	2,066

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 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. The electric utilities are currently estimating KWH sales for 2008 and 2009 to increase over the prior year by 1.2% and 1.1%, respectively.

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 increased 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).

• In 2006, the electric utilities' revenues increased by 14%, or $249 million, from 2005 primarily due to higher fuel prices ($200 million), interim rate relief granted by the PUC in late September 2005 ($30 million), slightly higher KWH sales ($13 million), and higher DSM program recovery revenues ($6 million), partly offset by lower shareholder incentives and lost margins ($4 million), including the surcharge transferred to base rates in the interim rate relief granted in September 2005. Since May 26, 2006, HECO and, since September 26, 2006, HELCO and MECO, have discontinued their recovery of lost margins and shareholder incentives for their DSM programs, which has resulted in reduced revenues. KWH sales increased 0.3% from 2005 primarily due to new load growth (i.e., increase in number of customers), largely offset by the impacts of cooler and less humid weather and customer conservation. Cooling degree days for Oahu were 9% lower in 2006 compared to 2005. The higher fuel prices are also reflected in the higher amount of customer accounts receivable and accrued unbilled revenues.

Operating income in 2006 was $5 million higher than in 2005 due primarily to the impact of HECO’s interim rate increase in late September 2005, partly offset by higher other expenses, including higher maintenance and retirement benefit expenses, and the discontinuation of the recovery of DSM lost margins and shareholder incentives.

Fuel oil and purchased power expenses in 2006 increased by 22% and 11%, respectively, due primarily to higher fuel prices, which are generally passed on to customers.

Other expenses increased 10% in 2006 due to an 8% (or $13 million) increase in “other operation” expense; a 10% (or $8 million) increase in maintenance expense; a 6% (or $7 million) increase in depreciation expense; and a 14% (or $23 million) increase in taxes, other than income taxes, primarily due to the increase in revenues. “Other operation” expenses increased 8% in 2006 when compared to 2005 due primarily to $5 million higher expenses for production operations (including expenses incurred to sustain or increase generating unit availability and lease rent and operating expenses for distributed generation units on Oahu), higher DSM expenses which are generally passed on to customers through a surcharge, and higher retirement benefits expenses. Pension and other postretirement benefit expenses for the electric utilities increased $9 million over 2005 due in part to the adoption of a 25 basis points lower discount rate as of December 31, 2005. Maintenance expenses increased 10% due to $7 million higher production maintenance expense (primarily due to generating plant maintenance and an increase in the number and greater scope of generating unit overhauls) and $1 million higher transmission and distribution maintenance expense (including higher substation maintenance, vegetation management and distribution line maintenance expenses). Higher depreciation expense was attributable to additions to plant in service in 2005 (including HECO’s New Kuahua Substation, Mokuone Substation 46 kilovolt (kV) and 12 kV line extensions, an office building air conditioning replacement and HELCO’s Keahole power plant noise mitigation measures).

The trend of increased O&M expenses is expected to continue in 2008 as the electric utilities expect higher DSM expenses (that are generally passed on to customers through a surcharge, including additional expenses for programs that were approved by the PUC in the EE DSM Docket) and higher production expenses, primarily due to the increased duty on HECO’s generating assets commensurate with the level of demand that has occurred over the past five years and higher costs for materials and contract services.

As a result of load growth on Oahu and other factors, there currently is an increased risk to generation reliability at least until HECO installs its planned new generating unit in 2009. 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 distributed generation at some substations and encouraging energy conservation. The marginal costs of supplying energy to meet growing demand, however, are increasing because of the decreasing peak reserve margin situation, and the trend of cost increases 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 amounts collected are refundable, with interest, to the extent they exceed the amount approved in the 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 and return on rate base) 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 14, 2008, the return on average common equity (ROACE) found by the PUC to be reasonable in the most recent final rate decision for each utility was 11.40% for HECO (D&O issued on December 11, 1995, based on a 1995 test year), 11.50% 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 amended proposed final D&O issued by the PUC on October 25, 2007 in HECO’s 2005 test year rate case and the interim rate increases in HECO, HELCO and MECO rate cases based on 2007, 2006 and 2007 test years issued in October, April and December 2007, respectively, were 10.70%.

For 2007, 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 4.85%, 8.17% and 5.98%, respectively. HECO's actual ROACE continues to be significantly lower than its allowed ROACE primarily because of increased other O&M expenses, which are expected to continue and have resulted in HECO seeking rate relief more often than in the past. The interim rate relief granted to HECO by the PUC in September 2005 and in October 2007 (see below) was based in part on increased costs of operating and maintaining HECO's system.

As of February 14, 2008, the return on rate base (ROR) found by the PUC to be reasonable in the most recent final rate decision for each utility was 9.16% 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. The ROR used for purposes of the amended proposed final D&O in HECO's 2005 test year rate case was 8.66%. For 2007, the actual RORs (calculated under the ratemaking method and reported to the PUC) for HECO, HELCO and MECO were 4.92%, 6.72% and 5.59%, 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 8 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 9.9%, or $99 million in annual base revenues, based on a 2005 test year, a 9.11% ROR and an 11.5% ROACE. The requested increase included transferring the cost of existing DSM programs from a surcharge line item on electric bills into base electricity charges. HECO also requested approval and/or modification of its existing and proposed DSM programs, and an associated utility incentive mechanism. Excluding the surcharge transfer amount, the requested net increase to customers was 7.3%, or $74 million.

In March 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 issues for the EE DSM Docket included (1) whether, and if so, what, energy efficiency goals should be established, (2) whether the proposed and/or other DSM programs will achieve the established energy efficiency goals and be implemented in a cost-effective manner, (3) what market structures are most appropriate for providing these or other DSM programs, (4) for utility-incurred costs, what cost recovery mechanisms and cost levels are appropriate, (5) whether, and if so, what incentive mechanisms are appropriate to encourage the implementation of DSM programs, and (6) which DSM programs should be approved, modified, or rejected. See "Other regulatory matters—Demand-side management programs" below for a discussion of the PUC's D&O issued in the EE DSM Docket on February 13, 2007.

In September 2005, HECO, the Division of Consumer Advocacy, Department of Commerce and Consumer Affairs of the State of Hawaii (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, excluding the portion of the original rate case bifurcated into the EE DSM Docket. The remaining 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 (with tariff changes implemented on September 28, 2005). 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 June 19, 2006, the PUC issued an order in HECO's pending 2005 test year rate case, indicating that the record in the pending case had not been developed for the purpose of addressing the factors in Act 162 (Hawaii Revised Statutes §269-16(g)). Act 162, which was effective in June 2006, requires the PUC to consider certain specific factors in evaluating fuel adjustment clauses. See "Energy cost adjustment clauses" in Note 3 of HEI's "Notes to Consolidated Financial Statements. The parties filed stipulations requesting the PUC not to review the Act 162 issues relating to the ECAC in the 2005 test year rate case since the case had been filed and the record in the case completed before Act 162 became law and the settlement agreement in the case included a provision allowing the ECAC to be continued.

On October 25, 2007, the PUC issued an amended proposed final D&O, authorizing an increase of 3.74%, or $45.7 million (or a net increase of $34 million or 2.7%), 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, when issued in final form, would reverse 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 would require 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 December 31, 2007 with interest, is approximately $0.7 million, which amount has been reserved for the refund. Interest on the refund amount would continue to accrue until the amount is refunded to customers. In the amended proposed final D&O, the PUC accepted the parties' position that the review of the ECAC under Act 162 would be made in HECO's 2007 test year rate case.

Under state law, if one or more of the Commissioners were not present at the evidentiary hearings in the proceeding, and the decision is adverse to a party in the proceeding, a proposed final D&O is required before a final D&O can be issued. The parties adversely affected by the proposed final D&O have ten days to file exceptions and present arguments to the PUC, before a final D&O is rendered. HECO and the Consumer Advocate did not file exceptions or seek to present arguments with respect to the amended proposed final D&O, but the DOD filed an exception relating to the manner of determining the interest expense deduction for computing the test year income tax expense. The DOD's position, if adopted by the PUC, would not have a material impact on the authorized rate increase.

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

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

The application addresses the energy cost adjustment clause (ECAC) provisions of Act 162 and requests 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 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. If the reduction in equity balance resulting from the AOCI charges is not restored for ratemaking purposes, the utility's position was that 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 postretirement benefits other than pensions (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. 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 $69.997 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 of $1.158 billion) 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 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 (which is accumulated contributions to its pension plan in excess of net periodic pension cost, which amounted 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.) The parties also agreed that the PUC's determination in the 2005 test year rate case of the issue regarding the interest expense deduction for computing the test year income tax expense (with respect to which the DOD had filed exceptions to the amended proposed final D&O in the 2005 test year rate case) would govern the resolution of that issue in the 2007 test year rate case.

In accordance with Act 162 (Hawaii Revised Statutes §269-16(g)), 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 will file proposed findings of fact and conclusions of law on all issues in this proceeding, including the ECAC, and the schedule for that filing is being determined. The parties agreed that their resolution of this 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 $69.997 million in annual revenues over rates effective at the time of the interim D&O, subject to refund with interest. The interim increase is based on the settlement agreement described above and did not include in rate base the HECO pension asset. The interim D&O also approves, 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.”

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

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 is 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 proposes 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 requests 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 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 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. 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.

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 includes 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 combustion turbine 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 includes 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 (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 energy cost adjustment clause 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.

Other regulatory matters. In addition to the items below, also see "HELCO power situation" and "East Oahu Transmission Project (EOTP)" in Note 3 of HEI's "Notes to Consolidated Financial Statements."

Demand-side management programs. In November 2004, HECO filed a request for a rate increase based on a 2005 test year and approval and/or modification of its existing and proposed DSM programs, and associated utility incentive mechanism. In March 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 based on a 2005 test year into a new EE DSM docket. The bifurcation order allowed HECO to temporarily continue, in the manner they were implemented at the time, its existing three commercial and industrial DSM programs and two residential DSM programs, until further order by the PUC. As a result of the bifurcation order in HECO's rate case, HECO continued its existing DSM programs and cost recovery mechanisms, including the recovery of incremental program costs for its energy efficiency DSM programs through a surcharge mechanism, pending the resolution of the EE DSM Docket.

Following the bifurcation order, HECO also continued to accrue shareholder incentives and lost margins. In December 2005 in the EE DSM Docket, HECO requested PUC approval, on an interim basis, for certain modifications to its existing energy efficiency DSM programs and a new interim DSM program (Interim DSM Proposals). HECO did not request shareholder incentives and lost margins for its proposed new interim DSM program, but did so for the modifications to its existing energy efficiency programs. In January 2006, the Consumer Advocate filed comments on HECO's Interim DSM Proposals, which generally supported the proposals, but objected to the continued recovery of shareholder incentives and lost margins for the existing energy efficiency DSM programs, as well as for the modifications.

In April 2006, the PUC issued an Interim Decision and Order (Interim D&O) approving HECO's requests to modify its existing DSM programs and implement its proposed interim DSM program. However, the PUC also ordered that HECO's recovery of lost margins and shareholder incentives for its DSM programs be discontinued within 30 days of the Interim D&O (i.e., by May 26, 2006), until further order by the PUC. Lost margins and shareholder incentives were estimated and recorded in the year earned, and collected from ratepayers in the current year (lost margins) or the following year (shareholder incentives). Revenues that HECO had previously expected to accrue for lost margins and shareholder incentives from May 26, 2006 through the end of 2006 were estimated at $2.1 million, or $1.2 million in after-tax net income.

In October 2001, HELCO and MECO reached agreements with the Consumer Advocate regarding the continuation of their DSM programs and filed requests to continue their four existing DSM programs. In November 2001, the PUC issued orders (one of which was later amended) that, subject to certain reporting requirements and other conditions, approved the agreements regarding the temporary continuation of HELCO's and MECO's DSM programs until one year after the PUC makes a revenue requirements determination in HECO's next rate case. Under the orders, however, HELCO and MECO were allowed to recover only lost margins and shareholder incentives accrued through the date that interim rates are established in HECO's next rate case, but were permitted in the orders to request to extend the time of such accrual and recovery for up to one additional year.

Based on the Interim D&O in the EE DSM docket, on May 25, 2006, HELCO and MECO filed a request for a one-year extension for the recovery of HELCO and MECO's lost margins and shareholder incentives or until final resolution of the EE DSM Docket. On October 4 and 5, 2006, the PUC issued orders that allowed HELCO and MECO to accrue lost margins and shareholder incentives only up to September 26, 2006 (i.e., one year beyond the interim rate increase in the HECO rate case).

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 authorized HECO to implement its eight proposed EE DSM programs (which include enhancements to its six existing programs, and two new programs, the Residential Low Income (RLI) and the Residential Customer Energy Awareness (RCEA) Programs), with certain modifications. In approving the EE DSM program portfolio, the PUC found that: (1) the EE DSM portfolio should achieve Energy Efficiency goals and should be implemented in a cost-effective manner and (2) the EE DSM programs are necessary to help address HECO's current reserve capacity shortfall.

In addition, 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, to become effective around January 2009. 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 it "intends to solicit bids for the PBF Administrator through an RFP or other appropriate procedure." Furthermore, "[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." A timeline for the proceeding has not been determined.

Unlike the EE DSM programs, load management DSM programs (see below) will continue to be administered by the utilities.

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 Integrated Resource Plan (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 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, and are awaiting PUC approval of those goals. Thus, HELCO and MECO recorded no incentives in 2007.

On March 8, 2007, HECO filed a motion for clarification and/or partial reconsideration of the D&O requesting, among other things, clarification of certain energy efficiency goals for 2007 and 2008, reconsideration of HECO's request for budget flexibility which would allow HECO to increase its DSM program budget within certain limits without PUC approval, and clarification of the calculation of the DSM utility incentive. On May 21, 2007, the PUC clarified the 2007 and 2008 energy efficiency goals and the calculation of the DSM utility incentive, and rejected HECO's request for budget flexibility, but did grant 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 February 2008, the PUC suspended HECO's request for the second increase in the 2007 program budget and requested supplemental information regarding actual expenses, actual participation levels, estimated program impacts and estimated benefit to cost ratios for the program. The supplemental filings will reflect a requested increase of $0.3 million based on actual expenses incurred in 2007.

In October 2007, the PUC opened a proceeding for the review of the utilities' DSM reports and program modifications. On November 30, 2007, the utilities filed their annual DSM Modifications and Evaluation (M&E) Reports. On January 14, 2008, the PUC approved the DSM program modifications proposed by the utilities in the M&E Reports.

In 2004, HECO and the Consumer Advocate reached agreement on a residential load management program and a commercial and industrial load management program and the PUC approved HECO's programs. Implementation of these programs began in early 2005. The 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 from HECO's system to reduce system load when deemed necessary by HECO. In 2007, following PUC approval, this program was expanded to include direct load control of residential central air-conditioning systems. 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. In addition, if HECO interrupts the load, an incentive is paid on the KWHs interrupted.

Avoided cost generic docket. In May 1992, the PUC instituted a generic investigation, including all of Hawaii's electric utilities, 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 KWHs or less who buy power from or sell power to the electric utility. The parties to the 1992 docket include the electric utilities, the Consumer Advocate, the DOD, and representatives of existing or potential independent power producers (IPPs). In March 1994, the parties entered into and filed a Stipulation to Resolve Proceeding, which was subject to PUC approval. The parties could not reach agreement with respect to certain of the issues, which are addressed in Statements of Position filed in March 1994. In July 2004, the PUC ordered the parties to review and update the agreements, information and data contained in the stipulation and file such information. On December 29, 2006, the parties filed an updated stipulation with the PUC. The parties agreed that avoided fuel costs, except for Lanai and Molokai, will be determined using a computer production simulation model and agreed on certain parameters that would be used to calculate avoided costs. The parties were not in total agreement on certain other issues, which will need to be decided by the PUC. HECO and its subsidiaries, the Consumer Advocate and the DOD filed a joint statement of position that they oppose retroactive compensation to Wailuku River Hydro for transformer losses, as proposed by Mauna Kea Power Company, Inc. and the Hawaii Agriculture Research Center. In May 2007, HECO provided the Consumer Advocate, in accordance with the updated stipulation, authorization to acquire HECO's specialized version of the production simulation software to enable the Consumer Advocate to perform independent analyses to verify HECO's results. The Consumer Advocate has acquired a copy of the software and has used it to replicate HECO's and MECO's production simulations submitted for their respective rate cases. If the PUC approves the Stipulated Agreement as submitted by the parties to the docket, avoided energy costs will thereafter be determined using the "resource-in / resource-out" methodology instead of the proxy method. Whether avoided energy costs are higher or lower under this methodology than the proxy method will depend on factors including, but not limited to, the planned outage schedule of the generating units, the mix of resources on the particular system, the forecast demand, and, for MECO and HELCO, the relative pricing of diesel fuel and industrial fuel oil.

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 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 are 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 $2.9 million (before interest) of the $9.0 million of incremental IRP costs incurred by the utilities during the 1997-2006 period, and the PUC's decisions are pending on these costs. Also, see Note 3 in HEI's "Notes to Consolidated Financial Statements" and "Demand-side management programs" above.

HECO's IRP. In October 2005, HECO filed its third IRP (IRP-3), which proposes multiple solutions to meet Oahu's future energy needs, including renewable energy resources, energy efficiency, conservation, technology (such as CHP and DG) and central station generation (including a combustion turbine generating unit in 2009 described under "HECO's 2009 Campbell Industrial Park (CIP) generating unit"). In addition, HECO currently plans for all existing generating units to remain in operation (future environmental and other regulatory considerations permitting) beyond the 20-year IRP planning period (2006-2025). On March 7, 2007, HECO, the Consumer Advocate and an environmental organization that had been permitted to intervene, filed a stipulation with the PUC, which the PUC approved in its D&O issued on March 21, 2007. The D&O required HECO to (1) file its Evaluation Report for IRP-3 by May 31, 2007, after which the IRP-3 docket would be closed, (2) initiate the development of its IRP-4, beginning with the first Advisory Group meeting in March 2007 and (3) file its IRP-4 Plan and Action Plans by June 30, 2008, unless ordered otherwise by the PUC. On March 29, 2007, the PUC opened a new docket for the IRP-4 plan and, pursuant to the stipulation, the first Advisory Group meeting was held on March 30, 2007. Numerous Advisory Group meetings and technical sessions have been held since then. HECO filed its Evaluation Report for IRP-3 on May 31, 2007. The updated IRP-3 plan continues to include multiple solutions to meet Oahu's future energy needs. The evaluation report expresses a strong preference for renewable energy and identifies near term, supply-side and demand-side resources that HECO is seeking to add. HECO anticipates that the firm capacity currently expected to be needed in 2022, which will be re-evaluated in IRP-4, will be met by a renewable firm capacity resource or resources. HECO is also considering conversion of its generating units to biofuels or biofuel blends.

HELCO's IRP. In May 2007, HELCO filed its third IRP, which proposes multiple solutions to meet future energy needs on the island of Hawaii. The plan includes the installation of a nominal 16 MW steam turbine (ST-7) in 2009 at its Keahole Generating Station (see "HELCO power situation" in Note 3 of HEI's "Notes to Consolidated Financial Statements"). The plan also follows through on a commitment to have no new fossil-fired generation installed after ST-7. The plan anticipates 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. The parties to the IRP-3 proceedings included HELCO and the Consumer Advocate. An environmental organization and a renewable energy organization were previously parties to the IRP-3 proceeding, but later withdrew. On November 16, 2007, HELCO and the Consumer Advocate filed a stipulated agreement which recommended that the PUC approve HELCO's IRP-3. In the stipulation, HELCO agreed to submit evaluation reports by March 31, 2009 and March 31, 2010, make various improvements to the IRP process, and submit its IRP-4 by March 31, 2011. On January 24, 2008, the PUC issued its D&O approving HELCO's IRP-3 and the stipulated agreement, except that the PUC required HELCO to file its IRP-4 no later than May 31, 2010.

MECO's IRP. In April 2007, MECO filed its third IRP, which proposes multiple solutions to meet future energy needs on the islands of Maui, Lanai and Molokai, including renewable energy resources (such as photovoltaics, additional wind, biomass and waste-to-energy), energy efficiency (continuation of existing and addition of new DSM programs), technology (such as CHP and DG) and competitive bidding for generation or blocks of generation on Maui for 20 MW in each of 2011 and 2013 and 18 MW in 2024 which, under the utility parallel plan, could be located at its Waena site. The plan also includes approximately 2 MW of additional generation through the year 2026 on each of the islands of Lanai and Molokai. On September 21, 2007, the parties to the IRP-3 proceedings, which includes MECO and the Consumer Advocate, filed a stipulated agreement in which they do not request a hearing, they recommend the PUC approve MECO's IRP-3, MECO agrees to submit evaluation reports by December 31, 2008 and December 31, 2009, MECO agrees to make various improvements to the IRP process and submit its IRP-4 by December 31, 2010, and allowance is made for disposition of this proceeding.

The purchased power agreement (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 not less than two years' prior written notice by either party. 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. As a result of this agreement with HC&S, for planning purposes it appears that the timing of the need for the second 20 MW block of firm capacity on Maui can be deferred from 2013 to the 2015 timeframe. However, identifying the timing of the need for the second 20 MW block of firm capacity in the 2015 timeframe does not reduce MECO's need to proceed expeditiously with the issuance of an RFP for this second capacity increment, given the multitude of factors that can impact the timing of system firm capacity needs and the potentially long lead time to acquire such resources.

HECO's 2009 Campbell Industrial Park generating unit. HECO plans to build a new 110 MW simple cycle combustion turbine (CT) generating unit at CIP and 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 2009, fueled by biodiesel, but with the capability of using diesel or naphtha. 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 Department of Health of the State of Hawaii (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.

Costs for the Project (exclusive of the costs of the community benefit measures described below) are currently estimated at $164 million. As of December 31, 2007, accumulated Project costs for planning, engineering, permitting, materials, land and AFUDC amounted to $23 million.

In August 2007, HECO entered into a contract with Imperium Services, LLC, to supply biodiesel for the planned generating unit, subject to PUC approval. In October 2007, HECO filed an application with the PUC for approval of this biodiesel supply contract. Imperium Services, LLC agreed to comply with HECO's procurement policy requiring sustainable sources of biofuel and biofuel feedstocks.

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).

Adequacy of supply.

HECO. HECO's 2008 Adequacy of Supply (AOS) letter, filed in January 2008, indicates 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 combustion turbine 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 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 a firm, dispatchable resource (with a strong preference for a renewable resource) to meet this need, while continuing contingency planning activities. Any plan to seek additional firm capacity is required to proceed under the guidance of the Competitive Bidding Framework issued by the PUC in December 2006. HECO is currently conducting its IRP-4 process, which includes an assessment of the firm capacity resource additions needed to address expected continuing reserve capacity shortfall.

HECO's gross peak demand was 1,327 MW in 2004, 1,273 MW in 2005, 1,315 MW in 2006 and 1,261 MW in 2007. 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 2008 Adequacy of Supply letter filed in January 2008 indicated that HELCO's generation capacity for the next three years, 2008 through 2010, is sufficiently large to meet all reasonably expected demands for service and provide reasonable reserves for emergencies.

MECO. MECO's 2008 Adequacy of Supply letter filed in January 2008 indicated that MECO's generation capacity for the next three years, 2008 through 2010, is sufficient to meet the forecasted demands on the islands of Maui, Lanai and Molokai. Although MECO may not at times have sufficient capacity on the Maui system to cover for the loss of the largest unit, MECO will implement appropriate mitigation measures to overcome any reserve capacity situations.

On occasions in 2006 and 2007, MECO experienced lower than normal generation capacity due to the unexpected temporary loss of several of its generating units, and issued public requests that its customers voluntarily conserve electricity.

October 2006 outages. On Sunday, October 15, 2006, shortly after 7 a.m., 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.

As is the electric utilities' practice with all major system emergencies, management immediately committed to investigating the outage caused by the earthquakes, including bringing in an outside industry expert to help identify any potential improvements to procedures or systems, and also made arrangements for a preliminary briefing of the PUC on October 19 and 20, 2006. HECO also conducted a public briefing on October 23, 2006. HECO has made it clear that in addition to any investigation it undertakes, it will 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. The docket is awaiting a decision by the PUC.

Management cannot predict the outcome of the investigation or its impacts on the utilities. Management currently believes the financial impacts of property damage and claims resulting from the earthquakes and outages are not material, but future findings and developments may change that belief.

Intra-governmental wheeling of electricity. In June 2007, the PUC initiated an investigation 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 DBEDT, the City and County of Honolulu and the Counties of Hawaii, Maui and Kauai), two environmental groups, and two renewable energy developers. Two renewable energy contractors and a renewable energy developer also have been granted more limited participant status. The procedural schedule includes technical workshops and meetings through November 2008, with a formal process to commence thereafter.

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 "Environmental regulation" in Note 3 of HEI's "Notes to Consolidated Financial Statements."

Energy Policy Act of 2005. On August 8, 2005, the President signed into law the Energy Policy Act of 2005 (the Act). The Act provides $14.5 billion in tax incentives over a 10-year period designed to boost conservation efforts, increase domestic energy production and expand the use of alternative energy sources, such as solar, wind, ethanol, biomass, hydropower and clean coal technology. Ocean energy sources, including wave power, are identified as renewable technologies. Section 355 of the Act authorizes a study by the U.S. Department of Energy of Hawaii's dependence on oil; however, that provision is subject to appropriation, as is $9 million authorized under Section 208 for a sugar cane ethanol program in Hawaii. No funds have been appropriated to date. Incentives also include tax credits and shorter depreciable lives for many assets associated with energy production and transmission. The Act's primary direct impact on HECO and its subsidiaries is currently expected to be the reduction in the depreciable tax life, from 20 years to 15 years, of certain electric transmission equipment placed into service after April 11, 2005.

Public Utility Holding Company Act of 1935 (1935 Act) and Public Utility Holding Company Act of 2005 (2005 Act). The repeal of the 1935 Act, effective February 8, 2006, eliminates significant federal restrictions on the scope, structure and ownership of electric utilities. Some believe that the repeal will result in increased institutional ownership of and private equity and hedge fund investments in public utilities, increased consolidation in the industry, more Federal Energy Regulatory Commission (FERC) oversight, and additional diversification by electric utilities. The increased oversight by FERC results in part from the adoption of the 2005 Act, which provides for FERC access to the books and records of utility holding companies and, absent exemptions or waivers, imposes certain record retention and accounting requirements on public utility holding companies. HEI and HECO filed a notification claiming a waiver of such requirements as single-state public utility holding companies. A written notice dated May 26, 2006 was received from FERC confirming the effectiveness of the HEI and HECO waivers. Regulation and oversight of HECO and its subsidiaries by the PUC, however, remains unchanged.

Renewable Portfolio Standard. The 2004 Hawaii Legislature amended an existing renewable portfolio standards (RPS) law to require 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. These standards may be met by the electric utilities on an aggregated basis and were met in 2005 when the electric utilities attained a RPS of 11.7%. It may be difficult, however, for the electric utilities to attain the required renewables percentages in the future, and management cannot predict the future consequences of failure to do so (including potential penalties to be established by the PUC).

The RPS law was further amended in 2006 to provide 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. The amendment also added provisions for penalties to be established by the PUC if the RPS requirements are not met and criteria for waiver of the penalties by the PUC, if the requirements cannot be met due to circumstances beyond the electric utility's control.

The law directed that the PUC , by December 31, 2007, develop and implement a utility ratemaking structure, which may include, but is not limited to, performance-based ratemaking, to provide incentives that encourage Hawaii's electric utility companies 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 which could not have been reasonably anticipated or ameliorated.

On January 11, 2007, the PUC opened a new docket (RPS Docket) to examine Hawaii's amended RPS law, to establish the appropriate penalties and to determine circumstances under which penalties should be levied. The PUC indicated that the 2006 amendment to the RPS law that added provisions for penalties effectively gives utilities incentive to comply with RPS and therefore the PUC would no longer complete the rulemaking process initiated in November 2004, but would instead proceed by way of this RPS Docket to handle any issues related to the utilities meeting RPS. The parties to the proceeding include the electric utilities, the Consumer Advocate, an environmental organization and HREA. The PUC set forth the issues for the proceeding to be (1) the appropriate penalty framework to establish under the RPS law for failure to meet the RPS, (2) the appropriate utility ratemaking structure to establish and include in the framework to provide incentives that encourage electric utilities to use cost effective renewable energy resources while allowing for deviations from the standards in the event the standards cannot be met in a cost-effective manner, or as a result of circumstances beyond the control of the electric utility that could not have been reasonably anticipated or ameliorated and (3) whether the framework should include a provision that provides incentives to encourage utilities to exceed the RPS or to meet their RPS ahead of time or both. In July 2007, HECO, HELCO and MECO proposed a Renewable Energy Infrastructure Program, including a surcharge mechanism, to encourage the funding of renewable energy infrastructure projects.

In October 2007, all but one of the parties executed and filed a stipulation for an RPS framework. The proposed Renewable Energy Infrastructure Program 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 December 2007, the PUC issued a decision and order approving the stipulated framework, with modifications, but deferred the incentive framework, including the proposed renewable energy infrastructure surcharge, to a new generic docket. The PUC also directed the parties to file supplemental briefs in the RPS Docket regarding: (1) the reasonable range of penalties (in $/MWh) to include in the framework, (2) whether RPS non-compliance penalties should be paid into a special fund or to the State of Hawaii and (3) whether electric utilities should be expressly prohibited from recovering RPS non-compliance penalties through electric rates. Supplemental briefs are due in March 2008, and reply briefs are due in April 2008. The procedural schedule for the new generic docket has not yet been set, but will include public hearings in May 2008. The parties for the new docket are the same as the parties for the RPS Docket.

Management cannot predict the outcome of this process.

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). The law provides a cap of 0.5% of the electric utility's peak demand on the total generating capacity produced by eligible customer-generators. The 2004 Legislature amended the net energy metering law by expanding the definition of "eligible customer generator" to include government entities, increasing the maximum size of eligible net metered systems from 10 kilowatts (kw) to 50 kw and limiting exemptions from additional requirements for systems meeting safety and performance standards to systems of 10 kw or less.

In 2005, the Legislature again 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), a renewable energy organization and a solar vendor organization. In September 2007, a stipulated agreement was 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 under 10 kw and to consider in the IRP process any further increases in the maximum capacity of customer-generators and the system cap. Depending on their magnitude, changes made by the PUC by rule or order could have a negative effect on electric utility sales. Management cannot predict the outcome of the investigative proceeding.

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

Non-fossil fuel purchased power contracts. The 2006 Hawaii State legislature passed a measure which 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 of the 2007 Hawaii State Legislature became law and 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. 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.

On April 2, 2007, the U.S. Supreme Court ruled, in Massachusetts v. EPA, that, contrary to the U.S. Environmental Protection Agency's (EPA's) position, the EPA has the authority to regulate greenhouse gases under the Clean Air Act. Although it is too early to assess the ultimate impact of the ruling, since the decision there have been reports that comprehensive legislation may be introduced in Congress this term to regulate greenhouse gas emissions.

Renewable energy. The 2007 Hawaii State Legislature passed a measure stating 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.

Biofuels. The 2007 Hawaii State Legislature passed a measure that has the stated purpose of encouraging further production and use of biofuels in Hawaii, establishes that biofuel processing facilities in Hawaii are a permitted use in designated agricultural districts and establishes a program with the Hawaii Department of Agriculture to encourage the production in Hawaii of energy feedstock (i.e., raw materials for biofuels).

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 any legislation or proposed legislation.

Other developments

Advanced Meter Infrastructure (AMI). HECO continues to evaluate two-way wireless technologies for utility applications through ongoing field tests of a pilot AMI system. The AMI system uses two-way Sensus Metering Systems’ FlexNet technology to communicate with 6,500 advanced meters at both residential and commercial customer sites. AMI technology enables automated meter reading, time-of-use pricing and conservation options for HECO customers. Other utility applications being evaluated include distribution system line monitoring and water heater and air conditioning load control for improved reliability for residential and commercial customers.

Liquidity and capital resources

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 (dollars in millions)	2007		2006	
Short-term borrowings	$ 29	1%	$ 113	6%
Long-term debt, net	885	43	766	41
Preferred stock	34	2	34	2
Common stock equity [1]	1,110	54	959	51
	$2,058	100%	$1,872	100%

1 Includes AOCI charge for retirement benefit plans in accordance with SFAS No. 158, as adjusted by the impact of decisions of the PUC in 2007.

As of February 14, 2008, the S&P and Moody’s ratings of HECO securities were as follows:

	S&P	Moody’s
Commercial paper	A-2	P-2
Revenue bonds (principal amount noted in parentheses, senior unsecured, insured as follows):		
Ambac Assurance Corporation ($0.2 billion)	AAA	Aaa
Financial Guaranty Insurance Company ($0.3 billion)	AA	A3
MBIA Insurance Corporation ($0.3 billion)	AAA	Aaa
XL Capital Assurance Inc. ($0.1 billion)	AAA	A3
HECO-obligated preferred securities of trust subsidiary	BB+	Baa2
Cumulative preferred stock (selected series)	Not rated	Baa3

The above 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.

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 May 2007, S&P lowered the long-term corporate credit and unsecured debt ratings on HECO, HELCO and MECO to BBB from BBB+, lowered the rating on HECO-obligated preferred securities of trust subsidiary to BB+ from BBB-, and lifted HECO’s outlook from “negative” to “stable”. 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).” S&P 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."

S&P also ranks business profiles from "1" (excellent) to "10" (vulnerable), and did not change HECO's business profile rank of "5".

In September 2007, S&P maintained HECO's ratings and business profile rank of "5" and indicated that unsupportive rate treatment that would result in the erosion of key financial parameters, especially cash flow coverage of debt, and a slump in the state economy could lead to downward rating pressure.

In December 2007, 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% (16% as of September 30, 2007-latest reported by Moody's) or Adjusted Cash Flow to Adjusted Interest declined to less than 3.6x (3.8x as of September 30, 2007-latest reported by Moody's) for an extended period, the rating could be lowered.

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, 2007, HECO had $2 million of short-term borrowings from MECO and HELCO had $37 million of short-term borrowings from HECO. HECO had an average outstanding balance of commercial paper for 2007 of $50 million and had $29 million of commercial paper outstanding as of December 31, 2007. Management believes that if HECO's commercial paper ratings were to be downgraded, it may be more difficult for HECO to sell commercial paper under current market conditions.

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. The agreement expires on March 31, 2011. See Note 6 of HEI's "Notes to Consolidated Financial Statements" for a description of the $175 million credit facility. As of December 31, 2007, the line was undrawn. 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.

Revenue bonds are issued by the Department of Budget and Finance of the State of Hawaii for the benefit 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 XL Capital Assurance, Inc. (XLCA), and the ratings of those bonds are based on the ratings of the obligations of the bond insurer rather than HECO. The currently outstanding revenue bonds were initially issued with S&P and Moody's ratings of AAA and Aaa, respectively, based on the ratings of the bond insurer. In 2008, however, ratings of FGIC and XLCA were downgraded by S&P and/or Moody's resulting in a downgrade of the bond ratings of certain of the bonds as shown in the table above. S&P and/or Moody's ratings of Ambac, FGIC, MBIA and XLCA are reported to be on negative outlook and/or watch and/or review for potential downgrade (or additional downgrade). The downgrades were reported to be due in part to the exposures of the bond insurers to the U.S. residential mortgage market.

Operating activities provided $186 million in net cash during 2007. Investing activities used net cash of $185 million, primarily for capital expenditures, net of contributions in aid of construction. Financing activities provided net cash of $1 million, including a $117 million net increase in long-term debt, largely offset by an $84 million net decrease in short-term borrowings and $28 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 in the second half of 2006 and first half of 2007.

SPRBs of up to $20 million (for HELCO) and up to $400 million ($260 million for HECO, $115 million for HELCO and $25 million for MECO) may be issued by the Department of Budget and Finance of the State of Hawaii under

2005 and 2007 legislative authorizations prior to the end of June 30, 2010 and June 30, 2012, respectively, to finance the electric utilities' capital improvement projects.

The PUC must approve issuances, if any, of equity and long-term debt securities by HECO, HELCO and MECO.

For the five-year period 2008 through 2012, the utility forecasts $1.3 billion of gross capital expenditures, approximately 49% of which is for transmission and distribution projects and 45% for generation projects, with the remaining 6% for general plant and other projects. These estimates do not include expenditures, which could be material, that would be required to comply with cooling water intake structure regulations adopted by the EPA in 2004 or the July 1999 Regional Haze Rule amendments (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 2008 through 2012 are currently estimated to total approximately $1.2 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 financing is expected to be required to fund this estimated shortfall as well as any unanticipated expenditures not included in the 2008 through 2012 forecast, such as increases in the costs of, 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 $303 million needed for the net capital expenditures in 2008. For 2008, gross capital expenditures are estimated to be $341 million, including approximately $139 million for transmission and distribution projects, approximately $172 million for generation projects and approximately $30 million for general plant and other projects. Consolidated net capital expenditures for HECO and subsidiaries for 2007, 2006 and 2005 were $186 million, $171 million and $194 million, respectively.

For a discussion of funding for the electric utilities' retirement benefits plans, see Note 1 of HEI's "Notes to Consolidated Financial Statements." 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 2007, 2006 and 2005, they made voluntary contributions in 2007 and 2005. Contributions by the electric utilities to the retirement benefit plans for 2007, 2006 and 2005 totaled $12 million, $10 million and $18 million, respectively, and are expected to total $14 million in 2008. In addition, the electric utilities paid directly less than $1 million of benefits in each of 2007, 2006 and 2005 and expect to pay less than $1 million of benefits in 2008. 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 2008 through 2012. 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, the impacts of DSM programs and combined heat and power 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.

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 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, 2007, HECO and its subsidiaries had recognized $150 million of revenues with respect to interim orders (not including revenues of $16 million for which a reserve, including interest, has been accrued to reflect the PUC’s proposed final D&O in the 2005 HECO rate case), 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 $2.9 million (before interest) of the $9.0 million of incremental IRP costs incurred by the utilities during the 1997-2006 period, and the PUC’s decision is pending on these costs.

Management cannot predict with certainty 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.”

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 (PPAs)” in Note 3 of HEI’s “Notes to Consolidated Financial Statements.” The Company estimates that 76.9% of the net energy generated and purchased by HECO and its subsidiaries in 2008 will be generated from the burning of oil. Purchased KWHs provided approximately 39.5% of the total net energy generated and purchased in 2007 compared to 38.2% in 2006 and 39.1% in 2005.

Failure or delay by the electric utilities’ oil suppliers and shippers to provide fuel pursuant to existing supply contracts, or failure by a major independent power producer 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 16%, 8% and 9% for 2007, 2006 and 2005, respectively, when compared to the prior year. This trend of increased operation and maintenance expenses is expected to continue in 2008 as the electric utilities expect higher DSM expenses (that are generally passed on to customers through a surcharge, including additional expenses for programs that were approved by the PUC in the EE DSM Docket) and higher production expenses, primarily to support the level of demand that has occurred over the past five years and higher costs for material and contract services. 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.

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 March 2000, the PUC approved a standard form contract for customer retention that allows HELCO to provide a rate option for customers who would otherwise reduce their energy use from HELCO's system by using energy from a nonutility generator. Based on HELCO's current rates, the standard form contract provides a 10% discount on base energy rates for qualifying "Large Power" and "General Service Demand" customers. In November 2006, HELCO entered into three-year standard form contracts with two of its hotel customers.

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 closed the competition proceeding and opened investigative proceedings on two specific issues (competitive bidding and DG) to move toward a more competitive electric industry environment under cost-based regulation.

<u>Competitive bidding proceeding</u>. The stated purpose of this proceeding was to evaluate competitive bidding as a mechanism for acquiring or building new generating capacity in Hawaii.

The parties in the proceeding included the Consumer Advocate, HECO, HELCO, MECO, Kauai Island Utility Cooperative (KIUC) and Hawaii Renewable Energy Alliance (HREA), a renewable energy organization. The issues addressed in the proceeding included whether a competitive bidding system should be developed for acquiring or building new generation and, if so, how a fair system can be developed that "ensures that competitive benefits result from the system and ratepayers are not placed at undue risk," what the guidelines and requirements for prospective bidders should be, and how such a system can encourage broad participation.

On June 30, 2006, the PUC issued a decision in this proceeding, which included a proposed framework to govern competitive bidding as a mechanism for acquiring or building new generation in Hawaii and required the parties to submit comments on the proposed framework. On December 8, 2006, the PUC issued a decision that reviewed the parties' comments and revised the competitive bidding framework, which became effective upon issuance of the decision. The final framework states, among other things, that: (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) an exemption from the framework is granted for cooperatively-owned utilities, (4) the framework does not apply to two pending projects (HECO's CIP-1 and HELCO's ST-7), MECO's M-18 project (which went into commercial operation in October 2006), specifically identified offers to sell energy on an as-available basis or to sell firm energy and/or capacity by non-fossil fuel producers that were under review by an electric utility at the time the framework was adopted (provided that negotiations with the nonfossil fuel producers for firm capacity were completed no later than December 31, 2007), and certain other situations identified in the framework, (5) waivers from competitive bidding for certain circumstances will be considered by the PUC and granted when considered appropriate, (6) 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,

(7) 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, (8) 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) in response to a need that is addressed by its Request for Proposal (RFP) or when the PUC otherwise determines, (9) the utility may consider its own self-bid proposals in response to generation needs identified in its RFP, (10) 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 (11) 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 the first half of 2007, the utilities filed proposed 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 proposed Code of Conduct, which were all approved by the PUC later in 2007. In December 2007, the PUC closed the competitive bidding docket.

On September 28, 2007, HECO issued a "Solicitation of Interest" seeking developers who are interested in entering a competitive bidding process to supply added renewable energy to Oahu's power grid. On October 9, 2007, in response to HECO's request for approval to proceed with the proposed RFP and approval of a HECO contract with an Independent Observer for that effort, the PUC issued an order opening a new docket to receive filings, review approval requests, and resolve disputes, if necessary, related to HECO's proposed RFP. The order also identified HECO and the Consumer Advocate as parties to this new docket and approved HECO's contract with the Independent Observer for the proposed RFP. In February 2008, HECO submitted a draft RFP to the PUC and to the Consumer Advocate, and notified parties expressing interest in participating of the availability of the draft RFP on HECO's website. The draft RFP seeks proposals for the supply of up to approximately 100 MW of long-term (i.e. 20 years) renewable energy for the island of Oahu under a power purchase agreement. While the draft RFP is primarily soliciting proposals for non-firm generation, HECO will also consider proposals for firm energy resources as long as the resources qualify under the RPS eligibility requirements. After a technical conference with interested parties is held and comments are received, a final proposed RFP will be submitted to the PUC for its review and approval.

On December 6, 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 and approval of a MECO contract with an Independent Observer for that effort, 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.

In December 2007, the electric utilities filed a letter in the competitive bidding docket requesting approval to update their list of non-fossil fuel purchase offers that are exempt from the competitive bidding process by including on the list three additional non-fossil fuel proposals that the electric utilities received prior to the PUC's adoption of the competitive bidding framework in December 2006. On the same date, HELCO also filed a letter requesting an extension of time to conclude negotiation of a PPA with a non-fossil fuel developer on the island of Hawaii. In January 2008, the PUC issued Order No. 23974 that re-opened the competitive bidding docket and denied the electric utilities' requests. In February 2008, the PUC approved a motion filed by the electric utilities for an extension of time to the end of February 2008 to file a motion for clarification and/or partial reconsideration of Order No. 23974. Later that month, the PUC denied HREA's motion requesting the PUC to clarify and reconsider its decision for two of the three non-fossil fuel proposals that the electric utilities sought to include in the list.

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

Distributed generation 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 in the DG proceeding. In the D&O, the PUC indicated 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.

With regard to DG ownership, the D&O affirmed the ability of the electric 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. In weighing the general advantages and disadvantages of allowing a utility to provide DG services on a customer's site, the PUC found that the "disadvantages outweigh the advantages." 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 electric utilities from providing DG services at this early stage of DG market development. Therefore, the D&O allows the utility to provide DG services on a customer-owned site as a regulated service when (1) the DG resolves a legitimate system need, (2) the DG is the lowest cost alternative to meet that need, and (3) it can be shown that, in an open and competitive process acceptable to the PUC, the customer operator was unable to find another entity ready and able to supply the proposed DG service at a price and quality comparable to the utility's offering.

In April 2006, the PUC provided clarification to the conditions under which the electric 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 electric utilities are evaluating potential DG projects. In July 2006, MECO filed an application for PUC approval of an agreement for the installation of a CHP system at a hotel site on the island of Lanai. The Consumer Advocate did not object to approval of MECO's application with the qualification that no determination be made at this time as to whether the costs associated with installation of the CHP system can be included in MECO's revenue requirements. MECO's response, filed in February 2007, explained that the Consumer Advocate's conditions would not allow MECO to proceed with the project as such a conditional approval would not provide reasonable assurance that MECO will be able to include the associated costs in its revenue requirement. MECO requested that the PUC approve the CHP agreement, approve inclusion of the fuel and transportation costs and associated taxes in MECO's ECAC and allow MECO to include the costs incurred in its revenue requirement for ratemaking purposes. In April 2007, MECO submitted a system economic analysis to the Consumer Advocate to address the Consumer Advocate's concerns and to enable MECO and the Consumer Advocate to reach a stipulation on the issues in the docket. In November 2007, MECO and the Consumer Advocate filed a stipulation recommending that the PUC approve the project and a decision by the PUC is pending.

The January 2006 D&O also required the electric utilities to file tariffs, establish reliability and safety requirements for DG, establish a non-discriminatory DG interconnection policy, develop a standardized interconnection agreement to streamline the DG application review process, establish standby rates based on unbundled costs associated with providing each service (i.e., generation, distribution, transmission and ancillary services), and establish detailed affiliate requirements should the utility choose to sell DG through an affiliate. The electric 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 the present time, but reserved the right to review the reasonableness of both tariffs in rate proceedings for each of the utilities.

Distributed generation tariff proceeding. By order dated December 28, 2006, the PUC opened a new proceeding to investigate the utilities' proposed DG interconnection tariff modifications and standby rate tariffs. Public hearings were held in February and March 2007. In April 2007, the PUC granted intervener status to HREA, a group of hotel and resort companies, a group consisting of a CHP vendor, a hotel company and a hospital management company, a senior living community company and the United States Combined Heat and Power Association. In September 2007, all parties except HREA executed and filed a stipulation for approval of the electric utilities' proposed DG interconnection tariffs. In October 2007, the electric utilities filed modified standby service tariffs and their statement of position on their proposed standby service tariffs. Informal discussions with the parties have been conducted for the purpose of reaching settlement or partial settlement of the standby service tariff issues. In January 2008, the

PUC approved a request from the parties to modify the schedule of proceedings. In the event a settlement agreement is reached by March 7, 2008, a PUC hearing on the agreement is scheduled for March 24, 2008. If an agreement is not reached, an evidentiary hearing would be held in April 2008.

Environmental matters. The HECO, HELCO and MECO generating stations operate under air pollution control permits issued by the 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 (CAA), 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 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" 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.

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, distributed generation or 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, 2007, regulatory liabilities and regulatory assets amounted to $285 million and $262 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, 2007 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, 2007, revenues applicable to energy consumed, but not yet billed to customers, amounted to $114 million.

Revenue amounts recorded pursuant to a PUC interim order are subject to refund, with interest, pending a final order. As of December 31, 2007, HECO and its subsidiaries had recognized $150 million of such revenues with respect to interim orders (not including revenues of $16 million for which a reserve, including interest, has been accrued to reflect the PUC’s proposed final D&O in the 2005 HECO rate case). 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 2007 with assets of $6.9 billion and net income of $53 million, compared to assets of $6.8 billion as of December 31, 2006 and net income of $56 million in 2006.

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 has been facing a challenging interest rate environment that has pressured its net interest margin. 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, putting downward pressure on net interest margin. As the Federal Reserve has already cut the discount rate and Federal Funds Rate twice in 2008, the potential for compression of ASB's margin will continue 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's asset quality remained strong in 2007 as a result of continued strength of the Hawaii economy and the stability of the Hawaii real estate market. Although new home purchase and home resale transaction volumes in Hawaii have fallen off, prices have remained stable and Hawaii's residential real estate market has not experienced the declines in values or increases in the levels of foreclosures seen in many mainland U.S. markets. The consensus outlook for the Hawaii economy is for the rate of growth to moderate in 2008, following several years of very strong growth. The slowdown in the economy may cause 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 provisions for loan losses may begin to increase, following several years of historically low loan losses and loan loss allowances.

Results of Operations

(dollars in millions)		2007	% change		2006	% change		2005
Revenues	$	425	4	$	408	5	$	388
Net interest income		197	(3)		203	(3)		210
Operating income		84	(5)		89	(16)		105
Net income		53	(5)		56	(14)		65
Return on average common equity		9.2%			10.0%			11.7%
Earning assets								
Average balance [1]	$	6,393	–	$	6,367	–	$	6,374
Weighted-average yield		5.59%	2		5.48%	6		5.19%
Costing liabilities								
Average balance [1]	$	6,156	–	$	6,154	–	$	6,157
Weighted-average rate		2.60%	10		2.37%	3		1.97%
Interest rate spread		2.99%	(4)		3.11%	(3)		3.22%
Net interest margin [2]		3.08%	(3)		3.18%	(3)		3.29%

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. If the current interest rate environment persists, compression of ASB's net interest margin will continue to adversely impact earnings.

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, 2007, ASB's loan portfolio mix, net, consisted of 75% residential loans, 11% commercial loans, 7% commercial real estate loans and 7% consumer loans. As of December 31, 2006, ASB's loan portfolio mix, net, consisted of 72% residential loans, 12% commercial loans, 9% commercial real estate loans and 7% consumer loans. ASB's mortgage-related securities portfolio consists primarily of shorter-duration assets and is affected by market interest rates and demand.

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. 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, 2007, ASB's costing liabilities consisted of 71% deposits and 29% other borrowings. As of December 31, 2006, ASB's costing liabilities consisted of 74% deposits and 26% other borrowings. Competition for deposits and the level of short-term interest rates have made it difficult to retain deposits and control funding costs. Deposit retention and growth will remain a challenge in the current environment.

Pressures from declines in the housing market will impact securities held in ASB's investment portfolio. Foreclosures within the subprime sector of the market have increased risk premiums for all mortgage-related securities, especially those underwritten in 2006 and 2007 for which underwriting standards for the collateral of the mortgage-related securities were thought to be most troublesome. While ASB does not have material exposure to securities backed by subprime collateral and does not hold any subprime positions issued within the last five years, a deep recession led by a material decline in housing prices could materially impair the value of the securities it currently holds. As of December 31, 2007, 74% of the portfolio is held in debentures or mortgage-related securities issued by government-sponsored entities. The remaining 26% of the portfolio is composed of mortgage-related securities issued by private issuers (25% are rated AAA and 1% are rated AA or A by nationally recognized statistical rating organizations). While trends in the portfolio's underlying collateral remain stable, a significant downturn in housing prices combined with a prolonged recession could erode credit support of non-agency mortgage-related securities and result in realized and unrealized losses in ASB's portfolio, and these losses could be material. The mortgage-related securities portfolio currently holds two positions whose principal is guaranteed by bond insurance companies whose ratings have either been downgraded or are on watch. The two positions, with a current book value of $0.3 million, are not impaired and ASB has the ability and intent of holding these positions to maturity.

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 or an "other-than-temporary" impairment in the value of the securities. As of December 31, 2007 and 2006, the unrealized losses, net of tax benefits, on available-for-sale investments and mortgage-related securities (including securities pledged for repurchase agreements) in AOCI was $18 million and $35 million, respectively. The decrease in unrealized losses was largely due to the downward movement in the general level of interest rates within the second half of 2007. See "Quantitative and Qualitative Disclosures about Market Risk."

The following table sets forth average balances, interest and dividend income, interest expense and weighted-average yields earned and rates paid, for certain categories of earning assets and costing liabilities for the years indicated. Average balances for each year have been calculated using the daily average balances during the year.

Years ended December 31	2007	2006	2005
($ in millions)			
Loans receivable			
Average balances [1]	$ 3,894	$ 3,688	$ 3,411
Interest income [2]	246	232	205
Weighted-average yield	6.31%	6.28%	6.01%
Investment and mortgage-related securities			
Average balances	$ 2,302	$ 2,507	$ 2,780
Interest income	106	113	123
Weighted-average yield	4.60%	4.52%	4.42%
Other investments [3]			
Average balances	$ 197	$ 172	$ 183
Interest and dividend income	5	4	3
Weighted-average yield	2.84%	2.18%	1.70%
Total earning assets			
Average balances	$ 6,393	$ 6,367	$ 6,374
Interest and dividend income	357	349	331
Weighted-average yield	5.59%	5.48%	5.19%
Deposit liabilities			
Average balances	$ 4,443	$ 4,540	$ 4,454
Interest expense	82	74	52
Weighted-average rate	1.84%	1.62%	1.17%
Borrowings			
Average balances	$ 1,713	$ 1,614	$ 1,703
Interest expense	78	72	69
Weighted-average rate	4.56%	4.49%	4.07%
Total costing liabilities			
Average balances	$ 6,156	$ 6,154	$ 6,157
Interest expense	160	146	121
Weighted-average rate	2.60%	2.37%	1.97%
Net average balance	$ 237	$ 213	$ 217
Net interest income	197	203	210
Interest rate spread	2.99%	3.11%	3.22%
Net interest margin [4]	3.08%	3.18%	3.29%

1 Includes nonaccrual loans.
2 Includes loan fees of $4.5 million, $5.3 million and $6.4 million for 2007, 2006 and 2005, respectively, together with interest accrued prior to suspension of interest accrual on nonaccrual loans.
3 Includes federal funds sold and interest bearing deposits and stock in the FHLB of Seattle ($98 million as of December 31, 2007).
4 Defined as net interest income as a percentage of average earning assets.

- 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 3.18% in 2006 to 3.08% 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 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. Management does not believe that the adverse development of the loans to one commercial borrower or the reclassification of certain commercial loans is reflective of a negative trend in the overall credit quality of the loan portfolio. ASB's allowance as a percentage of average loans was 0.78% at the end of 2007, compared to 0.85% and 0.90% at the end of 2006 and 2005, 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 estimated loan losses. ASB's nonaccrual and renegotiated loans represented 0.2% of total loans outstanding as of December 31, 2007, 2006 and 2005. 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 (which are expected to continue), and higher occupancy expenses, partly offset by lower compensation and employee benefit expenses as a result of the recognition in 2007 of a one-time curtailment gain of $8.8 million ($5.3 million, net of taxes) from a change in ASB's retirement benefit plan.

See Note 4 of HEI's "Notes to Consolidated Financial Statements" for a discussion of guarantees.

- Net interest income before provision for loan losses for 2006 decreased by $7 million, or 3.3%, when compared to 2005 as the challenging interest rate environment pressured ASB's net interest margin. Continued growth in average loans and deposits partially offset margin compression pressure from a flattening yield curve, which was inverted throughout the second half of 2006. Net interest margin decreased from 3.29% in 2005 to 3.18% in 2006 as the impact of growth in the loan portfolio and higher yields in the loan and mortgage-related securities portfolios was more than offset by increased funding costs. The increase in the average loan portfolio balance was helped by the continued strength in the Hawaii economy and real estate market. The decrease in the average investment and mortgage-related securities portfolios was due to the use of the proceeds from repayments in the portfolios to fund loans. Increased average deposit balances enabled ASB to replace other borrowings.

ASB's asset quality remained strong in 2006 due to continued strength in real estate and business conditions, which resulted in low historical loss ratios and low net charge-offs for ASB. However, a provision for loan losses of $1.4 million ($0.8 million, net of tax) was recorded in 2006, primarily due to one commercial borrower. This compares with a reversal of allowance for loan losses of $3 million ($2 million, net of tax) in 2005.

Noninterest income for 2006 increased by $2.7 million over 2005 due to higher fee income on deposit liabilities and gains on sales of securities, partially offset by lower income from the sale of investment and insurance products.

Noninterest expense for 2006 increased by $7.6 million over 2005 primarily due to higher legal and litigation-related expenses and occupancy expenses.

Legislation and regulation. ASB is subject to extensive regulation, principally by the Office of Thrift Supervision (OTS) and the Federal Deposit Insurance Corporation (FDIC). Depending on its level of regulatory capital and other considerations, these regulations could restrict the ability of ASB to compete with other institutions and to pay dividends to its shareholders. See the discussions below under "Liquidity and capital resources" and "Certain factors that may affect future results and financial condition." Also see "Regulatory compliance" in Note 4 of HEI's "Notes to Consolidated Financial Statements" for a discussion of a consent order issued by the OTS in January 2008.

FHLB of Seattle business and capital plan. In December 2004, the FHLB of Seattle signed an agreement with its regulator, the Federal Housing Finance Board (Finance Board), to adopt a business and capital plan to strengthen its risk management, capital structure and governance. At the time and as of December 31, 2007, ASB had an investment in FHLB of Seattle stock of $98 million. No dividends were received by ASB from the FHLB of Seattle during the fourth quarter of 2004, the last three quarters of 2005 and the first three quarters of 2006. In January 2007, the FHLB of Seattle announced that the Finance Board had terminated its agreement with the FHLB of Seattle, attributing the termination to its full compliance with the terms of the agreement and significant progress the FHLB of Seattle has made in implementing its business and capital management plan. ASB received cash dividends of $98,000 in each of December 2006 and February 2007, $147,000 in each of May 2007 and August 2007 and $196,000 in November of 2007.

Liquidity and capital resources

December 31	2007	% change	2006	% change
(dollars in millions)				
Assets	$6,861	1	$6,808	–
Available-for-sale investment and mortgage-related securities	2,141	(10)	2,367	(10)
Investment in stock of Federal Home Loan Bank of Seattle	98	–	98	–
Loans receivable, net	4,101	8	3,780	6
Deposit liabilities	4,347	(5)	4,576	–
Other bank borrowings	1,811	15	1,569	(3)

As of December 31, 2007, ASB was the third largest financial institution in Hawaii based on assets of $6.9 billion and deposits of $4.3 billion.

In March 2007, Moody's raised ASB's counterparty credit rating to A3 from Baa3 and acknowledged ASB's high capital ratios, excellent asset quality indicators and prudent liquidity posture. In April 2007, S&P raised ASB's long-term/short-term counterparty credit ratings to BBB/A-2 from BBB-/A-3 and acknowledged the improvement in ASB's interest rate risk and funding profiles from its community banking strategy, its still modest credit risk profile and its solid capital base. These 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, 2007 were $228 million lower than December 31, 2006. 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, 2007, FHLB borrowings totaled approximately $1.0 billion, representing 15% 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, 2007, ASB's unused FHLB borrowing capacity was approximately $1.1 billion. As of December 31, 2007, securities sold under agreements to repurchase totaled $0.8 billion, representing 11% 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, 2007, 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, 2007 and 2006, ASB had $3.2 million and $2.4 million of loans on nonaccrual status, respectively, or 0.1% of net loans outstanding. As of December 31, 2007 and 2006, ASB had no real estate acquired in settlement of loans.

In 2007, operating activities provided cash of $53 million. Net cash of $73 million was used by investing activities primarily due to purchases of investment and mortgage-related securities, net increases in loans held for investment and capital expenditures, partly offset by repayments of investment and mortgage-related securities. Financing activities used net cash of $29 million due to net decreases in deposits and the payment of common stock dividends, partly offset by net increases in other borrowings.

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, 2007, 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 the third largest financial institution in Hawaii, based on total assets, and is in direct competition for deposits and loans, not only with the two 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, 2007, the fair value and carrying value of the investment and mortgage-related securities held by ASB were $2.1 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 the 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, including those conducted by ASB's insurance agency subsidiary, Bishop Insurance Agency of Hawaii, Inc., 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, 2007, 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, 2007 with a tangible capital ratio of 7.8% (1.5%), a core capital ratio of 7.8% (4.0%) and a total risk-based capital ratio of 14.7% (8.0%).
- ASB met the capital requirements to be generally considered "well-capitalized" (noted in parentheses) as of December 31, 2007 with a leverage ratio of 7.8% (5.0%), a Tier-1 risk-based capital ratio of 13.9% (6.0%) and a total risk-based capital ratio of 14.7% (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 as related to the 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").

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, 2007, 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, 2007, approximately 88% 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 Federal National Mortgage Association (FNMA), Government National Mortgage Association (GNMA) and Federal Home Loan Mortgage Corporation (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. 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, 2007, ASB had investment and mortgage-related securities issued by FHLMC, GNMA and FNMA valued at $1.6 billion and private-issue mortgage-related securities valued at $0.5 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, 2007, ASB's allowance for loan losses was $30.2 million and ASB had $3.2 million of loans on nonaccrual status. In 2007, ASB recorded a provision for loan losses of $5.7 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 segments' exposures to these two risks are not material as of December 31, 2007.

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 by ASB's asset/liability management process, 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. Because the Company does not have a large portfolio of trading assets, the Company is not exposed to significant market risk from trading activities. The Company currently has no exposure to 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 (CMO) 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, 2007 and 2006 constitute "forward-looking statements" and were as follows:

December 31	2007			2006		
	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	(2.2)%	6.97%	(334)	(3.8)%	7.83%	(341)
+200	(0.9)	8.27	(204)	(2.6)	9.09	(215)
+100	(0.2)	9.46	(85)	(1.3)	10.29	(95)
Base	-	10.31	-	–	11.24	–
-100	(0.5)	10.40	9	2.0	11.64	40
-200	(3.0)	9.67	(64)	1.8	11.27	3
-300	(6.9)	8.68	(163)	0.3	10.60	(64)

* Change from base case in basis points.

Management believes that ASB's interest rate risk position as of December 31, 2007 represents a reasonable level of risk. Under the gradual interest rate change scenarios, the December 31, 2007 NII profile is less sensitive to increases in interest rates, and more sensitive to decreases in interest rates compared to the NII profile on December 31, 2006. These changes are primarily due to differences in the mix of assets and liabilities and changes in the level and shape of the yield curve. In the falling rate scenarios, expectations of faster mortgage prepayments and lower reinvestment rates cause the yield on residential loans and mortgage-related securities to decline faster than in the base case. Additionally, the cost of liabilities does not fall as much in part because the current low level of rates on existing liabilities limits the amount by which they can decline further. The net impact is to compress margins, causing NII to fall.

ASB's base NPV ratio as of December 31, 2007 was lower than on December 31, 2006. 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, 2007 was comparable to the sensitivity measures as of December 31, 2006 in rising rate scenarios. In the falling rate scenarios, the sensitivity measures as of December 31, 2007 generally showed larger declines than the sensitivity measures as of December 31, 2006, primarily due to the overall lower level of interest rates.

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, such as adjusting product pricing and asset/liability mix. 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, 2007, 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. Based upon commercial paper outstanding as of December 31, 2007 of $92 million and a hypothetical 10% increase/decrease in interest rates, annual interest expense would have increased/decreased on that commercial paper by $1 million.

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, 2007 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, 2007.

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, 2007. This report appears on page 55.

Constance H. Lau
President and
Chief Executive Officer

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

February 21, 2008

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, 2007, 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, 2007, 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, 2007 and 2006, 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, 2007, and our report dated February 21, 2008 expressed an unqualified opinion on those consolidated financial statements.

KPMG LLP

Honolulu, Hawaii
February 21, 2008

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, 2007 and 2006, 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, 2007. 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, 2007 and 2006, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2007, in conformity with U.S. generally accepted accounting principles.

As discussed in Notes 1 and 10 to the consolidated financial statements, the Company changed its method of accounting for income taxes in 2007 and as discussed in Note 1 to the consolidated financial statements, the Company changed its method of accounting for stock compensation in 2006.

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, 2007, 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 21, 2008 expressed an unqualified opinion on the effectiveness of the Company's internal control over financial reporting.

KPMG LLP

Honolulu, Hawaii
February 21, 2008

Consolidated Statements of Income

Hawaiian Electric Industries, Inc. and Subsidiaries

Years ended December 31	2007	2006	2005
(in thousands, except per share amounts)			
Revenues			
Electric utility	$ 2,106,314	$ 2,054,890	$ 1,806,384
Bank	425,495	408,365	387,910
Other	4,609	(2,351)	21,270
	2,536,418	2,460,904	2,215,564
Expenses			
Electric utility	1,975,729	1,888,172	1,644,681
Bank	341,485	319,807	283,009
Other	15,472	13,529	16,452
	2,332,686	2,221,508	1,944,142
Operating income (loss)			
Electric utility	130,585	166,718	161,703
Bank	84,010	88,558	104,901
Other	(10,863)	(15,880)	4,818
	203,732	239,396	271,422
Interest expense – other than on deposit liabilities and other bank borrowings	(78,556)	(75,678)	(75,309)
Allowance for borrowed funds used during construction	2,552	2,879	2,020
Preferred stock dividends of subsidiaries	(1,890)	(1,890)	(1,894)
Allowance for equity funds used during construction	5,219	6,348	5,105
Income from continuing operations before income taxes	131,057	171,055	201,344
Income taxes	46,278	63,054	73,900
Income from continuing operations	84,779	108,001	127,444
Discontinued operations – loss on disposal, net of income tax benefits	–	–	(755)
Net income	$ 84,779	$ 108,001	$ 126,689
Basic earnings (loss) per common share			
Continuing operations	$ 1.03	$ 1.33	$ 1.58
Discontinued operations	–	–	(0.01)
	$ 1.03	$ 1.33	$ 1.57
Diluted earnings (loss) per common share			
Continuing operations	$ 1.03	$ 1.33	$ 1.57
Discontinued operations	–	–	(0.01)
	$ 1.03	$ 1.33	$ 1.56
Dividends per common share	$ 1.24	$ 1.24	$ 1.24
Weighted-average number of common shares outstanding	82,215	81,145	80,828
Dilutive effect of stock-based compensation	204	228	372
Adjusted weighted-average shares	82,419	81,373	81,200

See accompanying “Notes to Consolidated Financial Statements.”

Consolidated Balance Sheets

Hawaiian Electric Industries, Inc. and Subsidiaries

December 31		2007		2006
(dollars in thousands)				
ASSETS				
Cash and equivalents		$ 145,855		$ 177,630
Federal funds sold		64,000		79,671
Accounts receivable and unbilled revenues, net		294,447		248,639
Available-for-sale investment and mortgage-related securities		2,140,772		2,367,427
Investment in stock of Federal Home Loan Bank of Seattle (estimated fair value $97,764)		97,764		97,764
Loans receivable, net		4,101,193		3,780,461
Property, plant and equipment, net				
Land	$ 51,477		$ 48,558	
Plant and equipment	4,285,189		4,148,707	
Construction in progress	156,130		101,313	
	4,492,796		4,298,578	
Less – accumulated depreciation	(1,749,386)	2,743,410	(1,651,088)	2,647,490
Regulatory assets		284,990		112,349
Other		338,405		296,698
Goodwill, net		83,080		83,080
		$ 10,293,916		$ 9,891,209
LIABILITIES AND STOCKHOLDERS' EQUITY				
Liabilities				
Accounts payable		$ 202,299		$ 165,505
Deposit liabilities		4,347,260		4,575,548
Short-term borrowings—other than bank		91,780		176,272
Other bank borrowings		1,810,669		1,568,585
Long-term debt, net—other than bank		1,242,099		1,133,185
Deferred income taxes		155,337		106,780
Regulatory liabilities		261,606		240,619
Contributions in aid of construction		299,737		276,728
Other		573,409		518,454
		8,984,196		8,761,676
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: 83,431,513 shares and 81,461,409 shares		1,072,101		1,028,101
Retained earnings		225,168		242,667
Accumulated other comprehensive loss, net of income tax benefits				
Net unrealized losses on securities	$(18,043)		$ (35,462)	
Retirement benefit plans	(3,799)	(21,842)	(140,066)	(175,528)
		1,275,427		1,095,240
		$ 10,293,916		$ 9,891,209

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, 2004	80,687	$1,010,090	$ 208,998	$ (8,143)	$1,210,945
Comprehensive income:					
Net income	–	–	126,689	–	126,689
Net unrealized losses on securities:					
Net unrealized losses arising during the period, net of tax benefits of $21,933	–	–	–	(29,335)	(29,335)
Less: reclassification adjustment for net realized gains included in net income, net of taxes of $70	–	–	–	(105)	(105)
Minimum pension liability adjustment, net of tax benefits of $95	–	–	–	(147)	(147)
Comprehensive income (loss)	–	–	126,689	(29,587)	97,102
Issuance of common stock:					
Stock Option and Incentive Plan and other plans	296	6,095	–	–	6,095
Expenses and other, net	–	2,781	–	–	2,781
Common stock dividends ($1.24 per share)	–	–	(100,293)	–	(100,293)
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

As of December 31, 2007, Hawaiian Electric Industries, Inc. (HEI) had reserved a total of 14,732,930 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.

In 1997, the HEI Board of Directors adopted a resolution designating 500,000 shares of Series A Junior Participating Preferred Stock in connection with HEI's Shareholders Rights Plan, but no shares have been issued and the Shareholders Rights Plan expired on November 1, 2007.

See accompanying "Notes to Consolidated Financial Statements."

Consolidated Statements of Cash Flows

Hawaiian Electric Industries, Inc. and Subsidiaries

Years ended December 31	2007	2006	2005
(in thousands)			
Cash flows from operating activities			
Net income	$ 84,779	$ 108,001	$ 126,689
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation of property, plant and equipment	147,881	141,184	133,892
Other amortization	11,878	10,778	8,269
Provision (reversal of allowance) for loan losses	5,700	1,400	(3,100)
Writedown of utility plant	11,701	–	–
Gain on pension curtailment	(8,809)	–	–
Deferred income taxes	(34,624)	(12,946)	43
Allowance for equity funds used during construction	(5,219)	(6,348)	(5,105)
Excess tax benefits from share-based payment arrangements	(195)	(1,052)	–
Loans receivable originated and purchased, held for sale	(39,688)	(23,767)	(26,893)
Proceeds from sale of loans receivable, held for sale	33,876	26,150	23,144
Changes in assets and liabilities, net of effects from the disposal of businesses			
Decrease (increase) in accounts receivable and unbilled revenues, net	(45,808)	834	(40,940)
Decrease (increase) in fuel oil stock	(27,559)	21,138	(26,880)
Decrease (increase) in federal tax deposit	–	30,000	(30,000)
Increase (decrease) in accounts payable	36,794	(17,831)	36,282
Increase (decrease) in taxes accrued	42,617	(2,273)	37,631
Changes in other assets and liabilities	4,017	10,784	(14,594)
Net cash provided by operating activities	217,341	286,052	218,438
Cash flows from investing activities			
Available-for-sale investment and mortgage-related securities purchased	(402,071)	(343,927)	(486,432)
Principal repayments on available-for-sale investment and mortgage-related securities	652,083	542,702	727,901
Proceeds from sale of available-for-sale investment and mortgage-related securities	1,109	61,131	28,039
Proceeds from sale of investments	35,920	–	33,809
Net increase in loans held for investment	(315,786)	(211,872)	(304,212)
Proceeds from sale of real estate acquired in settlement of loans	–	403	624
Capital expenditures	(218,297)	(210,529)	(223,675)
Contributions in aid of construction	19,011	19,707	21,083
Other	5,902	1,708	909
Net cash used in investing activities	(222,129)	(140,677)	(201,954)
Cash flows from financing activities			
Net increase (decrease) in deposit liabilities	(228,288)	18,129	261,247
Net increase (decrease) in short-term borrowings with original maturities of three months or less	(84,492)	35,213	65,147
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 in retail repurchase agreements	71,205	60,596	18,519
Proceeds from other bank borrowings	1,338,432	1,331,559	1,068,256
Repayments of other bank borrowings	(1,166,112)	(1,446,995)	(1,265,376)
Proceeds from issuance of long-term debt	242,539	100,000	59,462
Repayment of long-term debt	(136,000)	(110,000)	(84,000)
Principal payments on nonrecourse debt	(17,242)	(3,387)	(6,764)
Excess tax benefits from share-based payment arrangements	195	1,052	–
Net proceeds from issuance of common stock	21,072	5,481	3,689
Common stock dividends	(81,489)	(100,673)	(100,238)
Increase (decrease) in cash overdraft	(3,545)	4,631	1,861
Other	1,067	542	(112)
Net cash provided by (used in) financing activities	(42,658)	(104,551)	21,691
Net cash provided by (used in) discontinued operations--operating activities	–	7,530	(2,857)
Net increase (decrease) in cash and equivalents and federal funds sold	(47,446)	48,354	35,318
Cash and equivalents and federal funds sold, January 1	257,301	208,947	173,629
Cash and equivalents and federal funds sold, December 31	$ 209,855	$ 257,301	$ 208,947

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 engaged in electric utility, banking and other 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 2007 and 3.9% in 2006 and 2005.

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 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, 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 pension tracking mechanisms approved by the Public Utilities Commission of the State of Hawaii (PUC) on an interim basis, Hawaiian Electric Company, Inc. (HECO) and Maui Electric Company, Limited (MECO) generally will make contributions to the pension fund at the minimum level required under the law, until the pension assets (existing at the time of the PUC decisions and determined based on the cumulative fund contributions in excess of the cumulative net periodic pension cost recognized) are reduced to zero, at which time HECO and MECO would fund the pension cost as specified in the pension tracking mechanism. Hawaii Electric Light Company, Inc. (HELCO) 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. HEI uses the effective interest method to amortize the financing costs of the holding company over the term of the related long-term debt.

HECO and its subsidiaries use the straight-line method to amortize financing costs and premiums or discounts over the term of the related long-term 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 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.

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.

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, 2007, the antidilutive effect of stock appreciation rights (SARs) on 857,000 shares of common stock (for which the SARs' exercise prices were greater than the closing market price of HEI's common stock) 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. As of December 31, 2005, the antidilutive effect of SARs on 879,000 shares of common stock (for which the SARs' exercise prices were greater than the closing market price of HEI's common stock) were not 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

<u>Fair value measurements</u>. 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 to sell 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 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 had no impact on the Company’s financial statements, but will impact the Company’s fair value measurement disclosures in future periods.

<u>The fair value option for financial assets and financial liabilities</u>. 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.

<u>Income tax benefits of dividends on share-based payment awards</u>. 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.

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 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 must adopt SFAS No. 160 on January 1, 2009 prospectively, except for the presentation and disclosure requirements which must be applied retrospectively. Thus, beginning January 1, 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. Management has not yet determined what further impact, if any, the adoption of SFAS No. 160 will have on the Company’s financial statements.

Written loan commitments. In November 2007, the 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 is currently assessing the financial statement impact, if any, of SAB No. 109.

Reclassifications. Certain reclassifications have been made to prior years’ financial statements to conform to the 2007 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, 2007, customer accounts receivable include unbilled energy revenues of $114 million on a base of annual revenue of $2.1 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 2007, 2006 and 2005, HECO and its subsidiaries included approximately $185 million, $182 million and $159 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%, 8.4% and 8.5% in 2007, 2006 and 2005, respectively, and reflected quarterly compounding.

Bank

Loans receivable. American Savings Bank, F.S.B. and subsidiaries (ASB) state 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 the 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 the 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, 2007 and 2006, 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. ASB's $83.1 million of goodwill, 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. For the three years ended December 31, 2007, 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	2007		2006	
(in thousands)	Gross carrying amount	Accumulated amortization	Gross carrying amount	Accumulated amortization
Core deposit intangibles	$20,276	$20,276	$20,276	$18,662
Mortgage servicing assets	11,754	9,560	11,695	9,130
	$32,030	$29,836	$31,971	$27,792

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

(in thousands)	2007	2006	2005
Valuation allowance, January 1	$119	$207	$ 701
Provision (reversal of allowance)	92	(74)	(359)
Other than temporary impairment	(22)	(14)	(135)
Valuation allowance, December 31	$189	$119	$ 207

In 2007, 2006 and 2005, aggregate amortization expenses were $2.0 million, $2.2 million and $2.4 million, respectively.

The estimated aggregate amortization expenses for mortgage servicing assets for 2008, 2009, 2010, 2011 and 2012 are $0.4 million, $0.3 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, 2007 and 2006, the mortgage servicing assets had a net carrying value of $2.0 million and $2.4 million, respectively. In each of 2007, 2006 and 2005, mortgage servicing assets acquired through the sale or securitization of loans held for sale totaled $0.1 million. Amortization expenses for ASB's mortgage servicing assets amounted to $0.4 million, $0.5 million, and $0.7 million for 2007, 2006 and 2005, 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 income from continuing operations. 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 electric public 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 will partly own a new biodiesel refining plant to be built on the island of Maui by 2009 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, including those conducted by ASB's insurance agency subsidiary, Bishop Insurance Agency of Hawaii, Inc., are subject to regulation by the Hawaii Insurance Commissioner.

Other

"Other" includes amounts for the holding companies (HEI and HEI Diversified, Inc.) and 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
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
Income (loss) from continuing operations	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
Income (loss) from continuing operations	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
2005				
Revenues from external customers	$1,806,198	$ 387,910	$ 21,456	$2,215,564
Intersegment revenues (eliminations)	186	–	(186)	–
Revenues	1,806,384	387,910	21,270	2,215,564
Depreciation and amortization	131,350	10,065	746	142,161
Interest expense	49,408	121,426	25,901	196,735
Profit (loss)*	117,425	104,852	(20,933)	201,344
Income taxes (benefit)	44,623	39,969	(10,692)	73,900
Income (loss) from continuing operations	72,802	64,883	(10,241)	127,444
Capital expenditures	217,609	5,731	335	223,675
Assets (at December 31, 2005 **)	3,081,460	6,835,335	34,782	9,951,577

* Income (loss) from continuing operations before income taxes.
** Includes net assets of discontinued operations.

Intercompany electric 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	2007	2006	2005
(in thousands)			
Revenues			
Operating revenues	$2,096,958	$2,050,412	$1,801,710
Other – nonregulated	9,356	4,478	4,674
	2,106,314	2,054,890	1,806,384
Expenses			
Fuel oil	774,119	781,740	639,650
Purchased power	536,960	506,893	458,120
Other operation	214,047	186,449	172,962
Maintenance	105,743	90,217	82,242
Depreciation	137,081	130,164	122,870
Taxes, other than income taxes	194,607	190,413	167,295
Other – nonregulated	13,172	2,296	1,542
	1,975,729	1,888,172	1,644,681
Operating income from regulated and nonregulated activities	130,585	166,718	161,703
Allowance for equity funds used during construction	5,219	6,348	5,105
Interest and other charges	(54,183)	(53,478)	(50,323)
Allowance for borrowed funds used during construction	2,552	2,879	2,020
Income before income taxes and preferred stock dividends of HECO	84,173	122,467	118,505
Income taxes	30,937	46,440	44,623
Income before preferred stock dividends of HECO	53,236	76,027	73,882
Preferred stock dividends of HECO	1,080	1,080	1,080
Net income for common stock	$ 52,156	$ 74,947	$ 72,802

Consolidated Balance Sheet Data

December 31	2007	2006
(in thousands)		
Assets		
Utility plant, at cost		
Property, plant and equipment	$ 4,169,428	$ 4,038,264
Less accumulated depreciation	(1,647,113)	(1,558,913)
Construction in progress	151,179	95,619
Net utility plant	2,673,494	2,574,970
Regulatory assets	284,990	112,349
Other	465,404	375,815
	$ 3,423,888	$ 3,063,134
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	724,704	700,252
Accumulated other comprehensive income (loss)	1,157	(126,650)
Common stock equity	1,110,462	958,203
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	885,099	766,185
Total capitalization	2,029,854	1,758,681
Short-term borrowings from nonaffiliates	28,791	113,107
Deferred income taxes	162,113	118,055
Regulatory liabilities	261,606	240,619
Contributions in aid of construction	299,737	276,728
Other	641,787	555,944
	$ 3,423,888	$ 3,063,134

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 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 parenthesis are the original PUC authorized amortization or recovery periods and the remaining amortization or recovery periods as of December 31, 2007, if different.

Regulatory assets were as follows:

December 31	2007	2006
(in thousands)		
Retirement benefit plans (5 years for HELCO's $10 million prepaid pension regulatory asset, indeterminate for remainder)	$169,814	$ –
Income taxes, net (1 to 36 years)	74,605	73,178
Postretirement benefits other than pensions (18 years; 5 years)	8,949	10,738
Unamortized expense and premiums on retired debt and equity issuances (14 to 30 years; 1 to 21 years)	17,510	14,909
Demand-side management program costs, net (1 year)	4,113	4,521
Vacation earned, but not yet taken (1 year)	5,997	5,759
Other (1 to 20 years)	4,002	3,244
	$284,990	$112,349

The regulatory asset 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).

Regulatory liabilities were as follows:

December 31	2007	2006
(in thousands)		
Cost of removal in excess of salvage value (1 to 60 years)	$259,765	$239,049
Other (5 years; 2 to 5 years)	1,841	1,570
	$261,606	$240,619

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 $193 million (9%), $197 million (10%) and $176 million (10%) of their operating revenues from the sale of electricity to various federal government agencies in 2007, 2006 and 2005, 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, 2008, the estimated cost of minimum purchases under the fuel supply contracts is $0.9 billion per year for 2008 through 2012 and a total of $1.8 billion for the period 2013 through 2014. The actual cost of purchases in 2008 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 $795 million, $755 million and $662 million of fuel under contractual agreements in 2007, 2006 and 2005, respectively.

Power purchase agreements (PPAs). As of December 31, 2007, 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 $537 million, $507 million and $458 million for 2007, 2006 and 2005, 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 2008 through 2012 and a total of $1.0 billion in the period from 2013 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.

Interim increases. On September 27, 2005, the PUC issued an interim decision and order (D&O) in HECO's 2005 test year rate case granting a general rate increase on Oahu of 4.36%, or $53.3 million (3.33%, or a net increase of $41.1 million excluding the transfer of certain costs from a surcharge line item on electric bills into base electricity charges), which was implemented on September 28, 2005.

On October 25, 2007, the PUC issued an amended proposed final D&O in HECO's 2005 test year rate case, authorizing an increase of 3.74%, or $45.7 million (or a net increase of $34 million or 2.7%), in annual revenues. The amended proposed final D&O, when issued in final form, would reverse 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 would require a refund of the revenues associated with that reversal, including interest, retroactive to September 28, 2005 (the date the interim increase became effective), amounting to $16 million through December 31, 2007 ($9 million, net of tax benefits). Interest on the refund amount would continue to accrue until the amount is refunded to customers.

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

On October 22, 2007, the PUC issued, and HECO immediately implemented, an interim D&O in HECO's 2007 test year rate case, granting HECO an increase of $69.997 million in annual revenues over current effective rates at the time of the interim decision.

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 $13.2 million in annual revenues, or a 3.7% increase.

Through December 31, 2007, HECO and its subsidiaries had recognized $150 million of revenues with respect to interim orders ($14 million related to interim orders regarding certain integrated resource planning costs and $136 million related to interim orders with respect to HECO's interim surcharge to recover DG fuel and fuel trucking costs and general rate increase requests, not including revenues of $16 million for which a reserve, including interest, has been accrued to reflect the PUC's proposed final D&O in the 2005 HECO rate case), which revenues are subject to refund, with interest, if and to the extent they exceed the amounts allowed in final D&Os.

Energy cost adjustment clauses. On June 19, 2006, the PUC issued an order in HECO's 2005 test year rate case indicating that the record in the pending case had not been developed for the purpose of addressing the factors in Act 162, signed into law by the Governor of Hawaii on June 2, 2006. Act 162 states that any automatic fuel rate adjustment clause requested by a public utility in an application filed with the PUC shall be designed, as determined in the PUC's discretion, to (1) fairly share the risk of fuel cost changes between the public utility and its customers, (2) provide the public utility with sufficient incentive to reasonably manage or lower its fuel costs and encourage greater use of renewable energy, (3) allow the public utility to mitigate the risk of sudden or frequent fuel cost changes that cannot otherwise reasonably be mitigated through other commercially available means, such as through fuel hedging contracts, (4) preserve, to the extent reasonably possible, the public utility's financial integrity, and (5) minimize, to the extent reasonably possible, the public utility's need to apply for frequent applications for general rate increases to account for the changes to its fuel costs. While the PUC already had reviewed the automatic fuel rate adjustment clause in rate cases, Act 162 required that these five specific factors be addressed in the record. In October 2007, the PUC issued an amended proposed final D&O in HECO's 2005 test year rate case in which the PUC stated it would not require the parties in the rate case proceeding to file a stipulated procedural schedule on this issue, but that it expects HECO and HELCO to develop information relating to the Act 162 factors for examination during their next rate case proceedings.

The ECAC provisions of Act 162 were reviewed in the HELCO rate case based on a 2006 test year and are being reviewed in the HECO and MECO rate cases based on 2007 test years. 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. On April 4, 2007 the PUC issued an interim D&O in the HELCO 2006 test year rate case which reflected the continuation of HELCO's ECAC, consistent with a settlement agreement reached between HELCO and the Consumer Advocate.

In an order issued on August 24, 2007, the PUC added as an issue to be addressed in HECO's 2007 test year rate case whether HECO's ECAC complies with the requirements of Act 162 as codified in the Hawaii Revised Statutes (HRS). 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 proceeding. 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 in this proceeding. On October 22, 2007 the PUC issued an interim D&O in HECO's 2007 test year rate case which reflected the continuation of HECO's ECAC for purposes of the interim increase, consistent with the agreement reached among the parties. The parties will file proposed findings of fact and conclusions of law on all issues in this proceeding, including the ECAC, and the schedule for that filing is being determined. The parties have agreed that their resolution of the ECAC issue will not affect their agreement regarding revenue requirements in the proceeding. Management cannot predict the ultimate effect of the required Act 162 analysis on the continuation of the electric utilities' existing ECACs.

In an order issued on June 19, 2007, the PUC approved a procedural order for MECO's 2007 test year rate case and required MECO and the Consumer Advocate (the parties) to address an additional issue of whether MECO's ECAC complies with the requirements of Act 162 as codified in the HRS. In its direct testimony, the Consumer Advocate concluded that the ECAC's fixed efficiency factors are an effective means of sharing the operating and performance risks between MECO's ratepayers and shareholders and that MECO's ECAC provides a fair sharing of the risks of fuel cost changes between MECO and its ratepayers in a manner that preserves the financial integrity of MECO without the need for frequent rate filings. On December 7, 2007, the parties filed a stipulated settlement letter for this proceeding in which the parties agreed, among other things, that no further changes are required to MECO's ECAC in order to comply with the requirements of Act 162. On December 21, 2007 the PUC issued an interim D&O in MECO's 2007 test year rate case which reflected the continuation of MECO's ECAC for purposes of the interim increase, consistent with the agreement reached among the parties.

On April 23, 2007, the PUC issued an order denying HECO's proposal to recover $2.4 million, including revenue taxes, of distributed generation fuel and trucking and low sulfur fuel oil (LFSO) trucking costs since January 1, 2006 through the reconciliation process for the ECAC. However, the PUC allowed HECO to establish and implement a new and separate interim surcharge to recover its additional DG and LFSO costs on a going forward basis. HECO implemented an interim surcharge to recover such costs incurred from May 1, 2007.

HELCO power situation. In 1991, HELCO began planning to meet increased electric generation demand forecast for 1994. It 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 these 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 CT-4, CT-5 and ST-7, resulting in significant delays in the installation and operation of these generating units. However, in 2003, the parties opposing the plant expansion project (other than Waimana Enterprises, Inc. (Waimana), which did not participate in the settlement discussions and opposed the settlement) entered into a settlement agreement with HELCO and several Hawaii regulatory agencies, intended in part to permit HELCO to complete CT-4 and CT-5 (Settlement Agreement). The Settlement Agreement required HELCO to undertake a number of actions including expediting efforts to obtain the permits and approvals necessary for installation of ST-7 with selective catalytic reduction emissions control equipment, assisting the Department of Hawaiian Home Lands in installing solar water heating in its housing projects, supporting the Keahole Defense Coalition's participation in certain PUC cases, and cooperating with neighbors and community groups (including adding a Hot Line service). While certain of these actions have been completed, and required payments to other parties to the settlement agreement were timely made, a number of these actions are ongoing.

As a result of the final resolution of various proceedings due primarily to the Settlement Agreement, CT-4 and CT-5 became operational in mid-2004, there are no pending lawsuits involving the project, and work on ST-7 is proceeding. Noise mitigation equipment has been installed on CT-4 and CT-5 and additional noise mitigation work is ongoing to ensure compliance with the night-time noise standard applicable to the plant. Currently, HELCO can operate CT-4 and CT-5 as required to meet its system needs. Construction of a noise barrier was substantially completed in December 2007, and installation of other noise mitigation measures are planned. Subsequent testing will determine whether current restrictions on the operations of these units may be eliminated or eased.

HELCO's plans for ST-7 are progressing. In November 2003, HELCO filed a boundary amendment petition (to reclassify the Keahole plant site from conservation land use to urban land use) with the State of Hawaii Land Use Commission, which boundary amendment was approved in October 2005. In May 2006, HELCO obtained the County of Hawaii rezoning to a "General Industrial" classification, and in June 2006, received approval for a covered source permit amendment to include selective catalytic reduction with the installation of ST-7. Management believes that any other required permits will be obtained and anticipates an in-service date for ST-7 in mid-2009. HELCO has commenced engineering, design and certain construction work for ST-7. HELCO's current cost estimate for ST-7 is approximately $92 million, of which approximately $9 million has been incurred through December 31, 2007. HELCO has made about $32 million in additional commitments for materials, equipment and outside services, a substantial portion of which are subject to cancellation charges.

CT-4 and CT-5 costs incurred and allowed. HELCO's capitalized costs incurred in its efforts to put CT-4 and CT-5 into service and to support existing units (excluding costs for pre-air permit facilities) amounted to approximately $110 million. The $110 million of costs was reclassified from construction in progress to plant and equipment in 2004 ($103 million) and 2005 ($7 million) and depreciated beginning January 1, 2005 and 2006, respectively, and 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 HELCO 2006 rate case proceeding, subject to PUC approval. Under the settlement, HELCO agreed to write-off approximately $12 million of plant-in-service costs, net of average accumulated depreciation, relating to CT-4 and CT-5, resulting in an after-tax charge to net income in the first quarter of 2007 of approximately $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 reflects the settlement agreement reached between HELCO and the Consumer Advocate, including the agreement to write-off a portion of CT-4 and CT-5 costs. However, the interim order does not commit the PUC to accept any of the amounts in the interim increase in its final order. If it becomes probable that the PUC, in its final order, will disallow additional costs incurred for CT-4 and CT-5 for ratemaking purposes, HELCO will be required to record an additional write-off.

East Oahu Transmission Project (EOTP). HECO transmits bulk power to the Honolulu/East Oahu area over two major transmission corridors (Northern and Southern). HECO had planned to construct a partial underground/partial overhead 138 kilovolt (kV) line from the Kamoku substation to the Pukele substation, which serves approximately 16% of Oahu's electrical load, including Waikiki, in order to close the gap between the Southern and Northern corridors and provide a third transmission line to the Pukele substation. In total, this additional transmission capacity would benefit an area that comprises approximately 56% of the power demand on Oahu. However, in June 2002, an application for a permit which would have allowed construction in the originally planned route through conservation district lands was denied.

HECO continued to believe that the proposed reliability project (the East Oahu Transmission Project) was needed and, in December 2003, filed an application with the PUC requesting approval to commit funds (currently estimated at $74 million; see costs incurred below) for a revised EOTP using a 46 kV system. In March 2004, the PUC granted intervener status to an environmental organization and three elected officials (collectively treated as one party), and a more limited participant status to four community organizations. The environmental review process for the revised EOTP was completed and the PUC issued a Finding of No Significant Impact in April 2005.

In written testimony filed in June 2005, the 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 in 2002 of the approval necessary for the partial underground/partial overhead 138 kV line, and the related allowance for funds used during construction (AFUDC) of $5 million. In rebuttal testimony filed in August 2005, 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 addressed. The PUC held an evidentiary hearing on HECO's application in November 2005, and post-hearing briefing was completed in March 2006. Just prior to the November 2005 evidentiary hearing, the PUC approved that part of a stipulation between HECO and the Consumer Advocate providing that (i) this proceeding should determine whether HECO should be given approval to expend funds for the EOTP, but with the understanding that no part of the EOTP costs may be recovered from ratepayers unless and until the PUC grants HECO recovery in a rate case (which is consistent with other projects) and (ii) the issue as to whether the pre-2003 planning and permitting costs, and related AFUDC, should be included in the project costs is reserved to, and may be raised in, the next HECO rate case (or other proceeding) in which HECO seeks approval to recover the EOTP costs. In October 2007, the PUC issued a final D&O approving HECO's request to expend funds for a revised EOTP using a 46 kV system, 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.

Subject to obtaining other construction permits, HECO plans to construct the revised project, none of which is in conservation district lands, in two phases. The first phase is currently projected to be completed in 2010 and the projected completion date of the second phase is being evaluated.

As of December 31, 2007, the accumulated costs recorded for the EOTP amounted to $33 million, including (i) $12 million of planning and permitting costs incurred prior to 2003, (ii) $6 million of planning and permitting costs incurred after 2002 and (iii) $15 million for AFUDC. Management believes no adjustment to project costs is required as of December 31, 2007. 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.

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 identify 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. In 1995, the Department of Health of the State of Hawaii (DOH) issued letters indicating that it had identified a number of parties, including HECO, who appeared to be potentially responsible for historical subsurface petroleum contamination and/or operated their facilities upon petroleum-contaminated land at or near Honolulu Harbor in the Iwilei district of Honolulu. Certain of the identified parties formed a work group to determine the nature and extent of any contamination and appropriate response actions, as well as to identify additional potentially responsible parties (PRPs). The U.S. Environmental Protection Agency (EPA) became involved in the investigation in June 2000. Later in 2000, the DOH issued notices to additional PRPs. The parties in the work group and some of the new PRPs (collectively, the Participating Parties) entered into a joint defense agreement and signed a voluntary response agreement with the DOH. The Participating Parties agreed to fund 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.

In 2001, management developed and expensed a preliminary estimate of HECO's share of costs for continuing investigative work, remedial activities and monitoring at the Iwilei Unit of $1.1 million. Since 2001, subsurface investigation and assessment have been conducted and several preliminary oil removal tasks have been performed at the Iwilei Unit in accordance with notices of interest issued by the EPA and the DOH.

In 2003, HECO and other Participating Parties with active operations in the Iwilei area investigated their operations 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.

During 2006 and the beginning of 2007, the PRPs developed analyses of various remedial alternatives for two of the four remedial subunits of the Iwilei Unit. The DOH will use the analyses to make a final determination of which remedial alternatives the PRPs will be required to implement. The DOH is scheduled to complete the final remediation determinations for all remedial subunits of the Iwilei Unit by the end of the first quarter of 2008. HECO management developed an estimate of HECO's share of the costs associated with implementing the PRP recommended remedial approaches for the two subunits covered by the analyses of $1.2 million, which was expensed in 2006. Subsequently, based on the estimated costs for the remaining two subunits, as well as updated estimates for total remediation costs, HECO management expensed an additional $0.6 million in the third quarter of 2007.

As of December 31, 2007, the remaining accrual (amounts expensed less amounts expended) related to the Honolulu Harbor investigation was $1.8 million. Because (1) the full scope of additional investigative work, remedial activities and monitoring remain 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, which is located in the "Downtown" unit of the Honolulu Harbor site), the cost estimate may be subject to significant change and additional material investigative and remedial 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.

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. Effective September 9, 2004, the EPA issued a rule, which established location and technology-based design, construction and capacity standards for existing cooling water intake structures. These standards applied to HECO's Kahe, Waiau and Honolulu generating stations, unless the utility could demonstrate that at each facility implementation of these standards would result in costs either significantly higher than projected costs the EPA considered in establishing the standards for the facility (cost-cost test) or significantly greater than the benefits of meeting the standards (cost-benefit test). In either case, the EPA would then make a case-by-case determination of an appropriate performance standard. The regulation also would have allowed restoration of aquatic organism populations in lieu of meeting the standards. The rule required covered facilities to demonstrate compliance by March 2008. HECO had retained a consultant that was developing a cost effective compliance strategy and a preliminary assessment of technologies and operational measures under the rule.

On January 25, 2007, the U.S. Circuit Court for the Second Circuit issued a decision in Riverkeeper, Inc. v. EPA that remanded for further consideration and proceedings significant portions of the rule and found other portions of the rule to be impermissible. In particular, the court determined that restoration and the cost-benefit test provisions of the rule were impermissible under the Clean Water Act. It also remanded the best technology available determination to permit the EPA to provide a reasoned explanation for its decision or a new determination. It remanded the cost-cost test for the EPA's further consideration based on the best technology available determination and to afford adequate notice. Although the EPA has decided not to request the U.S. Supreme Court to review the Court of Appeal's decision, several utilities have sought Supreme Court review. If the Court of Appeal's decision stands, the ruling reduces the compliance options available to HECO. In addition, the EPA has not issued a schedule for rulemaking, which would be necessary to comply with the Court's decision. On July 9, 2007, the EPA formally suspended the rule. In the suspension announcement, the EPA 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. Currently, this guidance does not affect the HECO facilities subject to the cooling water intake requirements because none of the facilities are subject to permit renewal until mid-2009. Due to the uncertainties raised by the Court's decision as well as the need for further rulemaking by the EPA, 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, 2007, approximately 58% of the electric utilities' employees are members of the International Brotherhood of Electrical Workers, AFL-CIO, Local 1260, Unit 8, which is the only union representing employees of the Company. Four-year collective bargaining and benefit agreements with the union covered a term from November 1, 2003 to October 31, 2007 and have been extended to March 3, 2008. These collective bargaining agreements provided for non-compounded wage increases (3% on November 1, 2003; 1.5% on November 1, 2004, May 1, 2005, November 1, 2005 and May 1, 2006; and 3% on November 1, 2006). Negotiations for new agreements began in the third quarter of 2007 and are continuing.

Limited insurance. HECO and its subsidiaries purchase insurance coverages to protect themselves against loss of or damage to their properties and 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	2007	2006	2005
(in thousands)			
Interest and dividend income			
Interest and fees on loans	$245,593	$231,610	$205,084
Interest and dividends on investment and mortgage-related securities	111,470	117,160	125,924
	357,063	348,770	331,008
Interest expense			
Interest on deposit liabilities	81,879	73,614	52,064
Interest on other borrowings	78,019	72,482	69,362
	159,898	146,096	121,426
Net interest income	197,165	202,674	209,582
Provision (reversal of allowance) for loan losses	5,700	1,400	(3,100)
Net interest income after provision (reversal of allowance) for loan losses	191,465	201,274	212,682
Noninterest income			
Fees from other financial services	27,916	26,385	25,790
Fee income on deposit liabilities	26,342	18,779	16,989
Fee income on other financial products	7,418	8,025	9,058
Gain on sale of securities	1,109	1,735	175
Other income	5,647	4,671	4,890
	68,432	59,595	56,902
Noninterest expense			
Compensation and employee benefits	61,937	68,478	69,082
Occupancy	21,051	18,829	17,055
Equipment	14,417	14,700	13,722
Services	29,173	21,484	15,466
Data processing	10,458	10,164	10,598
Marketing	4,245	5,199	3,816
Office supplies, printing and postage	4,586	4,055	4,440
Communication	3,740	3,335	3,475
Other expense	26,301	26,067	27,029
	175,908	172,311	164,683
Income before minority interests and income taxes	83,989	88,558	104,901
Minority interests	–	–	45
Income taxes	30,882	32,776	39,969
Income before preferred stock dividends	53,107	55,782	64,887
Preferred stock dividends	–	–	4
Net income for common stock	$ 53,107	$ 55,782	$ 64,883

Consolidated Balance Sheet Data

December 31	2007	2006
(in thousands)		
Assets		
Cash and equivalents	$ 140,023	$ 172,370
Federal funds sold	64,000	79,671
Available-for-sale investment and mortgage-related securities	2,140,772	2,367,427
Investment in stock of Federal Home Loan Bank of Seattle	97,764	97,764
Loans receivable, net	4,101,193	3,780,461
Other	232,656	223,666
Goodwill and other intangibles, net	85,085	87,140
	$6,861,493	$6,808,499
Liabilities and stockholder's equity		
Deposit liabilities–noninterest-bearing	$ 652,055	$ 648,915
Deposit liabilities–interest-bearing	3,695,205	3,926,633
Other borrowings	1,810,669	1,568,585
Other	108,800	104,470
	6,266,729	6,248,603
Common stock	325,467	323,154
Retained earnings	287,710	280,046
Accumulated other comprehensive loss, net of tax benefits	(18,413)	(43,304)
	594,764	559,896
	$6,861,493	$6,808,499

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, 2007, ASB's available-for-sale federal agency obligations with carrying values of $50 million and $10 million had contractual maturity dates in 2008 and 2010 (with a callable date in 2008), respectively. 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.

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.

Pressures from declines in the housing market will impact securities held in ASB's investment portfolio. Foreclosures within the subprime sector of the market have increased risk premiums for all mortgage-related securities, especially those underwritten in 2006 and 2007 for which underwriting standards for the collateral of the mortgage-related securities were thought to be most troublesome. While ASB does not have material exposure to securities backed by subprime collateral and does not hold any subprime positions issued within the last five years, a deep and prolonged recession led by a material decline in housing prices could materially impair the value of the securities it currently holds. The mortgage-related securities portfolio currently holds two positions whose principal is guaranteed by bond insurance companies. The two positions, with a current book value of $0.3 million, are not impaired and ASB has the ability and intent of holding these positions to maturity. As of December 31, 2007, 74% of the portfolio is held in debentures or mortgage-related securities issued by government-sponsored entities. The remaining 26% of the portfolio is composed of mortgage-related securities issued by private issuers (25% are rated AAA and 1% are rated AA or A by nationally recognized statistical rating organizations). While trends in the portfolio's underlying collateral remain stable, a significant downturn in housing prices combined with a prolonged recession could erode credit support of non-agency mortgage-related securities and result in realized and unrealized losses in ASB's portfolio, and these losses could be material.

December 31, 2007

(dollars in thousands)	Amortized cost	Gross unrealized gains	Gross unrealized losses	Estimated fair value	Gross unrealized losses: Less than 12 months Count	Less than 12 months Fair Value	Less than 12 months Amount	12 months or longer Count	12 months or longer Fair Value	12 months or longer Amount
Available-for-sale										
Investment securities-federal agency obligation	$ 59,990	$ 45	$ (7)	$ 60,028	–	$ –	$ –	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

(dollars in thousands)	Amortized Cost	Gross unrealized gains	Gross unrealized losses	Estimated fair value	Gross unrealized losses: Less than 12 months Count	Less than 12 months Fair Value	Less than 12 months Amount	12 months or longer Count	12 months or longer Fair Value	12 months or longer 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)

December 31, 2005

(dollars in thousands)	Amortized cost	Gross unrealized gains	Gross unrealized losses	Estimated fair value	Gross unrealized losses: Less than 12 months Count	Less than 12 months Fair Value	Less than 12 months Amount	12 months or longer Count	12 months or longer Fair Value	12 months or longer Amount
Available-for-sale										
Investment securities-federal agency obligation	$ 24,965	$ –	$ (534)	$ 24,431	–	$ –	$ –	1	$ 24,431	$ (534)
Mortgage-related securities:										
FNMA, FHLMC and GNMA	2,230,279	3,482	(57,315)	2,176,446	68	664,606	(9,774)	147	1,385,218	(47,541)
Private issue	434,671	145	(6,342)	428,474	22	262,279	(3,175)	10	125,332	(3,167)
	$2,689,915	$3,627	$(64,191)	$2,629,351	90	$926,885	$(12,949)	158	$1,534,981	$(51,242)

As of December 31, 2007, 2006 and 2005, 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 2007, proceeds from sales of available-for-sale investment securities were $1 million resulting in gross realized gains of $1 million (since these were membership interests in which ASB had no basis). There were no sales of available-for-sale investment securities in 2006 and 2005. There were no sales of available-for-sale mortgage-related securities in 2007. In 2006 and 2005, proceeds from sales of available-for-sale mortgage-related securities were $61 million and $28 million resulting in gross realized gains of $1.8 million and $0.2 million and gross realized losses of $0.1 million and nil, respectively.

ASB pledged mortgage-related securities with a carrying value of approximately $727 million and $195 million as of December 31, 2007 and 2006, respectively, as collateral to secure advances from the FHLB, public funds and deposits in ASB's treasury, tax, and loan account with the Federal Reserve Bank of San Francisco. As of December 31, 2007 and 2006, mortgage-related securities with a carrying value of $900 million and $1,035 million, respectively, were pledged as collateral for securities sold under agreements to repurchase.

All securities in the ASB portfolio are investment grade bonds issued by FNMA, FHLMC, GNMA, or non-agency issuers. The non-agency bonds are collateralized by mortgage loan pools and utilize credit support structures that provide the securities with an investment grade rating. ASB has evaluated and determined that as of December 31, 2007 and 2006, all securities in the portfolio with unrealized losses are not other-than-temporarily impaired and these losses have not been included in earnings but instead have been included on a net basis in AOCI. Unrealized losses are primarily the result of changes in interest rates and market sentiment regarding specific issuers or sectors. Based on agency guarantees and credit support structures, management expects full payment of principal and interest on all bonds until maturity or call date. Management asserts that it has the intent and ability to hold all securities with unrealized losses until there is a recovery of fair value up to or beyond the amortized cost of its investment.

Loans receivable

December 31	2007	2006
(in thousands)		
Real estate loans		
One-to-four unit residential and commercial	$3,337,237	$2,961,880
Construction and development	137,451	260,870
	3,474,688	3,222,750
Consumer loans	265,989	264,537
Commercial loans	471,576	453,151
	4,212,253	3,940,438
Undisbursed portion of loans in process	(71,272)	(117,226)
Deferred fees and discounts, including net purchase accounting discounts	(26,192)	(22,033)
Allowance for loan losses	(30,211)	(31,228)
Loans held for investment	4,084,578	3,769,951
Loans held for sale	16,615	10,510
	$4,101,193	$3,780,461

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, 2006, ASB had impaired loans totaling $26.1 million, which consisted of $4.8 million of commercial real estate loans and $21.3 million of commercial loans. As of December 31, 2007 and 2006, impaired loans totaling $0.1 million and $0.3 million, respectively, had related allowances for loan losses of $0.01 million and $0.2 million, respectively. As of December 31, 2007 and 2006, ASB had $26.4 million and $25.8 million of impaired loans, respectively, for which there were no related allowances for loan losses. ASB realized $2.0 million, $1.9 million and $1.4 million of interest income on impaired loans in 2007, 2006 and 2005, respectively. The average balances of impaired loans during 2007, 2006 and 2005 were $25.5 million, $22.0 million and $20.8 million, respectively.

As of December 31, 2007 and 2006, ASB had nonaccrual and renegotiated loans of $6.3 million and $8.7 million, respectively.

ASB had no loans that were 90 days or more past due on which interest was being accrued as of December 31, 2007 and 2006.

As of December 31, 2007 and 2006, commitments not reflected in the consolidated balance sheets consisted of commitments to originate loans, other than the undisbursed portion of loans in process, of $94 million and $24 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, 2007 and 2006, ASB had commitments to sell residential loans of $11.3 million and $0.2 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 balance sheet in "Other" liabilities. As of December 31, 2007 and 2006, rate lock commitments were made on loans totaling $6.7 million and $0.2 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 "Other income," with an offset in the balance sheet in "Other" assets or liabilities. As of December 31, 2007 and 2006, the notional amounts for forward sales contracts were $11.3 million and $0.2 million, respectively. Valuation models are applied using current market information to estimate fair value. For 2007 and 2006, the net loss on derivatives was $49,000 and nil, respectively.

As of December 31, 2007 and 2006, ASB had commitments to sell education loans of $12 million and $10 million, respectively.

As of December 31, 2007 and 2006, standby, commercial and banker's acceptance letters of credit totaled $29 million and $27 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, 2007 and 2006, unused lines of credit and undrawn commercial loans totaled $1.0 billion.

ASB services real estate loans owned by third parties ($0.3 billion, $0.3 billion and $0.4 billion as of December 31, 2007, 2006 and 2005, respectively), which are not included in the accompanying consolidated financial statements. ASB reports fees earned for servicing loans as income when the related mortgage loan payments are collected and charges loan servicing costs to expense as incurred.

As of December 31, 2007 and 2006, ASB had pledged loans with an amortized cost of approximately $1.7 billion and $0.9 billion, respectively, as collateral to secure advances from the FHLB of Seattle.

As of December 31, 2007 and 2006, 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 $93 million and $90 million, respectively. The $3 million increase in such loans in 2007 was attributed to new loans and commitments to new and existing directors and executive officers of $4 million, partly offset by closed lines of credit and repayments of $1 million. As of December 31, 2007 and 2006, $69 million and $70 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)	2007	2006	2005
Allowance for loan losses, January 1	$31,228	$30,595	$33,857
Provision (reversal of allowance) for loan losses	5,700	1,400	(3,100)
Charge-offs, net of recoveries			
Real estate loans	(68)	(200)	(459)
Other loans	6,785	967	621
Net charge-offs	6,717	767	162
Allowance for loan losses, December 31	$30,211	$31,228	$30,595
Ratio of net charge-offs to average loans outstanding	0.17%	0.02%	<0.01%

Deposit liabilities

December 31	2007		2006	
(dollars in thousands)	Weighted-average stated rate	Amount	Weighted-average stated rate	Amount
Savings	0.74%	$1,401,866	1.03%	$1,569,514
Other checking				
Interest-bearing	0.36	514,179	0.26	522,442
Noninterest-bearing	–	345,515	–	330,346
Commercial checking	–	306,540	–	318,569
Money market	1.88	174,844	2.07	202,328
Term certificates	3.89	1,604,316	3.97	1,632,349
	1.79%	$4,347,260	1.89%	$4,575,548

As of December 31, 2007 and 2006, certificate accounts of $100,000 or more totaled $524 million and $530 million, respectively.

The approximate amounts of term certificates outstanding as of December 31, 2007 with scheduled maturities for 2008 through 2012 were $1,250 million in 2008, $152 million in 2009, $144 million in 2010, $42 million in 2011 and $8 million in 2012.

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

Years ended December 31	2007	2006	2005
(in thousands)			
Term certificates	$65,074	$55,466	$40,063
Savings	11,170	13,316	8,860
Money market	4,094	3,829	2,582
Interest-bearing checking	1,541	1,003	559
	$81,879	$73,614	$52,064

Other borrowings

Securities sold under agreements to repurchase.

December 31, 2007 Maturity	Repurchase liability	Weighted-average interest rate	Collateralized by mortgage-related securities–fair value plus accrued interest
(dollars in thousands)			
Overnight	$223,300	3.51%	$248,155
1 to 29 days	5,250	4.47	9,977
30 to 90 days	39,567	4.15	75,196
Over 90 days	496,552	4.08	570,170
	$764,669	3.92%	$903,498

At December 31, 2007, $250 million of securities sold under agreements to repurchase with a weighted average rate of 3.90% and maturity dates over 90 days are 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:

Years ended December 31	2007	2006	2005
(dollars in millions)			
Amount outstanding as of December 31	$765	$839	$687
Average amount outstanding during the year	$887	$771	$705
Maximum amount outstanding as of any month-end	$979	$839	$828
Weighted-average interest rate as of December 31	3.92%	4.22%	3.83%
Weighted-average interest rate during the year	4.22%	4.21%	3.50%
Weighted-average remaining days to maturity as of December 31	1,318	1,047	423

Advances from Federal Home Loan Bank.

December 31, 2007	Weighted-average stated rate	Amount
(dollars in thousands)		
Due in		
2008	5.44%	$ 168,000
2009	4.53	188,000
2010	5.43	250,000
2011	4.78	75,000
2012	4.48	265,000
Thereafter	4.52	100,000
	4.90%	$1,046,000

At December 31, 2007, $265 million of fixed rate FHLB advances with a weighted average rate of 5.17% are callable quarterly at par until maturity and $125 million of fixed rate FHLB advances with a weighted average rate of 4.16% are subject to a one time call at par.

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. As of December 31, 2007, ASB was in compliance with the minimum capital requirements under OTS regulations. 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, 2007, 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.

The $25 million decrease in accumulated other comprehensive loss from December 31, 2006 to December 31, 2007 was primarily due to the increase 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 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 shares of restricted stock in 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 Visa reorganization, 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 certain indemnified litigation involving Visa. In November 2007, Visa announced that it had reached a settlement with American Express regarding certain 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. 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. 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 does not impose restrictions on ASB's business activities; however it requires, among other things, various actions by ASB to strengthen its BSA/AML Program and its Compliance Management Program. ASB has implemented several initiatives to enhance its BSA/AML Program that address the requirements of the Order, and is also implementing initiatives to enhance its Compliance Management Program in accordance with the requirements of the Order. The Order is not expected to have a material financial impact on ASB.

ASB also consented on January 23, 2008 to the 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, which penalty has been paid.

ASB is unable to predict what other actions, if any, may be initiated by the OTS and other governmental authorities against ASB as a result of these deficiencies, or the impact of any such measures or actions on ASB or the Company.

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, 2007 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 2007 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, 2007, 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 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 2007 totaled $537 million, with purchases from AES Hawaii, Kalaeloa, HEP and HPOWER totaling $137 million, $193 million, $70 million and $38 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" (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, HECO has continued after 2004 its efforts to obtain from the IPPs the information necessary to make the determinations required under FIN 46R. In January 2005, 2006, 2007 and 2008, 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 the PPA (see below) and Kaheawa Wind Power, LLC (KWP) provided information as required under the PPA. Management has concluded that MECO does not have to consolidate KWP (which began selling power to MECO in June 2006 from its 30 MW windfarm) as MECO does not have a variable interest in KWP because the PPA does not require MECO to absorb variability of KWP.

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 is a Delaware limited partnership formed on October 13, 1988 for the purpose of designing, constructing, owning and operating a 200 MW cogeneration facility on Oahu, which includes two 75 MW oil-fired combustion turbines, two waste heat recovery steam generators, a 50 MW turbine generator and other electrical, mechanical and control equipment. The two combustion turbines were upgraded during 2004 resulting in an increase in the facility's nominal output rating to approximately 220 MW. Kalaeloa has a PPA with HECO (described above) and a steam delivery 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 (PURPA).

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

Apollo Energy Corporation. In October 2004, HELCO and Apollo Energy Corporation (Apollo) executed a restated and amended PPA which enables Apollo to repower its 7 MW facility, and install additional capacity, for a total allowed capacity of 20.5 MW. In December 2005, Apollo assigned the PPA to a subsidiary, which voluntarily, unilaterally and irrevocably waived and relinquished its right and benefit under the PPA to collect the floor rate for the entire term of the PPA. The 20.5 MW facility began commercial operations in April 2007. Based on information available, management concluded that HELCO does not have to consolidate Apollo as HELCO does not have a variable interest in Apollo because the PPA does not require HELCO to absorb any variability of Apollo.

6 • Short-term borrowings

Short-term borrowings as of December 31, 2007 and 2006 consisted of commercial paper issued by HEI and HECO and had weighted-average interest rates of 5.64% and 5.44%, respectively.

As of December 31, 2007 and 2006, HEI and HECO maintained syndicated credit facilities which totaled $100 million and $175 million, respectively. None of the facilities are secured. There were no borrowings under these facilities during 2007 or 2006.

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) 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 26% as of December 31, 2007, as calculated under the agreement) and "Consolidated Net Worth" of $850 million (Net Worth of $1.3 billion as of December 31, 2007, 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.

Effective February 19, 2008, HEI entered into a $50 million bilateral unsecured credit agreement expiring on November 18, 2008, with William Street LLC. Any draws on the facility bear interest, at the option of HEI, at either the "LIBO Rate" plus 75 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. Under this agreement, a ratings downgrade from BBB/Baa2 to BBB-/Baa3 by S&P and Moody's, respectively, would result in a commitment fee increase of 2.5 basis points and an interest rate increase of 75 basis points on any drawn amounts. A ratings upgrade to BBB+/Baa1 would result in a commitment fee decrease of 2 basis points and an interest rate decrease of 25 basis points on any drawn amounts. The agreement includes a provision for mandatory prepayments and reductions in the commitment amount in the event of certain asset sales, equity offerings or incurrence of indebtedness, as defined by the agreement, in the amount of 100% of the net cash proceeds received. Other provisions of the credit agreement are substantially the same as provisions in HEI's $100 million 5-year revolving unsecured credit agreement.

HEI's credit facilities are 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) 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 47% for HELCO and 45% for MECO as of December 31, 2007, as calculated under the agreement)). In addition to customary defaults, HECO's failure to maintain its financial ratios, as defined in its agreement, or meet other requirements will result in an event of default. For example, under the agreement, it is an event of default if HECO fails to maintain a "Consolidated Capitalization Ratio" (equity) of at least 35% (ratio of 54% as of December 31, 2007, as calculated under the agreement), if HECO fails to remain a wholly-owned subsidiary of HEI or if any event or condition occurs that results in any "Material Indebtedness" of HECO or any of its significant subsidiaries being subject to acceleration prior to its scheduled maturity. HECO's syndicated credit facility is maintained to support the issuance of commercial paper, but it may also be drawn for general corporate purposes and capital expenditures.

On May 23, 2007, S&P lowered the long-term corporate credit and unsecured debt ratings on HECO, HELCO and MECO to BBB from BBB+ 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 (dollars in thousands)	2007	2006
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 (SPRB) issued on behalf of electric utility subsidiaries		
4.60-4.65%, due 2026-2037	265,000	–
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	266,000
6.15-6.20%, due 2020-2029	55,000	130,000
	857,900	717,900
Less funds on deposit with trustee	(22,461)	–
Less unamortized discount	(1,886)	(3,261)
	833,553	714,639
HEI medium-term notes 6.90-6.93%, paid in 2007	–	10,000
HEI medium-term note 4.00%, due 2008	50,000	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
	$1,242,099	$1,133,185

As of December 31, 2007, the aggregate principal payments required on long-term debt for 2008 through 2012 are $50 million in 2008, nil in 2009 and 2010, $150 million in 2011 and $65 million in 2012.

Pensions. 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) and substantially all of the employees of ASB and its subsidiaries participate in the American Savings Bank Retirement Plan (ASB Pension Plan and, collectively, Plans). 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/Excess/Directors Plans). In general, benefits are based on the employees' years of service and compensation.

The continuation of the Plans and the Supplemental/Excess/Directors 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, and no participants have accrued any benefits after that time. The plan will be terminated at the time all remaining benefits have been paid. Effective December 31, 2007, ASB adopted changes to its defined benefit pension plan (see below).

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/Excess/ Directors 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) was signed into law on December 8, 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 (to be 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, rather than the accumulated benefit obligation, to calculate the funded status of pension plans).

By application filed on December 8, 2005 (AOCI Docket), the electric utilities had 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 when issued in final form, would reverse 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 would require 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. 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. The issue of whether to amortize HECO's prepaid pension asset ($51 million at December 31, 2007), if allowed to be included in rate base by the PUC, has thus been deferred until HECO's next rate case proceeding. Similarly, 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 at December 31, 2007 of $171 million pre-tax, compared to a retirement benefits pre-tax charge of $207 million at December 31, 2006).

Retirement benefits expense for the electric utilities for 2007, 2006 and 2005 was $27 million, $22 million and $13 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 2007 and 2006 and the funded status of these plans and amounts related to these plans reflected in the Company's balance sheet as of December 31, 2007 and 2006 were as follows:

	2007		2006	
(in thousands)	Pension benefits	Other benefits	Pension benefits	Other benefits
Benefit obligation, January 1	$985,562	$191,222	$ 961,117	$190,914
Service cost	30,996	4,773	32,486	5,099
Interest cost	57,851	10,829	54,200	10,620
Amendments	(17,574)	–	4,726	–
Actuarial gain	(10,350)	(10,313)	(21,832)	(5,856)
Benefits paid and expenses	(47,875)	(9,412)	(45,135)	(9,555)
Benefit obligation, December 31	998,610	187,099	985,562	191,222
Fair value of plan assets, January 1	875,278	136,366	809,950	119,625
Actual return on plan assets	75,274	11,608	106,702	15,957
Employer contribution	3,728	9,396	3,022	9,890
Benefits paid and expenses	(46,985)	(9,027)	(44,396)	(9,106)
Fair value of plan assets, December 31	907,295	148,343	875,278	136,366
Accrued benefit liability, December 31	(91,315)	(38,756)	(110,284)	(54,856)
AOCI, January 1	197,924	31,536	2,058	–
Recognized during year – net recognized transition obligation	(3)	(3,138)	(5)	(3,138)
Recognized during year – prior service (cost)/credit	197	(13)	205	(13)
Recognized during year – net actuarial losses	(11,282)	–	(12,005)	(412)
Occurring during year – prior service cost	(17,574)	–	4,726	–
Occurring during year – net actuarial gains	(17,243)	(11,982)	(56,850)	(11,895)
Other adjustments	8,809	–	259,795	46,994
	160,828	16,403	197,924	31,536
Impact of PUC D&Os	(152,888)	(18,120)	–	–
AOCI, December 31	7,940	(1,717)	197,924	31,536
Net actuarial loss	161,398	582	197,929	12,564
Prior service cost (gain)	(580)	131	(18)	144
Net transition obligation	10	15,690	13	18,828
	160,828	16,403	197,924	31,536
Impact of PUC D&Os	(152,888)	(18,120)	–	–
AOCI, December 31	7,940	(1,717)	197,924	31,536
Income tax benefits	(3,092)	668	(77,123)	(12,271)
AOCI, net of taxes, December 31	$ 4,848	$ (1,049)	$ 120,801	$ 19,265

The Company does not expect any plan assets to be returned to the Company during calendar year 2008.

The dates used to determine retirement benefit measurements for the defined benefit plans were December 31 of 2007, 2006 and 2005.

The defined benefit pension plans' accumulated benefit obligations, which do not consider projected pay increases (unlike the projected benefit obligations shown in the table above), as of December 31, 2007 and 2006 were $883 million and $854 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 expected long-term rate of return assumption of 8.5% was based on the plans' asset allocation, projected asset class returns provided by the plans' actuarial consultant and the past performance of the plans' assets.

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

	Pension benefits				Other benefits			
			Investment policy				Investment policy	
December 31	2007	2006	Target	Range	2007	2006	Target	Range
Asset category								
Equity securities	72%	72%	70%	65-75%	70%	71%	70%	65-75%
Fixed income	27	27	30	25-35%	30	29	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 Company's current estimate of contributions to the retirement benefit plans in 2008 is $14 million.

As of December 31, 2007, the benefits expected to be paid under the retirement benefit plans in 2008, 2009, 2010, 2011, 2012 and 2013 through 2017 amounted to $61 million, $63 million, $65 million, $67 million, $71 million and $403 million, respectively.

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

	Pension benefits			Other benefits		
December 31	2007	2006	2005	2007	2006	2005
Benefit obligation						
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
Net periodic benefit cost (years ended)						
Discount rate	6.00	5.75	6.00	6.00	5.75	6.00
Expected return on plan assets	8.5	9.0	9.0	8.5	9.0	9.0
Rate of compensation increase	4.2	4.6	4.6	4.2	4.6	4.6

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%. As of December 31, 2006, the assumed health care trend rates for 2007 and future years were as follows: medical, 10.00%, grading down to 5.00% for 2012 and thereafter; dental, 5.00%; and vision, 4.00%.

The components of net periodic benefit cost were as follows:

	Pension benefits			Other benefits		
Years ended December 31	2007	2006	2005	2007	2006	2005
(in thousands)						
Service cost	$30,996	$ 32,486	$ 29,369	$ 4,773	$ 5,099	$ 5,248
Interest cost	57,851	54,200	52,120	10,829	10,620	11,104
Expected return on plan assets	(68,381)	(71,684)	(73,971)	(9,939)	(9,918)	(9,853)
Amortization of net transition obligation	3	5	5	3,138	3,138	3,138
Amortization of net prior service cost (gain)	(197)	(205)	(623)	13	13	13
Amortization of net actuarial loss	11,282	12,005	5,924	–	412	442
Net periodic benefit cost	31,554	26,807	12,824	8,814	9,364	10,092
Impact of PUC D&Os	1,195	–	–	187	–	–
Net periodic benefit cost (adjusted for impact of PUC D&Os)	$32,749	$ 26,807	$ 12,824	$9,001	$ 9,364	$10,092

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 2008 are $(0.4) million, $6.8 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 2008 are nil, nil and $3.1 million, respectively.

The Company recorded pension expense of $26 million, $21 million and $11 million and OPEB expense of $7 million, $7 million and $8 million in 2007, 2006 and 2005, respectively, and charged the remaining amounts primarily to electric utility plant.

The projected benefit obligation, accumulated benefit obligation and fair value of plan assets for pension plans with an accumulated benefit obligation in excess of plan assets were $19 million, $16 million and nil, respectively, as of December 31, 2007 and December 31, 2006.

The health care cost trend rate assumptions can have a significant effect on the amounts reported for other benefits. As of December 31, 2007, a one-percentage-point increase in the assumed health care cost trend rates would have increased the total service and interest cost by $0.2 million and the postretirement benefit obligation by $3.2 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 $3.6 million.

ASB retirement benefit plan changes. ASB adopted changes to its defined benefit pension plan effective December 31, 2007 and began providing for employer contributions to its retirement savings plan on January 1, 2008.

The changes to the plans affected most employees and senior management and included:

1) Ending the accrual of benefits in and the addition of new participants to ASB's defined benefit pension plan effective December 31, 2007.
2) Providing for a matching employer contribution under ASB's retirement savings plan of 100% on the first 4% of eligible pay contributed by participants.
3) Providing for a discretionary employer contribution (based on the participant's number of years of vested service) up to 6% of eligible pay to ASB's retirement savings plan that is not contingent on contributions by participants.

The changes did not affect the vested pension benefits of former participants, including ASB retirees, as of December 31, 2007. All active participants who were employed on December 31, 2007 became fully vested in their accrued pension benefit as of December 31, 2007.

ASB recognized a one-time curtailment gain for its defined benefit pension plan of $8.8 million ($5.3 million, net of taxes) in December 2007.

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 (4,794,943 shares available for issuance under outstanding and future grants and awards as of December 31, 2007) 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 become exercisable in installments of 25% each year for four years, and expire if not exercised ten years from the date of the grant. The 2005 SARs awards, which have a ten year exercise life, generally become exercisable at the end of four years (i.e., cliff vesting) with the related dividend equivalents issued in the form of stock on an annual basis. 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 (including a valuation allowance due to limits on the deductibility of executive compensation) are as follows:

($ in millions)	2007	2006	2005
Share-based compensation expense [1]	1.3	1.6	3.6
Income tax benefit	0.4	0.7	1.1

1 The Company has not capitalized any share-based compensation cost. The estimated forfeiture rate for SARs was 4.6% and the estimated forfeiture rate for restricted stock was 12.7%.

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

	2007		2006		2005	
	Shares	(1)	Shares	(1)	Shares	(1)
Outstanding, January 1	660,000	$19.68	929,000	$19.88	1,122,500	$19.74
Granted	–	–	–	–	–	–
Exercised	(56,200)	$19.70	(269,000)	$20.38	(193,500)	19.07
Forfeited	–	–	–	–	–	–
Expired	–	–	–	–	–	–
Outstanding, December 31	603,800	$19.68	660,000	$19.68	929,000	$19.88
Options exercisable, December 31	603,800	$19.68	581,000	$19.57	651,500	$19.51

(1) Weighted-average exercise price

December 31, 2007			Outstanding & Exercisable	
Year of grant	Range of exercise prices	Number of options	Weighted-average remaining contractual life	Weighted-average exercise price
1998	$ 20.50	6,000	0.3	$20.50
1999	17.61 - 17.63	48,300	1.5	17.62
2000	14.74	52,000	2.3	14.74
2001	17.96	83,000	3.2	17.96
2002	21.68	134,000	4.1	21.68
2003	20.49	280,500	5.0	20.49
	$14.74 – 21.68	603,800	4.0	$19.68

As of December 31, 2007, all NQSOs outstanding were exercisable and had an aggregate intrinsic value (including dividend equivalents) of $4.0 million.

NQSO activity and statistics are summarized as follows:

($ in thousands, except prices)	2007	2006	2005
Shares vested	79,000	198,500	277,000
Aggregate fair value of vested shares	$350	$916	$1,215
Cash received from exercise	$1,107	$5,481	$3,689
Intrinsic value of shares exercised [1]	$575	$2,908	$2,375
Tax benefit realized for the deduction of exercises	$195	$965	$518
Dividend equivalent shares distributed under Section 409A	21,971	43,265	–
Weighted-average Section 409A distribution price	$26.14	$26.27	–
Intrinsic value of shares distributed under Section 409A	$574	$1,137	–
Tax benefit realized for Section 409A distributions	$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, 2007, all NQSOs were vested.

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

	2007		2006		2005	
	Shares	(1)	Shares	(1)	Shares	(1)
Outstanding, January 1	879,000	$26.12	879,000	$26.12	349,000	$26.02
Granted	–	–	–	–	554,000	26.18
Exercised	(4,000)	$26.18	–	–	(24,000)	26.02
Forfeited	(18,000)	$26.18	–	–	–	–
Expired	–	–	–	–	–	–
Outstanding, December 31	857,000	$26.12	879,000	$26.12	879,000	$26.12
Options exercisable, December 31	464,000	$26.08	399,000	$26.09	81,250	$26.02

(1) Weighted-average exercise price

December 31, 2007		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	325,000	4.1	$26.02	280,000	3.8	$26.02
2005	26.18	532,000	5.3	26.18	184,000	1.6	26.18
	$26.02 –26.18	857,000	4.9	$26.12	464,000	2.9	$26.08

As of December 31, 2007, 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)	2007	2006	2005
Shares vested	69,000	317,750	105,250
Aggregate fair value of vested shares	$341	$1,773	$537
Cash received from exercise	–	–	–
Intrinsic value of shares exercised [1]	$3	–	$10
Tax benefit realized for the deduction of exercises	$1	–	$4
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, 2007, there was $0.5 million of total unrecognized compensation cost related to SARs and that cost is expected to be recognized over a weighted average period of 1 year.

No SARs were granted in 2007 or 2006. The weighted-average fair value of each of the SARs granted during 2005 was $5.82 (at grant date). For 2005, the weighted-average assumptions used to estimate fair value include: risk-free interest rate of 4.1%, expected volatility of 18.1%, expected dividend yield of 5.9%, term of 10 years and expected life of 4.5 years. The weighted-average fair value of the SARs grant is estimated on the date of grant using a Binomial Option Pricing Model. See below for discussion of 2005 grant modification. The expected volatility is based on historical price fluctuations. The Company believes that historical volatility is appropriate based upon the Company's business model and strategies.

Section 409A modification. As a result of the changes enacted in Section 409A of the Internal Revenue Code of 1986, as amended (Section 409A), for 2007 and 2006, a total of 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.

As noted above, in December 2005, to comply with Section 409A, HEI modified certain provisions pertaining to the dividend equivalent rights attributable to the outstanding grants of NQSOs and SARs held by 40 employees under the 1987 HEI Stock Option and Incentive Plan, as amended. The modifications apply to the NQSOs granted in 2001, 2002, and 2003 and the SARs granted in 2004 and 2005 and in general accelerate the distribution of dividend equivalent shares earned after 2004. When a share-based award is modified, the Company recognizes the incremental compensation cost, which is measured as the excess, if any, of the fair value of the modified award over the fair value of the original award immediately before its terms are modified.

The assumptions used to estimate fair value at the time of the Section 409A modification for the 2005 SARs include: risk-free interest rate of 4.4%, expected volatility of 14.9%, original term of 10 years and expected dividend yield of 4.6%. The expected life used at the time of modification was 4.2 for 2005. As of December 7, 2005, the fair value of modified 2005 SARs, the fair value of original 2005 SARs and the additional compensation cost to be recognized per grant was $5.07, $4.95 and $0.12, respectively. The additional compensation cost for the Section 409A modification was not material.

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

	2007		2006		2005	
	Shares	(1)	Shares	(1)	Shares	(1)
Outstanding, January 1	91,800	$23.68	41,000	$23.50	34,000	$22.58
Granted	75,700	$23.50	60,800	$26.32	9,000	26.06
Restrictions ended	(16,000)	$23.48	(10,000)	$20.65	(2,000)	19.29
Forfeited	(5,500)	$26.04	–	–	–	–
Outstanding, December 31	146,000	$25.82	91,800	$25.68	41,000	$23.50

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

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

In 2007, 2006 and 2005, restricted stock granted had a grant date fair value of $1.9 million, $1.6 million and $0.2 million, respectively. In 2007, 2006 and 2005, restricted stock vested had a grant date fair value of $0.4 million, $0.2 million and nil, respectively. The tax benefit realized for the tax deductions from restricted stock were $0.2 million for 2007, $0.1 million for 2006 and immaterial for 2005.

As of December 31, 2007, there was $2.3 million of total unrecognized compensation cost related to nonvested restricted stock. The cost is expected to be recognized over a weighted-average period of 3 years.

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 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 and 2005, interest (income) expense on income taxes was $(0.3) million and $1.2 million, respectively.

In 2007, $1.2 million of interest on income taxes was reflected in "Interest expense – other than on deposit liabilities and bank borrowings." The Company will record penalties, if any, in the respective segment's expenses. As of December 31, 2007 and January 1, 2007 (implementation date), the total amount of accrued interest related to uncertain tax positions and recognized on the balance sheet was $2.8 million and $1.6 million, respectively.

As of December 31, 2007, the total amount of FIN 48 liability was $12.5 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. Management cannot estimate the range of the reasonably possible change.

The changes in total unrecognized tax benefits were as follows:

Year ended December 31	2007
(in millions)	
Unrecognized tax benefits, January 1	$ 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	1.8
Reductions for tax positions of prior years	(0.6)
Decreases due to tax positions taken	–
Settlements	–
Lapses of statute of limitations	–
Unrecognized tax benefits, December 31	$ 31.3

In addition to the FIN 48 liability, the 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 2006 currently remain subject to examination by the Internal Revenue Service and Department of Taxation of the State of Hawaii. HEIII, 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 2007 was 35%, compared to an effective tax rate for 2006 of 37%. The lower effective tax rate was primarily due to domestic production activities deductions related to the generation of electricity and the impact of state tax credits (including the acceleration of the state tax credits associated with the write-off of a portion of CT-4 and CT-5 costs) recognized against a smaller income tax expense base.

The components of income taxes attributable to income from continuing operations were as follows:

Years ended December 31	2007	2006	2005
(in thousands)			
Federal			
Current	$71,028	$65,501	$66,819
Deferred	(27,855)	(9,372)	(1,226)
Deferred tax credits, net	(1,154)	(1,259)	(1,351)
	42,019	54,870	64,242
State			
Current	8,194	5,848	3,586
Deferred	(5,615)	(1,468)	2,619
Deferred tax credits, net	1,680	3,804	3,453
	4,259	8,184	9,658
	$46,278	$63,054	$73,900

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	2007	2006	2005
(in thousands)			
Amount at the federal statutory income tax rate	$45,870	$59,869	$70,471
Increase (decrease) resulting from:			
State income taxes, net of effect on federal income taxes	2,768	5,319	6,278
Other, net	(2,360)	(2,134)	(2,849)
	$46,278	$63,054	$73,900

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

December 31	2007	2006
(in thousands)		
Deferred tax assets		
Cost of removal in excess of salvage value	$101,075	$ 93,014
Contributions in aid of construction and customer advances	76,342	38,582
Allowance for loan losses	13,816	12,202
Net unrealized losses on available-for-sale investment and mortgage-related securities (AOCI)	11,913	23,416
Retirement benefits (AOCI)	2,424	89,394
Other	42,511	23,543
	248,081	280,151
Deferred tax liabilities		
Property, plant and equipment	285,608	277,508
Leveraged leases	–	6,542
Retirement benefits	18,546	27,886
Goodwill	14,438	12,531
Regulatory assets, excluding amounts attributable to property, plant and equipment	29,050	28,495
FHLB stock dividend	20,552	20,552
Change in accounting method	23,036	–
Other	12,188	13,417
	403,418	386,931
Net deferred income tax liability	$155,337	$106,780

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, projections for future taxable income and available tax planning strategies, management believes it is more likely than not the Company will realize substantially all of the benefits of the deferred tax assets.

In the first quarter of 2005, the Company recorded a $2 million reserve, net of taxes, for interest the Company might incur on the potential taxes related to the disputed timing of dividend income recognition because of a change in ASB's 2000 and 2001 tax year-ends. In the second quarter of 2005, the Company made a $30 million deposit primarily to stop the further accrual of interest on the potential taxes related to the disputed timing of dividend income recognition. Also in the second quarter of 2005, $1 million of income taxes and interest payable, net of taxes, were reversed due to the resolution of other audit issues with the Internal Revenue Service (IRS). In the fourth quarter of 2005, additional IRS audit issues were resolved, resulting in the reversal of $1 million of interest expense, net of taxes.

As of December 31, 2007, 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 2007, 2006 and 2005, the Company paid interest to non-affiliates amounting to $233 million, $214 million and $192 million, respectively.

In 2007, 2006 and 2005, the Company paid income taxes amounting to $39 million, $69 million and $45 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 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 2007, 2006 and 2005, other noncash increases in common stock for director and officer compensatory plans were $2 million, $3 million and $5 million, respectively.

In 2007, 2006 and 2005, HECO and its subsidiaries capitalized as part of the cost of electric utility plant an allowance for equity funds used during construction amounting to $5 million, $6 million and $5 million, respectively.

In 2007, 2006 and 2005, the estimated fair value of noncash contributions in aid of construction amounted to $18 million, $14 million and $12 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.

12 • Regulatory restrictions on net assets

As of December 31, 2007, HECO and its subsidiaries could not transfer approximately $495 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, 2007, ASB could transfer approximately $179 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, 2007, 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, 2007, various securities rating agencies rated the private-issue mortgage-related securities held by ASB as investment grade.

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 developed 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	2007		2006	
(in thousands)	Carrying or notional amount	Estimated fair value	Carrying or notional amount	Estimated fair value
Financial assets				
Cash and equivalents	$ 145,855	$ 145,855	$ 177,630	$ 177,630
Federal funds sold	64,000	64,000	79,671	79,671
Available-for-sale investment and mortgage-related securities	2,140,772	2,140,772	2,367,427	2,367,427
Investment in stock of Federal Home Loan Bank of Seattle	97,764	97,764	97,764	97,764
Loans receivable, net	4,101,193	4,087,901	3,780,461	3,739,223
Financial liabilities				
Deposit liabilities	4,347,260	4,345,397	4,575,548	4,557,418
Other bank borrowings	1,810,669	1,852,762	1,568,585	1,566,571
Long-term debt	1,242,099	1,264,606	1,133,185	1,170,657
Off-balance sheet items				
HECO-obligated preferred securities of trust subsidiary	50,000	46,200	50,000	50,800

As of December 31, 2007 and 2006, loan commitments and unused lines and letters of credit had carrying amounts of $1.2 billion and $1.1 billion and the estimated fair value was $0.2 million and $0.1 million, respectively. As of December 31, 2007 and 2006, loans serviced for others had carrying amounts of $282.2 million and $323.6 million and the estimated fair value was $3.3 million and $4.2 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
2007					
Revenues [1, 2]	$554,023	$600,763	$673,461	$708,171	$2,536,418
Operating income [1, 2]	28,541	45,309	48,017	81,865	203,732
Net income (loss) [1, 2]	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
2006					
Revenues [6, 7]	$574,962	$604,969	$673,894	$607,079	$2,460,904
Operating income [6, 7]	69,151	60,729	66,356	43,160	239,396
Net income (loss) [6, 7]	32,337	27,224	32,323	16,117	108,001
Basic earnings (loss) per common share [3]	0.40	0.34	0.40	0.20	1.33
Diluted earnings (loss) per common share [4]	0.40	0.33	0.40	0.20	1.33
Dividends per common share	0.31	0.31	0.31	0.31	1.24
Market price per common share [5]					
High	27.26	27.92	28.94	28.18	28.94
Low	25.71	25.69	26.07	26.50	25.69

1 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).

2 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.

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.

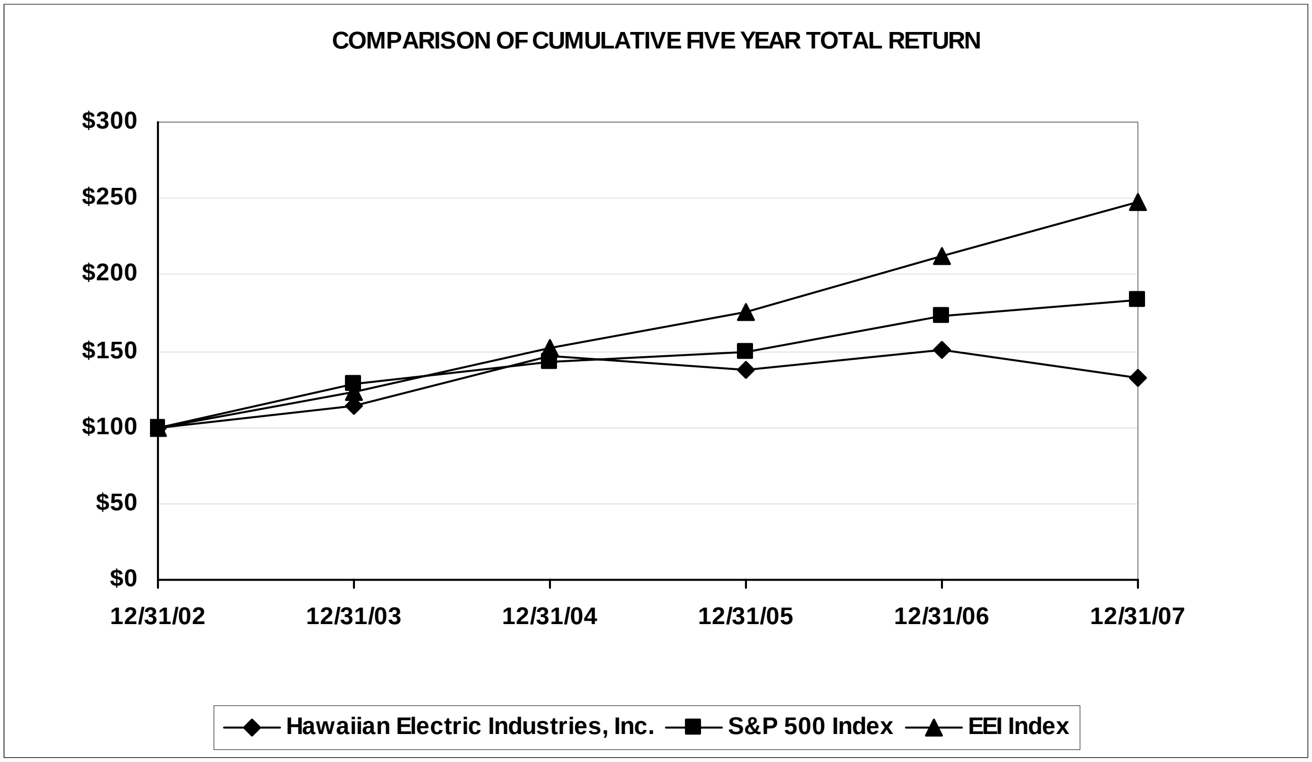
5 Market prices of HEI common stock (symbol HE) shown are as reported on the NYSE Composite Tape.

6 For 2006, amounts include interim rate relief for HECO (2005 test year).

7 The fourth quarter of 2006 includes an electric utility adjustment for quarterly rate schedule tariff reconciliation that relates to prior quarters.

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 (61 companies were included as of December 31, 2007). 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, 2002 in HEI Common Stock and the common stock of all companies in the indexes and that dividends were reinvested.



HEI Directors

Jeffrey N. Watanabe, 65 (1)*
Chairman
Hawaiian Electric Industries, Inc.
Honorary Of Counsel
Watanabe Ing & Komeiji LLP
(private law firm)

Constance H. Lau, 55 (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, 66 (3)*
Retired Chairman
Oceanic Time Warner
Cable Advisory Board
(cable television broadcasting)

Shirley J. Daniel, Ph.D., 54 (2)*
Professor of Accountancy
University of Hawaii-Manoa
(higher education)

Admiral Thomas B. Fargo,
USN (Retired), 59 (2, 3)*
President, Trex Enterprises Corporation
(high-technology R&D)
Former Commander of the
U.S. Pacific Command

Richard W. Gushman, II, 61*
President and Owner
DGM Group
(real estate development)

Victor Hao Li, S.J.D., 66 (3)*
Co-chairman
Asia Pacific Consulting Group
(international business consultant)

Bill D. Mills, 56 (1, 3, 4)
Chairman
The Mills Group
(real estate development)

A. Maurice Myers, 67 (3)
Retired Chairman, President and
Chief Executive Officer
Waste Management, Inc.
(environmental services)

Diane J. Plotts, 72 (1, 2, 3)*
Business Advisor

James K. Scott, Ed.D., 56 (2, 4)*
President
Punahou School
(private education)

Kelvin H. Taketa, 53 (4)*
President and Chief Executive Officer
Hawaii Community Foundation
(statewide charitable foundation)

Barry K. Taniguchi, 60 (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:
Bill D. Mills, Chairman
(4) Nominating & Corporate Governance:
Kelvin H. Taketa, Chairman

Information as of February 21, 2008.

* Also member of one or more subsidiary boards.

HEI Executive Officers and Subsidiary Presidents

Constance H. Lau, 55
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

Andrew I. T. Chang, 68
Vice President–Government Relations
1985

Curtis Y. Harada, 52
Controller and Acting Financial Vice
President, Treasurer and
Chief Financial Officer
1989

Warren H.W. Lee, 60 *
President, Hawaii Electric Light
Company, Inc.
1972

T. Michael May, 61
President and Chief Executive Officer
Hawaiian Electric Company, Inc.
1992

Edward L. Reinhardt, 55
President, Maui Electric Company, Limited
1986

Chester A. Richardson, 59
Vice President–General Counsel
2007

Timothy K. Schools, 38
President, American Savings Bank, F.S.B.
2007

Patricia U. Wong, 51
Vice President–Administration and
Corporate Secretary
1990

Information as of February 21, 2008.

Year denotes year of first employment by the company.

* Mr. Lee will retire on March 9, 2008. Jay M. Ignacio has been appointed to replace Mr. Lee.

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 2007 Form 10-K Annual Report for Hawaiian Electric Industries, Inc. and Hawaiian Electric Company, Inc., including financial statements and schedules, may be obtained from HEI upon written request without charge from shareholder services at the above address 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 also can 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 6, 2008, 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: 808-531-7286

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 2007 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 May 15, 2007, 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.