HAWAIIAN ELECTRIC CO INC
Form 10-K
March 11, 2005
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D. C. 20549

FORM 10-K

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2004

OR

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission File Number	Registrant; State of Incorporation; Address; and Telephone Number	I.R.S. Employer Identification No.
1-8503	**HAWAIIAN ELECTRIC INDUSTRIES, INC.,** a Hawaii corporation 900 Richards Street, Honolulu, Hawaii 96813 Telephone (808) 543-5662	**99-0208097**
1-4955	**HAWAIIAN ELECTRIC COMPANY, INC.,** a Hawaii corporation 900 Richards Street, Honolulu, Hawaii 96813 Telephone (808) 543-7771	**99-0040500**

Securities registered pursuant to Section 12(b) of the Act:

Registrant	Title of each class	Name of each exchange

		on which registered
Hawaiian Electric Industries, Inc.	Common Stock, Without Par Value	New York Stock Exchange
Hawaiian Electric Industries, Inc.	Preferred Stock Purchase Rights	New York Stock Exchange
Hawaiian Electric Company, Inc.	Guarantee with respect to 6.50% Cumulative Quarterly Income Preferred Securities Series 2004 (QUIPS^{SM})	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:

Registrant	**Title of each class**
Hawaiian Electric Industries, Inc.	None
Hawaiian Electric Company, Inc.	Cumulative Preferred Stock

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ¨

Indicate by check mark whether Registrant Hawaiian Electric Industries, Inc. is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes x No ¨

Indicate by check mark whether Registrant Hawaiian Electric Company, Inc. is an accelerated filer (as defined in Rule 12b-2 of the Act). Yes ¨ No x

	Aggregate market value of the voting common equity held by non-affiliates of the registrants on June 30, 2004	Number of shares of common stock outstanding of the registrants on February 28, 2005
Hawaiian Electric Industries, Inc. (HEI)	$2,097,756,284.40	80,710,097 (Without par value)
Hawaiian Electric Company, Inc. (HECO)	Not applicable	12,805,843 ($6 2/3 par value)

DOCUMENTS INCORPORATED BY REFERENCE

Portions of Proxy Statement of Hawaiian Electric Industries, Inc. for the 2005 Annual Meeting of Shareholders to be filed	Part III

This combined Form 10-K represents separate filings by Hawaiian Electric Industries, Inc. and Hawaiian Electric Company, Inc. Information contained herein relating to any individual registrant is filed by each registrant on its own behalf. Neither registrant makes any representations as to the information relating to the other registrant.

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GLOSSARY OF TERMS

Defined below are certain terms used in this report:

Terms	Definitions
1935 Act	Public Utility Holding Company Act of 1935
AES Hawaii	AES Hawaii, Inc., formerly known as AES Barbers Point, Inc.
ASB	American Savings Bank, F.S.B., a wholly-owned subsidiary of HEI Diversified, Inc. and parent company of American Savings Investment Services Corp. (and its subsidiary since March 15, 2001, Bishop Insurance Agency of Hawaii, Inc.), AdCommunications, Inc. and ASB Realty Corporation. Former subsidiaries include American Savings Mortgage Co., Inc. (dissolved in July 2003) and ASB Service Corporation (dissolved in January 2004).
BIF	Bank Insurance Fund
BLNR	Board of Land and Natural Resources of the State of Hawaii
Btu	British thermal unit
CDUP	Conservation District Use Permit
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act
Chevron	Chevron Products Company, a fuel oil supplier
Company	When used in Hawaiian Electric Industries, Inc. sections, the Company refers to Hawaiian Electric Industries, Inc. and its direct and indirect subsidiaries, including, without limitation, Hawaiian Electric Company, Inc., Maui Electric Company, Limited, Hawaii Electric Light Company, Inc., HECO Capital Trust III*, Renewable Hawaii, Inc., HEI Diversified, Inc., American Savings Bank, F.S.B. and its subsidiaries, Pacific Energy Conservation Services, Inc., HEI Properties, Inc., Hycap Management, Inc. (in dissolution), Hawaiian Electric Industries Capital Trust II*, Hawaiian Electric Industries Capital Trust III*, The Old Oahu Tug Service, Inc. (formerly Hawaiian Tug & Barge Corp.) and HEI Power Corp. and its subsidiaries (discontinued operations, except for subsidiary HEI Investments, Inc.). Former subsidiaries include HECO Capital Trust I (dissolved in April 2004)*, HECO Capital Trust II (dissolved in April 2004)*, HEI District Cooling, Inc. (dissolved in October 2003), ProVision Technologies, Inc. (sold in July 2003), HEI Leasing, Inc. (dissolved in October 2003), Hawaiian Electric Industries Capital Trust I (dissolved in April 2004)*, HEI Preferred Funding, LP (dissolved in April 2004)* and Malama Pacific Corp. (discontinued operations, dissolved in June 2004). (*unconsolidated subsidiaries as of January 1, 2004)
	When used in Hawaiian Electric Company, Inc. sections, the Company refers to Hawaiian Electric Company, Inc. and its direct subsidiaries, including, without limitation, Maui Electric Company, Limited, Hawaii Electric Light Company, Inc., HECO Capital Trust III and Renewable Hawaii, Inc. Former subsidiaries include HECO Capital Trust I (dissolved in April 2004)* and HECO Capital Trust II (dissolved in April 2004)*. (*unconsolidated subsidiaries as of January 1, 2004)
Consumer Advocate	Division of Consumer Advocacy, Department of Commerce and Consumer Affairs of the State of Hawaii
CT	Combustion turbine
DLNR	Department of Land and Natural Resources of the State of Hawaii
D&O	Decision and order

DOD	Department of Defense federal
DOH	Department of Health of the State of Hawaii

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GLOSSARY OF TERMS *(continued)*

Terms	Definitions
DSM	Demand-side management
DTCC	Dual-train combined-cycle
EAPRC	East Asia Power Resources Corporation
ECA	Energy cost adjustment
Enserch	Enserch Development Corporation
EPA	U.S. Environmental Protection Agency
ERL	Environmental Response Law of the State of Hawaii
FDIC	Federal Deposit Insurance Corporation
FDICIA	Federal Deposit Insurance Corporation Improvement Act of 1991
federal	U.S. Government
FHLB	Federal Home Loan Bank
FICO	Financing Corporation
FIRREA	Financial Institutions Reform, Recovery, and Enforcement Act of 1989
Hamakua Partners	Hamakua Energy Partners, L.P., formerly known as Encogen Hawaii, L.P.
HRD	Hawi Renewable Development, Inc.
HCPC	Hilo Coast Power Company, formerly Hilo Coast Processing Company
HC&S	Hawaiian Commercial & Sugar Company, a division of A&B-Hawaii, Inc.
HECO	Hawaiian Electric Company, Inc., an electric utility subsidiary of Hawaiian Electric Industries, Inc. and parent company of Maui Electric Company, Limited, Hawaii Electric Light Company, Inc., HECO Capital Trust III* and Renewable Hawaii, Inc. Former subsidiaries include HECO Capital Trust I (dissolved in April 2004)* and HECO Capital Trust II (dissolved in April 2004)*. (*unconsolidated subsidiaries as of January 1, 2004)
HECO s Consolidated Financial Statements	Hawaiian Electric Company, Inc. s Consolidated Financial Statements in Item 8 herein
HECO s MD&A	Hawaiian Electric Company, Inc. s Management s Discussion and Analysis of Financial Condition and Results of Operations in Item 7 herein
HEI	Hawaiian Electric Industries, Inc., direct parent company of Hawaiian Electric Company, Inc., HEI Diversified, Inc., Pacific Energy Conservation Services, Inc., HEI Properties, Inc., Hycap Management, Inc., Hawaiian Electric Industries Capital Trust II*, Hawaiian Electric Industries Capital Trust III*, The Old Oahu Tug Service, Inc. (formerly Hawaiian Tug & Barge Corp.) and HEI Power Corp. (discontinued operations, except for subsidiary HEI Investments, Inc.). Former subsidiaries include HEI District Cooling, Inc. (dissolved in October 2003), ProVision Technologies, Inc. (sold in July 2003), HEI Leasing, Inc. (dissolved in October 2003), Hawaiian Electric Industries Capital Trust I (dissolved in April 2004)* and Malama Pacific Corp. (discontinued operations, dissolved in June 2004). (*unconsolidated subsidiaries as of January 1, 2004)
HEI s Consolidated Financial Statements	Hawaiian Electric Industries, Inc. s Consolidated Financial Statements in Item 8 herein

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GLOSSARY OF TERMS *(continued)*

Terms	Definitions
HEI s MD&A	Hawaiian Electric Industries, Inc. s Management s Discussion and Analysis of Financial Condition and Results of Operations in Item 7 herein
HEI s 2005 Proxy Statement	Portions of Hawaiian Electric Industries, Inc. s 2005 Proxy Statement to be filed, which portions are incorporated into this Form 10-K by reference
HEIDI	HEI Diversified, Inc., a wholly-owned subsidiary of Hawaiian Electric Industries, Inc. and the parent company of American Savings Bank, F.S.B.
HEIII	HEI Investments, Inc. (formerly HEI Investment Corp.), a wholly-owned subsidiary of HEI Power Corp.
HEIPC	HEI Power Corp., a wholly owned subsidiary of Hawaiian Electric Industries, Inc., and the parent company of numerous subsidiaries, several of which were dissolved or otherwise wound up in 2002, 2003 and 2004, pursuant to a formal plan to exit the international power business (formerly engaged in by HEIPC and its subsidiaries) adopted by the HEI Board of Directors in October 2001
HEIPC Group	HEI Power Corp. and its subsidiaries
HEIPI	HEI Properties, Inc., a wholly-owned subsidiary of Hawaiian Electric Industries, Inc.
HELCO	Hawaii Electric Light Company, Inc., an electric utility subsidiary of Hawaiian Electric Company, Inc.
HITI	Hawaiian Interisland Towing, Inc.
HTB	Hawaiian Tug & Barge Corp. On November 10, 1999, HTB sold substantially all of its operating assets and the stock of Young Brothers, Limited, and changed its name to The Old Oahu Tug Services, Inc.
IPP	Independent power producer
IRP	Integrated resource plan
Kalaeloa	Kalaeloa Partners, L.P.
KCP	Kawaihae Cogeneration Partners
KDC	Keahole Defense Coalition
kV	kilovolt
KIP	Kalaeloa Investment Partners
KPP	Kahua Power Partners LLC
KWH	Kilowatthour
LSFO	Low sulfur fuel oil
MBtu	Million British thermal unit
MECO	Maui Electric Company, Limited, an electric utility subsidiary of Hawaiian Electric Company, Inc.
MPC	Malama Pacific Corp., a wholly-owned subsidiary of Hawaiian Electric Industries, Inc. On September 14, 1998, the HEI Board of Directors adopted a plan to exit the residential real estate development business engaged in by Malama Pacific Corp. and its then-existing subsidiaries. As of December 31, 2004, MPC and all of its subsidiaries had been dissolved.
MSFO	Medium sulfur fuel oil
MW	Megawatt/s (as applicable)
NA	Not applicable
NM	Not meaningful

NOV	Notice of Violation
OPA	Federal Oil Pollution Act of 1990
OTS	Office of Thrift Supervision, Department of Treasury

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GLOSSARY OF TERMS *(continued)*

Terms	Definitions
PCB	Polychlorinated biphenyls
PECS	Pacific Energy Conservation Services, Inc., a wholly-owned subsidiary of Hawaiian Electric Industries, Inc.
PGV	Puna Geothermal Venture
PPA	Power purchase agreement
PSD permit	Prevention of Significant Deterioration/Covered Source permit
PUC	Public Utilities Commission of the State of Hawaii
PURPA	Public Utility Regulatory Policies Act of 1978
QF	Qualifying Facility under the Public Utility Regulatory Policies Act of 1978
QTL	Qualified Thrift Lender
RCRA	Resource Conservation and Recovery Act of 1976
Registrant	Each of Hawaiian Electric Industries, Inc. and Hawaiian Electric Company, Inc.
ROACE	Return on average common equity
SAIF	Savings Association Insurance Fund
SARs	Stock appreciation rights
SEC	Securities and Exchange Commission
ST	Steam turbine
state	State of Hawaii
Tesoro	Tesoro Hawaii Corp. dba BHP Petroleum Americas Refining Inc., a fuel oil supplier
TOOTS	The Old Oahu Tug Service, Inc. (formerly Hawaiian Tug & Barge Corp.), a wholly-owned subsidiary of Hawaiian Electric Industries, Inc. On November 10, 1999, HTB sold the stock of YB and substantially all of HTB s operating assets and changed its name.
UIC	Underground Injection Control
UST	Underground storage tank
VIE	Variable interest entities
YB	Young Brothers, Limited, which was sold on November 10, 1999, was formerly a wholly-owned subsidiary of Hawaiian Tug & Barge Corp.

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Cautionary Statements and Risk Factors that May Affect Future Results

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. I addition, any statements concerning future financial performance (including future revenues, expenses, earnings or losses or growth rates), ongoing business strategies or prospects and possible future actions 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 of collateral underlying loans and mortgage-related securities) and the military presence in Hawaii;

- the effects of weather and natural disasters;

- global developments, including the effects of terrorist acts, the war on terrorism, continuing U.S. presence in Iraq and Afghanistan and potential conflict or crisis with North Korea;

- the timing and extent of changes in interest rates;

- the risks inherent in changes in the value of and market for securities available for sale and pension and other retirement plan assets;

- changes in assumptions used to calculate retirement benefits costs and changes in funding requirements;

- demand for services and market acceptance risks;

- increasing competition in the electric utility and banking industries;

- capacity and supply constraints or difficulties, especially if measures such as demand-side management (DSM), distributed generation, combined heat and power or other firm capacity supply-side resources fall short of achieving their forecast benefits or are otherwise insufficient to reduce or meet forecast peak demand;

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;

the ability of independent power producers to deliver the firm capacity anticipated in their power purchase agreements;

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 s subsidiaries (including HECO 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 and their subsidiaries (including changes in taxation, environmental laws and regulations and governmental fees and assessments); decisions by the Public Utilities Commission of the State of Hawaii (PUC) in rate cases and other proceedings and by other agencies and courts on land use, environmental and other permitting issues; required corrective actions (such as with respect to environmental conditions, capital adequacy and business practices);

the risks associated with the geographic concentration of HEI s businesses;

the effects of changes in accounting principles applicable to HEI, HECO and their subsidiaries, including continued regulatory accounting under Statement of Financial Accounting Standards No. 71 and the possible effects of applying new accounting principles applicable to variable interest entities (VIEs) to power purchase arrangements with independent power producers;

the effects of changes by securities rating agencies in their ratings of the securities of HEI and HECO;

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 rights of American Savings Bank, F.S.B. (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;

the ultimate net proceeds from the disposition of assets and settlement of liabilities of discontinued or sold operations;

the final outcome of tax positions taken by HEI and its subsidiaries;

the ability of consolidated HEI to execute strategies to generate capital gains and utilize capital loss carryforwards on future tax returns;

the risks of suffering losses that are uninsured; and

other risks or uncertainties described elsewhere in this report and in other periodic reports 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 and its subsidiaries undertake no obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events or otherwise.

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PART I

ITEM 1. BUSINESS

HEI

HEI was incorporated in 1981 under the laws of the State of Hawaii and is a holding company with its principal subsidiaries engaged in the electric utility, banking and other businesses operating primarily in the State of Hawaii. HEI s predecessor, HECO, was incorporated under the laws of the Kingdom of Hawaii (now the State of Hawaii) on October 13, 1891. As a result of a 1983 corporate reorganization, HECO became an HEI subsidiary and common shareholders of HECO became common shareholders of HEI.

HECO and its operating subsidiaries, Maui Electric Company, Limited (MECO) and Hawaii Electric Light Company, Inc. (HELCO), are regulated electric public utilities providing the only electric public utility service on the islands of Oahu, Maui, Lanai, Molokai and Hawaii, which islands collectively include approximately 93% of Hawaii s electric public utility market. HECO also owns all the common securities of HECO Capital Trust III (Delaware statutory trust), which was formed to effect the issuance of $50 million of cumulative quarterly income preferred securities in 2004, for the benefit of HECO, MECO and HELCO. In December 2002, HECO formed a subsidiary, Renewable Hawaii, Inc., to invest in renewable energy projects.

Besides HECO and its subsidiaries, HEI also owns directly or indirectly the following subsidiaries: HEI Diversified, Inc. (HEIDI) (a holding company) and its subsidiary, ASB, and the subsidiaries of ASB; Pacific Energy Conservation Services, Inc. (PECS); HEI Properties, Inc. (HEIPI); Hycap Management, Inc. (in dissolution); Hawaiian Electric Industries Capital Trusts II and III (formed in 1997 to be available for trust securities financings); The Old Oahu Tug Service, Inc. (TOOTS); and HEI Power Corp. (HEIPC) and its subsidiaries (discontinued operations).

ASB, acquired in 1988, was the third largest financial institution in the State of Hawaii based on total assets and had 66 branches as of December 31, 2004. ASB has subsidiaries involved in the sale and distribution of insurance products and an inactive advertising agency for ASB and its subsidiaries and a subsidiary, ASB Realty Corporation, which elected to be taxed as a real estate investment trust (see Note 10 to HEI s Consolidated Financial Statements under ASB state franchise tax dispute and settlement).

HEIDI was also the parent company of HEIDI Real Estate Corp., which was formed in February 1998. In September 1999, HEIDI Real Estate Corp. s name was changed to HEIPI, and HEIDI transferred ownership of HEIPI to HEI. At December 31, 2004, HEIPI s venture capital investments had a carrying value of $1.5 million.

PECS was formed in 1994 and currently is a contract services company providing limited support services in Hawaii.

ProVision Technologies, Inc., formed in October 1998 to sell, install, operate and maintain on-site power generation equipment and auxiliary appliances in Hawaii and the Pacific Rim, was sold in July 2003. HEI Leasing, Inc. was formed in February 2000 to own passive investments and real estate subject to leases, but was never active and was dissolved in October 2003. Hycap Management, Inc., including its former subsidiary HEI Preferred Funding, LP (a limited partnership in which Hycap Management, Inc. was the sole general partner), and Hawaiian

Electric Industries Capital Trust I (a Delaware statutory trust in which HEI owned all the common securities) were formed to effect the issuance of $100 million of 8.36% HEI-obligated trust preferred securities in 1997, which securities were redeemed in April 2004. Hawaiian Electric Industries Capital Trust I and HEI Preferred Funding, LP were dissolved and terminated in 2004, and Hycap Management, Inc. began dissolution in 2004 for a period of three years and then will terminate. HEI District Cooling, Inc. was formed in August 1998 to develop, build, own, lease, operate and/or maintain, either directly or indirectly, central chilled water cooling system facilities, and other energy related products and services for commercial and residential buildings, but was dissolved in October 2003.

In November 1999, Hawaiian Tug & Barge Corp. (HTB) sold substantially all of its operating assets and the stock of YB for a nominal gain, changed its name to TOOTS and ceased maritime freight transportation operations. TOOTS currently administers certain employee and retiree-related benefits programs and monitors matters related its former operations and the operations of its former subsidiary.

For information about the Company s discontinued operations, see Note 14 to HEI s Consolidated Financial Statements.

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For financial information about the Company s industry segments, see Note 2 to HEI s Consolidated Financial Statements.

For additional information about the Company, see HEI s MD&A, HEI s Quantitative and Qualitative Disclosures about Market Risk and HEI s Consolidated Financial Statements.

The Company s website address is www.hei.com. The information on the Company s website is not incorporated by reference in this annual report on Form 10-K unless specifically incorporated herein by reference. HEI and HECO currently make available free of charge through this website, www.hei.com, their annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and all amendments to those reports (since 1994) as soon as reasonably practicable after such material is electronically filed with, or furnished to, the SEC.

Electric utility

HECO and subsidiaries and service areas

HECO, MECO and HELCO are regulated operating electric public utilities engaged in the production, purchase, transmission, distribution and sale of electricity on the islands of Oahu; Maui, Lanai and Molokai; and Hawaii, respectively. HECO was incorporated under the laws of the Kingdom of Hawaii (now State of Hawaii) in 1891. HECO acquired MECO in 1968 and HELCO in 1970. In 2004, the electric utilities revenues and net income from continuing operations amounted to approximately 81% and 75%, respectively, of HEI s consolidated amounts, compared to approximately 78% and 67% in 2003 and approximately 76% and 76% in 2002, respectively.

The islands of Oahu, Maui, Lanai, Molokai and Hawaii have a combined population currently estimated at 1,202,000, or approximately 95% of the population of the State of Hawaii, and comprise a service area of 5,766 square miles. The principal communities served include Honolulu (on Oahu), Wailuku and Kahului (on Maui) and Hilo and Kona (on Hawaii). The service areas also include numerous suburban communities, resorts, U.S. Armed Forces installations and agricultural operations.

The state has granted HECO, MECO and HELCO nonexclusive franchises, which authorize the utilities to construct, operate and maintain facilities over and under public streets and sidewalks. HECO s franchise covers the City & County of Honolulu, MECO s franchises cover the County of Maui and the County of Kalawao, and HELCO s franchise covers the County of Hawaii. Each of these franchises will continue in effect for an indefinite period of time until forfeited, altered, amended or repealed.

For additional information about HECO, see HEI s MD&A, HEI s Quantitative and Qualitative Disclosures about Market Risk and HEI s Consolidated Financial Statements and HECO s MD&A, HECO s Quantitative and Qualitative Disclosures about Market Risk and HECO s Consolidated Financial Statements.

Sales of electricity

HECO, MECO and HELCO provide the only electric public utility service on the islands they serve. The following table sets forth the number of electric customer accounts as of December 31, 2004, 2003 and 2002 and electric sales revenues by company for each of the years then ended:

	2004		2003		2002	
(dollars in thousands)	**Customer accounts**	**Electric sales revenues**	**Customer accounts**	**Electric sales revenues**	**Customer accounts**	**Electric sales revenues**
HECO	288,456	$ 1,050,388	286,677	$ 960,717	283,161	$ 865,608
MECO	61,996	250,750	61,423	213,806	59,983	191,029
HELCO	71,594	240,947	68,893	213,268	66,411	191,589
	422,046	$ 1,542,085	416,993	$ 1,387,791	409,555	$ 1,248,226

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Revenues from the sale of electricity in 2004 were from the following types of customers in the proportions shown:

	HECO	MECO	HELCO	Total
Residential	32%	37%	41%	34%
Commercial	32	34	41	34
Large light and power	35	29	18	31
Other	1			1
	100%	100%	100%	100%

KWH sales of HECO and its subsidiaries follow a seasonal pattern, but they do not experience the extreme seasonal variation like some electric utilities on the mainland. The seasonal variation in sales is largely the result of corresponding mild variations in weather. Sales tend to increase in the warmer summer months, probably as a result of increased demand for air conditioning and refrigeration. However, the weather in Hawaii is generally temperate, and Hawaii does not experience the wide range of fluctuations in temperature and humidity seen in the hot summers and cold winters in some parts of the mainland.

HECO and its subsidiaries derived approximately 10%, 10% and 9% of their operating revenues from the sale of electricity to various federal government agencies in 2004, 2003 and 2002, respectively.

Formerly one of HECO s larger customers, the Naval Base at Barbers Point, Oahu, closed in 1999 with redevelopment of the base to occur through 2020. Considering (1) that the base closure necessitated relocation of essential flight operations and support personnel to another base on Oahu and (2) the Naval Air Station Barbers Point Community Redevelopment Plan will increase development of the area, HECO continues to expect that the closure is likely to result in an overall increase in demand for electricity over time.

In 1995, HECO and the U.S. General Services Administration (GSA) entered into a Basic Ordering Agreement (GSA-BOA) under which HECO would arrange for the financing and installation of energy conservation projects at federal facilities in Hawaii. In 1996, HECO signed an umbrella Basic Ordering Agreement with the Department of Defense (DOD-BOA) and in 2001, a new DOD-BOA was signed. Under these and other agreements, HECO has completed energy conservation and other projects for federal agencies over the years.

Executive Order 13123, adopted in 1994, mandates that each federal agency develop and implement a program to reduce energy consumption by 35% by the year 2010 to the extent that these measures are cost effective. The 35% reduction will be measured relative to the agency s 1985 energy use. HECO continues to work with various federal agencies to implement demand-side management (DSM) programs that will help them achieve their energy reduction objectives. Neither HEI nor HECO management can predict with certainty the impact of Executive Order 13123 on HEI s or HECO s future financial condition, results of operations or liquidity.

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Selected consolidated electric utility operating statistics

	2004	2003	2002	2001	2000
KWH sales (millions)					
Residential	3,000.6	2,875.9	2,778.5	2,665.2	2,627.2
Commercial	3,247.3	3,168.3	3,073.6	3,016.1	2,923.5
Large light and power	3,762.6	3,676.5	3,639.2	3,636.5	3,666.9
Other	52.8	54.4	53.0	52.6	54.1
	10,063.3	9,775.1	9,544.3	9,370.4	9,271.7
KWH net generated and purchased (millions)					
Net generated	6,572.5	6,280.2	6,249.7	6,042.4	6,247.0
Purchased	4,066.5	4,054.3	3,829.6	3,861.6	3,572.0
	10,639.0	10,334.5	10,079.3	9,904.0	9,819.0
Losses and system uses (%)	5.2	5.2	5.1	5.2	5.4
Energy supply (year-end)					
Net generating capability MW	1,642	1,606	1,606	1,608	1,608
Firm purchased capability MW	529	531	510	531	532
	2,171	2,137	2,116	2,139	2,140
Net peak demand MW [1]	1,694	1,638	1,583	1,564	1,527
Btu per net KWH generated	10,767	10,663	10,673	10,675	10,818
Average fuel oil cost per Mbtu (cents)	684.3	580.5	466.4	539.3	538.5
Customer accounts (year-end)					
Residential	366,217	362,400	356,244	352,132	347,316
Commercial	53,854	52,659	51,386	50,974	50,434
Large light and power	555	549	551	542	547
Other	1,420	1,385	1,374	1,344	1,342
	422,046	416,993	409,555	404,992	399,639
Electric revenues (thousands)					
Residential	$ 527,970	$ 471,697	$ 426,291	$ 425,287	$ 421,129
Commercial	522,230	474,017	425,595	436,751	422,977
Large light and power	483,737	434,319	389,312	409,977	414,067
Other	8,148	7,758	7,028	7,349	7,487
	$ 1,542,085	$ 1,387,791	$ 1,248,226	$ 1,279,364	$ 1,265,660
Average revenue per KWH sold (cents)					
Residential	17.60	16.40	15.34	15.96	16.03
Commercial	16.08	14.96	13.85	14.48	14.47
Large light and power	12.86	11.81	10.70	11.27	11.29

Other	15.44	14.26	13.26	13.98	13.84
Average revenue per KWH sold	15.32	14.20	13.08	13.65	13.65
Residential statistics					
Average annual use per customer account (KWH)	8,239	8,004	7,840	7,620	7,618
Average annual revenue per customer account	$ 1,450	$ 1,313	$ 1,203	$ 1,216	$ 1,221
Average number of customer accounts	364,225	359,288	354,419	349,782	344,882

[1] Sum of the net peak demands on all islands served, noncoincident and nonintegrated.

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Generation statistics

The following table contains certain generation statistics as of December 31, 2004 and for the year ended December 31, 2004. The capability available for operation at any given time may be more or less than the generating capability shown because of capability restrictions or temporary outages for inspection, maintenance, repairs or unforeseen circumstances.

	Island of Oahu- HECO	Island of Maui- MECO	Island of Lanai- MECO	Island of Molokai- MECO	Island of Hawaii- HELCO	Total
Net generating and firm purchased capability (MW) at December 31, 2004[1]						
Conventional oil-fired steam units	1,106.8	35.9			62.2	1,204.9
Diesel		94.9	10.3	9.6	30.8	145.6
Combustion turbines (peaking units)	101.8					101.8
Combustion turbines		41.6		2.2	88.9	132.7
Combined-cycle unit		56.8				56.8
Firm contract power[2]	406.0	16.0			107.6	529.6
	1,614.6	245.2	10.3	11.8	289.5	2,171.4
Net peak demand (MW)	1,281.0	206.5	4.8	6.7	194.5	1,693.5[3]
Reserve margin	26.5%	18.8%	114.4%	76.8%	48.8%	28.6%
Annual load factor	72.2%	69.6%	69.3%	66.1%	69.2%	71.5%[3]
KWH net generated and purchased (millions)	8,127.0	1,262.0	29.2	38.9	1,181.9	10,639.0

1 HECO units at normal ratings; MECO and HELCO units at reserve ratings.

2 Nonutility generators HECO: 180 MW (Kalaeloa Partners, L.P., oil-fired), 180 MW (AES Hawaii, Inc., coal-fired) and 46 MW (H-Power, refuse-fired); MECO: 16 MW (Hawaiian Commercial & Sugar Company, primarily bagasse-fired); HELCO: 26 MW (Puna Geothermal Venture, geothermal), 22 MW (Hilo Coast Power Company, coal-fired, which contract terminated on January 1, 2005) and 60 MW (Hamakua Energy Partners, L.P., oil-fired).

3 Noncoincident and nonintegrated.

Generating reliability

HECO, HELCO and MECO have isolated electrical systems that are not interconnected to each other or to any other electrical grid. HECO serves the island of Oahu and HELCO serves the island of Hawaii. MECO has three separate electrical systems one each on the islands of Maui, Molokai and Lanai.

Because each island system cannot rely upon backup generation from neighboring utilities, HECO, HELCO and MECO each maintain a higher level of reserve generation than is typically carried by interconnected mainland utilities, which are able to share reserve capacity. These higher levels of reserve margins are required to meet peak electric demands, to provide for scheduled maintenance of generating units (including the units operated by independent power producers (IPPs) relied upon for firm capacity) and to allow for the forced outage of the largest generating unit in the system. Although the planning for, and installation of, adequate levels of reserve generation have contributed to the achievement of generally high levels of system reliability, service interruptions do occur from time to time as a result of unforeseen circumstances. For example, HECO implemented load shedding and temporarily shut off power to a significant number of customers on one occasion in 2002, due to unplanned generating unit outages. Load shedding is a predetermined plan that prevents overloading and possible major damage to generating units and potentially a much larger power outage.

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Prior to two new generating units becoming operational at its Keahole power plant in 2004, HELCO s management was concerned about the possibility of power interruptions as a result of the operating status of various IPPs supplying power to it and the condition and performance of aging generators on the HELCO system. (See discussion in Note 11 to HECO s Consolidated Financial Statements). A significant number of HELCO s customers experienced rolling blackouts on two occasions in 2002 due to unplanned generating unit outages.

Integrated resource planning and requirements for additional generating capacity

As a result of a proceeding initiated in 1990, the Public Utilities Commission of the State of Hawaii (PUC) issued an order in 1992 requiring the energy utilities in Hawaii to develop integrated resource plans (IRPs). 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. In its 1992 order, the PUC adopted a framework, which established both the process and the guidelines for developing IRPs. The PUC s framework directs that each plan cover a 20-year planning horizon with a five-year program implementation schedule and states that the planning cycle will be repeated every three years. Under the framework, the PUC may approve, reject or require modifications of the utilities IRPs.

The framework also states that utilities are entitled to recover all appropriate and reasonable integrated resource planning and implementation costs, including the costs of planning and implementing DSM programs. Under appropriate circumstances, the utilities have been allowed in the past to recover lost margins resulting from DSM programs and earn shareholder incentives. The PUC has approved IRP cost recovery provisions for HECO, MECO and HELCO. Pursuant to the cost recovery provisions, the electric utilities have been allowed to recover through a surcharge the costs for approved DSM programs (including DSM program lost margins and shareholder incentives), and other incremental IRP costs incurred by the utilities and approved by the PUC, to the extent the costs are not included in their base rates.

In October 2001, HECO and the Consumer Advocate finalized agreements, which were approved by the PUC in November 2001, under which HECO s energy efficiency programs (three commercial and industrial DSM programs and two residential DSM programs) would be continued until a decision is reached in HECO s next rate case (filed in November 2004). Under the agreements, HECO will cap the recovery of lost margins and shareholder incentives if such recovery would cause HECO to exceed its current authorized return on rate base. HECO also agreed it will not pursue the continuation of lost margins recovery and shareholder incentives through a surcharge mechanism in future rate cases. Consistent with the HECO agreements, in October 2001, MECO and HELCO reached agreements with the Consumer Advocate 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, allowed MECO and HELCO to continue temporarily their respective four existing energy efficiency DSM programs. See Other regulatory matters Demand-side management programs agreements with the Consumer Advocate in HEI s MD&A, which also includes a discussion of HECO s residential and commercial and industrial load management programs.

In August 2000, pursuant to a stipulation filed by the electric utilities and the parties in the IRP cost proceedings, the PUC issued an order allowing the electric utilities to begin recovering the 1995 through 1999 incremental IRP costs, subject to refund with interest, pending the PUC s final decision and order (D&O) approving recovery of each respective year s incremental IRP costs. Procedural schedules for the IRP cost proceedings have been established with respect to the 2000-2003 IRP costs, such that the electric utilities can begin recovering incremental IRP costs in the month after the filing of the actual costs incurred for the year, subject to refund with interest, pending the PUC s final D&O approving recovery of the costs. The Consumer Advocate has objected to the recovery of $2.9 million (before interest) of the $11.0 million of incremental IRP costs incurred during the 1995-2003 period, and the PUC s decision is pending on this matter.

The electric utilities have completed the recovery of their respective 1995 through 2002 incremental IRP costs through a surcharge on customer bills, subject to refund with interest. In addition, HECO completed the recovery of its 2003 incremental IRP costs in June 2004, subject to refund with interest. MECO is scheduled to complete the recovery of its 2003 incremental IRP costs by May 2005. As of December 31, 2004, the amount of revenues, including interest and revenue taxes, that the electric utilities recorded for IRP cost recoveries, subject to refund with interest, amounted to $17 million. HECO and MECO expect to begin recovering their incremental

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2004 IRP costs, subject to refund with interest pending a final D&O, following the filing of actual 2004 costs (which is expected to occur in late March or early April 2005).

In early 2001, the PUC issued its final D&O in the HELCO 2000 test year rate case, in which the PUC concluded that it is appropriate for HELCO to recover its IRP costs through base rates (and included an estimated amount for such costs in HELCO s test year revenue requirements) and to discontinue recovery of incremental IRP costs through the separate surcharge. HELCO recovered its incremental IRP costs incurred in 2000, which were incurred prior to the final D&O in its rate case, through its surcharge. HELCO s IRP costs incurred for 2001 and future years are recovered through HELCO s base rates. HELCO will continue to recover its DSM program costs, lost margins and shareholder incentives approved by the PUC in a separate surcharge.

The utilities have characterized their proposed IRPs as 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 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, in which the PUC further reviews the details of the proposed programs and the utilities proposals for the recovery of DSM program expenditures, lost margins and shareholder incentives.

HECO s IRP. HECO filed its second IRP with the PUC in January 1998 and updated the status of its DSM and Supply Side Action Plans in July 1999. In January 2001, the parties to the proceeding filed a stipulation for PUC approval to expedite the proceeding and the PUC approved the stipulation, closed the docket and ordered HECO to submit its IRP annual evaluation report and program implementation schedule by October 2002 (subsequently extended to December 2002) and its next (third) IRP by October 2005, as stipulated. The PUC also ordered HECO to immediately notify it in writing if HECO requires additional generation prior to the 2009 time frame.

In December 2002, HECO filed with the PUC its IRP evaluation report, updating the second IRP to reflect the latest sales and fuel forecasts and updated key planning assumptions.

On the supply side, HECO s updated second IRP focused on the planning for the next generating unit addition in the 2009 time frame a 107 MW simple-cycle combustion turbine. The updated second IRP also includes plans to add a second 107 MW simple-cycle combustion turbine in 2015, and in 2016, a conversion unit 105 MW steam turbine to create a dual-train combined-cycle unit. However, the report notes there is flexibility to allow HECO to defer the need for the second and third generating units should alternative generation technologies advance to the point they are economically and technically feasible substitutes for conventional generation. In addition, pursuant to HECO s generation asset management program, all existing generating units are currently planned to be operated (future environmental considerations permitting) beyond the 20-year IRP planning period (1998-2017).

On the demand side, in November 2001, the PUC issued two D&Os allowing HECO to temporarily continue its five energy efficiency DSM programs until its next rate case. The five energy efficiency DSM programs are designed to reduce the rate of increase in Oahu s energy use, defer construction of new generating units, minimize the state s use of oil, and achieve savings for utility customers who participate in the programs. The energy efficiency DSM programs include incentives for customers to install efficient lighting, refrigeration, water-heating and air-conditioning equipment and industrial motors. HECO s updated second IRP includes two DSM load management programs (i.e., a Residential Direct Load Control Program and a Commercial and Industrial Direct Load Control Program). HECO filed applications with the PUC requesting approval of these two load management programs in June and December 2003, respectively. In October 2004, the PUC approved HECO s two programs and implementation of the programs began in early 2005.

In September 2003, the PUC opened a docket to commence HECO s third IRP, which HECO was ordered by the PUC to file by October 2005. HECO expects its third IRP will propose multiple solutions to meet Oahu s future energy needs, including renewable energy resources, energy efficiency, conservation, technology (such as combined heat and power (CHP)) and central station generation. Given the lead times needed for permitting and regulatory approvals, in October 2003 HECO submitted a covered source permit application with the DOH for a simple cycle combustion turbine sized in the 100 MW range in Campbell Industrial Park on Oahu, which could be added as a peaking unit in the event new central generation was required in 2009, as was indicated in HECO s second IRP. The application specifies that the unit would use diesel fuel oil or naphtha, with ability to convert to a bio-fuel, like ethanol, when it becomes commercially available. This application was subsequently amended, in part

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to include the possibility that a second simple-cycle combustion turbine may be needed sooner than projected (for example, if energy efficiency and load management DSM, CHP and renewable energy program impacts are not fully realized, or if system demand increases more than projected).

In June 2004, HECO conducted an updated 5-year sales and peak forecast for Oahu that projects increased system peak requirements based on the island s strengthening economy. Based on this forecast, HECO supplied information to the PUC in its 2005 annual Adequacy of Supply letter. This letter concluded that HECO s generation capacity for Oahu for the next three years (2005-2007) is sufficiently large to meet all reasonably expected demands for service if HECO is able to acquire the forecast peak reduction benefits of its energy efficiency and load management DSM programs and there is expeditious review and approval of its proposed enhanced energy efficiency DSM programs, and either the CHP program currently pending before the PUC or individual CHP contracts submitted to the PUC.

New larger energy efficiency DSM programs were developed during the on-going IRP process and, pursuant to the DSM stipulation, approval for the enhanced DSM programs has been requested in HECO s pending rate increase application, which was filed in November 2004 (although HECO also plans to seek approval on a more accelerated basis if possible). On the supply-side, CHP system installations are behind schedule, due to suspension of the CHP program application and individual CHP contract applications pending action in the generic DG docket. Also on the supply-side, HECO and Kalaeloa executed amendments to the Kalaeloa PPA, subject to certain conditions including PUC approval, under which Kalaeloa would provide up to 29 MW of additional firm capacity (see FIN 46R discussion in Note 1 to HECO s Consolidated Financial Statements).

Demand for electricity on Oahu continues to increase. An all-time peak demand of 1,327 MW (gross) was recorded on October 12, 2004, and was 20 MW higher than the projected peak for 2004 in the June 2004 forecast. On October 13, 2004, HECO issued a public request that its customers voluntarily conserve energy as two units were out for scheduled maintenance and two units were unexpectedly unavailable.

As a result of load growth and other factors, the 2005 Adequacy of Supply letter concludes that there currently is an increased risk to generation reliability, and that generation reserve margins, although substantial, are lower than is considered desirable under the circumstances. Also, the risk of having generation-related customer outages will be higher if the peak reduction impacts of planned DSM programs or CHP installations fall short of achieving their forecast benefits. This situation is expected to continue, if the peak demand continues to grow as forecast, at least until 2009, which is the earliest that HECO expects to be able to install its planned combustion turbine. The letter also indicates that HECO is working on plans to implement a number of potential interim mitigation measures, such as installing portable leased, distributed 1.6 MW generating units at substations or other sites, and initiating a customer demand response program to supplement its load management DSM programs.

MECO s IRP. MECO filed its second IRP with the PUC in May 2000. A stipulated prehearing order was approved by the PUC in October 2000. The parties filed individual Statements of Position in May 2001. In February 2004, the parties to the proceeding filed a stipulation for PUC approval to expedite the proceeding and in April 2004 the PUC approved the stipulation, closed the docket, and ordered MECO to submit its IRP annual evaluation reports and program implementation schedules by April 2004 and April 2005 and its next (third) IRP by October 2006, as stipulated.

In April 2004, MECO filed with the PUC its IRP evaluation report, updating the second IRP to reflect the latest sales and fuel forecasts and updated key planning assumptions.

MECO s second IRP identified changes in key forecasts and assumptions since the development of MECO s initial IRP. On the supply side, MECO s second IRP focused on the planning for the installation of approximately 150 MW of additional generation through the year 2020 on the island of Maui, including 38 MW of generation at its Maalaea power plant site in increments from 2000-2005, 100 MW at its new Waena site in increments from 2007-2018, beginning with a 20 MW combustion turbine in 2007, and 10 MW from the acquisition of a wind resource in 2003 (currently, MECO expects to begin purchasing 30 MW of wind energy in 2006, subject to PUC approval). Approximately 4 MW of additional generation through the year 2020 is planned for each of the islands of Lanai and Molokai. MECO completed the installation of a 20 MW increment (the second) at Maalaea in September 2000, and the final increment of 18 MW, which was originally expected to be installed in 2005, is currently expected to be installed in the third quarter of 2006 (in August 2004 MECO received the necessary air permit, which became effective in September 2004).

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On the demand side, in November 2001 the PUC issued a D&O allowing MECO to continue temporarily its four existing energy efficiency DSM programs, which are similar in design to HECO s programs. MECO s IRP included plans for a new energy efficiency DSM program and two new load management DSM programs. While MECO does not plan to proceed with a new energy efficiency DSM program at this time, MECO is planning on filing applications for the two new load management DSM programs by the end of 2005.

HELCO s IRP. In September 1998, HELCO filed with the PUC its second IRP, which was updated in March 1999 and revised in June 1999. A schedule for the proceeding was approved by the PUC, and the parties to the proceeding completed two rounds of discovery. In January 2004, the parties to the proceeding filed a stipulation for PUC approval to expedite the proceeding and in February 2004 the PUC approved the stipulation, closed the docket and ordered HELCO to submit its IRP annual evaluation report by the end of March 2004 and its next (third) IRP by October 2005, as stipulated. The PUC also ordered HELCO to immediately notify it in writing should circumstances change pertaining to, among other things, HELCO s supply-side resources and load and sales forecast. The PUC subsequently opened a docket to commence HELCO s third IRP.

In March 2004, HELCO filed with the PUC its IRP evaluation report, updating the second IRP to reflect the latest sales and fuel forecasts and updated key planning assumptions.

The second IRP identified changes in key forecasts and assumptions since the development of HELCO s initial IRP. On the supply side, HELCO s second IRP focused on the planning for generating unit additions after near-term additions. Due to delays in adding new generation, the near-term additions proposed in HELCO s second IRP included installing two 20 MW combustion turbines (CTs) at its Keahole power plant site and proceeding in parallel with a power purchase agreement (PPA) with Hamakua Energy Partners, L.P. (Hamakua Partners, formerly Encogen Hawaii, L.P.) for a 60 MW (net) dual-train combined-cycle (DTCC) facility.

The Hamakua Partners PPA was approved in 1999 and its DTCC facility was completed in December 2000. (See the discussion of HELCO power purchase agreements in Nonutility generation.) The two Keahole CTs, CT-4 and CT-5, which were the first two phases of a planned 56 MW (net) DTCC unit, were put into limited commercial operation in May 2004 and June 2004, respectively. (See HELCO power situation in Note 11 to HECO s Consolidated Financial Statements.) A PPA with Hilo Coast Power Company (HCPC) for 18 MW of firm capacity terminated at the end of 1999, but as a result of the delays in adding new generation, HELCO had been purchasing 22 MW of firm capacity from HCPC s coal-fired facility under a restated and amended PPA, which was terminated as of January 1, 2005. HELCO also has deferred the retirements of some of its older generating units. HELCO s current plans are to install a 16 MW steam turbine, ST-7, in 2009 or earlier pending approval of land use re-classification, zoning approval and obtaining all the necessary permits and approvals to complete the DTCC unit. After the installation of ST-7, the target date for the next firm capacity addition is the 2017 timeframe. The timing of the need for additional new generation may change, however, based on factors such as the condition of the units whose retirements have been deferred, and the status of the nonutility generators providing firm capacity, including Puna Geothermal Venture (PGV). (See the discussion of HELCO power purchase agreements in Nonutility generation below.)

On the demand side, in December 2001 the PUC issued a D&O allowing HELCO to continue temporarily its four existing energy efficiency DSM programs, which are similar in design to HECO s programs.

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New capital projects

The capital projects of the electric utilities may be subject to various approval and permitting processes, including obtaining PUC approval of the project, air permits from the Department of Health of the State of Hawaii (DOH) and/or the U.S. Environmental Protection Agency (EPA), land use permits from the Hawaii Board of Land and Natural Resources (BLNR) and land use entitlements from the applicable county. Difficulties in obtaining, or the inability to obtain, the necessary approvals or permits could result in project delays, increased project costs and/or project abandonments. Extensive project delays and significantly increased project costs could result in a portion of the project costs being excluded from rates. If a project is abandoned, the project costs are generally written-off to expense, unless the PUC determines that all or part of the costs may be deferred for later recovery in rates.

In addition to HELCO s Keahole power plant expansion project, HECO s East Oahu Transmission Project (see discussion in Note 11 to HECO s Consolidated Financial Statements), and MECO s Maalaea power plant expansion project (see preceding discussion in Integrated resource planning and requirements for additional generating capacity section under the sub-heading MECO s IRP), the Company has two other significant capital projects. In December 2004, construction was completed on a $40 million project for an underground fuel pipeline that transports fuel from HECO s tank farm at Campbell Industrial Park to HECO s Waiau power plant. Also in 2004, construction commenced on HECO s $23 million project to construct a New Dispatch Center which will house a modernized Energy Management System, and which will be integrated with new Outage Management and Customer Information systems. The New Dispatch Center project is expected to be completed in 2007, with the Energy Management System operational in 2006.

HECO also plans to request approval from the PUC to build a generating unit (an approximately 100 MW combustion turbine planned to be added in 2009) and a 138 kV overhead transmission line (approximately two miles long, generally paralleling an existing overhead line through the industrial area between the AES and Campbell Industrial Park substations, to provide additional transmission capacity for the new generating unit as well as for existing units at Campbell Industrial Park).

Nonutility generation

The Company has supported state and federal energy policies which encourage the development of alternate energy sources that reduce the use of fuel oil. The Company s alternate energy sources range from wind, geothermal and hydroelectric power, to energy produced by the burning of bagasse (sugarcane waste), municipal waste and coal.

HECO PPAs. HECO currently has three major PPAs. In March 1988, HECO entered into a PPA with AES Barbers Point, Inc. (now known as AES Hawaii, Inc. (AES Hawaii)), a Hawaii-based, indirect subsidiary of The AES Corporation. The agreement with AES Hawaii, as amended in August 1989, provides that, for a period of 30 years beginning September 1992, HECO will purchase 180 MW of firm capacity. The AES Hawaii 180 MW coal-fired cogeneration plant, which became operational in September 1992, utilizes a clean coal technology. The facility is designed to sell sufficient steam to be a Qualifying Facility (QF) under the Public Utility Regulatory Policies Act of 1978 (PURPA). See discussion of a lawsuit against The AES Corporation, AES Hawaii, HECO and HEI in Note 11 to HECO s Consolidated Financial Statements. Under the amended PPA, AES Hawaii must obtain certain consents from HECO prior to entering into any arrangement to refinance the facility. In the second quarter of 2003, HECO and AES Hawaii reached agreement on the terms upon which HECO would consent to a proposed refinancing. Under the agreement, which was contingent on obtaining certain PUC approvals and completion of the refinancing, HECO received consideration for its consent, primarily in the form of a PPA amendment that reduced the cost of firm capacity supplied to HECO pursuant to the PPA, retroactive to June 1, 2003. The benefit of the firm capacity cost reduction, totaling approximately $2.9 million annually for the remaining term of the PPA, is being passed on to ratepayers through a reduction in rates. AES Hawaii also has granted HECO an option, subject to certain conditions, to acquire an interest in portions of the AES Hawaii facility site that are not needed for the existing plant operations, and which potentially could be used for the development of another coal-fired facility. On July 1, 2003, the PUC issued a D&O approving the PPA amendment and a rate adjustment (lowering rates) on short notice. On July 31, 2003, the proposed refinancing was completed and capacity payments were reduced, retroactive to June 1, 2003.

In October 1988, HECO entered into an agreement with Kalaeloa Partners, L.P. (Kalaeloa), a limited partnership whose sole general partner was an indirect, wholly-owned subsidiary of ASEA Brown Boveri, Inc. (ABB), which has guaranteed certain of Kalaeloa s obligations and, through affiliates, contracted to design, build, operate and maintain the facility. The agreement with Kalaeloa, as amended, provides that HECO will purchase 180 MW of firm capacity for a period of 25 years beginning in May 1991. The Kalaeloa facility, which was completed in the second quarter of 1991, is a combined-cycle operation, consisting of two oil-fired combustion turbines burning low sulfur fuel oil (LSFO) and a steam turbine that utilizes waste heat from the combustion turbines. The facility is designed to sell sufficient steam to be a QF. As of February 28, 1997, the ownership of Kalaeloa was restructured so that 1% was owned by the ABB subsidiary as the general partner and 99% was owned by Kalaeloa Investment Partners (KIP) as the limited partner. KIP is a limited partnership comprised of PSEG Hawaiian Management, Inc. and PSEG Hawaiian Investment, Inc. (nonregulated affiliates of Public Service Enterprise Group Incorporated) and Harbert Power Corporation. Subsequently, HECO consented to, and the PUC approved of, the transfer of the general partner partnership interest from the ABB subsidiary to an entity affiliated with the owners of KIP. During the second quarter of 2003, Kalaeloa approached HECO with plans to upgrade the combustion turbines (the M upgrade) by installing new parts designed to improve their efficiency and output. The upgraded combustion turbines would allow Kalaeloa to increase the capacity of the facility by approximately 20 MW. Under the agreement, Kalaeloa may not make any modifications to the facility that would either increase or decrease the generating capacity of the facility without the prior approval of HECO, except as required by law or regulation. The agreement also provides that HECO shall not be obligated to approve a change in facility capacity if such change would adversely impact HECO system reliability or result in an increased cost of power to HECO from the facility. On December 31, 2003, HECO and Kalaeloa entered into a Consent and Agreement (Consent) in which HECO consented to the M upgrade. The Consent provides that neither the M upgrade nor HECO s consent to the M upgrade shall obligate HECO to accept additional energy made available as a result of the M upgrade, or to enter into negotiations to accept any change in the firm capacity of the facility, and shall not affect the rights of the parties under the section of the agreement related to an increase in firm capacity.

The PPA with Kalaeloa provides that if Kalaeloa s facility is able to demonstrate, under certain conditions, that it is able to deliver capacity above the 180 MW of firm capacity (up to a maximum of 189 MW), the firm capacity under the PPA shall be increased to the level that was demonstrated. Under the PPA, the additional capacity above 180 MW shall be paid at $112 per kilowatt per year (as compared to the payment rate of $164.35 per kilowatt per year for capacity up to and including 180 MW). On October 12, 2004, HECO and Kalaeloa executed two amendments to the PPA: 1) Confirmation Agreement Concerning Section 5.2B(2) Of Power Purchase Agreement And Amendment No. 5 To Power Purchase Agreement (Amendment No. 5), and 2) Agreement For Increment Two Capacity And Amendment No. 6 To Power Purchase Agreement Between HECO And Kalaeloa (Amendment No. 6). Amendment No. 5 confirms Kalaeloa s demonstration, through a test conducted in 2004, that its facility is able to deliver 189 MW of capacity from the existing facility, and sets the capacity payment rate for capacity above 180 MW at $112 per kilowatt per year. Amendment No. 5 also clarifies, modifies, or amends certain provisions of the PPA. Amendment No. 6 provides for the purchase of up to 20 MW of additional capacity, beyond the 189 MW capacity confirmed in Amendment No. 5, at $112 per kilowatt per year. The amount of capacity which HECO will purchase, up to the additional 20 MW, will be demonstrated through a test conducted in 2005. Amendment Nos. 5 and 6 were submitted to the PUC for approval on November 5, 2004. The approval by the PUC and inclusion of the associated purchased power expenses in HECO rates are needed for the amendments to be effective (see FIN 46R discussion in Note 1 to HECO s Consolidated Financial Statements).

HECO also entered into a PPA in March 1986 and a firm capacity amendment in April 1991 with the City and County of Honolulu with respect to a refuse-fired plant (H-POWER). The H-POWER facility began to provide firm energy in 1990 and currently supplies HECO with 46 MW of firm capacity. The firm capacity amendment provides that HECO will purchase firm capacity until mid-2015.

HECO purchases energy on an as-available basis from two nonutility generators, which are diesel-fired qualifying cogeneration facilities at the two oil refineries (10 MW and 18 MW) on Oahu. HECO previously purchased energy on an as-available basis from an approximately 3 MW combustion turbine fired by methane gas from a landfill. In March 2002, the combustion turbine suffered a major failure. In July 2002, the owner of the facility requested that HECO terminate the PPA and HECO agreed.

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The PUC has approved and allowed rate recovery for the firm capacity and purchased energy costs related to HECO s three major PPAs that provide a total of 406 MW of firm capacity, representing 25% of HECO s total net generating and firm purchased capacity on the island of Oahu as of December 31, 2004. The PUC also has approved and allowed rate recovery for the purchased energy costs related to HECO s as-available energy PPAs.

HELCO and MECO PPAs. As of December 31, 2004, HELCO and MECO had PPAs for 108 MW and 16 MW (includes 4 MW of system protection) of currently available firm capacity, respectively, but HELCO s PPA with HCPC for 22 MW was terminated as of January 1, 2005 (see below).

HELCO has a 35-year PPA with Puna Geothermal Venture (PGV) for 30 MW of firm capacity from its geothermal steam facility expiring on December 31, 2027. PGV s output was reduced to 6 MW from April 2002 to March 2003. The loss of generation was attributed to blockage of a source well due to a failed liner 5,000 feet below the Earth s surface and decreasing steam quality emanating from one of PGV s source wells. PGV completed drilling an additional source well in February 2003, and converted the blocked source well into an injection well in early March 2003. The new injection well was tested and PGV s capacity is currently between 25 to 28 MW. PGV obtained a permit from the DOH for the new injection well in March 2003. Without the new injection well, PGV was able to produce only about 10 to 11 MW due to the high moisture content of the steam from the new source well. PGV is assessing whether to drill another source well or to install new generation equipment designed to utilize the lower quality steam. While PGV indicates it is evaluating its options to enable it to restore its 30 MW commitment to HELCO as soon as possible, HELCO cannot predict when PGV will be able to meet its contractual commitment. HELCO s PPA with PGV provides for annual availability sanctions against PGV if PGV does not provide up to the contracted 30 MW of capacity. In the first quarter of 2003, HELCO recorded $0.7 million lower purchased power expense from PGV for availability sanctions for not meeting contracted capacity for 2002. In addition, since PGV had not yet restored its 30 MW commitment to HELCO by December 31, 2003, availability sanctions for 2003, of approximately $0.2 million, were assessed against PGV in 2004. Sanctions for 2004, estimated at approximately $0.1 million, will be assessed against PGV in 2005. On June 3, 2004, HELCO was informed that ORNI 8 LLC, a wholly owned affiliate of Ormat Nevada Inc., acquired PGV through the acquisition of the PGV partner entities from Constellation Power, Inc. The transaction did not require HELCO s consent or PUC approval. PGV has indicated its intent to pursue improvements to the plant to increase its capacity, and to pursue negotiations with HELCO for a new or amended PPA.

On October 4, 1999, HELCO entered into a PPA with HCPC effective January 1, 2000 through December 31, 2004, subject to early termination by HELCO, whereby HELCO purchases 22 MW of firm capacity from HCPC s coal-fired facility. On May 27, 2004, HELCO provided notice to HCPC to terminate the PPA as of January 1, 2005, and the PPA with HCPC was terminated as of January 1, 2005.

In October 1997, HELCO entered into an agreement with Encogen, a limited partnership whose general partners at the time were wholly-owned special-purpose subsidiaries of Enserch and Jones Capital Corporation. Enserch Corporation and J.A. Jones, Inc. (Jones), the parent companies of Enserch and Jones Capital Corporation, respectively, guaranteed certain of Encogen s obligations. The agreement provides that HELCO will purchase up to 60 MW (net) of firm capacity for a period of 30 years. The DTCC facility, which primarily burns naphtha, consists of two oil-fired combustion turbines and a steam turbine that utilizes waste heat from the combustion turbines. The PUC approved the agreement on July 14, 1999. On November 8, 1999, HELCO entered into a PPA Novation with Encogen and Hamakua Partners, which recognizes the transfer of the obligations of Encogen under the PPA to Hamakua Partners. Hamakua Partners was formed as a result of the sale of the general partner and limited partner partnership interests of Enserch to entities affiliated with TECO Energy Inc. (TECO), which is a Florida-based energy company and parent company of Tampa Electric Company, a regulated electric utility. TECO has replaced the guarantee of Enserch Corporation of certain of Hamakua Partners obligations.

On August 12, 2000, Hamakua Partners began providing HELCO with firm capacity from the first phase of a two-phase construction completion schedule. On December 31, 2000, Hamakua Partners began providing firm capacity from the entire facility, following completion of the second phase of construction. In June 2001, Hamakua Partners demonstrated 60 MW of output from the facility. Subsequently, the output deteriorated due to technical problems in the steam turbine. Hamakua Partners has since resolved its nozzle plugging problems, but due to high nitrogen oxide emissions and high steam turbine vibration problems, the output had been limited to 55-57 MW in early 2003. Hamakua Partners requested maintenance outages to correct the problems and returned to providing

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HELCO with 60 MW later in 2003. In September 2003, Jones filed for reorganization in bankruptcy in North Carolina. Jones is the parent company of the managing general partner and a limited partner of Hamakua Partners, and is one of the two co-guarantors of the Hamakua Partners project. In June 2004, under a court approved motion, substantially all of the assets of Jones including its interest in Hamakua Partners was sold to Black River Energy, an affiliate of United States Power Fund L. P. (USPF). In July 2004, the remaining 50% ownership in Hamakua Partners was sold by TECO to an affiliate of Black River Energy. As a result of both sales, USPF is now the sole owner of the Hamakua facility.

HELCO purchases energy on an as-available basis from a number of nonutility generators. The largest include a 12.1 MW run-of-the-river hydroelectric facility and a 7 MW wind facility. Wailuku River Hydroelectric L.P., the owner of the hydroelectric facility, has an existing contract to provide HELCO with as-available power through May 2023. Apollo Energy Corporation (Apollo), the owner of the wind facility, has an existing contract to provide HELCO with as-available windpower through June 29, 2002 (and extending thereafter until terminated by HELCO or Apollo). Apollo filed a petition for hearing with the PUC on April 28, 2000, alleging that it had unsuccessfully attempted to negotiate a new power purchase agreement with HELCO. Apollo had offered to repower its existing 7 MW facility by the end of 2000 and to install additional wind turbines, up to a total allowed capacity of 15 MW, by the end of 2001. The parties agreed to limit to four issues the matters being presented to the PUC for guidance: whether Apollo is entitled to capacity payments; whether Apollo is entitled to a minimum purchase rate; whether certain performance standards should apply; and whether HELCO s proposed dispute resolution provision should apply. A hearing on these issues was held on October 3 to 5, 2000. On May 30, 2001, the PUC issued a D&O in which it ordered HELCO and Apollo to continue to negotiate a PPA, consistent with the terms of the D&O, and to submit by August 13, 2001 either a finalized PPA or status reports informing the PUC of matters preventing finalization of a PPA. HELCO and Apollo were unable to agree to a PPA by August 13, 2001, and each submitted a status report. The parties continued to negotiate in 2002, 2003 and 2004, and reached agreement on a PPA on October 13, 2004. The PPA enables Apollo to repower its existing 7 MW facility, and install an additional 13.5 MW of capacity, for a total windfarm capacity of 20.5 MW. The PPA was submitted to the PUC for approval on November 26, 2004.

On January 8, 2001, HELCO entered into a PPA with Hawi Renewable Development, Inc. (HRD) for the purchase of as-available energy from HRD s proposed 5 MW windfarm. An amendment to the PPA was completed on April 30, 2002. The PPA, as amended, was approved by the PUC on January 14, 2003.

On December 30, 2003, HELCO and Hawi Renewable Development, LLC (HRD LLC) entered into a PPA under which HRD LLC would sell energy from an expanded wind farm (approximately 10.6 MW) at HRD s 5 MW wind farm site (which can accommodate the expanded wind farm). It is anticipated that the output of the 10.6 MW wind farm may be limited on occasion. The PUC approved the PPA on May 14, 2004.

MECO has a PPA with Hawaiian Commercial & Sugar Company (HC&S) for 16 MW of firm capacity. The HC&S generating units primarily burn bagasse (sugar cane waste) along with secondary fuels of oil or coal. HC&S has had some difficulties in meeting its contractual obligations to MECO over the years through 2003 due to operational constraints. The PPA remains in force and effect through December 31, 2007, and from year to year thereafter, subject to termination on or after December 31, 2007 on not less than two years prior written notice by either party.

Beginning in 2006, MECO expects to purchase as-available energy from Kaheawa Wind Power, LLC (KWP) under a PPA between MECO and KWP dated December 3, 2004. KWP plans to install a 30 MW windfarm at Ukumehame, Maui. The PPA was submitted to the PUC for approval on December 16, 2004.

The PUC has approved and allowed rate recovery for the firm capacity and purchased energy costs for MECO s and HELCO s approved firm capacity and as-available energy PPAs.

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Fuel oil usage and supply

The rate schedules of the Company s electric utility subsidiaries include energy cost adjustment (ECA) clauses under which electric rates (and consequently the revenues of the electric utility subsidiaries generally) 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 discussion below under Rates, and Regulation of electric utility rates and Electric utility revenues in HEI s MD&A.

HECO s steam power plants burn LSFO. HECO s combustion turbine peaking units burn No. 2 diesel fuel (diesel). MECO s and HELCO s steam power plants burn medium sulfur fuel oil (MSFO) and their combustion turbine and diesel engine generating units burn diesel. The LSFO supplied to HECO is primarily derived from Indonesian and other Far East crude oils processed in Hawaii refineries. The MSFO supplied to MECO and HELCO is derived from U.S. domestic crude oil and various foreign crude oil grades processed in Hawaii refineries.

In December 1997, HECO executed contracts for the purchase of LSFO and the use of certain fuel distribution facilities with Chevron Products Company (Chevron) and BHP Petroleum Americas Refining Inc. (BHP). Subsequently, Tesoro Hawaii Corp. (Tesoro) acquired BHP and assumed all rights and obligations under the contract between HECO and BHP. The Chevron and BHP (now Tesoro) fuel supply and facilities operations contracts have a term of seven years commencing January 1, 1998. The PUC approved the contracts and permits the inclusion of costs incurred under these contracts in HECO s ECA clauses. HECO pays market-related prices for fuel supplies purchased under these agreements.

In March and April of 2004, HECO executed 10-year extensions of the existing contracts, commencing January 1, 2005, for the purchase of LSFO with Chevron and Tesoro with no material changes in the primary commercial arrangements including volumes and pricing formulas. The PUC approved these contract extensions in December 2004. In December 2004, HECO executed long-term contracts with Chevron for the continued use of certain Chevron fuel distribution facilities and for the operation and maintenance of certain HECO fuel distribution facilities.

HECO, MECO and HELCO executed joint fuel supply contracts with Chevron and BHP (now Tesoro) for the purchase of diesel and MSFO supplies and for the use of certain petroleum distribution facilities for a period of seven years commencing January 1, 1998. The PUC approved these contracts and the electric utilities pay market-related prices for diesel and MSFO supplied under these agreements.

In March and April of 2004, HECO, HELCO and MECO executed 10-year extensions of the existing contracts, commencing January 1, 2005, for the purchase of diesel and MSFO with Chevron and Tesoro, including the use of certain petroleum storage and distribution facilities, with no material changes in the primary commercial arrangements including volumes and pricing formulas. The PUC approved these contract extensions in December 2004.

The diesel supplies acquired by the Lanai Division of MECO are purchased under a contract with a local petroleum wholesaler, Lanai Oil Co., Inc. On March 1, 2000, the PUC approved an amended contract with a term extending through December 31, 2001, and further extending through December 31, 2003 unless terminated as of the end of 2001. This agreement has been extended through December 31, 2005.

See the fuel oil commitments information set forth in the Fuel contracts section in Note 11 to HECO s Consolidated Financial Statements.

The following table sets forth the average cost of fuel oil used by HECO, MECO and HELCO to generate electricity in the years 2004, 2003 and 2002:

	HECO		MECO		HELCO		Consolidated	
	$/Barrel	**¢/MBtu**	**$/Barrel**	**¢/MBtu**	**$/Barrel**	**¢/MBtu**	**$/Barrel**	**¢/MBtu**
2004	40.53	641.8	51.02	855.1	42.32	688.3	42.67	684.3
2003	35.49	561.3	39.52	662.1	34.96	566.4	36.23	580.5
2002	27.95	442.3	32.78	548.5	30.58	496.7	29.10	466.4

The average per-unit cost of fuel oil consumed to generate electricity for HECO, MECO and HELCO reflects a different volume mix of fuel types and grades. In 2004, over 98% of HECO s generation fuel consumption consisted of LSFO. The balance of HECO s fuel consumption was diesel. Diesel made up approximately 76% of MECO s and 34% of HELCO s fuel consumption. MSFO made up the remainder of the fuel consumption of MECO and HELCO.

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In general, MSFO is the least costly fuel, diesel is the most expensive fuel and the price of LSFO falls between the two on a per-barrel basis. During 2004, the prices of LSFO, MSFO and diesel rose above the levels reached at the end of 2003 reflecting stronger demand for petroleum products world wide, particularly in the U.S. and China, tight U.S. crude oil and petroleum product inventories and continued geopolitical uncertainty. Thus the annual prices paid by the electric utilities for LSFO, MSFO and diesel averaged approximately 15%, 14% and 38%, respectively, above the average price for that grade of fuel in 2003. Though prices in 2004 continued the upward trend when compared to the year earlier, the rate of increase lessened somewhat from the previous annual increase. During 2003, the prices of LSFO, MSFO and diesel remained at or above the high levels reached at the end of 2002 reflecting geopolitical uncertainty with the invasion of Iraq and tight U.S. crude oil and petroleum inventories.

In December 2000, HELCO and MECO executed contracts of private carriage with Hawaiian Interisland Towing, Inc. (HITI) for the shipment of MSFO and diesel supplies from their fuel suppliers facilities on Oahu to storage locations on the islands of Hawaii and Maui, respectively, commencing January 1, 2002. These contracts were the result of a competitive bidding process and provide for the employment of a double-hull bulk petroleum barge at freight rates approximately the same as prevailed under predecessor transportation contracts with HITI. The double-hull barge entered utility service in March 2002. The contracts are for an initial term of 5 years with options for three additional 5-year extensions. On December 10, 2001, the PUC approved these contracts and issued a final order that permits HELCO and MECO to include the fuel transportation and related costs incurred under the provisions of these agreements in their respective ECA clauses.

HITI never takes title to the fuel oil or diesel fuel, but does have custody and control while the fuel is in transit from Oahu. If there were an oil spill in transit, HITI is contractually obligated to indemnify HELCO and/or MECO. HITI has liability insurance coverage for oil spill related damage of $1 billion. State law provides a cap of $700 million on liability for releases of heavy fuel oil transported interisland by tank barge. In the event of a release, HELCO and/or MECO may be responsible for any clean-up and/or fines that HITI or its insurance carrier does not cover.

The prices that HECO, MECO and HELCO pay for purchased energy from nonutility generators are generally linked to the price of oil. The AES Hawaii energy prices vary primarily with an inflation indicator. The energy prices for Kalaeloa, which purchases LSFO from Tesoro, vary primarily with world LSFO prices. The H-POWER, HC&S and PGV energy prices are based on the electric utilities respective PUC-filed short-run avoided energy cost rates (which vary with their respective composite fuel costs), subject to minimum floor rates specified in their approved PPAs. The Hamakua Partners energy prices vary primarily with HELCO s diesel costs.

The Company estimates that 79% of the net energy generated and purchased by HECO and its subsidiaries in 2005 will be generated from the burning of oil. Increases in fuel oil prices are passed on to customers through the electric utility subsidiaries ECA clauses. Failure by the Company s oil suppliers to provide fuel pursuant to the supply contracts and/or substantial increases in fuel prices could adversely affect consolidated HECO s and the Company s financial condition, results of operations and/or liquidity. HECO s policy, however, is to maintain an inventory of fuel oil equivalent to a 35 day supply. HELCO s and MECO s policies are to maintain approximately a one month s supply of both MSFO and diesel. The PPAs with AES Hawaii and Hamakua Partners require that they maintain certain minimum fuel inventory levels.

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Transmission systems

HECO has 138 kV transmission and 46 kV subtransmission lines. HELCO has 69 kV transmission and 34.5 kV transmission and subtransmission lines. MECO has 69 kV transmission and 23 kV subtransmission lines on Maui and 34.5 kV transmission lines on Molokai. Lanai has no transmission lines and uses 12 kV lines to distribute electricity. The electric utilities overhead and underground transmission and subtransmission lines, as well as their distribution lines, are uninsured because the amount of insurance available is limited and the premiums are extremely high.

Lines are added when needed to serve increased loads and/or for reliability reasons. In some design districts on Oahu, lines must be placed underground. By state law, the PUC generally must determine whether new 46 kV, 69 kV or 138 kV lines can be constructed overhead or must be placed underground. The process of acquiring permits and regulatory approvals for new lines can be contentious, time consuming (leading to project delays) and costly.

HECO system. HECO serves Oahu s electricity requirements with firm capacity (net) generating units located in West Oahu (1,027 MW); Waiau, adjacent to Pearl Harbor (481 MW); and Honolulu (107 MW). HECO s nonfirm power sources (approximately 28 MW) are located primarily in West Oahu. HECO transmits power to its service areas on Oahu through approximately 219 miles of overhead and underground 138 kV transmission lines (of which approximately 8 miles are underground) and approximately 523 miles of overhead and underground 46 kV subtransmission lines.

HECO s power sources are located primarily in West Oahu, but the bulk of HECO s system load is in the Honolulu/East Oahu area. Accordingly, HECO transmits bulk power to the Honolulu/East Oahu area over two major transmission corridors (Northern and Southern). HECO had planned to construct a part underground/part overhead 138 kilovolt (kV) transmission line from the Kamoku substation to the Pukele substation in order to close the gap between the Southern and Northern corridors and provide a third 138 kV transmission line to the Pukele substation. Construction of the proposed transmission line in its originally proposed location required the BLNR to approve a CDUP for the overhead portion of the line that would have been in conservation district lands. Several community and environmental groups opposed the project, particularly the overhead portion of the line and, in June 2002, the BLNR denied HECO s request for a CDUP.

HECO continues to believe that the proposed project (the East Oahu Transmission Project) is needed to improve the reliability of the Pukele substation, which serves approximately 16% of Oahu s electrical load, including Waikiki, and to address future potential line overloads under certain contingencies. In 2003, HECO completed its evaluation of alternative ways to accomplish the project (including using 46 kV transmission lines). As part of its evaluation, HECO conducted a community-based process to obtain public views of the alternatives. In December 2003, HECO filed an application with the PUC requesting approval to commit funds (currently estimated at $55 million, which amount includes $23 million of costs already incurred) for its revised East Oahu Transmission Project. See discussion in Note 11 to HECO s Consolidated Financial Statements.

HELCO system. HELCO serves the island of Hawaii s electricity requirements with firm capacity (net) generating units located in West Hawaii (77 MW) and East Hawaii (212 MW). HELCO s nonfirm power sources total 24 MW, but are expected to increase by 24 MW in 2006. HELCO transmits power to its service area on the island of Hawaii through approximately 468 miles of 69 kV overhead lines and approximately 173 miles of 34.5 kV overhead lines.

MECO system. MECO serves its electricity requirements with firm capacity (net) generating units located on the island of Maui (245 MW), Molokai (12 MW) and Lanai (10 MW). Beginning in 2006, MECO expects to purchase 30 MW of as-available energy, under a PPA between

MECO and Kaheawa Wind Power, LLC (KWP) dated December 3, 2004. The PPA was submitted to the PUC for approval on December 16, 2004. MECO transmits power to its service area through approximately 143 miles of 69 kV overhead lines, approximately 15 miles of 34.5 kV overhead lines, and approximately 85 miles of 23 kV overhead lines.

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Rates

HECO, MECO and HELCO are subject to the regulatory jurisdiction of the PUC with respect to rates, issuance of securities, accounting and certain other matters. See Regulation and other matters Electric utility regulation.

All rate schedules of HECO and its subsidiaries contain ECA clauses as described previously. Under current law and practices, specific and separate PUC approval is not required for each rate change pursuant to automatic rate adjustment clauses previously approved by the PUC. Rate increases, other than pursuant to such automatic adjustment clauses, require the prior approval of the PUC after public and contested case hearings. PURPA requires the PUC to periodically review the ECA clauses of electric and gas utilities in the state, and such clauses, as well as the rates charged by the utilities generally, are subject to change.

See Regulation of electric utility rates, Most recent rate requests and Electric utility revenues in HEI s MD&A.

Public Utilities Commission of the State of Hawaii

After serving 14 months on the PUC, Carlito P. Caliboso (an attorney previously in private practice) was reappointed to the PUC, confirmed by the state senate for a six year term expiring June 30, 2010, and continues to serve as Chairman of the PUC. Also serving as commissioners are Janet E. Kawelo (term expiring June 30, 2006, who previously served as the Deputy Director for the State Department of Land and Natural Resources) and Wayne H. Kimura (term expiring June 30, 2008, who previously served as State Comptroller with the State Department of Accounting and General Services).

John E. Cole was appointed Executive Director of the Division of Consumer Advocacy effective May 17, 2004. Prior to becoming the Executive Director, Mr. Cole was a member of the Governor of the State of Hawaii s Policy Team, which serves as advisor to the Governor on state-wide policy matters. Mr. Cole is an attorney.

Most recent rate requests

See Most recent rate requests in HEI s MD&A.

Competition

In December 1996, the PUC instituted 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. See Competition in HEI s MD&A.

Electric and magnetic fields

Research on potential adverse health effects from exposure to electric and magnetic fields (EMF) continues. To date, no definite relationship between EMF and health risks has been clearly demonstrated. In 1996, the National Academy of Sciences examined more than 500 studies and stated that the current body of evidence does not show that exposure to EMFs presents a human-health hazard. An extensive study released in 1997 by the National Cancer Institute and the Children s Cancer Group found no evidence of increased risk for childhood leukemia from EMF. In 1999, the National Institute of Environmental Health Sciences (NIEHS) Director s Report concluded that while EMF could not be found to be entirely safe, the evidence of a health risk was weak and did not warrant aggressive regulatory actions. In 2002, the NIEHS further stated that for most health outcomes, there is no evidence that EMF exposures have adverse effects, and also that there is some evidence from epidemiology studies that exposure to power-frequency EMF is associated with an increased risk for childhood leukemia. In the same brochure, the NIEHS further concluded that this association is difficult to interpret in the absence of reproducible laboratory evidence or a scientific explanation that links magnetic fields with childhood leukemia.

While EMF has not been established as a cause of any health condition by any national or international agency, EMF remains the subject of ongoing studies and evaluations. EMF has been classified as a possible human carcinogen by more than one public health organization. In 2004, the U.K. National Radiological Protection Board (NRPB) published a report that supported a precautionary approach and recommended adoption of guidelines for limiting exposure to EMF. In the U.S., there are no federal standards limiting occupational or residential exposure to 60-Hz EMF.

The implications of the foregoing reports have not yet been determined. However, these reports may raise the profile of the EMF issue for electric utilities.

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HECO and its subsidiaries are monitoring the research and continue to participate in utility industry funded studies on EMF and, where technically feasible and economically reasonable, continue to pursue reducing EMFs, in the design and installation of new transmission and distribution facilities. Management cannot predict the impact, if any, the EMF issue may have on HECO, HELCO and MECO in the future.

Legislation

See Legislation and regulation in HEI s MD&A.

Commitments and contingencies

See Certain factors that may affect future results and financial condition Other regulatory and permitting contingencies in HEI s MD&A and Note 11 to HECO s Consolidated Financial Statements for a discussion of important commitments and contingencies, including (but not limited to) HELCO s Keahole power situation; HECO s East Oahu Transmission Project; the lawsuit against The AES Corporation, HECO and HEI; and the Honolulu Harbor environmental investigation.

City and County sewer line. On July 22, 2004, a contractor (hired by HECO for a utility line extension project to support the expansion of the City and County of Honolulu s wastewater treatment plant) accidentally drilled into a force main sewer line owned by the City and County. The City and County made a formal demand that HECO provide full compensation for damages to the force main sewer line. Management believes HECO has defenses against any assertions that it has liability for the incident as well as insurance coverage (over a deductible amount). Accordingly, HECO responded to the demand asserting its defenses against liability. HECO has increased its general liability reserves to provide for clean-up costs in the event it is found to have responsibility for such costs.

Bank American Savings Bank, F.S.B.

General

ASB was granted a federal savings bank charter in January 1987. Prior to that time, ASB had operated since 1925 as the Hawaii division of American Savings & Loan Association of Salt Lake City, Utah. As of December 31, 2004, ASB was the third largest financial institution in the State of Hawaii based on total assets of $6.8 billion and deposits of $4.3 billion. In 2004, ASB s revenues and net income from continuing operations amounted to approximately 19% and 38%, respectively, of HEI s consolidated amounts, compared to approximately 21% and 48% in 2003 and approximately 24% and 48% in 2002, respectively.

At the time of HEI s acquisition of ASB in 1988, HEI agreed with the Office of Thrift Supervision s (OTS) predecessor regulatory agency that ASB s regulatory capital would be maintained at a level of at least 6% of ASB s total liabilities, or at such greater amount as may be required from time to time by regulation. Under the agreement, HEI s obligation to contribute additional capital was limited to a maximum aggregate amount of approximately $65.1 million. At December 31, 2004, HEI s maximum obligation to contribute additional capital has been reduced to approximately $28.3 million because of additional capital contributions of $36.8 million by HEI to ASB since the acquisition, exclusive of capital contributions made in connection with ASB s 1997 acquisition of most of the Hawaii operations of Bank of America, FSB (including the $75 million capital contribution made by HEIDI in December 2004 after ASB redeemed $75 million of preferred stock that had been issued to HEIDI in connection with the 1997 acquisition). ASB is subject to OTS regulations on dividends and other distributions applicable to financial institutions regulated by the OTS and ASB must receive a letter of non-objection before it can declare and pay a dividend to HEI.

ASB s earnings depend primarily on its net interest income the difference between the interest income earned on interest-earning assets (loans receivable and investment and mortgage-related securities) and the interest expense incurred on interest-bearing liabilities (deposit liabilities and borrowings, including advances from the Federal Home Loan Bank (FHLB) of Seattle and securities sold under agreements to repurchase). Other factors primarily affecting ASB s operating results include gains or losses on sales of securities available-for-sale, fee income, provision for loan losses, changes in the value of mortgage servicing rights and expenses from operations.

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For additional information about ASB, see the sections under Bank in HEI s MD&A, HEI s Quantitative and Qualitative Disclosures about Market Risk and Note 4 to HEI s Consolidated Financial Statements.

The following table sets forth selected data for ASB for the years indicated:

	Years ended December 31,		
	2004	**2003**	**2002**
Common equity to assets ratio			
Average common equity divided by average total assets [1]	7.10%	7.20%	7.20%
Return on assets			
Net income for common stock divided by average total assets [1]	0.62	0.88	0.92
Return on common equity			
Net income for common stock divided by average common equity [1]	8.7	12.2	12.7
Tangible efficiency ratio			
Total general and administrative expenses divided by net interest income and other income	61	61	58

1 Average balances calculated using the average daily balances (except for common equity, which is calculated using the average month-end balance).

ASB s tangible efficiency ratio the cost of earning $1 of revenue remained flat at 61% from 2003 to 2004. The tangible efficiency ratio rose from 58% for 2002 to 61% for 2003 as net interest income decreased due to margin compression and general and administrative expenses grew due to costs to transform ASB to a full-service community bank. The transformation project will require continued investment in people and technology. ASB s ongoing challenge is to manage expenses in order to keep increasing costs and increasing revenues in balance.

Consolidated average balance sheet

The following table sets forth average balances of ASB s major balance sheet categories for the years indicated. Average balances have been calculated using the daily average balances.

	Years ended December 31,		
(in thousands)	**2004**	**2003**	**2002**
Assets			
Investment securities	$ 240,466	$ 200,891	$ 246,321
Mortgage-related securities	2,799,303	2,707,395	2,654,302
Loans receivable, net	3,121,878	3,071,877	2,844,341
Other	424,464	418,296	392,338

	$ 6,586,111	$ 6,398,459	$ 6,137,302
Liabilities and stockholder s equity			
Savings deposits	$ 2,956,126	$ 2,663,325	$ 2,394,435
Term certificates	1,157,944	1,224,820	1,323,118
Other borrowings	1,819,598	1,851,258	1,770,831
Other	109,544	123,167	132,223
Stockholder s equity	542,899	535,889	516,695
	$ 6,586,111	$ 6,398,459	$ 6,137,302

In 2004, the low interest rate environment and continued strength in the Hawaii real estate market resulted in an increase in average loans receivables. The average residential mortgage portfolio as of year-end 2004 grew by $37.7 million or 1.5% over the 2003 year-end average residential mortgage portfolio. Average commercial real estate loans, net of undisbursed loan funds, increased $12.4 million or 6.2% over 2003 primarily due to commercial construction real estate loans originated in 2004 of $85.8 million. ASB s average business portfolio increased by $11.0 million or 4.0% during 2004 as ASB s transformation to a full-service community bank continued. The average consumer loan portfolio decreased $8.2 million or 3.6% from 2003 as low interest rates and improving real estate values resulted in higher mortgage refinancing and high consumer loan payoffs. Average savings deposits increased during the year as ASB continued to attract core deposits. Average term certificate balances decreased in 2004 as ASB did not aggressively pursue term certificates. Average other borrowings also

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decreased during 2004 as the increase in average savings deposits enabled ASB to repay some of its maturing, higher costing other borrowings. In 2003, the low interest rate environment and continued strength in the Hawaii real estate market drove record loan production and an increase in average loans receivables. The average residential mortgage portfolio as of year-end 2003 grew by $194 million, or 8.5%, over 2002 year-end. ASB increased its average business portfolio by $52 million, or 23.5%, during 2003. The increase in savings deposits and the decrease in term certificates were due to ASB s efforts in attracting low-costing core deposits and ASB not aggressively pursuing term certificates.

Asset/liability management

See HEI s Quantitative and Qualitative Disclosures about Market Risk.

Interest income and interest expense

See Results of operations Bank in HEI s MD&A for a table of average balances, interest and dividend income, interest expense and weighted-average yields earned and rates paid for certain categories of interest-earning assets and interest-bearing liabilities for the years ended December 31, 2004, 2003 and 2002.

The following table shows the effect on net interest income of (1) changes in interest rates (change in weighted-average interest rate multiplied by prior year average portfolio balance) and (2) changes in volume (change in average portfolio balance multiplied by prior period rate). Any remaining change is allocated to the above two categories on a *pro rata* basis.

	Increase (decrease) due to		
(in thousands)	**Rate**	**Volume**	**Total**
Year ended December 31, 2004 vs. 2003			
Income from interest-earning assets			
Loan portfolio	$ (17,381)	$ 3,206	$ (14,175)
Mortgage-related securities	5,250	3,725	8,975
Investments	(1,637)	1,129	(508)
	(13,768)	8,060	(5,708)
Expense from interest-bearing liabilities			
Deposits	(5,349)	(1,275)	(6,624)
FHLB advances and other borrowings	(2,739)	(1,174)	(3,913)
	(8,088)	(2,449)	(10,537)
Net interest income	$ (5,680)	$ 10,509	$ 4,829
Year ended December 31, 2003 vs. 2002			
Income from interest-earning assets			

Loan portfolio	$ (19,637)	$ 15,503	$ (4,134)
Mortgage-related securities	(30,425)	2,669	(27,756)
Investments	(73)	(1,439)	(1,512)
	(50,135)	16,733	(33,402)
Expense from interest-bearing liabilities			
Deposits	(18,338)	(1,485)	(19,823)
FHLB advances and other borrowings	(13,209)	3,474	(9,735)
	(31,547)	1,989	(29,558)
Net interest income	$ (18,588)	$ 14,744	$ (3,844)

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Other income

In addition to net interest income, ASB has various sources of other income, including fee income from credit and debit cards and fee income from deposit liabilities and other financial products and services. Other income totaled approximately $57.2 million in 2004, $58.5 million in 2003 and $53.0 million in 2002. The decrease in other income for 2004 was due to net gains on sales of securities totaling $4.1 million in 2003 compared to a net loss of $0.1 million in 2004, partially offset by higher fee income in 2004. The increase in other income in 2003 was the result of net gains on sale of securities totaling $4.1 million compared to a net loss of $0.6 million in 2002, higher fee income from its debit and automated teller machines (ATM) cards resulting from ASB s expansion of its debit card base and additional ATM services and higher fee income from its deposit liabilities as a result of restructuring of deposit products. Offsetting these increases were lower gains on sales of loans in 2003 compared to 2002 and a lower accrual for the costs of administering delinquent loans in 2002.

Lending activities

General. Loans and mortgage-related securities of $6.2 billion represented 91.3% of total assets at December 31, 2004, compared to $5.8 billion, or 88.8%, and $5.7 billion, or 90.6%, at December 31, 2003 and 2002, respectively. ASB s loan portfolio consists primarily of conventional residential mortgage loans.

The following tables set forth the composition of ASB s loan and mortgage-related securities portfolio:

	December 31,					
	2004		2003		2002	
(dollars in thousands)	Balance	% of total	Balance	% of total	Balance	% of total
Real estate loans[1]						
Conventional (1-4 unit residential)	$ 2,464,133	39.89%	$ 2,438,573	42.13%	$ 2,347,446	40.96
Commercial real estate	226,699	3.67	208,683	3.60	193,627	3.38
Construction and development	202,466	3.28	100,986	1.75	46,150	0.81
	2,893,298	46.84	2,748,242	47.48	2,587,223	45.15
Less						
Deferred fees and discounts	(20,701)	(0.34)	(20,268)	(0.35)	(18,937)	(0.33)
Undisbursed loan funds	(132,208)	(2.14)	(69,884)	(1.21)	(21,412)	(0.37)
Allowance for loan losses	(15,663)	(0.25)	(14,734)	(0.26)	(23,708)	(0.42)
Total real estate loans, net	2,724,726	44.11	2,643,356	45.66	2,523,166	44.03
Other loans						
Consumer and other loans	232,189	3.76	222,743	3.85	245,853	4.29
Commercial loans	310,999	5.04	286,068	4.94	247,114	4.31

	543,188	8.80	508,811	8.79	492,967	8.60
Less						
Deferred fees and discounts	(526)	(0.01)	(606)	(0.01)	(416)	
Undisbursed loan funds	(3)		(31)		(1)	
Allowance for loan losses	(18,194)	(0.30)	(29,551)	(0.51)	(21,727)	(0.38)
Total other loans, net	524,465	8.49	478,623	8.27	470,823	8.22
Mortgage-related securities, net of discounts	2,928,507	47.40	2,666,619	46.07	2,736,679	47.75
Total loans and mortgage-related securities, net	$ 6,177,698	100.00%	$ 5,788,598	100.00%	$ 5,730,668	100.00%

[1] Includes renegotiated loans.

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	December 31,			
	2001		2000	
(dollars in thousands)	Balance	% of total	Balance	% of total
Real estate loans[1]				
Conventional (1-4 unit residential)	$ 2,242,329	43.02%	$ 2,719,754	51.49%
Commercial real estate	196,515	3.77	156,177	2.95
Construction and development	52,043	1.00	38,913	0.74
	2,490,887	47.79	2,914,844	55.18
Less				
Deferred fees and discounts	(17,946)	(0.34)	(21,588)	(0.41)
Undisbursed loan funds	(22,910)	(0.45)	(17,559)	(0.33)
Allowance for loan losses	(26,085)	(0.50)	(24,800)	(0.47)
Total real estate loans, net	2,423,946	46.50	2,850,897	53.97
Other loans				
Consumer and other loans	252,487	4.84	238,351	4.51
Commercial loans	197,333	3.79	134,784	2.55
	449,820	8.63	373,135	7.06
Less				
Deferred fees and discounts				
Undisbursed loan funds	(5)		(58)	
Allowance for loan losses	(16,139)	(0.31)	(12,649)	(0.24)
Total other loans, net	433,676	8.32	360,428	6.82
Mortgage-related securities, net of discounts	2,354,849	45.18	2,070,827	39.21
Total loans and mortgage-related securities, net	$ 5,212,471	100.00%	$ 5,282,152	100.00%

1 Includes renegotiated loans. In 2001, ASB exchanged loans for $0.4 billion of mortgage-related securities.

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The following table summarizes ASB s loan portfolio, excluding loans held for sale and undisbursed commercial real estate construction and development loan funds at December 31, 2004 and 2003, based upon contractually scheduled principal payments and expected prepayments allocated to the indicated maturity categories:

December 31, 2004	Due			
(in millions)	Less than 1 year	1-5 years	After 5 years	Total
Residential loans - Fixed	$ 427	$ 890	$ 855	$ 2,172
Residential loans - Adjustable	115	208	63	386
	542	1,098	918	2,558
Commercial real estate loans - Fixed	5	11	20	36
Commercial real estate loans - Adjustable	73	41	87	201
	78	52	107	237
Consumer loans - Fixed	12	19	14	45
Consumer loans - Adjustable	50	93	36	179
	62	112	50	224
Commercial loans - Fixed	89	69	38	196
Commercial loans - Adjustable	63	47	5	115
	152	116	43	311
Total loans - Fixed	533	989	927	2,449
Total loans - Adjustable	301	389	191	881
	$ 834	$ 1,378	$ 1,118	$ 3,330

December 31, 2003	Due			
(in millions)	Less than 1 year	1-5 years	After 5 years	Total
Residential loans - Fixed	$ 401	$ 866	$ 783	$ 2,050
Residential loans - Adjustable	123	237	86	446
	524	1,103	869	2,496

Commercial real estate loans - Fixed	5	19	17	41
Commercial real estate loans - Adjustable	28	47	84	159
	33	66	101	200
Consumer loans - Fixed	13	25	17	55
Consumer loans - Adjustable	52	84	23	159
	65	109	40	214
Commercial loans - Fixed	91	57	29	177
Commercial loans - Adjustable	59	43	7	109
	150	100	36	286
Total loans - Fixed	510	967	846	2,323
Total loans - Adjustable	262	411	200	873
	$ 772	$ 1,378	$ 1,046	$ 3,196

Origination, purchase and sale of loans. Generally, residential and commercial real estate loans originated by ASB are secured by real estate located in Hawaii. As of December 31, 2004, approximately $10.5 million of loans purchased from other lenders were secured by properties located in the continental United States. For additional information, including information concerning the geographic distribution of ASB s mortgage-related securities portfolio and the geographic concentration of credit risk, see Note 13 to HEI s Consolidated Financial Statements.

The amount of loans originated during 2004, 2003, 2002, 2001 and 2000 were $1.4 billion, $1.6 billion, $1.2 billion, $1.0 billion and $0.5 billion, respectively. The demand for loans is primarily dependent on the Hawaii real estate market, business conditions, interest rates and loan refinancing activity. The decrease in loan originations in 2004 was due to a slowdown in residential refinancing activity. The increase in loan originations in 2003, 2002 and 2001 was due to the strength in the Hawaii real estate market and low interest rates which have resulted in increased affordability of housing for consumers and higher loan refinancings.

Residential mortgage lending. ASB is permitted to lend up to 100% of the appraised value of the real property securing a loan. Its general policy is to require private mortgage insurance when the loan-to-value ratio of the property exceeds 80% of the lower of the appraised value or purchase price at origination. For nonowner-occupied residential properties, the loan-to-value ratio may not exceed 95% of the lower of the appraised value or purchase price at origination.

Construction and development lending. ASB provides both fixed- and adjustable-rate loans for the construction of one-to-four unit residential and commercial properties. Construction and development financing generally involves a higher degree of credit risk than long-term financing on improved, occupied real estate. Accordingly, all construction and development loans are priced higher than loans secured by completed structures. ASB s underwriting, monitoring and disbursement practices with respect to construction and development financing are designed to ensure sufficient funds are available to complete construction projects. As of December 31, 2004, 2003 and 2002, ASB had commercial real estate construction and development loans of $108 million, $35 million and $4 million and residential construction and development loans of $94 million, $66 million and $42 million, respectively. See Loan portfolio risk elements and Multifamily residential and commercial real estate lending.

Multifamily residential and commercial real estate lending. ASB provides permanent financing and construction and development financing secured by multifamily residential properties (including apartment buildings) and secured by commercial and industrial properties (including office buildings, shopping centers and warehouses) for its own portfolio as well as for participation with other lenders. In 2004, 2003 and 2002, ASB originated $153 million, $81 million and $66 million loans secured by multifamily or commercial and industrial properties. ASB provided commercial real estate construction financing of $86 million which contributed to the increase in originations during 2004. ASB enhanced its commercial real estate lending capabilities and plans to continue to increase commercial real estate lending in the future. One of the objectives of commercial real estate lending is to diversify ASB s loan portfolio as commercial and real estate loans tend to have higher yields and shorter durations than residential mortgage loans.

Consumer lending. ASB offers a variety of secured and unsecured consumer loans. Loans secured by deposits are limited to 90% of the available account balance. ASB offers home equity lines of credit, secured and unsecured VISA cards, checking account overdraft protection and other general purpose consumer loans. In 2004, 2003 and 2002, gross consumer loan originations of $156 million, $138 million and $132 million, accounted for approximately 11.4%, 8.6% and 10.8%, respectively, of ASB s total loan originations.

Business lending. ASB is authorized to make both secured and unsecured business loans to business entities. This lending activity is part of ASB s strategic transformation to a full-service community bank and is designed to diversify ASB s asset structure, shorten maturities, improve rate sensitivity of the loan portfolio and attract business checking deposits. In 2004, 2003 and 2002, gross business loan originations of $351 million, $195 million and $226 million, respectively, accounted for approximately 25.6%, 12.0% and 18.6%, respectively, of ASB s total loan originations and business loans represented 9.6%, 9.2% and 8.3%, respectively, of ASB s total net loan portfolio.

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Loan origination fee and servicing income. In addition to interest earned on loans, ASB receives income from servicing loans, for late payments and from other related services. Servicing fees are received on loans originated and subsequently sold by ASB where ASB acts as collection agent on behalf of third-party purchasers.

ASB generally charges the borrower at loan settlement a loan origination fee of 1% of the amount borrowed. See Loans receivable in Note 1 to HEI s Consolidated Financial Statements.

Loan portfolio risk elements. When a borrower fails to make a required payment on a loan and does not cure the delinquency promptly, the loan is classified as delinquent. If delinquencies are not cured promptly, ASB normally commences a collection action, including foreclosure proceedings in the case of secured loans. In a foreclosure action, the property securing the delinquent debt is sold at a public auction in which ASB may participate as a bidder to protect its interest. If ASB is the successful bidder, the property is classified in a real estate owned account until it is sold. ASB s real estate acquired in settlement of loans represented 0.01%, 0.12% and 0.19% of total assets at December 31, 2004, 2003 and 2002, respectively.

In addition to delinquent loans, other significant lending risk elements include: (1) loans which accrue interest and are 90 days or more past due as to principal or interest, (2) loans accounted for on a nonaccrual basis (nonaccrual loans), and (3) loans on which various concessions are made with respect to interest rate, maturity, or other terms due to the inability of the borrower to service the obligation under the original terms of the agreement (renegotiated loans). The level of delinquent and nonaccrual loans represented 0.4%, 0.7%, 1.1%, 2.3%, and 2.2% of ASB s total net loans outstanding at December 31, 2004, 2003 and 2002, 2001 and 2000, respectively. ASB had no loans that were 90 days or more past due on which interest was being accrued as of the dates presented in the table below. The following table sets forth certain information with respect to nonaccrual and renegotiated loans as of the dates indicated:

	December 31,				
(in thousands)	**2004**	**2003**	**2002**	**2001**	**2000**
Nonaccrual loans					
Real estate					
One-to-four unit residential	$ 2,240	$ 2,784	$ 9,783	$ 22,495	$ 26,738
Commercial real estate	235		983	10,129	15,132
Total real estate	2,475	2,784	10,766	32,624	41,870
Consumer	411	341	1,382	1,965	2,844
Commercial	3,510	2,236	3,633	3,018	2,872
Total nonaccrual loans	$ 6,396	$ 5,361	$ 15,781	$ 37,607	$ 47,586
Nonaccrual loans to total net loans	0.2%	0.2%	0.5%	1.3%	1.4%
Renegotiated loans not included above					
Real estate					
One-to-four residential	$ 1,243	$ 2,148	$	$	$ 48
Commercial real estate	3,653	3,877	7,582	3,874	
Commercial	427	1,919	2,175	2,681	
Total renegotiated loans	$ 5,323	$ 7,944	$ 9,757	$ 6,555	$ 48

Nonaccrual and renegotiated loans to total net loans	0.4%	0.4%	0.9%	1.5%	1.5%

ASB s policy generally is to place loans on a nonaccrual status (i.e., interest accrual is suspended) when the loan becomes 90 days or more past due or on an earlier basis when there is a reasonable doubt as to its collectibility.

In 2001, the decrease in nonaccrual loans of $10.0 million was primarily due to lower delinquencies in residential loans and a commercial real estate loan taken into real estate owned. In 2002, the decrease in nonaccrual loans of $21.8 million was due to $12.7 million lower delinquencies in residential loans, a $5.0 million payoff of a commercial real estate loan and a $4.1 million reclassification of a commercial real estate loan to accrual status. In 2003, the decrease in nonaccrual loans of $10.4 million was primarily due to $7.0 million lower delinquencies in residential loans as a result of improved credit quality of ASB s loan portfolio due to the strong

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real estate market in Hawaii. In 2004, the increase in nonaccrual loans of $1.0 million was primarily due to an increase in commercial loans on nonaccrual status.

Allowance for loan losses. See Note 1 to HEI s Consolidated Financial Statements.

The following table presents the changes in the allowance for loan losses for the years indicated:

	Years ended December 31,				
(dollars in thousands)	**2004**	**2003**	**2002**	**2001**	**2000**
Allowance for loan losses, beginning of year	$ 44,285	$ 45,435	$ 42,224	$ 37,449	$ 35,348
Provision for loan losses	(8,400)	3,075	9,750	12,500	13,050
Charge-offs					
Residential real estate loans	40	892	2,345	4,651	8,867
Commercial real estate loans		174	441	315	
Consumer loans	1,790	3,027	3,479	3,644	3,801
Commercial loans	2,479	2,601	1,479	1,013	670
Total charge-offs	4,309	6,694	7,744	9,623	13,338
Recoveries					
Residential real estate loans	346	1,244	858	1,210	1,926
Commercial real estate loans	562	426	52	342	214
Consumer loans	549	586	257	313	244
Commercial loans	824	213	38	33	5
Total recoveries	2,281	2,469	1,205	1,898	2,389
Allowance for loan losses, end of year	$ 33,857	$ 44,285	$ 45,435	$ 42,224	$ 37,449
Ratio of allowance for loan losses, December 31, to average loans outstanding	1.08%	1.44%	1.60%	1.42%	1.16%
Ratio of provision for loan losses during the year to average loans outstanding	NM	0.10%	0.34%	0.42%	0.41%
Ratio of net charge-offs during the year to average loans outstanding	0.06%	0.14%	0.23%	0.26%	0.34%

NM Not meaningful.

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

December 31	**2004**		**2003**		**2002**		**2001**		**2000**	
(dollars in thousands)	**Balance**	**% of total**	**Balance**	**% of total**	**Balance**	**% of total**	**Balance**	**% of total**	**Balance**	**% of total**
Residential real estate	$ 10,137	74.4%	$ 4,031	76.9%	$ 6,246	77.6%	$ 9,933	78.0%	$ 13,224	83.9%
Commercial real estate	5,355	9.7	6,008	7.5	6,343	6.4	9,031	6.7	8,928	4.7
Consumer	4,008	6.8	6,540	6.8	8,489	8.0	8,538	8.6	7,609	7.3
Commercial	13,986	9.1	14,758	8.8	12,118	8.0	6,388	6.7	4,126	4.1
Unallocated	371	NA	12,948	NA	12,239	NA	8,334	NA	3,562	NA
	$ 33,857	100.0%	$ 44,285	100.0%	$ 45,435	100.0%	$ 42,224	100.0%	$ 37,449	100.0%

NA Not applicable.

In 2004, ASB s allowance for loan losses decreased by $10.4 million compared to a decrease of $1.2 million in 2003. Considerable strength in real estate and business conditions in 2004 resulted in lower historical loss ratios and lower net charge-offs enabled ASB to recognize a negative provision of $8.4 million for loan losses.

The allowance for loan losses for each category was also impacted by external factors affecting the national and Hawaii economy, specific industries and sectors and interest rates. In prior years, the impact of these external factors was reflected in the unallocated category of the allowance for loan losses; however, beginning in 2004 these factors are largely reflected in the allowance for loan losses allocated to each specific loan portfolio.

In 2003, ASB s allowance for loan losses decreased by $1.2 million compared to an increase of $3.2 million in 2002. The decrease in 2003 was due to lower net charge-offs as a result of lower delinquencies. The increasing value of Hawaii real estate and continued low interest rates gave debtors the opportunity to sell their properties or refinance before defaulting. ASB also continued to improve its collection efforts. Residential, consumer and commercial real estate loan delinquencies continued to decrease during 2003 and lower loan loss reserves were required for those lines of business. The growth in the commercial loan portfolio as a result of ASB s strategic focus of diversifying its loan portfolio from single-family home mortgages to commercial loans has required additional loan loss reserves. The unallocated component of the allowance for loan losses, which takes into consideration economic trends and differences in the estimation process that are not necessarily captured in determining the allowance for loan losses for each category, increased slightly.

In 2002, ASB s allowance for loan losses increased by $3.2 million compared to an increase of $4.8 million in 2001. The 2002 increase was due to a higher loans receivable balance and a higher unallocated component of the allowance for loan losses. The allowance was increased to account for ASB s strategic focus of diversifying its loan portfolio from single-family home mortgages to commercial loans that have higher credit risk. Charge-offs were lower in 2002 compared to 2001 as a result of lower delinquencies. The strong Hawaii real estate market and low interest rates gave debtors the opportunity to sell their properties or refinance before defaulting. In addition, ASB improved its collection efforts. Residential and commercial real estate loan delinquencies decreased during 2002 and lower loan loss reserves were required for those lines of business. The allowance for loan losses on consumer loans remained essentially the same during 2002.

In 2001, ASB s allowance for loan losses increased by $4.8 million. Charge-offs were lower in 2001 compared to 2000 as a result of lower delinquencies. The 2001 increase in the allowance for loan losses was due to the increase in commercial real estate and commercial loans in the loan portfolio that have higher credit risk and a higher unallocated component of the allowance, which takes into consideration economic trends and differences in the estimation process that are not necessarily captured in determining the allowance for loan losses for each loan category.

Investment activities

In recent years, ASB s investment portfolio consisted primarily of stock of the FHLB of Seattle, federal agency obligations and mortgage-related securities. ASB owns private-issue mortgage-related securities as well as investment and mortgage-related securities issued by the Federal Home Loan Mortgage Corporation (FHLMC), Government National Mortgage Association (GNMA) and Federal National Mortgage Association (FNMA). At December 31, 2004, the various securities rating agencies rated all of the private-issue mortgage-related securities as investment grade. ASB did not maintain a portfolio of securities held for trading during 2004, 2003 or 2002.

As of December 31, 2004, 2003 and 2002, ASB s held-to-maturity investment portfolio consisted of $97.4 million, $94.6 million and $89.5 million, respectively, of investment in FHLB stock. The weighted-average yield on investments during 2004, 2003 and 2002 was 3.29%, 5.45% and 6.19%, respectively. The amount that ASB is required to invest in FHLB stock is determined by regulatory requirements. See Bank operations in HEI s MD&A for a discussion of dividends on ASB s investment in FHLB of Seattle Stock and recent events that have adversely affected those dividends. Also, see Regulation and other matters Bank regulation Federal Home Loan Bank System.

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The following table summarizes ASB s investment portfolio, at December 31, 2004, based upon contractually scheduled principal payments and expected prepayments allocated to the indicated maturity categories:

(in millions)	Less than 1 year	1-5 years	6-10 years	After 10 years	Total
Federal agency obligations	$ 25	$	$	$	$ 25
FHLMC, GNMA, FNMA	620	1,396	417	103	2,536
Private issue	213	170	8	1	392
	$ 858	$ 1,566	$ 425	$ 104	$ 2,953
Weighted average yield	4.14%	4.19%	4.41%	4.71%	

Note: ASB does not currently invest in tax exempt obligations.

At December 31, 2004, ASB had mortgage-related securities issued by FHLMC, GNMA and FNMA valued at $2.5 billion and private-issue mortgage-related securities valued at $0.4 billion in its available-for-sale investment portfolio.

Deposits and other sources of funds

General. Deposits traditionally have been the principal source of ASB s funds for use in lending, meeting liquidity requirements and making investments. ASB also derives funds from the receipt of interest and principal on outstanding loans receivable and mortgage-related securities, borrowings from the FHLB of Seattle, securities sold under agreements to repurchase and other sources. ASB borrows on a short-term basis to compensate for seasonal or other reductions in deposit flows. ASB also may borrow on a longer-term basis to support expanded lending or investment activities. Advances from the FHLB and securities sold under agreements to repurchase continue to be a significant source of funds that have a higher cost of funds than core deposits.

Deposits. ASB s deposits are obtained primarily from residents of Hawaii. In 2004 and 2003, ASB had average deposits of $4.1 billion and $3.9 billion, respectively. Net savings inflow in 2004, 2003 and 2002 was $269.9 million, $225.5 million and $121.2 million, respectively. In the three years ended December 31, 2004, ASB had no deposits placed by or through a broker.

The following table illustrates the distribution of ASB s average deposits and average daily rates by type of deposit for the years indicated. Average balances have been calculated using the average daily balances.

	Years ended December 31,					
	2004			2003		
(dollars in thousands)	Average balance	% of total deposits	Weighted average rate %	Average balance	% of total deposits	Weighted average rate %
Savings accounts	$ 1,613,856	39.2%	0.40%	$ 1,352,507	34.8%	0.56%
Negotiable order of withdrawal accounts	1,019,464	24.8	0.03	913,228	23.5	0.05
Money market accounts	322,806	7.8	0.45	397,590	10.2	0.61
Certificate accounts	1,157,944	28.2	3.36	1,224,820	31.5	3.54
Total deposits	$ 4,114,070	100.0%	1.15%	$ 3,888,145	100.0%	1.38%

	Year ended December 31, 2002		
(dollars in thousands)	Average balance	% of total deposits	Weighted average rate %
Savings accounts	$ 1,188,042	31.9%	1.22%
Negotiable order of withdrawal accounts	802,651	21.6	0.13
Money market accounts	403,742	10.9	1.51
Certificate accounts	1,323,118	35.6	3.92
Total deposits	$ 3,717,553	100.0%	1.98%

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At December 31, 2004, ASB had $303.3 million in certificate accounts of $100,000 or more, maturing as follows:

(in thousands)	Amount
Three months or less	$ 102,451
Greater than three months through six months	43,229
Greater than six months through twelve months	73,975
Greater than twelve months	83,649
	$ 303,304

Deposit-insurance premiums and regulatory developments. The Savings Association Insurance Fund (SAIF) insures the deposit accounts of ASB and other thrifts. The Bank Insurance Fund (BIF) insures the deposit accounts of commercial banks. The Federal Deposit Insurance Corporation (FDIC) administers the SAIF and BIF. In December 1997, ASB acquired BIF assessable deposits as well as SAIF assessable deposits from Bank of America, FSB.

In December 1996, the FDIC adopted a risk-based base rate schedule for SAIF deposits, effective January 1, 1997, that was identical to the existing risk-based base rate schedule for BIF deposits: zero to 27 cents per $100 of deposits. Added to this base rate schedule through 1999 was the assessment to fund the Financing Corporation s (FICO s) interest obligations, which assessment was initially set at 6.48 cents per $100 of deposits for SAIF deposits and 1.3 cents per $100 of deposits for BIF deposits (subject to quarterly adjustment). By law, the FICO s assessment rate on deposits insured by the BIF had to be one-fifth the rate on deposits insured by the SAIF until January 1, 2000. Effective January 1, 2000, the assessment rate for funding FICO interest payments became identical for SAIF and BIF deposits. The assessment rate for funding FICO interest payments is determined quarterly and, as a well capitalized thrift, ASB s base deposit insurance premium effective for the December 31, 2004 quarterly payment is zero and its assessment for funding FICO interest payments is 1.44 cents per $100 of SAIF and BIF deposits, on an annual basis, based on deposits as of September 30, 2004.

Borrowings. ASB obtains advances from the FHLB of Seattle provided certain standards related to creditworthiness have been met. Advances are secured by a blanket pledge of certain notes held by ASB and the mortgages securing them. To the extent that advances exceed the amount of mortgage loan collateral pledged to the FHLB of Seattle, the excess must be covered by qualified marketable securities held under the control of and at the FHLB of Seattle or at an approved third party custodian. FHLB advances generally are available to meet seasonal and other withdrawals of deposit accounts, to expand lending and to assist in the effort to improve asset and liability management. FHLB advances are made pursuant to several different credit programs offered from time to time by the FHLB of Seattle.

At December 31, 2004, 2003 and 2002, advances from the FHLB amounted to $1.0 billion, $1.0 billion and $1.2 billion, respectively. The weighted-average rates on the advances from the FHLB outstanding at December 31, 2004, 2003 and 2002 were 4.48%, 4.28% and 5.10%, respectively. The maximum amount outstanding at any month-end during 2004, 2003 and 2002 was $1.0 billion, $1.1 billion and $1.2 billion, respectively. Advances from the FHLB averaged $1.0 billion, $1.0 billion and $1.1 billion during 2004, 2003 and 2002, respectively, and the approximate weighted-average rate on the advances was 4.43%, 4.62% and 5.29%, respectively.

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 statements of financial condition. The securities underlying the agreements to repurchase continue to be reflected in the asset accounts (see Note 4 to HEI s Consolidated Financial Statements). At December 31, 2004, 2003 and 2002, the entire outstanding amounts under these agreements of $811 million (including accrued interest of $2.5 million), $831 million (including accrued interest of $1.8 million) and $667 million (including accrued interest of $6.4 million), respectively, were to purchase identical securities. The weighted-average rates on securities sold under agreements to repurchase outstanding at December 31, 2004, 2003 and 2002 were 3.44%, 2.50% and 3.17%, respectively. The maximum amount outstanding at any month-end during 2004, 2003 and 2002 was $990 million, $958 million and $751 million, respectively. Securities sold under agreements to repurchase averaged $842 million, $807 million and $663 million during 2004, 2003 and 2002, respectively, and the approximate weighted-average interest rate under those agreements was 2.65%, 2.63% and 3.11%, respectively.

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The following table sets forth information concerning ASB s advances from the FHLB and securities sold under agreements to repurchase at the dates indicated:

	December 31,		
(dollars in thousands)	**2004**	**2003**	**2002**
Advances from the FHLB	$ 988,231	$ 1,017,053	$ 1,176,252
Securities sold under agreements to repurchase	811,438	831,335	667,247
Total borrowings	$ 1,799,669	$ 1,848,388	$ 1,843,499
Weighted-average rate	4.01%	3.48%	4.40%

Competition

The banking industry in Hawaii is highly competitive. ASB is the third largest financial institution in Hawaii 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. ASB s main competitors are banks, savings associations, credit unions, mortgage bankers, mortgage brokers, finance companies and brokerage firms. These competitors offer a variety of financial 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. Competition for deposits comes primarily from other savings institutions, commercial banks, credit unions, money market and mutual funds and other investment alternatives. In Hawaii, there were 8 FDIC-insured financial institutions, of which 2 were thrifts and 6 were commercial banks, and approximately 100 credit unions at December 31, 2004. Additional competition for deposits comes from various types of corporate and government borrowers, including insurance companies. 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 products and services offered. Competition for origination of first mortgage loans comes primarily from mortgage banking and brokerage firms, commercial banks, other savings institutions, insurance companies and real estate investment trusts. ASB believes that it is able to compete for such loans primarily through the competitive interest rates and loan fees it charges, the types of mortgage loan programs it offers and the efficiency and quality of the services it provides its borrowers and the real estate business community.

In 2002, ASB began implementing a strategic plan to move from its traditional position as a thrift institution, focused on retail banking and residential mortgages, to a full-service community bank. To make the shift, ASB continued to build its business and commercial real estate lines of business in 2002. The origination of business and commercial real estate loans involves risks 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 established by ASB for its business and commercial real estate loans.

In September 2002, ASB launched its STAR initiative (Strategic & Tactical Alignment of Resources), in which four of its lines of business Retail Banking, Mortgage Banking, Commercial Real Estate and Commercial Banking began implementing changes intended to increase profitability and enhance customer service.

In recent years, there has been significant bank and thrift merger activity affecting Hawaii, including the merger in 2004 of the holding companies for the state s 4th and 5th largest financial institutions (based on assets). Management cannot predict the impact, if any, of these mergers on the Company s future competitive position, results of operations or financial condition.

See Certain factors that may affect future results and financial condition Bank Regulation of ASB Federal Thrift Charter in HEI s MD&A for a discussion of the Gramm-Leach-Bliley Act of 1998.

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Other

HEI Investments, Inc.

HEI Investment Corp. (HEIIC), incorporated in May 1984 primarily to make passive investments in corporate securities and other long-term investments, changed its name to HEI Investments, Inc. (HEIII) in January 2000. HEIII is not an investment company under the Investment Company Act of 1940 and has no direct employees. In February 2000, HEIII became a subsidiary of HEIPC.

HEIII s long-term investments currently consist primarily of investments in leveraged leases. Since 1985, HEIII (then called HEIIC) has had a 15% ownership interest in an 818 MW coal-fired generating unit in Georgia, which is subject to a leveraged lease agreement. In 1987, HEIIC purchased commercial buildings on leasehold properties located in the continental United States, along with the related lease rights and obligations. These leveraged, purchase-leaseback investments include two major buildings housing operations of Hershey Foods in Pennsylvania and five supermarkets leased to The Kroger Co. in various states. HEIII s investments in leveraged leases are accounted for in the Company s continuing operations. For a discussion of HEIII s former ownership interest in EPHE Philippines Energy Company, Inc. (EPHE), see Discontinued operations.

HEI Properties, Inc.

HEIDI Real Estate Corp., originally a subsidiary of HEIDI, was formed in February 1998. In September 1999, its name was changed to HEIPI and HEIDI transferred ownership of HEIPI to HEI. HEIPI currently holds primarily venture capital investments. As of December 31, 2004, HEIPI s venture capital investments (in companies based in Hawaii and the U.S. mainland) amounted to $1.5 million.

The Old Oahu Tug Service, Inc.

On November 10, 1999, HTB changed its name to TOOTS. Prior to that date, HTB (a former maritime transportation company) was the parent of YB (a regulated interisland cargo carrier). In November 1999, HTB sold substantially all of its operating assets and the stock of YB and ceased maritime freight transportation operations. TOOTS currently administers certain employee and retiree-related benefits programs and monitors matters related its former operations and the operations of its former subsidiary.

Discontinued operations

For information concerning the Company s discontinued international power operations formerly conducted by HEIPC and its subsidiaries, see Certain factors that may affect future results and financial condition Consolidated Discontinued operations and asset dispositions in HEI s MD&A and Note 14 to HEI s Consolidated Financial Statements.

On March 6, 2000, a subsidiary of HEIII, HEIPC Philippines Holding Co., Inc., acquired a 50% interest in EPHE Philippines Energy Company, Inc. (EPHE), which was the owner of approximately 91.7% of the common stock of East Asia Power Resources Corporation (EAPRC), a Philippines holding company primarily engaged in the electric generation business in Manila and Cebu. The Company wrote off this investment as of December 31, 2000 and subsequently classified the write-off in discontinued operations. Subsequently HEIPC Philippines Holding Co., Inc. was dissolved and thereafter the capital stock it held in EPHE at the time of the dissolution was cancelled pursuant to an EPHE capital stock reduction approved by the Philippine Securities and Exchange Commission.

The Company s loss of its investment in EAPRC of approximately $90 million was recognized in 2000 for financial reporting purposes (including an income tax benefit of $35 million) and was included in HEI s 2001 income tax return as an ordinary loss. In 2002, HEI requested that the Internal Revenue Service (IRS) concur with HEI s position that the loss was deductible against the operating income of its other operating subsidiaries. On January 6, 2004, the IRS signed a closing agreement accepting HEI s treatment of the write-off in 2000 of its indirect investment in EAPRC as an ordinary loss for federal corporate income tax purposes in its 2001 tax return.

Regulation and other matters

Holding company regulation. HEI and HECO are holding companies within the meaning of the Public Utility Holding Company Act of 1935 (1935 Act). However, under current rules and regulations, they are exempt from the comprehensive regulation of the SEC under the 1935 Act except for Section 9(a)(2) (relating to the acquisition of securities of other public utility companies) through compliance with the requirement that they file annually Form U-3A-2

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under the 1935 Act for holding companies which own utility businesses that are intrastate in character. The exemption afforded HEI and HECO may be revoked if the SEC finds that such exemption may be detrimental to the public interest or the interest of investors or consumers. HEI and HECO may own or have interests in foreign utility operations without adversely affecting this exemption so long as the requirements of other exemptions under the 1935 Act are satisfied. In connection with HEIPC s now-discontinued foreign electric utility operations, HEI had obtained the PUC certification which is a prerequisite to obtaining an exemption for foreign utility operations and to the Company s maintenance of its exemption under the 1935 Act if it acquires such ownership interests. Prior to 2000, three Forms U-57 were filed for foreign projects and an investment. In March 2000, HEI filed a Form U-57 on behalf of EAPRC (for the HEIPC Group s investment in that entity). With the discontinuance of HEIPC s international power operations, no further Form U-57 filings are contemplated.

Legislation has been introduced in Congress in the past that would repeal the 1935 Act, leaving the regulation of utility holding companies to be governed by other federal and state laws. Management cannot predict if similar legislation will be proposed or enacted in the future or the final form it might take.

HEI is subject to an agreement entered into with the PUC (the PUC Agreement) when HECO became a subsidiary of HEI. The PUC Agreement, among other things, requires HEI to provide the PUC with periodic financial information and other reports concerning intercompany transactions and other matters. It prohibits the electric utilities from loaning funds to HEI or its nonutility subsidiaries and from redeeming common stock of the electric utility subsidiaries without PUC approval. Further, the PUC could limit the ability of the electric utility subsidiaries to pay dividends on their common stock. See Restrictions on dividends and other distributions and Electric utility regulation (regarding the PUC review of the relationship between HEI and HECO).

As a result of the acquisition of ASB, HEI and HEIDI are subject to OTS registration, supervision and reporting requirements as savings and loan holding companies. In the event the OTS has reasonable cause to believe that the continuation by HEI or HEIDI of any activity constitutes a serious risk to the financial safety, soundness, or stability of ASB, the OTS is authorized under the Home Owners Loan Act of 1933, as amended, to impose certain restrictions in the form of a directive to HEI and any of its subsidiaries, or HEIDI and any of its subsidiaries. Such possible restrictions include limiting (i) the payment of dividends by ASB; (ii) transactions between ASB, HEI or HEIDI, and the subsidiaries or affiliates of ASB, HEI or HEIDI; and (iii) the activities of ASB that might create a serious risk that the liabilities of HEI and its other affiliates, or HEIDI and its other affiliates, may be imposed on ASB. This authority would allow the OTS to prohibit dividends, limit affiliate transactions or otherwise restrict activities as a result of losses suffered by HEI, HEIDI or their other subsidiaries, and thus conceivably may be an indirect means of limiting affiliations between ASB and affiliates engaged in nonfinancial activities. See Restrictions on dividends and other distributions.

OTS regulations also generally prohibit savings and loan holding companies and their nonthrift subsidiaries from engaging in activities other than those which are specifically enumerated in the regulations. However, the OTS regulations provide for an exemption which is available to HEI and HEIDI if ASB satisfies the qualified thrift lender (QTL) test discussed below. See Bank regulation Qualified thrift lender test. ASB must continue to meet the qualified thrift lender test in order to avoid restrictions on the activities of HEI and HEIDI and their subsidiaries. ASB met the QTL test at all times during 2004, but the failure of ASB to satisfy the QTL test in the future could result in a need to divest ASB. If such divestiture were to be required, federal law limits the entities that might be eligible to acquire ASB.

OTS-regulated thrifts must file a quarterly Thrift Financial Report (TFR) to provide the OTS with specific information. Effective with the March 31, 2004 TFR, the Company has provided required details concerning (i) holding companies (HEI and HEIDI) and (ii) transactions with affiliates.

HEI and HEIDI are prohibited, directly or indirectly, or through one or more subsidiaries, from (i) acquiring control of, or acquiring by merger or purchase of assets, another insured institution or holding company thereof, without prior written OTS approval; (ii) acquiring more than 5%

of the voting shares of another savings association or savings and loan holding company which is not a subsidiary; or (iii) acquiring or retaining control of a savings association not insured by the FDIC. No director or officer of HEI or HEIDI, or person beneficially owning more than 25% of such holding company s voting shares, may, except with the prior approval of the OTS, (a) also serve as a director, officer, or employee of any insured institution or (b) acquire control of any savings association not a subsidiary of such holding company.

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ASB Realty Corporation, a subsidiary of ASB, is licensed as a nondepository financial services loan company under the Hawaii Code of Financial Institutions. As a result of its direct or indirect voting control of ASB Realty Corporation, each of HEI, HEIDI and ASB has registered as a Financial Institution Holding Company and an Institution-Affiliated Party under the Hawaii Code. As a Financial Institution Holding Company, HEI, HEIDI and ASB are subject to examination by the Hawaii Commissioner of Financial Institutions (Hawaii Commissioner) to determine whether their respective conditions or activities are jeopardizing the safety and soundness of ASB Realty Corporation s operations. However, the Hawaii Commissioner is authorized to conduct such an examination only if the Hawaii Commissioner has good cause to believe that the holding company is experiencing financial adversity which might have a material negative impact on the safety and soundness of ASB Realty Corporation. The Hawaii Commissioner has authority to issue a cease and desist order to ASB Realty Corporation, ASB, HEIDI and HEI, if, for example, the Commissioner has reasonable grounds to believe that such entity is violating or about to violate the Hawaii Code or is engaged in or about to engage in illegal, unauthorized, unsafe or unsound practices. In appropriate circumstances, the Commissioner may also have authority to order ASB Realty Corporation to correct any impairment of its capital and surplus and to prohibit ASB, HEIDI and HEI from participating in the affairs of ASB Realty Corporation. A plan for the dissolution of ASB Realty Corporation has been submitted for regulatory approval.

Restrictions on dividends and other distributions. HEI is a legal entity separate and distinct from its various subsidiaries. As a holding company with no significant operations of its own, the principal sources of its funds are dividends or other distributions from its operating subsidiaries, borrowings and sales of equity. The rights of HEI and, consequently, its creditors and shareholders, to participate in any distribution of the assets of any of its subsidiaries is subject to the prior claims of the creditors and preferred stockholders of such subsidiary, except to the extent that claims of HEI in its capacity as a creditor are recognized.

The abilities of certain of HEI s subsidiaries to pay dividends or make other distributions to HEI are subject to contractual and regulatory restrictions. Under the PUC Agreement, in the event that the consolidated common stock equity of the electric utility subsidiaries falls below 35% of total electric utility capitalization (including in capitalization the current maturities of long-term debt, but excluding short-term borrowings), the electric utility subsidiaries would be restricted, unless they obtained PUC approval, in their payment of cash dividends to 80% of the earnings available for the payment of dividends in the current fiscal year and preceding five years, less the amount of dividends paid during that period. The PUC Agreement also provides that the foregoing dividend restriction shall not be construed to relinquish any right the PUC may have to review the dividend policies of the electric utility subsidiaries. The consolidated common stock equity of HEI s electric utility subsidiaries was 54% of their total capitalization (including in capitalization the current maturities of long-term debt, but excluding short-term borrowings) as of December 31, 2004. As of December 31, 2004, HECO and its subsidiaries had common stock equity of $1.0 billion, of which approximately $424 million was not available for transfer to HEI without regulatory approval.

The ability of ASB to make capital distributions to HEI and other affiliates is restricted under federal law. Subject to a limited exception for stock redemptions that do not result in any decrease in ASB s capital and would improve ASB s financial condition, ASB is prohibited from declaring any dividends, making any other capital distribution, or paying a management fee to a controlling person if, following the distribution or payment, ASB would be deemed to be undercapitalized, significantly undercapitalized or critically undercapitalized. See Bank regulation Prompt corrective action. All capital distributions are subject to an indication of no objection by the OTS. Also see Note 12 to HEI s Consolidated Financial Statements.

HEI and its subsidiaries are also subject to debt covenants, preferred stock resolutions and the terms of guarantees that could limit their respective abilities to pay dividends. The Company does not expect that the regulatory and contractual restrictions applicable to HEI or its direct and indirect subsidiaries will significantly affect the operations of HEI or its ability to pay dividends on its common stock.

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Electric utility regulation. The PUC regulates the rates, issuance of securities, accounting and certain other aspects of the operations of HECO and its electric utility subsidiaries. See the previous discussions under Electric utility Rates and Electric utility Most recent rate requests, and Most recent rate requests and Regulation of electric utility rates in HEI s MD&A.

Any adverse decision or policy made or adopted by the PUC, or any prolonged delay in rendering a decision, could have a material adverse effect on consolidated HECO s and the Company s financial condition, results of operations or liquidity.

The PUC has ordered the electric utility subsidiaries to develop plans for the integration of demand- and supply-side resources available to meet consumer energy needs efficiently, reliably and at the lowest reasonable cost. See the previous discussion under Electric utility Integrated resource planning and requirements for additional generating capacity.

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 dockets on two specific issues (competitive bidding and distributed generation (DG)) to move toward a more competitive electric industry environment under cost-based regulation. The stated purpose of the competitive bidding investigation is to evaluate competitive bidding as a mechanism for acquiring or building new generating capacity in Hawaii. See Competition in HEI s MD&A.

Certain transactions between HEI s electric public utility subsidiaries (HECO, MECO and HELCO) and HEI and affiliated interests are subject to regulation by the PUC. All contracts (including summaries of unwritten agreements) made on or after July 1, 1988 of $300,000 or more in a calendar year for management, supervisory, construction, engineering, accounting, legal, financial and similar services and for the sale, lease or transfer of property between a public utility and affiliated interests must be filed with the PUC to be effective, and the PUC may issue cease and desist orders if such contracts are not filed. All such affiliated contracts for capital expenditures (except for real property) must be accompanied by comparative price quotations from two nonaffiliates, unless the quotations cannot be obtained without substantial expense. Moreover, all transfers of $300,000 or more of real property between a public utility and affiliated interests require the prior approval of the PUC and proof that the transfer is in the best interest of the public utility and its customers. If the PUC, in its discretion, determines that an affiliated contract is unreasonable or otherwise contrary to the public interest, the utility must either revise the contract or risk disallowance of the payments for ratemaking purposes. In ratemaking proceedings, a utility must also prove the reasonableness of payments made to affiliated interests under any affiliated contract of $300,000 or more by clear and convincing evidence. An affiliated interest is defined by statute and includes officers and directors of a public utility, every person owning or holding, directly or indirectly, 10% or more of the voting securities of a public utility, and corporations which have in common with a public utility more than one-third of the directors of that public utility.

In January 1993, to address community concerns expressed at the time, HECO proposed that the PUC initiate a review of the relationship between HEI and HECO and the effects of that relationship on the operations of HECO. The PUC opened a docket and initiated such a review and in May 1994, the PUC selected a consultant. The consultant s 1995 report concluded that on balance, diversification has not hurt electric ratepayers. Other major findings were that (1) no utility assets have been used to fund HEI s nonutility investments or operations, (2) management processes within the electric utilities operate without interference from HEI and (3) HECO s access to capital did not suffer as a result of HEI s involvement in nonutility activities and that diversification did not permanently raise or lower the cost of capital incorporated into the rates paid by HECO s utility customers. In December 1996, the PUC issued an order that adopted the report in its entirety, ordered HECO to continue to provide the PUC with status reports on its compliance with the PUC agreement (pursuant to which HEI became the holding company of HECO) and closed the investigation and proceeding. In the order, the PUC also stated that it adopted the recommendation of the DOD that HECO, MECO and HELCO present a comprehensive analysis of the impact that the holding company structure and investments in nonutility subsidiaries have on a case-by-case basis on the cost of capital to each utility in future rate cases and remove such effects from the cost of capital. The PUC has accepted, in subsequent MECO and HELCO rate cases, the presentations made by MECO and HELCO that there was no such impact in those cases. HECO has made a similar presentation in its pending rate case. See also Holding company regulation.

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HECO and its electric utility subsidiaries are not subject to regulation by the Federal Energy Regulatory Commission under the Federal Power Act, except under Sections 210 through 212 (added by Title II of PURPA and amended by the Energy Policy Act of 1992), which permit the Federal Energy Regulatory Commission to order electric utilities to interconnect with qualifying cogenerators and small power producers, and to wheel power to other electric utilities. Title I of PURPA, which relates to retail regulatory policies for electric utilities, and Title VII of the Energy Policy Act of 1992, which creates exempt wholesale generators (EWGs) as a category that is exempt from the 1935 Act and addresses transmission access, also apply to HECO and its electric utility subsidiaries. HECO and its electric utility subsidiaries are also required to file various financial and operational reports with the Federal Energy Regulatory Commission. The Company cannot predict the extent to which cogeneration, EWGs or transmission access will reduce its electrical loads, reduce its current and future generating and transmission capability requirements or affect its financial condition, results of operations or liquidity.

Because they are located in the State of Hawaii, HECO and its subsidiaries are exempt by statute from limitations set forth in the Powerplant and Industrial Fuel Act of 1978 on the use of petroleum as a primary energy source.

Bank regulation. ASB, a federally chartered savings bank, and its holding companies are subject to the regulatory supervision of the OTS and, in certain respects, the FDIC and the Hawaii Commissioner of Financial Institutions. See above under Holding company regulation. In addition, ASB must comply with Federal Reserve Board reserve requirements.

Deposit insurance coverage. The Federal Deposit Insurance Act, as amended by the Federal Deposit Insurance Corporation Insurance Act of 1991 (FDICIA), and regulations promulgated by the FDIC, govern insurance coverage of deposit amounts. Generally, the deposits maintained by a depositor in an insured institution are insured to $100,000, with the amount of all deposits held by a depositor in the same capacity (even if held in separate accounts) aggregated for purposes of applying the $100,000 limit. For example, all deposits held in a depositor s individual capacity are aggregated with each other but not with deposits maintained by such depositor and his or her spouse in a qualifying joint account, these latter joint deposits being separately insured to an aggregate of $100,000. An individual s interest in deposits at the same institution in any combination of certain retirement accounts and employee benefit plans will be added together and insured up to $100,000 in the aggregate.

Institutions that are well capitalized under the FDIC s prompt corrective action regulations are generally able to provide pass-through insurance coverage (i.e., insurance coverage that passes through to each owner/beneficiary of the applicable deposit) for the deposits of most employee benefit plans (i.e., $100,000 per individual participating, not $100,000 per plan). Consequently, the FDIC deposit insurance regulations require financial institutions to provide employee benefit plan depositors information, not otherwise available, on the institution s capital category and whether pass-through deposit insurance is available. As of December 31, 2004, ASB was well capitalized.

Federal thrift charter. See Certain factors that may affect future results and financial condition Bank Regulation of ASB Federal Thrift Charter in HEI s MD&A.

Legislation. The Gramm-Leach-Bliley Act of 1998 (the Gramm Act) imposes on financial institutions an obligation to protect the security and confidentiality of its customers nonpublic personal information and the FDIC and OTS issued final guidelines for the establishment of standards for safeguarding such information effective from July 1, 2001. On August 12, 2003, the FDIC and OTS issued a request for comment on proposed interagency guidance describing the regulatory agencies expectations that every financial institution develop a response program to protect against and address reasonably foreseeable risks associated with internal and external threats to the security of customer information maintained by the financial institution or its service providers. The Gramm Act also requires public disclosure of certain agreements entered into by insured depository institutions and their affiliates in fulfillment of the Community Reinvestment Act of 1977, and the filing of an annual report with the appropriate regulatory agencies. The FDIC and the OTS implemented these provisions of the Gramm Act by issuing final rules effective from April 1, 2001. Although the Act will continue to impose additional compliance costs on ASB, ASB believes that any ongoing compliance costs will not be substantial.

In June 2004, the SEC issued for public comment proposed final rules to implement the Gramm Act s exemptions for financial institutions from the definition of broker in the Securities and Exchange Act of 1934. On October 8, 2004, the federal financial institution regulatory agencies submitted to the SEC a joint objection to the proposed final rules. Included among the agencies concerns was the impact of the proposed rules on networking arrangements whereby a financial institution refers its customers to a broker-dealer for securities services and employees of the financial institution are permitted to receive from the broker-dealer a nominal fee for such referrals. The agencies viewed the SEC s proposed rules in this regard as highly complex, restrictive and inflexible and inconsistent with longstanding guidance from the SEC staff and the agencies themselves. ASB does have a networking arrangement with Duerr Financial Corporation that would be potentially affected by the proposed rules and will continue to monitor regulatory developments.

The International Money Laundering Abatement and Financial Anti-Terrorism Act of 2001 (the 2001 Act), which is part of the USA Patriot Act, imposes on financial institutions a wide variety of additional obligations with respect to such matters as collecting information, monitoring relationships and reporting suspicious activities. Among other things, the 2001 Act requires the U.S. Treasury to issue regulations establishing minimum requirements for verifying the identity of persons seeking to open an account, maintaining records of the information used for such verification, and consulting lists of known or suspected terrorists or terrorist organizations. Since October 1, 2003, financial institutions have been required to fully implement a customer identification program. Additional compliance costs resulting from these requirements are not material. The 2001 Act also requires financial institutions to establish anti-money laundering programs and, with respect to correspondent and private banking accounts of non-U.S. persons, to implement appropriate due diligence policies to detect money laundering activities carried out through such accounts. ASB is monitoring the steps being taken by the regulatory agencies to implement these and other provisions of the 2001 Act.

The Fair and Accurate Credit Transactions Act of 2003 (the FACT ACT), which was signed into law on December 4, 2003, amended the Fair Credit Reporting Act of 1978 to enhance the ability of consumers to combat identity theft, to increase the accuracy of consumer reports, to allow consumers to exercise greater control of regarding the type and number of solicitations they receive, and to restrict the use and distribution of sensitive medical information. During 2004, the federal financial institutions regulatory agencies, including the OTS, took several steps to implement the FACT Act. On April 28, 2004, the agencies issued for comment proposed rules (1) permitting creditors to obtain and use medical information in connection with a determination of a consumer s eligibility for credit when such information is necessary and appropriate to protect legitimate operational, transactional, risk, consumer and other needs consistent with the Congressional intent to restrict the appropriate use of medical information, and (2) prescribing certain circumstances when the sharing of consumer medical information between affiliates is permitted.

On July 15, 2004, the agencies issued for comment another set of proposed rules implementing the FACT Act which would generally prohibit a person from using information received from an affiliate to make a solicitation for marketing purposes to a consumer unless the consumer is given notice and an opportunity and simple method to opt out of receiving such solicitations. The agencies have implemented provisions of the FACT Act by revising the Interagency Guidelines Establishing Standards for Safeguarding Customer Information, effective July 1, 2005, to require each financial institution, including thrifts, to develop, implement and maintain, as part of its existing information security program, appropriate measures to properly dispose of consumer information such as that derived from consumer reports. The Guidelines were also renamed as the Interagency Guidelines Establishing Standards for Information Security.

On May 19, 2004, the federal financial institution regulatory agencies issued for public comment a notice of a proposed interagency statement on sound practices concerning complex structured finance activities. The focus of the statement was the use of finance transactions to alter the appearance of a customer s public financial statements in ways that are not consistent with the economic reality of the transactions or to inappropriately reduce a customer s tax liabilities. The agencies acknowledged that such activities are typically conducted only by larger financial institutions. ASB does not believe the finance transactions in which it engages are of the type described in the interagency statement, but ASB will continue to monitor regulatory developments in this area.

Capital requirements. Under the Financial Institutions Reform, Recovery, and Enforcement Act of 1989 (FIRREA), the OTS has set three capital standards for thrifts, each of which must be no less stringent than those applicable to national banks. As of December 31, 2004, ASB was in compliance with all of the minimum standards with a core capital ratio of 7.1% (compared to a 4.0% requirement), a tangible capital ratio of 7.1% (compared to a 1.5%

requirement) and total risk-based capital ratio of 15.6% (based on risk-based capital of $510.7 million, $248.4 million in excess of the 8.0% requirement).

Effective April 1, 1999, the OTS revised its risk-based capital standards as part of the effort by the OTS, FDIC, the Board of Governors of the Federal Reserve System and the Office of the Comptroller of the Currency to implement the provisions of the Riegle Community Development and Regulatory Improvement Act of 1994, which requires these agencies to work together to make uniform their respective regulations and guidelines implementing common statutory or supervisory policies. These OTS revisions affect the risk-based capital treatment of: (1) construction loans on presold residential properties; (2) junior liens on 1- to 4-family residential properties; (3) investments in mutual funds; and (4) the core capital leverage ratio for institutions which do not have a composite rating of 1 under the Uniform Financial Institution Rating System (i.e., the CAMELS rating system). Under the new rules, an institution with a composite rating of 1 under the CAMELS rating system must maintain core capital in an amount equal to at least 3% of adjusted total assets. All other institutions must maintain a minimum core capital of 4% of adjusted total assets, and higher capital ratios may be required if warranted by particular circumstances. As of December 31, 2004, ASB met the applicable minimum core capital requirement of the revised OTS regulations.

Effective July 1, 2002, new OTS rules eliminated the requirement that one-to-four-family residential mortgage loans have a maximum loan-to-value ratio of not more than 80% at origination in order to qualify for a 50% risk rate in calculating capital charges. The new rules conform OTS practice to the more flexible federal Interagency Guidelines for Real Estate Lending by requiring that qualifying mortgage loans be underwritten in accordance with prudent underwriting standards, including standards (i) relating the amortized principal balance of the loan to the value of the property at origination and (ii) establishing acceptable forms of credit enhancement for loans exceeding loan-to-value thresholds. In addition, the new rule eliminates the former requirement that a thrift must deduct from total capital the portion of a land loan or non-residential construction loan that exceeds an 80% loan-to-value ratio.

On January 1, 2002, new OTS regulations went into effect with respect to the regulatory capital treatment of recourse obligations, residual interests, direct credit substitutes and asset- and mortgage-backed securities. The revised capital regulations affect institutions that (1) securitize and sell their assets but retain a residual interest or provide recourse arrangements; (2) credit enhance third party assets; or (3) invest in third party asset- and mortgage-backed securities. Recourse obligations, residual interests, direct credit substitutes and asset- and mortgage-backed securities are now risk-weighted based on their credit agency rating. The new regulations have had a slight positive impact on ASB s risk-based capital.

On July 1, 2002, new regulations went into effect which reduced the risk rating under the OTS risk-based capital rules for claims on and claims guaranteed by qualifying securities firms, such as broker-dealers which are registered with the SEC and comply with net capital requirements, from 100% to 20%, and to zero percent for certain claims on qualifying securities firms that are collateralized with, for example, cash deposits or securities issued by or guaranteed by the U.S.

Current OTS risk-based capital requirements are based on an internationally agreed-upon framework for capital measurement (the 1988 Accord) that was developed by the Basel Committee on Banking Supervision (BCBS). In April 2003, BCBS released for comment proposed revisions to the 1988 Accord. A set of further proposed revisions was released by BCBS in June 2004. BCBS expects that its proposed revisions to the 1988 Accord will begin to be implemented as of year-end 2006, with parallel running both of some of its more advanced approaches and current risk-based capital regulations during 2007, and full implementation of its proposed revisions as of year-end 2007. On August 4, 2003, the federal financial institution regulatory agencies, including OTS, issued an advance notice of proposed rule making (Advance Notice) soliciting comment on possible changes to U.S. risk-based capital requirements in light of the BCBS proposed revisions to the 1988 Accord. The agencies have also issued for public comment three proposed supervisory guidances on internal ratings-based systems for computing corporate credit risk, retail credit risk and operational risk in a manner consistent with the BCBS proposed revisions to the 1988 Accord. The Advance Notice describes the purpose of the BCBS proposal as making risk-based capital requirements more risk sensitive than are the requirements of the 1988 Accord and current U.S. (including OTS) rules implementing the 1988 Accord. The agencies have announced their intention of issuing a notice in 2005 for proposed rule making that will comprehensively implement the BCBS proposal. The agencies have also announced that they plan to permit parallel running during calendar year 2007 of the yet-to-be proposed BCBS-inspired final

rules with the current risk-based capital regime, with the BCBS-inspired final rules becoming fully effective in the United States in January 2008. The possible changes to the U.S. rules described in the Advance Notice are greatest with respect to financial institutions with banking and thrift assets of $250 billion or more or total on-balance-sheet foreign exposure of $10 billion or more. However, impacts on smaller financial institutions such as ASB are possible. ASB will continue to monitor these regulatory developments.

Affiliate transactions. Significant restrictions apply to certain transactions between ASB and its affiliates, including HEI and its direct and indirect subsidiaries. FIRREA significantly altered both the scope and substance of such limitations on transactions with affiliates and provided for thrift affiliate rules similar to, but more restrictive than, those applicable to banks. On November 27, 2002, the Federal Reserve Board (FRB) issued Regulation W, effective April 1, 2003 which, generally speaking, unifies in one public document FRB s prior interpretations of the statutory provisions governing affiliate transactions. Although thrifts are excluded from Regulation W, on December 12, 2002, OTS issued an interim final rule, also effective April 1, 2003, which applies Regulation W to thrifts with modifications appropriate to the greater restrictions under which thrifts operate. Most of these greater restrictions were carried over into the OTS final rule, which became effective November 6, 2003. For example, ASB is prohibited from making any loan or other extension of credit to an entity affiliated with ASB unless the affiliate is engaged exclusively in activities which the Federal Reserve Board has determined to be permissible for bank holding companies. There are also various other restrictions which apply to certain transactions between ASB and certain executive officers, directors and insiders of ASB. ASB is also barred from making a purchase of or any investment in securities issued by an affiliate, other than with respect to shares of a subsidiary of ASB.

Financial Derivatives and Interest Rate Risk. In 1996, the Board of Governors of the Federal Reserve System, the FDIC and the Office of the Comptroller of the Currency issued a joint agency policy statement to bankers to provide guidance on sound practices for managing interest rate risk. However, the OTS has elected not to pursue a standardized policy towards interest rate risk and investment and derivatives activities with the other federal banking regulators.

The OTS issued final rules on financial derivatives, effective January 1, 1999. The OTS views these final rules as consistent with, although more detailed than, the 1996 joint policy statement. The purpose of these rules is to update the OTS rules on financial derivatives, which had remained virtually unchanged for over 15 years. Most significantly, the new rules address interest rate swaps, a derivative instrument commonly used by thrifts to manage interest rate risk which was not addressed in the prior OTS rules. Currently ASB does not use interest rate swaps to manage interest rate risk, but may do so in the future. Generally speaking, the new rules permit thrifts to engage in transactions involving financial derivatives to the extent these transactions are otherwise authorized under applicable law and are safe and sound. The new rules have required ASB to revise its internal procedures for handling financial derivative transactions, including increased involvement of the ASB Board of Directors.

Concurrently with the issuance of the new rules of financial derivative transactions, the OTS also adopted on December 1, 1998 Thrift Bulletin 13a (TB 13a) for purpose of providing guidance on the management of interest rate risks, investment securities and derivatives activities. TB 13a also describes the guidelines OTS examiners will use in assigning the Sensitivity to Market Risk component rating under the Uniform Financial Institutions Rating System (i.e., the CAMELS rating system). TB 13a became effective on December 1, 1998, and replaced several previous Thrift Bulletins dealing with interest rate risk and securities activities.

Effective July 1, 2002, new OTS rules eliminated the interest rate risk component of the OTS s risk-based capital regulations. As a result of waivers granted by the Acting OTS Director, these regulations had never gone into effect and the OTS had relied instead on the interest rate risk guidelines of TB 13a, which will continue in effect. The OTS will apply a 100% risk weight to all stripped, mortgage-related securities regardless of issuer or guarantor.

TB 13a updated the OTS s minimum standards for thrift institutions interest rate risk management practices with regard to board-approved risk limits and interest rate risk measurement systems, and made several significant changes. First, under TB 13a, institutions no longer set board-approved limits or provide measurements for the plus and minus 400 basis point interest rate scenarios prescribed by the original TB 13. TB 13a also changes the form in which those limits should be expressed. Second, TB 13a provides guidance on how the OTS will assess the prudence of an institution s risk limits. Third, TB 13a raises the size threshold above which institutions should calculate their own estimates of the interest rate sensitivity of Net Portfolio Value (NPV) from $500 million to

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$1 billion in assets. Fourth, TB 13a specifies a set of desirable features that an institution s risk measurement methodology should utilize. Fifth, TB 13a provides an extensive discussion of sound practices for interest rate risk management.

TB 13a also contains guidance on thrifts investment and derivatives activities by describing the types of analysis institutions should perform prior to purchasing securities or financial derivatives. TB13a also provides guidelines on the use of certain types of securities and financial derivatives for purposes other than reducing portfolio risk.

Finally, TB 13a provides detailed guidelines for implementing part of the Notice announcing the revision of the CAMELS rating system, published by the Federal Financial Institutions Examination Council. That publication announced revised interagency policies that, among other things, established the Sensitivity to Market Risk component rating (the S rating). TB 13a provides quantitative guidelines for an initial assessment of an institution s level of interest rate risk. Examiners have broad discretion in implementing those guidelines. It also provides guidelines concerning the factors examiners consider in assessing the quality of an institution s risk management systems and procedures.

Liquidity. Effective July 18, 2001, the OTS removed the regulation that required a savings association to maintain an average daily balance of liquid assets of at least 4% of their liquidity base and retained a provision requiring a savings association to maintain sufficient liquidity to ensure safe and sound operations. ASB s principal sources of liquidity are customer deposits, wholesale borrowings, the sale of mortgage loans into the secondary market channels and the maturity and repayment of portfolio loans and mortgage-related securities. ASB s principal sources of borrowings are advances from the FHLB and securities sold under agreements to repurchase from broker/dealers. ASB is approved by the FHLB to borrow up to 35% of assets to the extent it provides qualifying collateral and holds sufficient FHLB stock. At December 31, 2004, ASB s unused FHLB borrowing capacity was approximately $1.4 billion. ASB utilizes growth in 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 make investments. At December 31, 2004, ASB had loan commitments, undisbursed loan funds and unused lines and letters of credit of $0.9 billion. Management believes ASB s current sources of funds will enable it to meet these obligations while maintaining liquidity at satisfactory levels.

Supervision. The adoption of FDICIA subjected the banking and thrift industries to heightened regulation and supervision. FDICIA made a number of reforms addressing the safety and soundness of the deposit insurance system, supervision of domestic and foreign depository institutions and improvement of accounting standards. FDICIA also limited deposit insurance coverage, implemented changes in consumer protection laws and called for least-cost resolution and prompt corrective action with regard to troubled institutions.

Pursuant to FDICIA, the federal banking agencies promulgated regulations which apply to the operations of ASB and its holding companies. Such regulations address, for example, standards for safety and soundness, real estate lending, accounting and reporting, transactions with affiliates, and loans to insiders.

Prompt corrective action. FDICIA establishes a statutory framework that is triggered by the capital level of a savings association and subjects it to progressively more stringent restrictions and supervision as capital levels decline. The OTS rules implement the system of prompt corrective action. In particular, the rules define the relevant capital measures for the categories of well capitalized , adequately capitalized , undercapitalized , significantly undercapitalized and critically undercapitalized.

A savings association that is undercapitalized or significantly undercapitalized is subject to additional mandatory supervisory actions and a number of discretionary actions if the OTS determines that any of the actions is necessary to resolve the problems of the association at the least possible long-term cost to the SAIF. A savings association that is critically undercapitalized must be placed in conservatorship or receivership within 90 days, unless the OTS and the FDIC concur that other action would be more appropriate. As of December 31, 2004, ASB was well-capitalized.

Interest rates. FDIC regulations restrict the ability of financial institutions that are undercapitalized to offer interest rates on deposits that are significantly higher than the rates offered by competing institutions. As of December 31, 2004, ASB was well capitalized and thus not subject to these interest rate restrictions.

Qualified thrift lender test. FDICIA amended the QTL test provisions of FIRREA by reducing the percentage of assets thrifts must maintain in qualified thrift investments from 70% to 65%, and changing the computation period to require that the percentage be reached on a monthly average basis in 9 out of the previous 12 months. The 1997 Omnibus Appropriations Act expanded the types of loans that constitute qualified thrift investments from the traditional category of housing-related loans to include small business loans, education loans, loans made through credit card accounts, as well as a basket of other consumer loans and certain other types of assets not to exceed 20% of total assets. Savings associations that fail to satisfy the QTL test by not holding the required percentage of qualified thrift investments are subject to various penalties, including limitations on their activities. Failure to satisfy the QTL test would also bring into operation restrictions on the activities that may be engaged in by HEI, HEIDI and their other subsidiaries and could effectively result in the required divestiture of ASB. At all times during 2004, ASB was in compliance with the QTL test. As of December 31, 2004, 89.0% of ASB s portfolio assets was qualified thrift investments. See Holding company regulation.

Federal Home Loan Bank System. ASB is a member of the FHLB System which consists of 12 regional FHLBs. The FHLB System provides a central credit facility for member institutions. Historically, the FHLBs have served as the central liquidity facilities for savings associations and sources of long-term funds for financing housing. The FHLB may only make long-term advances to ASB for the purpose of providing funds for financing residential housing. At such time as an advance is made to ASB or renewed, it must be secured by collateral from one of the following categories: (1) fully disbursed, whole first mortgages on improved residential property, or securities representing a whole interest in such mortgages; (2) securities issued, insured or guaranteed by the U.S. Government or any agency thereof; (3) FHLB deposits; and (4) other real estate-related collateral that has a readily ascertainable value and with respect to which a security interest can be perfected. The aggregate amount of outstanding advances secured by such other real estate-related collateral may not exceed 30% of ASB s capital.

As a result of the Gramm-Leach-Bliley Act, each regional FHLB is required to formulate and submit for Federal Housing Finance Board (Board) approval a plan to meet new minimum capital standards to be promulgated by the Board. The Board issued the final regulations establishing the new minimum capital standards on January 30, 2001. As mandated by Gramm-Leach-Bliley, these regulations require each FHLB to maintain a minimum total capital leverage ratio of 5% of total assets and include risk-based capital standards requiring each FHLB to maintain permanent capital in an amount sufficient to meet credit risk and market risk. In June 2001, the FHLB of Seattle formulated a capital plan to meet these new minimum capital standards, which plan was submitted to and approved by the Board. The capital plan requires ASB to own capital stock in the FHLB of Seattle in an amount equal to the total of 3.5% of the FHLB of Seattle s advances to ASB plus the greater of (i) 5% of the outstanding balance of loans sold to the FHLB of Seattle by ASB or (ii) 0.75% of ASB s mortgage loans and pass through securities. At December 31, 2004, ASB was required under the capital plan to own capital stock in the FHLB of Seattle in the amount of $64 million and owned capital stock in the amount of $97 million, or $33 million in excess of the requirement. Under the capital plan, stock in the FHLB of Seattle is subject to a 5-year notice of redemption. This 5-year notice period has an adverse but immaterial effect on ASB s liquidity.

Community Reinvestment. In 1977, Congress enacted the Community Reinvestment Act (CRA) to ensure that banks and thrifts help meet the credit needs of their communities, including low- and moderate-income areas, consistent with safe and sound lending practices. The OTS will consider ASB s CRA record in evaluating an application for a new deposit facility, including the establishment of a branch, the relocation of a branch or office, or the acquisition of an interest in another bank or thrift. ASB currently holds an outstanding CRA rating.

Other laws. ASB is subject to federal and state consumer protection laws which affect lending activities, such as the Truth-in-Lending Law, the Truth-in-Savings Act, the Equal Credit Opportunity Act, the Real Estate Settlement Procedures Act and several federal and state financial privacy acts. These laws may provide for substantial penalties in the event of noncompliance. ASB believes that its lending activities are in compliance with these laws and regulations. On June 7, 2004, the federal institution regulatory agencies, including OTS, issued a request for comment on proposed interagency guidance on overdraft protection programs, which indicated several agency safety and soundness concerns with respect to such programs: lack of individual account underwriting; lack of prudent risk management; desirability of charging off overdraft balances within 30 days; the need to follow generally accepted accounting principles and applicable agency guidance in income reporting, loss recognition and loss estimation; and the need to apply proper risk-based capital treatment to outstanding overdrawn balances and issued commitments. The agencies also expressed concern that many such overdraft protection programs raised compliance issues under various customer protection laws such as truth in advertising, the Truth-in-Lending Act and the Truth-in-Savings Act. ASB does not believe the proposed guidance will significantly modify its overdraft protection program.

Environmental regulation. HEI and its subsidiaries are subject to federal and state statutes and governmental regulations pertaining to water quality, air quality and other environmental factors.

HECO, HELCO and MECO, like other utilities, are subject to periodic inspections by federal, state, and in some cases, local environmental regulatory agencies, including, but not limited to, agencies responsible for regulation of water quality, air quality, hazardous and other waste, and hazardous materials. These inspections may result in the identification of items needing correction or other action. When the corrective or other necessary action is taken, no further regulatory action is expected. Except as otherwise disclosed in this report (including in HEI s MD&A and HECO s Consolidated Financial Statements), the Company believes that each subsidiary has taken appropriate action on environmental conditions requiring action and that as a result of such actions, such environmental conditions will not have a material adverse effect on consolidated HECO or the Company.

Water quality controls. The generating stations, substations and other facilities of the utility subsidiaries operate under federal and state water quality regulations and permits, including but not limited to the Clean Water Act National Pollution Discharge Elimination System (governing point source discharges, including wastewater and storm water discharges), Underground Injection Control (UIC) (regulating disposal of wastewater into the subsurface), the Spill Prevention, Control and Countermeasure (SPCC) program and other regulations associated with discharges of oil and other substances to surface water.

Section 316(b) of the Clean Water Act requires that the EPA ensure that the location, design, construction and capacity of power plant cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts. On February 16, 2004, the EPA Administrator signed a final regulation implementing Section 316(b). The regulation establishes location, design, construction and capacity standards for existing cooling water intake systems that use large amounts of cooling water. Strong technology-based performance standards apply unless a facility shows that these standards will result in very high costs or little environmental benefit at the facility site. The EPA estimates that the rule affects approximately 550 facilities across the nation. The new rule was published in the Federal Register on July 9, 2004 and became effective on September 9, 2004. This new rule applies to HECO s Kahe, Waiau and Honolulu generating stations. HECO will have 3.5 years from the effective date of the rule to demonstrate compliance. HECO plans to conduct a monitoring program and cost-benefit analysis to demonstrate that HECO s existing intake systems have minimal environmental impacts. Concurrently, HECO will evaluate alternative compliance mechanisms allowed by the rule, some of which could entail significant costs to implement. HECO has not yet budgeted any such costs in its five-year capital expenditures forecast. In December 2004, HECO retained a consultant to develop a cost effective compliance strategy and a preliminary assessment of technologies and operational measures.

In 2000, the EPA introduced new regulations that prohibit the construction of large capacity cesspools, many of which are regulated under the DOH s UIC permitting program. All large capacity cesspools must be permanently closed by April 2005. Some alternatives to using large capacity cesspools include connecting to existing municipal sanitary sewer systems or installing large capacity septic treatment systems. MECO completed its cesspool replacement projects at the Maalaea and Kahului generating stations in late 2003. HECO and HELCO are in the process of closing cesspools at the Kahe generating station and the Kanoelehua Base Yard, respectively. These cesspools will be closed in place and converted to permitted seepage pits to accept treated wastewater from new septic tank treatment systems. HECO and HELCO are on schedule to comply with the April 2005 deadline, however, there is a current permitting backlog that potentially could cause a short delay in the issuance of operating permits for the wastewater systems.

The Federal Oil Pollution Act of 1990 (OPA) governs actual or threatened oil releases in navigable U.S. waters (inland waters and up to three miles offshore) and waters of the U.S. exclusive economic zone (up to 200 miles to sea from the shoreline). In the event of an oil release to navigable U.S. waters, OPA establishes strict and joint and several liability for responsible parties for 1) oil removal costs incurred by the federal government or the state, and

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2) damages to natural resources and real or personal property. Responsible parties include vessel owners and operators of on-shore facilities. OPA imposes fines and jail terms ranging in severity depending on how the release was caused. OPA also requires that responsible parties submit certificates of financial responsibility sufficient to meet the responsible party s maximum limited liability.

HELCO experienced two pipeline-related releases in Hilo during 2004. The first occurred on January 13, 2004 when a third party contractor accidentally ruptured HELCO s fuel oil pipeline on Hualani Street. Response and remediation efforts were completed by HELCO and a Removal Action Report and request for No Further Action was submitted to the DOH on May 20. Cost reimbursement is being sought from the third party contractor that ruptured the pipeline. The second incident took place on September 13, 2004 at Pier 3 in Hilo Harbor when a release of fuel oil owned by HELCO occurred during fuel transfer operations from a barge to storage facilities owned by Chevron. The source of the leak was a pipeline jointly owned by HELCO and Chevron that runs beneath the pier. A temporary pipeline was installed by HELCO to facilitate further transfer of fuel in order to continue to supply HELCO power plants. Cleanup activities at the pier were completed on October 9, 2004. Although a final cost-sharing allocation between HELCO and Chevron has not yet been determined, in general, costs associated with pipeline maintenance, repair and replacement, as well as cleanup costs are shared 50%-50% between Chevron and HELCO.

Except as otherwise disclosed herein, the Company believes that each subsidiary s costs of responding to petroleum releases to date will not have a material adverse effect on the respective subsidiary or the Company.

EPA regulations under OPA also require that certain facilities that store petroleum prepare and implement Spill Prevention, Containment and Countermeasure (SPCC) Plans in order to prevent releases of petroleum to navigable waters of the U.S. HECO, HELCO and MECO facilities subject to the SPCC program are in compliance with these requirements. On July 17, 2002, the EPA amended the SPCC regulations to include facilities, such as substations, that use (as opposed to store) petroleum products. HECO, HELCO and MECO have determined that the amended SPCC program applies to a number of their substations. Subsequently, the EPA issued three additional extensions of the compliance dates for the amended regulations. The EPA s most recent extension was issued on August 11, 2004. Existing facilities that started operation prior to August 16, 2002, must maintain or amend SPCC plans before February 17, 2006 and implement these plans by August 18, 2006. Regulated facilities that start operations after August 16, 2002, through August 18, 2006, must prepare and implement an SPCC Plan by August 18, 2006. HECO, HELCO and MECO are currently developing SPCC plans for all facilities that are subject to the amended SPCC requirements.

Air quality controls. The generating stations of the utility subsidiaries operate under air pollution control permits issued by the DOH and, in a limited number of cases, by the EPA. 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. If the Clear Skies Bill is adopted as currently proposed, HECO, and to a lesser extent, HELCO and MECO will likely incur significant capital and operations and maintenance costs beginning one to two years after enactment. HECO boilers may be affected by the air toxics provisions (Title III) of the CAA when the Maximum Allowable Control Technology (MACT) emission standards are established for those units. HECO believes that, if adopted as currently proposed, the recent EPA proposal to regulate nickel emissions from oil-fired boilers may result in significant capital investments and operations and maintenance costs for HECO s steam generating units within the three-year period after adoption. The EPA has announced that the final rule will be promulgated by March 2005, although it is unclear at this time whether the nickel control requirements will remain in the final rule.

HECO has submitted comments to the EPA on two proposed air quality regulations: the EPA s proposal to regulate nickel emissions from oil-fired steam utility boilers (discussed above) and the proposed revisions to the rule designed to control haze at National Parks. Regarding the proposed nickel emissions regulation, HECO commented that the EPA s assumptions underlying the proposal greatly overestimated risk associated with nickel emissions, existing utility units could not reliably meet the proposed emission standard even when employing the default control technology upon which the EPA based the proposed standards, and island utilities such as HECO would need a longer period of time to comply with the regulations if adopted. Regarding the regional haze proposal, HECO commented that the regulations should take into account natural sources of haze such as Kilauea Volcano and

suggested that the agency specifically approve specified air quality emissions models in addition to the ones identified in the proposed rule. Management believes the regional haze control rules, if adopted as currently proposed, may require installation of costly Best Available Retrofit Technology on one or more generating units operated by the utilities. Due to the complexity of the current proposal to control haze impacts and the latitude that states will be granted in applying the proposed regulation, management is unable to determine, at this time, to which utility generating units, if any, the rule will apply or the cost of compliance, which could be significant.

CAA operating permits (Title V permits) have been issued for all affected generating units except for HELCO s Keahole CT-2, for which a permit is currently pending. DOH prepared a proposed permit incorporating revised emission limits for particulate matter and oxides of nitrogen as agreed to with HELCO. The EPA is currently reviewing the proposed permit and HELCO anticipates the EPA s approval. Also, the installation of the planned noise mitigation equipment measures for Keahole CT-4 began on August 9, 2004, and was completed on November 19, 2004. The installation of the planned noise mitigation equipment measures for Keahole CT-5 was completed on January 21, 2005. Noise mitigation work is expected to be completed in the second quarter of 2005.

On September 5, 2003, MECO received a NOV issued by the DOH alleging violations of opacity conditions in permits issued under the DOH s Air Pollution Control Law for two generating units at MECO s Maalaea Power Plant. The NOV ordered MECO to immediately take corrective action to prevent further opacity incidents and pay a penalty of $1.6 million. After requesting a hearing, the DOH and MECO reached a settlement of the NOV that required MECO to come into full compliance with the opacity rules for the units by December 31, 2004 and to pay a penalty of approximately $0.8 million to the DOH. The Consent Order also resolved all civil liability of MECO to the DOH for all opacity violations from February 1, 1999 to December 31, 2004. Since entering the Consent Order, MECO has been in full compliance with the opacity rules for the units. On January 12, 2005, DOH informed MECO that the case will be closed.

Hazardous waste and toxic substances controls. The operations of the electric utility and former freight transportation subsidiaries are subject to regulations promulgated by the EPA to implement the provisions of the Resource Conservation and Recovery Act (RCRA), the Superfund Amendments and Reauthorization Act and the Toxic Substances Control Act. In 2001, the DOH obtained primacy to operate state-authorized RCRA (hazardous waste) programs. The DOH s state contingency plan and the State of Hawaii Environmental Response Law (ERL) rules were adopted in August 1995.

On both federal and state levels, RCRA provisions identify certain wastes as hazardous and set forth measures that must be taken in the transportation, storage, treatment and disposal of these wastes. Some wastes generated at steam electric generating stations possess characteristics that subject them to these EPA regulations. Since October 1986, all HECO generating stations have operated RCRA-exempt wastewater treatment units to treat potentially regulated wastes from occasional boiler waterside and fireside cleaning operations. Steam generating stations at MECO and HELCO also operate similar RCRA-exempt wastewater management systems.

The EPA issued a final regulatory determination on May 22, 2000, concluding that fossil fuel combustion wastes do not warrant regulation as hazardous under Subtitle C of RCRA. This determination retains (or maintains) the existing hazardous waste exemption for these types of wastes. It also allows for more flexibility in waste management strategies. The electric utilities waste characterization programs continue to demonstrate the adequacy of the existing treatment systems. Waste recharacterization studies indicate that treatment facility wastestreams are nonhazardous.

RCRA underground storage tank (UST) regulations require all facilities with USTs used for storing petroleum products to comply with costly leak detection, spill prevention and new tank standard retrofit requirements. All HECO, HELCO and MECO USTs currently meet these standards and continue in operation.

In October 2003, the DOH and EPA initiated separate investigations at HECO s Waiau Generating Station for the alleged offsite transport, treatment and disposal of hydrochloric acid by a HECO contractor. HECO continued to respond to DOH inquiries and requests for information during 2004. HECO then received a Warning Letter from DOH on or about November 1, 2004. A response letter was submitted to the DOH on December 3, 2004 and HECO does not anticipate enforcement action from the DOH. HECO has confirmed that the EPA will not be pursuing separate enforcement action regarding this incident.

The Emergency Planning and Community Right-to-Know Act under Superfund Amendments and Reauthorization Act Title III requires HECO, MECO and HELCO to report potentially hazardous chemicals present

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in their facilities in order to provide the public with information on these chemicals so that emergency procedures can be established to protect the public in the event of hazardous chemical releases. All HECO, MECO and HELCO facilities are in compliance with applicable annual reporting requirements to the State Emergency Planning Commission, the Local Emergency Planning Committee and local fire departments. Since January 1, 1998, the steam electric industry category has been subject to Toxics Release Inventory (TRI) reporting requirements. All HECO, HELCO and MECO facilities are in compliance with TRI reporting requirements.

The Toxic Substances Control Act regulations specify procedures for the handling and disposal of polychlorinated biphenyls (PCB), a compound found in transformer and capacitor dielectric fluids. HECO, MECO and HELCO have instituted procedures to monitor compliance with these regulations. In addition, HECO and its subsidiaries have implemented a program to identify and replace PCB transformers and capacitors in the HECO system All HECO, MECO and HELCO facilities are currently believed to be in compliance with PCB regulations.

The ERL, as amended, governs releases of hazardous substances, including oil, in areas within the state s jurisdiction. Responsible parties under the ERL are jointly, severally and strictly liable for a release of a hazardous substance into the environment. Responsible parties include owners or operators of a facility where a hazardous substance comes to be located and any person who at the time of disposal of the hazardous substance owned or operated any facility at which such hazardous substance was disposed. The DOH issued final rules (or State Contingency Plan) implementing the ERL on August 17, 1995.

HECO is currently involved in an ongoing investigation regarding releases of petroleum to the subsurface in the Honolulu Harbor area. (See Note 11 to HECO s Consolidated Financial Statements.) Under the terms of the agreement for the sale of YB, HEI and TOOTS had certain environmental obligations arising from conditions existing prior to the sale of YB, including obligations with respect to the Honolulu Harbor investigation. In 2003, TOOTS paid $250,000 to fund response activities related to the Honolulu Harbor area as a one-time cash-out payment in lieu of continuing with further response activities. See Note 3 to HEI s Consolidated Financial Statements.

On July 30, 2002, personnel at MECO s Maalaea Generating Station discovered a leak in an underground diesel fuel line. MECO immediately discontinued using the fuel line and notified the DOH of the release. MECO replaced the leaking fuel line with a temporary aboveground line and then constructed a new aboveground fuel line and concrete containment trough as a permanent replacement. MECO also notified the U.S. Fish & Wildlife Service (USFWS), which manages the Kealia Pond National Wildlife Refuge that is located south of the Maalaea facility. MECO constructed a sump at the point of the leak to remove fuel from the subsurface. To date, MECO has recovered over 11,880 gallons of diesel fuel from the estimated 19,000-gallon release. In addition, MECO has installed soil borings and groundwater monitoring wells to assess the vertical and horizontal impacts of the fuel release. As a precautionary measure, with the guidance and consent of the USFWS and the DOH, MECO installed an interception trench in the buffer zone and in a small part of the Wildlife Refuge. The interception trench is designed to capture and facilitate removal of any fuel migrating from the impacted areas and to act as a barrier to migration beyond the trench. Based on results of the latest monitoring study in December 2004, the interception trench continues to operate as designed. Based on the results of the subsurface investigation and the location and design of the interception trench, management believes that the risk of the fuel release affecting wildlife, sensitive wildlife habitat or the ocean, which lies approximately one-quarter mile south of the Maalaea facility, is minimal. Total costs incurred as of December 31, 2004 were approximately $0.9 million. An estimated $0.2 million is expected to be expended during 2005-2006 to address ongoing monitoring and product recovery efforts. MECO reserved adequate amounts to cover expenditures to date as well as costs projected for the future. Remediation efforts have significantly reduced the volume of the product plume and product recovery has reached asymptotic levels. Based on this data, MECO and HECO representatives met with the DOH on October 6, 2004 to discuss the possibility of concluding the project. As a result, a Monitoring and Closure Plan was developed and submitted to the DOH on December 14, 2004. This plan includes the elimination of selected monitoring wells, a reduction in sampling frequency, the generation of free product and dissolved phase plume models, and continued monitoring for two years after free product is determined to have been removed to the maximum extent possible. The DOH issued a December 28, 2004 letter accepting the closure plan. Once modeling information shows that product has been removed to the extent practicable and MECO obtains two years of groundwater monitoring data that meets DOH action levels, MECO anticipates the project can be terminated.

HECO, HELCO and MECO, like other utilities, periodically identify leaking petroleum-containing equipment such as USTs, piping and transformers. In a few instances, small amounts of PCBs have been identified in the leaking equipment. Each subsidiary reports releases from such equipment when and as required by applicable law and addresses impacts due to the releases in compliance with applicable regulatory requirements.

ASB may be subject to the provisions of Comprehensive Environmental Response, Compensation and Liability Act (CERCLA) and regulations promulgated thereunder. CERCLA imposes liability for environmental cleanup costs on certain categories of responsible parties, including the current owner and operator of a facility and prior owners or operators who owned or operated the facility at the time the hazardous substances were released or disposed. CERCLA exempts persons whose ownership in a facility is held primarily to protect a security interest, provided that they do not participate in the management of the facility. Although there may be some risk of liability for ASB for environmental cleanup costs in the event ASB forecloses on, and becomes the owner of, property with environmental problems, the Company believes the risk is not as great for ASB as it may be for other depository institutions that have a larger portfolio of commercial loans.

Securities ratings

See Liquidity and capital resources in HEI s MD&A for the Standard & Poor s (S&P) and Moody s Investors Service s (Moody s) ratings of HEI s and HECO s securities. 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. These ratings reflect only the view of the applicable rating agency at the time the ratings are issued, from whom an explanation of the significance of such ratings may be obtained. There is no assurance that any such credit rating will remain in effect for any given period of time or that such rating will not be lowered, suspended or withdrawn entirely by the applicable rating agency if, in such rating agency s judgment, circumstances so warrant. Any such lowering, suspension or withdrawal of any rating may have an adverse effect on the market price or marketability of HEI s and/or HECO s securities, which could increase the cost of capital of HEI and HECO. Neither HEI nor HECO management can predict future rating agency actions or their effects on the future cost of capital of HEI or HECO.

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 MBIA Insurance Corporation, Ambac Assurance Corporation, XL Capital Assurance, Inc. or Financial Guaranty Insurance Company and the ratings of those bonds are based on the ratings of the obligations of the bond insurer rather than HECO.

Research and development

HECO and its subsidiaries expensed approximately $3.3 million, $3.1 million and $2.8 million in 2004, 2003 and 2002, respectively, for research and development. Contributions to the Electric Power Research Institute accounted for more than half of the expenses. There were also expenses in the areas of energy conservation, new technologies, environmental and emissions controls, and expenses for studies relative to technologies that are applicable or may be applicable in the future to HECO, its subsidiaries and their customers.

Employee relations

At December 31, 2004 and 2003, the Company had 3,354 and 3,197 full-time employees, respectively, as follows:

December 31	**2004**	**2003**
HEI	45	44
HECO and its subsidiaries	2,013	1,862
ASB and its subsidiaries	1,291	1,285
Other subsidiaries	5	6
	3,354	3,197

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The employees of HEI and its direct and indirect subsidiaries, other than the electric utilities, are not covered by any collective bargaining agreement. Of the 2,013 full time employees of HECO and its subsidiaries at December 31, 2004, 59% were covered by collective bargaining agreements. See Collective bargaining agreements in HEI s MD&A.

ITEM 2. PROPERTIES

HEI leases office space from nonaffiliated lessors in downtown Honolulu under leases that expire in May 2005 and March 2006. HEI also subleases office space in a downtown Honolulu building leased by HECO under an expired lease for which HECO is negotiating a new lease to November 2024. The properties of HEI s subsidiaries are as follows:

Electric utility

See page 5 for the Generation statistics of HECO and its subsidiaries, including net generating and firm purchased capability, reserve margin and annual load factor. Also, see Transmission systems in Item 1.

The electric utilities overhead and underground transmission and distribution systems (with the exception of substation buildings and contents) have a replacement value roughly estimated at $3 billion and are uninsured because the amount of transmission and distribution system insurance available is limited and the premiums are extremely high.

Electric lines are located over or under public and nonpublic properties. See page 2 for a discussion of the nonexclusive franchises of HECO and subsidiaries. Most of the leases, easements and licenses for HECO s, HELCO s and MECO s lines have been recorded.

HECO owns and operates three generating plants on the island of Oahu at Honolulu, Waiau and Kahe, with an aggregate net generating capability of 1,208.6 MW at December 31, 2004. The three plants are situated on HECO-owned land having a combined area of 535 acres and one 3 acre parcel of land under a lease expiring December 31, 2018. In addition, HECO owns a total of 121 acres of land on which substations, transformer vaults, distribution baseyards and the Kalaeloa cogeneration facility are located.

HECO owns overhead transmission lines, overhead distribution lines, underground cables, poles (fully owned or jointly owned) and steel or aluminum high voltage transmission towers. The transmission system operates at 46,000 volts and 138,000 volts. The total capacity of HECO s transmission and distribution substations was 6,654,100 kilovoltamperes at December 31, 2004.

HECO owns buildings and approximately 11.5 acres of land located in Honolulu which houses its operating, engineering and information services departments and a warehousing center. It also leases an office building and certain office spaces in Honolulu. The lease for the office building expired in November 2004, and HECO is currently negotiating a new lease to November 2024. The leases for certain office spaces expire on various dates through January 31, 2015 with options to extend to various dates through January 31, 2020.

HECO owns 19.2 acres of land at Barbers Point used to situate fuel oil storage facilities with a combined capacity of 970,700 barrels. HECO also owns fuel oil tanks at each of its plant sites with a total maximum usable capacity of 844,600 barrels and an underground fuel pipeline that transports fuel from HECO s tank farm at Campbell Industrial Park to HECO s Waiau power plant.

HELCO owns and operates five generating plants on the island of Hawaii. These plants at Hilo (2), Waimea, Kona and Puna have an aggregate net generating capability of 181.9 MW as of December 31, 2004 (excluding a small run-of-river hydro unit and one small windfarm). The plants are situated on HELCO-owned land having a combined area of approximately 43 acres. HELCO also owns fuel storage facilities at these sites with a total maximum usable capacity of 76,041 barrels of bunker oil, and 48,812 barrels of diesel. HELCO also owns 6 acres of land in Kona, which is used for a baseyard, and one acre of land in Hilo, which houses its administrative offices. HELCO also leases 4 acres of land for its baseyard in Hilo under a lease expiring in 2030. The deeds to the sites located in Hilo contain certain restrictions which do not materially interfere with the use of the sites for public utility purposes. HELCO occupies 78 acres of land for the windfarm (with an aggregate net capability of 2.3 MW as of December 31, 2004), pursuant to a long-term operating agreement.

MECO owns and operates two generating plants on the island of Maui, at Kahului and Maalaea, with an aggregate net generating capability of 229.2 MW as of December 31, 2004. The plants are situated on MECO-owned land

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having a combined area of 28.6 acres. MECO also owns fuel oil storage facilities at these sites with a total maximum usable capacity of 176,355 barrels. MECO owns two 1 MW stand-by diesel generators and a 6,000 gallon fuel storage tank located in Hana. MECO owns 65.7 acres of undeveloped land at Waena. The Waena land is currently being used for agricultural purposes by the former landowner under a license agreement dated November 19, 1996. The license agreement was originally scheduled to expire on December 31, 2004 but has been extended, effective January 1, 2005, on a month-to-month basis until the area is required for development by MECO for utility purposes, or February 28, 2006, whichever comes first.

MECO s administrative offices and engineering and distribution departments are located on 9.1 acres of MECO-owned land in Kahului.

MECO also owns and operates smaller distribution systems, generation systems (with an aggregate net capability of 22.1 MW as of December 31, 2004) and fuel storage facilities on the islands of Lanai and Molokai, primarily on land owned by MECO.

Bank

ASB owns and leases several office buildings in downtown Honolulu and owns land and an operations center in the Mililani Technology Park on Oahu.

The following table sets forth the number of bank branches owned and leased by ASB by island:

	Number of branches		
December 31, 2004	**Owned**	**Leased**	**Total**
Oahu	8	38	46
Maui	3	5	8
Kauai	3	2	5
Hawaii	2	4	6
Molokai		1	1
	16	50	66

At December 31, 2004, the net book value of branches and office facilities is approximately $43 million. Of this amount, $33 million represents the net book value of the land and improvements for the branches and office facilities owned by ASB and $10 million represents the net book value of ASB s leasehold improvements. The leases expire on various dates from January 2005 through November 2036 and many of the leases have extension provisions.

ITEM 3. LEGAL PROCEEDINGS

The descriptions of legal proceedings (including judicial proceedings and proceedings before the PUC and environmental and other administrative agencies) in Item 1. Business and in the notes to HEI s Consolidated Financial Statements, and information concerning legal proceedings terminated during the fourth quarter of 2004, are incorporated by reference in this Item 3. Certain HEI subsidiaries (including HECO and its subsidiaries) are involved in ordinary routine litigation incidental to their respective businesses.

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ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

HEI and HECO:

During the fourth quarter of 2004, no matters were submitted to a vote of security holders of the Registrants.

EXECUTIVE OFFICERS OF THE REGISTRANT (HEI)

The following persons are, or may be deemed to be, executive officers of HEI. Their ages are given as of March 11, 2005 and their years of company service are given as of December 31, 2004. Officers are appointed to serve until the meeting of the HEI Board of Directors after the next Annual Meeting of Shareholders (which will occur on April 26, 2005) and/or until their successors have been appointed and qualified (or until their earlier resignation or removal). Company service includes service with an HEI subsidiary.

HEI Executive Officers	Business experience for past five years
Robert F. Clarke, age 62	
Chairman of the Board, President and Chief Executive Officer	9/98 to date
Director	4/89 to date
(Company service: 17 years)	
Eric K. Yeaman, age 37	
Financial Vice President, Treasurer and Chief Financial Officer	01/03 to date
(Company service: 2 years)	
Eric K. Yeaman, prior to joining HEI, served as Chief Operating and Financial Officer of Kamehameha Schools from 4/02 to 1/03, Chief Financial Officer of Kamehameha Schools from 7/00 to 4/02 and Senior Manager Audit and Advisory Services of Arthur Andersen LLP (at Arthur Andersen LLP from 9/89 to 7/00).	
Peter C. Lewis, age 70	
Vice President Administration and Corporate Secretary	1/99 to date
(Company service: 36 years)	
Patricia U. Wong, age 48	
Vice President	1/05 to date
Vice President Corporate Excellence, HECO	3/98 to 12/04
(Company service: 14 years)	
Charles F. Wall, age 65	
Vice President and Corporate Information Officer	7/90 to date
(Company service: 14 years)	
Andrew I. T. Chang, age 65	
Vice President Government Relations	4/91 to date

(Company service: 19 years)

Curtis Y. Harada, age 49 Controller	1/91 to date

(Company service: 15 years)

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HEI Executive Officers	Business experience for past five years
(continued)	
T. Michael May, age 58	
President and Chief Executive Officer, HECO	9/95 to date
Director, HEI	9/95 to 12/04
Senior Vice President, HEI	9/95 to 4/01
(Company service: 12 years)	
Constance H. Lau, age 52	
President and Chief Executive Officer, ASB	6/01 to date
Director, HEI	6/01 to 12/04
Senior Executive Vice President and Chief Operating Officer, ASB	12/99 to 6/01
(Company service: 20 years)	

HEI s executive officers, with the exception of Charles F. Wall, Andrew I. T. Chang and Patricia U. Wong, are also officers and/or directors of one or more of HEI s subsidiaries. Mr. May and Ms. Lau are deemed to be executive officers of HEI for purposes of this Item under the definition of Rule 3b-7 of the SEC s General Rules and Regulations under the Securities Exchange Act of 1934.

There are no family relationships between any executive officer of HEI and any other executive officer or director of HEI or any arrangements or understandings, between any executive officer or director of HEI and any person, pursuant to which the executive officer or director of HEI was selected.

Peter C. Lewis has announced his retirement effective at the Annual Meeting of Shareholders to be held on April 26, 2005, and he is to be succeeded by Patricia U. Wong.

PART II

ITEM 5. MARKET FOR REGISTRANTS COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

HEI:

The information required by this item is incorporated herein by reference to Note 12, Regulatory restrictions on net assets and Note 16, Quarterly information (unaudited) of HEI s Consolidated Financial Statements and Item 6 and Item 12, Equity compensation plan information. Certain restrictions on dividends and other distributions of HEI are described in this report under Item 1. Business Regulation and other matters Restrictions on dividends and other distributions. HEI s common stock is traded on the New York Stock Exchange and the total number of holders of record of HEI common stock as of February 28, 2005, was 13,237.

In 2004, HEI issued an aggregate of 18,800 shares (split-adjusted) of unregistered common stock pursuant to the HEI 1990 Nonemployee Director Stock Plan, as amended and restated effective April 20, 2004 (the HEI Nonemployee Director Plan). Under the HEI Nonemployee Director Plan, each HEI nonemployee director received, in addition to an annual cash retainer, an annual stock grant of 1,400 shares (split-adjusted) of HEI common stock (2,000 shares (split-adjusted) for the first time grant to a new HEI director) and each nonemployee subsidiary director who is not also an HEI nonemployee director received an annual stock grant of 600 shares (split-adjusted) of HEI common stock. The HEI Nonemployee Director Plan is currently the only plan for nonemployee directors and provides for annual stock grants (described above) and annual cash retainers for nonemployee directors of HEI and its subsidiaries.

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

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Purchases of HEI common shares were made as follows:

ISSUER PURCHASES OF EQUITY SECURITIES

Period*	(a) Total Number of Shares Purchased **	(b) Average Price Paid per Share **	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number (or Approximate Dollar Value) of Shares that May Yet Be Purchased Under the Plans or Programs
October 1 to 31, 2004	49,631	$ 26.93		NA
November 1 to 30, 2004	137,747	28.47		NA
December 1 to 31, 2004	287,366	28.39		NA
	474,744	$ 28.26		NA

NA Not applicable.

* Trades (total number of shares purchased) are reflected in the month in which the order is placed.

** The purchases were made to satisfy the requirements of the DRIP and HEIRSP for shares purchased for cash or by the reinvestment of dividends by participants under those plans and none of the purchases were made under publicly announced repurchase plans or programs. Average prices per share are calculated exclusive of any commissions payable to the brokers making the purchases for the DRIP and HEIRSP. Of the shares listed in column (a), 49,631 of the 49,631 shares, 130,947 of the 137,747 shares and 250,066 of the 287,366 shares were purchased for the DRIP and the remainder were purchased for the HEIRSP. All purchases were made through a broker on the open market.

HECO:

The information required with respect to Market information and holders is not applicable to HECO. Since the corporate restructuring on July 1, 1983, all the common stock of HECO has been held solely by its parent, HEI, and is not publicly traded.

The dividends declared and paid on HECO s common stock for the four quarters of 2004 and 2003 were as follows:

Quarters ended	2004	2003
March 31	$ 11,613,000	$ 15,290,000
June 30		13,242,000
September 30		13,917,000
December 31		15,270,000

HECO did not pay dividends to HEI in the last nine months of 2004 because HECO was strengthening its capital structure. Also, see Liquidity and capital resources in HEI s MD&A.

See the discussion of regulatory restrictions on distributions in Note 12 to HECO s Consolidated Financial Statements.

ITEM 6. SELECTED FINANCIAL DATA

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HEI:

Selected Financial Data

Hawaiian Electric Industries, Inc. and Subsidiaries

Years ended December 31	2004	2003	2002	2001	2000
(dollars in thousands, except per share amounts)					
Results of operations					
Revenues	$ 1,924,057	$ 1,781,316	$ 1,653,701	$ 1,727,277	$ 1,732,311
Net income (loss)					
Continuing operations	$ 107,739	$ 118,048	$ 118,217	$ 107,746	$ 109,336
Discontinued operations	1,913	(3,870)		(24,041)	(63,592)
	$ 109,652	$ 114,178	$ 118,217	$ 83,705	$ 45,744
Basic earnings (loss) per common share					
Continuing operations	$ 1.36	$ 1.58	$ 1.63	$ 1.60	$ 1.68
Discontinued operations	0.02	(0.05)		(0.36)	(0.98)
	$ 1.38	$ 1.53	$ 1.63	$ 1.24	$ 0.70
Diluted earnings per common share	$ 1.38	$ 1.52	$ 1.62	$ 1.23	$ 0.70
Return on average common equity	9.5%	10.7%	12.0%	9.5%	5.4%
Return on average common equity-continuing operations *	9.4%	11.1%	12.0%	12.2%	13.0%
Financial position **					
Total assets	$ 9,610,627	$ 9,201,158	$ 8,933,553	$ 8,552,041	$ 8,532,780
Deposit liabilities	4,296,172	4,026,250	3,800,772	3,679,586	3,584,646
Securities sold under agreements to repurchase	811,438	831,335	667,247	683,180	596,504
Advances from Federal Home Loan Bank	988,231	1,017,053	1,176,252	1,032,752	1,249,252
Long-term debt, net	1,166,735	1,064,420	1,106,270	1,145,769	1,088,731
HEI- and HECO-obligated preferred securities of trust subsidiaries		200,000	200,000	200,000	200,000
Preferred stock of subsidiaries not subject to mandatory redemption	34,405	34,406	34,406	34,406	34,406
Stockholders equity	1,210,945	1,089,031	1,046,300	929,665	839,059
Common stock					
Book value per common share **	$ 15.01	$ 14.36	$ 14.21	$ 13.06	$ 12.72
Market price per common share					
High	29.55	24.00	24.50	20.63	18.97
Low	22.96	19.10	17.28	16.78	13.85
December 31	29.15	23.69	21.99	20.14	18.60
Dividends per common share	1.24	1.24	1.24	1.24	1.24

Dividend payout ratio	90%	81%	76%	100%	176%
Dividend payout ratio-continuing operations	91%	78%	76%	78%	74%
Market price to book value per common share **	194%	165%	155%	154%	146%
Price earnings ratio ***	21.4x	15.0x	13.5x	12.6x	11.1x
Common shares outstanding (thousands) **	80,687	75,838	73,618	71,200	65,982
Weighted-average	79,562	74,696	72,556	67,508	65,090
Shareholders ****	35,292	34,439	34,901	37,387	38,372
Employees **	3,354	3,197	3,220	3,189	3,126

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

** At December 31.

*** Calculated using December 31 market price per common share divided by basic earnings per common share from continuing operations.

**** At December 31, Registered shareholders plus participants in the HEI Dividend Reinvestment and Stock Purchase

Plan who are not registered shareholders. At February 16, 2005, HEI had 35,408 registered shareholders and participants.

The Company discontinued its international power operations in 2001 and its residential real estate operations in 1998. See Note 14, Discontinued operations, of the Notes to Consolidated Financial Statements. Also see Commitments and contingencies in Note 3 of the 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.

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.

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HECO:

Selected Financial Data

Hawaiian Electric Company, Inc. and Subsidiaries

Years ended December 31	**2004**	**2003**	**2002**	**2001**	**2000**
(in thousands)					
Income statement data					
Operating revenues	$ 1,546,875	$ 1,393,038	$ 1,252,929	$ 1,284,312	$ 1,270,635
Operating expenses	1,425,583	1,268,200	1,117,772	1,148,980	1,137,474
Operating income	121,292	124,838	135,157	135,332	133,161
Other income	8,926	6,170	7,095	7,436	9,935
Income before interest and other charges	130,218	131,008	142,252	142,768	143,096
Interest and other charges	47,961	51,017	50,967	53,388	54,730
Income before preferred stock dividends of HECO	82,257	79,991	91,285	89,380	88,366
Preferred stock dividends of HECO	1,080	1,080	1,080	1,080	1,080
Net income for common stock	$ 81,177	$ 78,911	$ 90,205	$ 88,300	$ 87,286

At December 31	**2004**	**2003**	**2002**	**2001**	**2000**
(dollars in thousands)					
Balance sheet data					
Utility plant	$ 3,709,857	$ 3,531,299	$ 3,381,316	$ 3,270,855	$ 3,162,779
Accumulated depreciation	(1,361,703)	(1,290,929)	(1,205,336)	(1,120,858)	(1,039,475)
Net utility plant	$ 2,348,154	$ 2,240,370	$ 2,175,980	$ 2,149,997	$ 2,123,304
Total assets	$ 2,770,985	$ 2,581,256	$ 2,493,436	$ 2,423,836	$ 2,406,944
Capitalization:[1]					
Short-term borrowings from non-affiliates and affiliate	$ 88,568	$ 6,000	$ 5,600	$ 48,297	$ 113,162
Long-term debt, net	752,735	699,420	705,270	685,269	667,731
Preferred stock not subject to mandatory redemption	34,293	34,293	34,293	34,293	34,293
HECO-obligated preferred securities of subsidiary trusts		100,000	100,000	100,000	100,000
Common stock equity	1,017,104	944,443	923,256	877,154	825,012
Total capitalization	$ 1,892,700	$ 1,784,156	$ 1,768,419	$ 1,745,013	$ 1,740,198
Capital structure ratios (%)[1]					
Debt	44.5	39.6	40.2	42.0	44.9

Preferred stock	1.8	1.9	1.9	2.0	2.0
HECO-obligated preferred securities of subsidiary trusts		5.6	5.7	5.7	5.7
Common stock equity	53.7	52.9	52.2	50.3	47.4

[1] Includes amounts due within one year, short-term borrowings from nonaffiliates and affiliate, and sinking fund and optional redemption payments.

HEI owns all of HECO s common stock. Therefore, per share data is not meaningful.

See Note 11, Commitments and Contingencies, in HECO s Notes to Consolidated Financial Statements for a discussion of certain contingencies that could adversely affect the Company s future results of operations and financial condition.

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ITEM 7. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

HEI (pages 53 to 89):

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

The following discussion should be read in conjunction with 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 that follow.

Executive overview and strategy

The Company s three strategic objectives are to operate the electric utility and bank subsidiaries for long-term growth, maintain the annual dividend and increase the Company s financial flexibility by strengthening the balance sheet and maintaining credit ratings.

HEI, through its electric utility subsidiaries, supplies power to 93% of the Hawaii electric public utility market. HEI also provides a wide array of banking and other financial services to consumers and businesses through its bank subsidiary, ASB, Hawaii s third largest financial institution based on asset size.

In 2004, income from continuing operations was $108 million, compared to $118 million in 2003. Basic earnings per share from continuing operations were $1.36 per share in 2004, down 14% from 2003 due primarily to an after-tax charge of $20 million, or $0.25 per share, due to a June 2004 tax ruling and subsequent settlement (see Bank franchise taxes sections below), and a 7% increase in weighted average common shares outstanding due primarily to a March 2004 common stock offering. Partially offsetting the tax charge were lower financing costs at HEI Corporate and the electric utilities and a reduction in ASB s allowance for loan losses of $5 million (after-tax) in 2004, compared with an increase of $2 million (after-tax) in 2003. The future success of the Company will be heavily influenced by Hawaii s economy, which is driven by tourism, the federal government (including the military), real estate and construction. Real gross state product grew by an estimated 2.6% in 2004 and is projected by the State of Hawaii Department of Business, Economic Development and Tourism (DBEDT) to grow by 2.7% in 2005.

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 (split-adjusted). The indicated dividend yield at December 31, 2004 was 4.3%. HEI s Board and management believe that HEI should achieve a 65% payout ratio on a sustainable basis before it considers increasing the common stock dividend above its current level. The dividend payout ratios based on net income for 2004, 2003 and 2002 were 90%, 81% and 76% (payout ratios of 91%, 78% and 76% based on income from continuing operations), respectively. The high payout ratio for 2004 was primarily due to the charge to net income of $20 million due to a June 2004 adverse tax ruling and subsequent settlement and an increased number of shares outstanding from the sale of 2 million shares (pre-split) of common stock in March 2004. Without the bank franchise tax charge, the payout ratio for 2004 would have been 76% (77% based on income from continuing operations).

In the first half of 2004, HEI strengthened its balance sheet through a common stock sale and repayment and refinancing of debt, which significantly reduced financing costs.

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.

Electric utility

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 doesn t expose the utilities to the problems 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

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investment, placing emphasis on energy efficiency and conservation, pursuing technology opportunities such as combined heat and power 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 in the early permitting stages for a new generating unit, which is projected to be placed in service by 2009, and is making progress with plans to build the East Oahu Transmission Project (EOTP), a needed alternative route to move power from the west side of the island. The two phases of the EOTP are scheduled to be completed in 2007 and 2009. The PUC has approved HECO s plans for a new Energy Management System and a new Dispatch Center on Oahu, which are scheduled to be completed in 2006 and 2007, respectively, and are estimated to cost $23 million. If further PUC approvals are obtained, new Outage Management and Customer Information Systems will also be integrated. On the island of Hawaii, after years of delay, the two 20 megawatt (MW) combustion turbines at Keahole are operating. On the island of Maui, a necessary air permit was received, effective September 8, 2004, for the installation of an 18 MW steam turbine at its Maalaea power plant site. Further, the utilities are seeking PUC approval for additional DSM rebate programs and pursuing combined heat and power agreements for onsite generation with specific customers, subject to PUC approval.

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 kilowatthour (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 9.9%, or $98.6 million in annual base revenues, based on an 11.5% return on average common equity. See Most recent rate requests Hawaiian Electric Company, Inc. below. The final decision and order for the last rate case on Oahu was issued in 1995. The requested increase amount includes transferring the cost of existing energy conservation and efficiency programs from a surcharge to base rates, so the requested net increase to customers is 7.3%, or $74.2 million. Approximately $20.4 million of the $74.2 million net request is for the costs of new residential and commercial energy conservation and efficiency programs. The balance of the request is largely for recovery of (1) the costs of capital improvement projects, (2) the proposed purchase of additional firm capacity and energy from Kalaeloa Partners, L.P., (3) other measures taken to address peak load increases, and (4) increased operation and maintenance expenses (see Most recent rate requests below). An interim decision is expected in the fourth quarter of 2005.

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 distributed generation. 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 advance the long-term development of renewable energy in Hawaii.

Net income for HECO and its subsidiaries was $81 million in 2004 compared to $79 million in 2003. The increase was primarily due to higher KWH sales and lower financing costs, partly offset by higher expenses. KWH sales growth was 2.9% for 2004. Assuming continuing strength in the U.S. and Hawaii economies, management expects higher KWH sales again in 2005.

Bank

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 finished 2004 with assets of $6.8 billion and net income of $41 million, including a $20 million after-tax charge for franchise taxes for prior years due to an adverse tax ruling. Excluding the $20 million charge, net income would have been $61 million in 2004, compared to an adjusted $52 million in 2003 (see Bank franchise taxes below).

The quality of ASB s assets, the interest rate environment and the strategic transformation of ASB have impacted and will continue to impact its financial results.

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Due to improved asset quality resulting from the strength in the Hawaii economy and the real estate market, ASB was able to recognize a $5 million after-tax negative provision for loan losses during 2004. ASB s allowance as a percentage of average loans was 1.08% at the end of 2004. This ratio falls between the benchmark ratios for national banks and thrifts, which is appropriate because ASB s large residential mortgage portfolio is typical of a thrift and ASB has added business and commercial real estate loans typical of commercial banks. 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.

The bank has been facing a challenging interest rate environment that has compressed margins. The Federal Reserve Bank s rate increases since mid-2004 have led to higher short-term interest rates, while during the same period, long-term interest rates have remained low or fallen, resulting in a flatter yield curve. The higher short-term interest rates have put upward pressure on deposit rates, while the low long-term interest rates have held down asset yields, putting downward pressure on net interest margins. If the flattening persists, or the yield curve becomes flatter, the potential for further compression of ASB s margins 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 lowers funding costs (as of December 31, 2004, core deposits as a percentage of total liabilities were 50%, compared to 47% and 44% as of December 31, 2003 and 2002, respectively);

(2) diversifying its loan portfolio with higher yielding, shorter maturity loans or variable rate loans such as business, commercial real estate and consumer loans, which also creates a broader income stream for the bank;

(3) investing in mortgage-related securities with short average lives; and

(4) taking advantage of the lower interest-rate environment by lengthening the maturities of interest-bearing liabilities.

ASB has been undergoing a transformation, involving four major lines of business, to become a full service community bank serving both individual and business customers. Two have been completed commercial real estate and mortgage banking, and a third has made significant progress commercial banking. The retail banking transformation has begun and is the most significant transformation due to the systems and processing improvements needed to move from a product-centric to a customer-centric focus. The transformation project will require continued investment in people and technology. ASB s ongoing challenge is to manage expenses in order to keep increasing costs and increasing revenues in balance.

Economic conditions

Because its core businesses provide local electric utility and banking services, HEI s operating results are significantly influenced by the strength of Hawaii s economy, which has been growing modestly. Growth in real gross state product was an estimated 2.6% in 2003 and 2004.

Tourism is widely acknowledged as the largest component of the Hawaii economy. Visitor days visitor arrivals multiplied by length of stay is a key indicator of the trend in kilowatthour sales. In 2004, visitor days hit a record 63 million, exceeding the record set in 2003 of 59 million by 7%. Other key tourism statistics that indicate the general health of the industry and Hawaii economy include hotel occupancy and visitor expenditures. Hotel occupancy rates averaged 78% for the 11 months ended November 30, 2004, 6% higher than for the same period in 2003. Visitor expenditures totaled $10.3 billion for 2004, increasing 5% compared with 2003.

Key non-tourism sectors in Hawaii, particularly the military and residential real estate, are also fueling economic growth. There has been a surge in defense spending over the last two years with a 13%, or $520 million, increase from 2002 to 2003. While 2004 statistics are not yet available, continued growth is expected with several key military developments projected to bring $3.8 billion in construction projects into the state over the next several years. These projects include preparations for an Army Stryker Brigade, the arrival of eight C-17 Air Force cargo planes and military housing renewal projects. For 2005, nearly $865 million in federal defense dollars have been

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earmarked for Hawaii, including $368 million for military construction projects, in addition to payroll and daily operation funds.

Although mortgage rates have been fluctuating recently, they are still low and continue to support real estate activity. In 2004, single-family dwelling and condominium resale volumes on Oahu were up 6% and 14%, respectively, while the December 2004 median sales prices were up 24% and 21%, respectively, compared with December 2003. In December 2004, the median price of a single-family dwelling on Oahu was $495,000, on the island of Hawaii was $350,500 and on Maui was $594,500.

In general, the construction industry in Hawaii has been doing well. Private building permits were up 15% overall for the 10 months ended October 31, 2004 compared with same period in 2003, and were also up in the residential (up 36%) and additions and alterations (up 27%) categories, but down in the commercial and industrial (down 45%) category. Local economists anticipate 6% growth in construction in 2004 and a 14% increase for 2005.

Hawaii s improving economy is also reflected in other general economic statistics. Total salary and wage jobs increased by 2.5% for the 11 months ended November 30, 2004 compared with the same period in 2003. Hawaii s unemployment rate of 3.3% was well below the national average of 5.4% as of November 30, 2004. DBEDT also estimates real personal income growth of 2.5% in 2004 compared to 2003.

Given these positive trends in key economic indicators, DBEDT expects Hawaii s economy to grow moderately by 2.7% in 2005, excluding inflation. Future growth in Hawaii s economy is expected to be tied primarily to the rate of expansion in the mainland U.S. and Japan economies and continued growth in military spending, but remains vulnerable to uncertainties in the world s geopolitical environment.

Results of Operations

Consolidated

(in millions, except per share amounts)	2004	% change	2003	% change	2002
Revenues	$ 1,924	8	$ 1,781	8	$ 1,654
Operating income	271	3	264	(1)	266
Income from continuing operations	$ 108	(9)	$ 118		$ 118
Loss from discontinued operations	2	NM	(4)	NM	
Net income	$ 110	(4)	$ 114	(3)	$ 118
Electric utility	$ 81	3	$ 79	(13)	$ 90
Bank	41	(27)	56		56
Other	(14)	15	(17)	39	(28)
Income from continuing operations	$ 108	(9)	$ 118		$ 118
Basic earnings (loss) per share					

Continuing operations	$ 1.36	(14)	$ 1.58	(3)	$ 1.63
Discontinued operations	0.02	NM	(0.05)	NM	
	$ 1.38	(10)	$ 1.53	(6)	$ 1.63
Dividends per share	$ 1.24		$ 1.24		$ 1.24
Weighted-average number of common shares outstanding	79.6	7	74.7	3	72.6
Dividend payout ratio	90%		81%		76%
Dividend payout ratio continuing operations	91%		78%		76%

NM Not meaningful.

Stock split

On April 20, 2004, HEI announced 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 above, in the accompanying financial statements and notes and elsewhere in this report have been adjusted to reflect the stock split (unless otherwise noted). See Note 1 of the Notes to Consolidated Financial Statements.

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Bank franchise taxes (consolidated HEI)

The 2004 results of operations include an after-tax charge of $20 million, or $0.25 per share, due to a June 2004 tax ruling and subsequent settlement as discussed in Note 10 of the Notes to Consolidated Financial Statements under ASB state franchise tax dispute and settlement. The following table presents a reconciliation of HEI s consolidated net income to net income excluding this $20 million charge in 2004 and including additional bank franchise taxes in prior periods as if the Company had not taken a dividends received deduction on dividends paid by its real estate investment trust (REIT) subsidiary. Management believes the adjusted information below presents results from continuing operations on a more comparable basis for the periods shown. However, net income, or earnings per share, including these adjustments is not a presentation in accordance with accounting principles generally accepted in the United States of America (GAAP) and may not be comparable to presentations made by other companies or more useful than the GAAP presentation included in HEI s consolidated financial statements.

Years ended December 31	**2004**	**2003**	**2002**
(in thousands, except per share amounts)			
Income from continuing operations	$ 107,739	$ 118,048	$ 118,217
Basic earnings per share - continuing operations	$ 1.36	$ 1.58	$ 1.63
Cumulative bank franchise taxes, net of taxes, through December 31, 2003	$ 20,340	$	$
Additional bank franchise taxes, net of taxes (if recorded in prior periods)	$	$ (3,793)	$ (4,237)
As adjusted			
Income from continuing operations	$ 128,079	$ 114,255	$ 113,980
Basic earnings per share - continuing operations	$ 1.61	$ 1.53	$ 1.57
Return on average common equity [1]	11.2%	10.9%	11.7%

[1] Calculated using adjusted income from continuing operations divided by the simple average adjusted common equity.

Taking into account the adjustments in the table above, HEI s consolidated income from continuing operations would have increased 12% for 2004, compared to 2003.

Pension and other postretirement benefits

For 2004, the Company s pension and other postretirement benefit (collectively, retirement benefit) plans assets generated a total return of 10.5%, resulting in realized and unrealized gains of $82 million. Realized and unrealized gains were $154 million for 2003 and realized and unrealized losses were $112 million for 2002. The market value of the retirement benefit plans assets as of December 31, 2004 was $893 million. The Company made cash contributions to the retirement benefit plans totaling $37 million in 2004, $48 million in 2003 and $10 million in 2002. Contributions are expected to total $17 million in 2005, but actual contributions may differ depending on the performance of the retirement benefit plans assets and the status of interest rates.

Based on various assumptions (e.g., discount rate and expected return on plan assets, which are noted below) and assuming no further changes in retirement benefit plan provisions, consolidated HEI s, consolidated HECO s and ASB s accumulated other comprehensive income (AOCI) balance, net of tax benefits, related to the minimum pension liability at December 31, 2004 and 2003 and retirement benefits expense, net of income taxes, for 2005 (estimated) will be, and 2004 and 2003 were, as follows:

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Years ended December 31	(Estimated) 2005	2004	2003
($ in millions)			
Consolidated HEI			
AOCI balance, net of tax benefits, December 31	NA	$ (1.1)	$ (1.4)
Retirement benefits expense, net of income tax benefits [1]	$ 11.4	6.8	12.1
Consolidated HECO			
AOCI balance, net of tax benefits, December 31	NA		(0.2)
Retirement benefits expense, net of income tax benefits [1]	7.8	3.8	8.4
ASB			
AOCI balance, net of tax benefits, December 31	NA	(0.2)	(0.2)
Retirement benefits expense, net of income tax benefits [1]	2.6	2.0	2.7
Assumptions			
Discount rate, January 1	6.00%	6.25%	6.75%
Expected return on plan assets	9.00%	9.00%	9.00%

[1] Does not include impact of the Medicare Prescription Drug, Improvement and Modernization Act of 2003.

NA Not available.

The 2005 estimated retirement benefits expenses, net of income tax benefits, are 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, 2005).

If the Company and consolidated HECO are required to record substantially greater charges to AOCI in the future, the electric utilities returns on average rate base (RORs) could increase and exceed the PUC authorized RORs, which may ultimately result in reduced revenues and lower earnings. Further, if required to record significant charges to AOCI, the Company s and consolidated HECO s financial ratios may deteriorate, which could result in security ratings downgrades and difficulty (or greater expense) in obtaining future financing. There also may be possible financial covenant violations (although there are no advances currently outstanding under any credit facility subject to financial covenants) as certain bank lines of credit of the Company and HECO require that HECO maintain a minimum ratio of consolidated equity to consolidated capitalization, excluding short-term borrowings, of 35% (actual ratio of 56% as of December 31, 2004); the Company maintain a consolidated net worth, exclusive of intangible assets, of at least $900 million (actual net worth, exclusive of intangible assets, of $1.1 billion as of December 31, 2004); and HEI, on a non-consolidated basis, maintain a ratio of indebtedness to capitalization of not more than 50% (actual ratio of 27% as of December 31, 2004).

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Following is a general discussion of revenues, expenses and net income or loss by business segment. Additional segment information is shown in Note 2 of the Notes to Consolidated Financial Statements.

Electric utility

($ in millions, except per barrel amounts)	2004	% change	2003	% change	2002
Revenues [1]	$ 1,551	11	$ 1,397	11	$ 1,257
Expenses					
Fuel oil	483	24	389	25	311
Purchased power	399	8	368	13	326
Other	495	7	463	9	425
Operating income	174	(2)	177	(9)	195
Allowance for funds used during construction	8	35	6	6	6
Net income	81	3	79	(13)	90
Return on average common equity	8.3%		8.5%		10.0%
Average price per barrel of fuel oil [1]	$ 42.67	18	$ 36.23	25	$ 29.10
Kilowatthour sales (millions)	10,063	3	9,775	2	9,544
Cooling degree days (Oahu)	5,107	2	5,010	4	4,798
Number of employees (at December 31)	2,013	8	1,862	(2)	1,894

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

In 2004, the electric utilities revenues increased by 11%, or $154 million, from 2003 primarily due to higher energy prices ($114 million) and a 2.9% increase in KWH sales of electricity ($41 million). The increase in 2004 KWH sales from 2003 was primarily due to higher customer usage due in part to the strength in Hawaii s economy (including higher real personal income, lower unemployment, higher visitor days, increased military activity and stronger real estate market) and warmer weather (probably resulting in more air conditioning usage). Cooling degree days were 1.9% higher in 2004 compared to 2003. The higher energy prices are also reflected in the higher amount of customer accounts receivable and accrued unbilled revenues.

Operating income was $3 million lower than in 2003 mainly due to higher other expenses, primarily higher maintenance expenses.

Fuel oil and purchased power expenses in 2004 increased by 24% and 8%, respectively, due primarily to higher fuel prices, which are generally passed on to customers, and more KWHs generated and purchased.

Other expenses increased 7% in 2004 due to a 1% (or $2 million) increase in other operation expense; a 20% (or $13 million) increase in maintenance expense; a 4% (or $4 million) increase in depreciation expense due to additions to plant in service in 2003; and a 10% (or $13 million) increase in taxes, other than income taxes, primarily due to the increase in revenues.

Other operation expenses increased 1% in 2004 when compared to 2003 due primarily to higher administrative and general expenses, including increases in general liability reserves and workers compensation claims, and higher transmission and distribution line inspection expense, largely offset by lower retirement benefits expense and emission fees. Pension and other postretirement benefit expenses for the electric utilities were $8 million lower than 2003 due primarily to the increase in plan assets as of December 31, 2003 compared to December 31, 2002 resulting from market performance and contributions of the electric utilities of $34 million during 2004. Maintenance expenses increased 20% due to greater scope of generating unit overhauls, higher production corrective maintenance, and higher transmission and distribution maintenance work.

In 2003, the electric utilities revenues increased by 11%, or $140 million, from 2002 primarily due to higher energy prices ($111 million), a 2.4% increase in KWH sales of electricity ($32 million) and higher DSM lost margins and shareholder incentives ($4 million), partly offset by lower DSM program and Integrated Resource Plan (IRP) costs to be recovered ($5 million). The increase in 2003 KWH sales from 2002 was primarily due to increases in the number of residential customers and residential and commercial usage resulting in part from an improving Hawaii economy (higher visitor days and stronger real estate market) and warmer weather (probably resulting in more air

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conditioning usage). The growth in sales was achieved despite the impact on tourism of concerns over the Japanese economy, the war in Iraq, terrorism and Severe Acute Respiratory Syndrome (SARS). Cooling degree days were 4.4% higher in 2003 compared to 2002.

Operating income was $18 million lower than in 2002 mainly due to higher other expenses, primarily higher retirement benefit expenses.

Fuel oil expense and purchased power expense in 2003 increased by 25% and 13%, respectively, due primarily to higher fuel prices, which are generally passed on to customers, and more KWHs generated and purchased.

Other expenses were up 9% in 2003 due to an 18% (or $24 million) increase in other operation expense; a 5% (or $5 million) increase in depreciation expense due to additions to plant in service in 2002, including HECO s Kewalo-Kamoku 138 kilovolt line; a 9% (or $11 million) increase in taxes, other than income taxes, primarily due to the increase in revenues; partly offset by a 3% (or $2 million) decrease in maintenance expense due in part to less underground distribution line corrective maintenance. As the electric utilities focused on capital expenditures to ensure reliability, ducted cables were installed to replace, rather than repair, direct buried cables when cable problems occurred.

Other operation expense increased 18% primarily due to higher retirement benefits expense and environmental expenses (including higher emission fees). Pension and other postretirement benefit costs, net of amounts capitalized, for the electric utilities swung $24 million over 2002 ($14 million expense in 2003 versus a $10 million credit in 2002), partly due to revised assumptions (decreasing the discount rate 50 basis points to 6.75% and the long-term rate of return on assets 100 basis points to 9.0% as of December 31, 2002 compared to December 31, 2001). Other operation expense for 2003 also included $3.1 million of charges related to a settlement reached in November 2003 involving the expansion of the existing plant at Keahole on the island of Hawaii (see Note 3 of the Notes to Consolidated Financial Statements), offset by lower DSM and IRP costs. In January 2004, the Department of Health of the State of Hawaii (DOH) waived 2003 emissions fees; thus, 2003 emissions fees of $1.5 million, which were accrued in 2003, were reversed in the first quarter of 2004.

Most recent rate requests

HEI s electric utilities initiate PUC proceedings from time to time to request electric rate increases to cover rising operating costs (e.g., higher energy conservation and efficiency program costs and higher purchased power capacity charges) and the cost of plant and equipment, including the cost of new capital projects to maintain and improve service reliability. As of February 16, 2005, 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 (decision and order (D&O) issued on December 11, 1995, based on a 1995 test year), 11.50% for Hawaii Electric Light Company, Inc. (HELCO) (D&O issued on February 8, 2001, based on a 2000 test year) and 10.94% for Maui Electric Company, Limited (MECO) (amended D&O issued on April 6, 1999, based on a 1999 test year). For 2004, the simple average ROACEs (calculated under the rate-making method and reported to the PUC) for HECO, HELCO and MECO were 8.49%, 6.98% and 10.45%, respectively. HELCO s actual 6.98% ROACE for 2004, which is substantially less than its allowed ROACE of 11.50%, reflects in part HELCO s decision to discontinue accruing an allowance for funds used during construction (AFUDC), effective December 1, 1998, on its CT-4 and CT-5 generating units that were installed at the Keahole power plant. Although CT-4 and CT-5 are currently in-service, HELCO s ROACE will continue to be negatively impacted by CT-4 and CT-5 as electric rates will not change for the unit additions until HELCO files a rate increase application and the PUC grants HELCO rate relief.

As of February 16, 2005, the return on average 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). For 2004, the simple average RORs (calculated under the rate-making method) for HECO, HELCO and MECO were 7.13%, 7.25% and 8.83% (after reduction of MECO s revenues from shareholder incentives and lost margins in 2004), respectively.

If required to record significant charges to AOCI related to a minimum liability for retirement benefits, the electric utilities RORs could increase and exceed the PUC authorized RORs, which may ultimately result in reduced revenues and lower earnings.

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Hawaiian Electric Company, Inc. The final D&O for the last rate case on Oahu was issued in 1995.

In November 2004, HECO filed a request with the PUC to increase base rates 9.9%, or $98.6 million in annual base revenues, based on a 2005 test year, a 9.11% return on rate base and an 11.5% return on average common equity. The requested increase includes transferring the cost of existing energy conservation and efficiency programs from a surcharge line item on electric bills into base electricity charges. Excluding this surcharge transfer amount, the requested net increase to customers is 7.3%, or $74.2 million. Approximately $20.4 million of the $74.2 million net request is for the costs of new residential and commercial energy conservation and efficiency programs. The balance of the request is largely for recovery of (1) the costs of capital improvement projects completed since the last rate case, (2) the proposed purchase of up to an additional 29 MW of firm capacity and energy from Kalaeloa Partners, L.P., which is subject to PUC review and approval, (3) other measures taken to address peak load increases arising out of economic growth and increasing electricity use, and (4) increased operation and maintenance expenses. The PUC held a public hearing in January 2005 and evidentiary hearings are expected in the third quarter of 2005. An interim decision is expected in the fourth quarter of 2005.

In October 2002, HECO filed an application with the PUC for approval to change its depreciation rates based on a study of depreciation expense for 2000 and to change to vintage amortization accounting for selected plant accounts. In March 2004, HECO and the Consumer Advocate reached an agreement and the PUC approved the agreement in September 2004. In accordance with the agreement, HECO changed its depreciation rates and changed to vintage amortization accounting for selected plant accounts effective September 1, 2004. Under vintage amortization accounting, additions to electric utility plant in each year are grouped together in a vintage account for that year, as opposed to tracking each asset separately. Each vintage account is amortized over its average service life as determined in the depreciation study and, when fully amortized, the original cost of that vintage account is retired from utility plant in service. If the new rates and accounting had been in effect from the beginning of 2004, depreciation expense for the first eight months of 2004 would have been an estimated $1.3 million lower.

Hawaii Electric Light Company, Inc. The timing of a future HELCO rate increase request to recover costs, including cost for the installation of two combustion turbines (CT-4 and CT-5) at Keahole, will depend on future circumstances. See HELCO power situation in Note 3 of the Notes to Consolidated Financial Statements.

Other regulatory matters

Demand-side management programs - lost margins and shareholder incentives. HECO, HELCO and MECO s energy efficiency DSM programs, currently approved by the PUC, provide for the recovery of lost margins and the earning of shareholder incentives.

Lost margins are accrued and collected prospectively based on the programs forecast levels of participation, and are subject to two adjustments based on (1) the actual level of participation and (2) the results of impact evaluation reports. The difference between the adjusted lost margins and the previously collected lost margins are subject to refund or recovery, with any over- or under-collection accruing interest at HECO, HELCO or MECO s authorized rate of return on rate base. HECO, HELCO and MECO filed the impact evaluation report for the 2000-2003 period with the PUC in November 2004 and plan to adjust the lost margin recovery as required in the second quarter of 2005. Past adjustments required for lost margins have not had a material effect on HECO, HELCO or MECO s financial statements.

Shareholder incentives are accrued currently and collected retrospectively based on the programs actual levels of participation for the prior year. Beginning in 2001, shareholder incentives collected are subject to retroactive adjustment based on the results of impact evaluation reports, similar to the adjustment process for lost margins.

Demand-side management programs agreements with the Consumer Advocate. In October 2001, HECO and the Consumer Advocate finalized agreements, subject to PUC approval, for the continuation of HECO s three commercial and industrial DSM programs and two residential DSM programs until HECO s next rate case. These agreements were in lieu of HECO continuing to seek approval of new 5-year DSM programs and provided that DSM programs to be in place after HECO s next rate case are to be determined as part of the case. Under the agreements, HECO agreed to cap the recovery of lost margins and shareholder incentives if such recovery would cause HECO to exceed its current authorized return on rate base (i.e. the rate of return on rate base found by the PUC to be reasonable in the most recent rate case for HECO). HECO also agreed it will not pursue the continuation of lost margins recovery and shareholder incentives through a surcharge mechanism in future rate cases. In

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October 2001, HELCO and MECO reached similar agreements with the Consumer Advocate 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 (1) the agreements regarding the temporary continuation of HECO s five existing DSM programs until HECO s next rate case and (2) 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 are 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 may request to extend the time of such accrual and recovery for up to one additional year. In 2002, MECO s revenues from shareholder incentives were $0.7 million lower than the amount that would have been recorded if MECO had not agreed to cap such incentives when its authorized ROR was exceeded. Also in 2002, HELCO slightly exceeded its authorized ROR resulting in a reduction of revenues from shareholders incentives for 2002 by $31,000 (recorded in January 2003). In 2002, HECO did not exceed its authorized ROR. In 2003, none of the electric utilities exceeded their respective authorized RORs. In 2004, HECO and HELCO did not exceed their respective authorized RORs, but MECO exceeded its authorized ROR, resulting in a reduction of revenues from shareholders incentives and lost margins for 2004 by $1.0 million (recorded in December 2004).

One of the conditions to the temporary continuation of the DSM programs requires the utilities and the Consumer Advocate to review, every six months, the economic and rate impacts resulting from implementing the agreement. In reviewing HELCO s ROR for 2003, the Consumer Advocate raised an issue regarding Keahole settlement expenses and HELCO agreed to refund, with interest, all of the lost margins and shareholder incentives it had earned in 2003. In June 2004, HELCO recorded reduced revenues of $1.1 million to reflect the lost margins and shareholder incentives for 2003 that were refunded to customers in August 2004. No issues were raised regarding the lost margins and shareholder incentives earned by HECO or MECO in 2003.

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. 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 kilowatthours interrupted. Customer incentives for the programs are expected to be approximately $1 million for the first full year and total $7 million over 5 years.

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 the proxy method 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 kilowatthours or less who buy/sell power from/to the electric utility. In addition to the electric utilities, the parties to the 1992 docket include the Consumer Advocate, the Department of Defense, and representatives of existing or potential independent power producers (IPPs). In March 1994, the parties entered into and filed a Stipulation to Resolve Proceedings, which is 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. No further action was taken in the docket until July 2004, at which time the PUC ordered the parties to review and update, if necessary, the agreements, information and data contained in the stipulation and file such information and stated that further action will follow. The requested information will be submitted by the end of March 2005.

Collective bargaining agreements

Each of the electric utilities entered into a new four-year collective bargaining agreement in 2003 with the union which represents 59% of electric utility employees. See Collective bargaining agreements in Note 3 of the Notes to Consolidated Financial Statements.

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Legislation and regulation

Congress and the Hawaii legislature periodically consider legislation that could have positive or negative effects on the utilities and their customers. For example, although it is currently stalled in a House-Senate conference committee, comprehensive energy legislation is still before Congress that could increase the domestic supply of oil as well as increase support for energy conservation programs and mandate the use of renewables by utilities.

The 2001 Hawaii Legislature adopted a law which required the utilities to meet a renewable portfolio standard of 7% by December 31, 2003. The Company met this standard with over 8% of the utilities consolidated electricity sales for 2003 from renewable resources (as defined under the renewable portfolio standards (RPS) law). The 2004 Hawaii Legislature amended the RPS law to require electric utilities to meet a renewable portfolio standard of 8% by December 31, 2005, 10% by December 31, 2010, 15% by December 31, 2015, and 20% by December 31, 2020. The definition of renewable energy as amended in 2004, includes not only electrical energy savings brought about by the use of solar and heat pump water heating (which were already included in the definition), but also such savings brought about by seawater air-conditioning district cooling systems, solar air conditioning and ice storage, quantifiable energy conservation measures, and use of rejected heat from co-generation and combined heat and power systems (excluding fossil-fueled qualifying facilities that sell electricity to electric utility companies, and central station power projects). HECO, HELCO and MECO are permitted to aggregate their renewable portfolios in order to achieve these standards. The PUC has to determine if an electric utility is not able to meet the standard in a cost-effective manner or due to circumstances beyond its control. If such a determination is made, the utility is relieved of its responsibility to achieve the standard for that period of time. The PUC also may provide incentives to encourage electric utility companies to exceed their RPS or to meet their RPS ahead of time, or both. The law also requires participation by the State to support and facilitate achievement of the RPS. An independent, peer-reviewed study will be conducted by the Hawaii Natural Energy Institute. The study will look at the electric utilities capability of achieving the standards based on a number of factors, including impact on customer rates, utility system reliability and stability, costs and availability of appropriate renewable energy resources and technologies, permitting approvals, and impacts on the economy, culture, community and environment.

The RPS law also directs the PUC, by December 31, 2006, to develop and implement a utility ratemaking structure, which may include, but is not limited to performance-based ratemaking (PBR), 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 November 1, 2004, the PUC transmitted an Initial Concept Paper, entitled Electric Utility Rate Design in Hawaii, describing the PUC s intended methodology for fulfilling the legislative mandate, and requested comments. As summarized in the paper, the PUC has a legislative mandate to formulate an electric utility rate design, by December 31, 2006 that (1) enables the achievement of RPS requiring that renewable energy resources are to have a specific share in the power generation mix by a particular period of time, (2) encourages investments in renewable energy facilities, (3) conforms to the existing regulatory regime, which is cost-of-service regulation, or to alternative regulatory regimes, such as PBR, and (4) provides utilities an opportunity to earn a reasonable rate of return. The overall process envisioned by the PUC is the conduct of three sets of workshops, and the creation of a document leading to rulemaking. Comments were submitted on behalf of the electric utilities, as well as 12 other persons and organizations. The first workshop was held in November 2004, and involved comments by the PUC s modeling consultant, Economists Incorporated, and many of those who submitted written comments. According to the Initial Concept Paper, the PUC, employing a collaborative approach, plans to hold three workshops encouraging public discussion of its work-in-progress. The goal of the first workshop was to describe and gather comments on the PUC s methodology as a whole. The goal of the second workshop, planned for March 2005, is to describe and gather comments on the key factors driving successful RPS schemes and PBR regimes as well as on their use as inputs to the design of electric utility rates in Hawaii. The goal of the third workshop, planned for May or June 2005, is to describe and gather comments on the simulation of the power market in Hawaii incorporating, as discussed in the prior workshops, the lessons learned on electric utility rate design under various RPS schemes and PBR regimes, as well as on its use as a tool for electric utility rate design in Hawaii. The PUC envisions that the end result of all the analysis will be a document that forms the basis of a set of rules to be adopted in a conventional

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rulemaking process to follow, providing input to the PUC s decisions on electric utility ratemaking. Management cannot predict the outcome of this process.

The electric utilities continue to pursue a three-prong renewable energy strategy: a) promote the development of cost-effective, commercially viable renewable energy projects, b) facilitate the integration of intermittent renewable energy resources, and c) encourage renewable energy research, development, and demonstration projects (e.g., photovoltaic energy). They are also conducting integrated resource planning to evaluate the increased use of renewables within the electric utilities service territories.

Among the various ways that the electric utilities support renewable energy are solar water heating and heat pump programs and the negotiation and execution of purchased power contracts with nonutility generators using renewable sources (e.g., refuse-fired, geothermal, hydroelectric and wind turbine generating systems). In December 2003, HELCO signed an approximate 10.6 MW as-available wind power contract with Hawi Renewable Development, and the contract was approved by the PUC in May 2004. In October 2004, a contract with Apollo Energy Corporation to repower an existing 7 MW windfarm to 20 MW was signed and an application for PUC approval was submitted in November 2004. In December 2004, MECO signed an approximately 30 MW as-available wind power contract with Kaheawa Wind Power, LLC and submitted an application for PUC approval.

In December 2002, HECO formed an unregulated subsidiary, RHI, with initial approval to invest up to $10 million in selected renewable energy projects. RHI is seeking to stimulate renewable energy initiatives by prospecting for new projects and sites, and taking a passive, minority interest in third party renewable energy projects. In 2003 and 2004, RHI solicited competitive proposals for investment opportunities in qualified projects. To date, RHI has signed a memorandum of understanding (MOU) and project agreement for a small-scale municipal solid waste-to-energy project and a MOU for a small-scale landfill gas-to-energy project, both situated on Oahu. Project investments by RHI will generally be made only after developers secure the necessary approvals and permits and independently execute a power purchase agreement with HECO, HELCO or MECO, approved by the PUC.

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 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. These amendments could have a negative effect on electric utility sales. However, based on experience under the 10 kw limit and assessment of market opportunity for 50 kw applications, management does not expect any such effect to be material.

The 2004 legislature also 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.

For a discussion of environmental legislation and regulations, see Environmental matters below.

Other developments

HECO has completed a small-scale technical feasibility trial of the Broadband over Power Line (BPL) technology in Honolulu, and is now proceeding with a medium-scale pilot in an expanded residential/commercial area in Honolulu. The purpose of this pilot is to continue to evaluate the technical feasibility of the BPL technology and its applications in a variety of configurations and environments. BPL-enabled utility applications to be evaluated include distribution system monitoring and control, advanced remote metering, and residential direct load control. Although its evaluation will be focused primarily on utility applications of BPL, HECO will also be evaluating broadband information services that might potentially be provided by other service providers. The pilot will involve 50 to 100 residential subscribers in overhead, underground, and multi-dwelling unit electric distribution environments. The pilot is expected to commence in 2005 and run for approximately a year.

In October 2004, the Federal Communications Commission (FCC) released a Report and Order In the Matter of Amendment of Part 15 Regarding New Requirements and Measurement Guidelines for Access Broadband Over

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Power Line Systems and In the Matter of Carrier Current Systems, Including Broadband Over Power Line Systems. The Report and Order amends and adopts new rules for Access Broadband over Power Line systems (Access BPL) and states that the FCC s goals in developing the rules for Access BPL are therefore to provide a framework that will both facilitate the rapid introduction and development of BPL systems and protect licensed radio services from harmful interference. Currently, there are no PUC regulations for electric utility applications of BPL systems.

Bank

(in millions)	2004	% change	2003	% change	2002
Revenues	$ 364	(2)	$ 371	(7)	$ 399
Net interest income	194	3	190	(2)	193
Operating income	105	13	93		93
Net income	41	(27)	56		56
Return on average common equity [1]	8.0%		12.1%		12.9%
Interest-earning assets					
Average balance [2]	$ 6,162	3	$ 5,980	4	$ 5,745
Weighted-average yield	4.98%	(5)	5.23%	(13)	6.03%
Interest-bearing liabilities					
Average balance [2]	$ 5,934	3	$ 5,739	5	$ 5,488
Weighted-average rate	1.90%	(12)	2.15%	(23)	2.79%
Interest rate spread	3.08%		3.08%	(5)	3.24%

1 In late December 2004, ASB s capital structure changed when ASB redeemed its preferred stock held by HEIDI ($75 million) and HEIDI infused common equity into ASB ($75 million). If ASB s reported common equity as of December 31, 2004 was reduced by $75 million for the calculation, ASB s ROACE would have been 8.7%.

2 Calculated using the average daily balances.

Bank franchise taxes (ASB)

The results of operations for 2004 include a net charge of $20 million due to a June 2004 tax ruling and subsequent settlement as discussed in Note 10 of the Notes to Consolidated Financial Statements under ASB state franchise tax dispute and settlement. The following table presents a reconciliation of ASB s net income to net income excluding the $20 million charge in 2004 and including additional bank franchise taxes in prior periods as if ASB had not taken a dividends received deduction on dividends paid by its REIT subsidiary. Management believes the adjusted information below presents ASB s net income on a more comparable basis for the periods shown. However, net income, including these adjustments, is not a presentation in accordance with GAAP and may not be comparable to presentations made by other companies or more useful than the GAAP presentation included in HEI s consolidated financial statements.

Years ended December 31	2004	2003	2002
(in thousands)			
Net income	$ 41,062	$ 56,261	$ 56,225
Cumulative bank franchise taxes, net of taxes, through December 31, 2003	20,340		

Additional bank franchise taxes, net of taxes (if recorded in prior periods)		(3,793)	(4,237)
Net income as adjusted	$ 61,402	$ 52,468	$ 51,988
ROACE as adjusted[1]	13.3%	11.7%	12.3%

1 Calculated using adjusted net income divided by the simple average adjusted common equity (excluding the $75 million common equity infusion in December 2004).

Taking into account the adjustments in the table above, ASB s 2004 net income would have increased 17% compared to 2003.

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Bank operations

Earnings of ASB depend primarily on net interest income, which is the difference between interest earned on interest-earning assets and interest paid on interest-bearing liabilities. 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. At December 31, 2004, ASB s loan portfolio mix consisted of 74% residential loans, 10% business loans, 7% consumer loans and 9% commercial real estate loans. At December 31, 2003, ASB s loan portfolio mix consisted of 77% residential loans, 9% business loans, 7% consumer loans and 7% commercial real estate 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 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. At December 31, 2004, ASB s costing liabilities consisted of 51% core deposits, 20% term certificates and 29% FHLB advances and other borrowings. At December 31, 2003, ASB s costing liabilities consisted of 48% core deposits, 20% term certificates and 32% FHLB advances and other borrowings.

Other factors primarily affecting ASB s operating results include gains or losses on sales of securities available-for-sale, fee income, provision for loan losses, changes in the value of mortgage servicing rights and expenses from operations.

Low interest rates and high mortgage refinancing volume in 2003 and the first half of 2004 have put pressure on ASB s interest rate spread as the loan portfolio repriced upon refinancing at lower interest rates, while at the same time deposit rates were already at low levels in 2003. The Federal Reserve Bank s rate increases since mid-2004 have led to higher short-term interest rates, while during the same period, long-term interest rates have remained low or fallen, resulting in a flatter yield curve. The higher short-term interest rates have put upward pressure on deposit rates, while the low long-term interest rates have held down asset yields, putting downward pressure on net interest margins. If the flattening persists, or the yield curve becomes flatter, the potential for further compression of ASB s margins will continue to be a concern.

Although higher long-term interest rates could reduce the market value of mortgage-related securities and reduce stockholder s equity through a balance sheet charge to AOCI, this reduction in the market value of mortgage-related securities would not result in a charge to net income in the absence of an other-than-temporary impairment in the value of the securities. At December 31, 2004 and 2003, the unrealized losses, net of tax benefits, on available-for-sale mortgage-related securities (including securities pledged for repurchase agreements) in AOCI was $7 million and $1 million, respectively, reflecting the impact of higher interest rates in 2004. See Quantitative and qualitative disclosures about market risk.

In December 2004, the FHLB of Seattle signed an agreement with its regulator, the Federal Housing Finance Board, under which it will review and strengthen its risk management, capital structure, governance and business plan. Pending the approval of a final business and capital management plan by its regulator, the FHLB of Seattle s Board of Directors deferred declaring a dividend based on its fourth quarter 2004 earnings until the first quarter of 2005 (as of December 31, 2004, ASB had an investment in FHLB stock of $97 million), and has indicated that dividends on its stock will not exceed the lower of the daily average Federal Funds effective rate during the prior quarter or 50% of the FHLB of Seattle s earnings during the prior quarter, subject additionally to the FHLB of Seattle s retained earnings policy. In March 2005, the FHLB of Seattle indicated that the strategies under consideration to improve the FHLB of Seattle s long-term financial position will negatively impact its earnings and retained earnings in the interim, and thus potentially limit its ability to pay dividends and accommodate stock repurchases. In the first three quarters of 2004, the FHLB of Seattle had paid total dividends on ASB s investment in FHLB of Seattle stock of $2.7 million.

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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 interest-earning assets and interest-bearing 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,		
(in thousands)	**2004**	**2003**	**2002**
Loan			
Average balances [1]	$ 3,121,878	$ 3,071,877	$ 2,844,341
Interest income [2]	184,773	198,948	203,082
Weighted-average yield	5.92%	6.48%	7.14%
Mortgage-related securities			
Average balances	$ 2,799,303	$ 2,707,395	$ 2,654,302
Interest income	116,471	107,496	135,252
Weighted-average yield	4.16%	3.97%	5.10%
Investments [3]			
Average balances	$ 240,466	$ 200,891	$ 246,321
Interest and dividend income	5,876	6,384	7,896
Weighted-average yield	2.44%	3.18%	3.21%
Total interest-earning assets			
Average balances	$ 6,161,647	$ 5,980,163	$ 5,744,964
Interest and dividend income	307,120	312,828	346,230
Weighted-average yield	4.98%	5.23%	6.03%
Deposits			
Average balances	$ 4,114,070	$ 3,888,145	$ 3,717,553
Interest expense	47,184	53,808	73,631
Weighted-average rate	1.15%	1.38%	1.98%
Borrowings			
Average balances	$ 1,819,598	$ 1,851,258	$ 1,770,831
Interest expense	65,603	69,516	79,251
Weighted-average rate	3.61%	3.76%	4.48%
Total interest-bearing liabilities			
Average balances	$ 5,933,668	$ 5,739,403	$ 5,488,384
Interest expense	112,787	123,324	152,882
Weighted-average rate	1.90%	2.15%	2.79%
Net balance, net interest income and interest rate spread			
Net balance	$ 227,979	$ 240,760	$ 256,580
Net interest income	194,333	189,504	193,348
Interest rate spread	3.08%	3.08%	3.24%

1 Includes nonaccrual loans.

2 Includes interest accrued prior to suspension of interest accrual on nonaccrual loans, together with loan fees of $6.1 million, $8.6 million and $4.2 million for 2004, 2003 and 2002, respectively.

3 Includes stock in the FHLB of Seattle.

Net interest income before provision for loan losses for 2004 increased by $5 million or 2.5%, when compared to 2003. ASB experienced margin compression from a flattening yield curve, but year-over-year net interest rate spread remained the same at 3.08% due to growth in the loan portfolio and mortgage-related securities funded by strong core deposit growth. The increase in average loan portfolio balance was due to a strong Hawaii real estate market and low interest rates. The increase in the average investment and mortgage-related securities portfolios were due to the reinvestment into short-term investments of excess liquidity resulting from an inflow of deposits. Average deposit balances grew by $226 million as ASB continued to attract core deposits. During 2004, average core deposits increased by $293 million offset by a decrease in the average balance of term certificates of $67 million. The shift in deposit mix lowered the weighted average rate on deposits. The higher deposit balances enabled ASB to repay some of its maturing, higher costing other borrowings.

Due to considerable strength in real estate and business conditions, which resulted in lower historical loss ratios and lower net charge-offs for ASB, and other factors discussed above, ASB recorded a negative provision for loan losses of $8 million ($5 million, net of tax) in 2004. This compares with a provision for loan losses of $3 million ($2 million, net of tax) in 2003.

Other income for 2004 decreased by $1 million, or 2.3%, when compared to 2003 due to $4 million of gains on sale of securities in 2003, partially offset by higher fee income in 2004.

General and administrative expenses for 2004 increased by $3 million, or 1.8%, over 2003, primarily due to costs associated with Sarbanes-Oxley Act of 2002 (SOX) compliance efforts.

On January 19, 2005, ASB became aware that the methodology it was using to amortize premiums and discounts on its mortgage-related securities portfolio was not in strict conformance with Statement of Financial Accounting Standards (SFAS) No. 91, Accounting for Nonrefundable Fees and Costs Associated with Originating or Acquiring Loans and Initial Direct Costs of Leases. Specifically, ASB determined that its method for estimating the cumulative impact of revised effective yield following the provisions of paragraph 19 of SFAS No. 91 when considering prepayments no longer approximated the results from a strict application of these provisions. This resulted in over-amortization of net premiums. Accordingly, ASB recalculated the amortization of premiums and discounts on its December 31, 2004 mortgage-related securities portfolio in strict accordance with SFAS No. 91 and recognized $1.5 million in additional net income ($2.5 million pre-tax interest income) in the fourth quarter of 2004 for an adjustment for net premium overamortization.

Net interest income before provision for loan losses for 2003 decreased by $4 million, or 2.0%, when compared to 2002. Margin compression throughout most of 2003 lowered net interest spread from 3.24% for 2002 to 3.08% in 2003 as the low interest rate environment and significant refinancing activity in the mortgage and mortgage-related securities portfolios lowered the yield on earning assets. These lower yields coupled with an inability to lower the interest rates paid on deposits to a commensurate degree reduced the interest rate spread. The average loan portfolio balance increased by $228 million as the very low interest rate environment and continued strength in the Hawaii real estate market spurred record loan production. ASB s average residential mortgage portfolio as of year-end 2003 grew by $194 million, or 8.5%, over 2002 year-end. ASB increased its average business portfolio by $52 million, or 23.5%, during 2003 as its transformation to a full service community bank continued. Average deposit balances grew by $171 million as ASB continued to attract core deposits. During 2003, average core deposit balances increased by $269 million offset by a decrease in the average balance of term certificates of $98 million. The shift in deposit mix lowered the weighted average rate on deposits. In response to pressure on interest rate spreads as a result of the low interest rate environment, ASB restructured a total of $389 million of FHLB advances during 2003. The restructurings involved paying off existing, higher rate FHLB advances with advances that have lower rates and longer maturities. The restructurings resulted in a reduction of interest expense on these FHLB advances of approximately $5 million for 2003.

ASB s provision for loan losses of $3 million in 2003 decreased by $7 million compared to 2002 as delinquencies continued to decline. A strong Hawaii real estate market and low interest rates gave debtors the opportunity to sell their properties or refinance before defaulting on loans. In addition, ASB improved its collections efforts. These factors contributed to the lower delinquency levels during 2003. Residential, consumer and commercial real estate loan delinquencies have decreased during the year and lower loan loss reserves were required for those lines of business. The growth of the business loan portfolio has required additional loan loss reserves on those loans.

Other income for 2003 increased by $5 million, or 10.3%, over 2002, principally as a result of net gains on sales of securities totaling $4 million compared to a net loss of $1 million in 2002, higher fee income from its debit and automated teller machine (ATM) cards resulting from ASB s expansion of its debit card base and additional ATM

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services and higher fee income from its deposit liabilities as a result of restructuring of deposit products. Offsetting these increases were lower gains on sale of loans in 2003 compared to 2002 and a lower accrual for the costs of administering delinquent loans in 2002.

ASB s general and administrative expenses for 2003 increased by $8 million, or 5.9%, over 2002. Compensation and benefits for 2003 was $6 million higher than in 2002 primarily due to increased investment in ASB s workforce to support its transformation initiatives.

During 2004 and 2003, ASB s allowance for loan losses decreased by $10 million and $1 million, respectively, compared to an increase to its allowance of $3 million in 2002. As of December 31, 2004, 2003 and 2002, ASB s allowance for loan losses was 1.08%, 1.44% and 1.60%, respectively, of average loans outstanding.

ASB s nonaccrual and renegotiated loans represented 0.4%, 0.4% and 0.9% of total loans outstanding at December 31, 2004, 2003 and 2002, respectively. See Note 4 of the Notes to Consolidated Financial Statements.

Legislation and regulation

Congress is considering legislation to revamp oversight of government-sponsored enterprises (GSEs). The bill would abolish the Office of Federal Housing Enterprise Oversight (regulator of Fannie Mae and Freddie Mac) and the Federal Housing Finance Board (regulator of the FHLB), create a new regulatory agency to oversee GSEs, and invest in this new agency the authority, among other things, to place limitations on non-mission assets, to establish prudent management and operation standards for GSEs concerning matters such as the management of asset and investment portfolio growth, to impose prompt-corrective action measures on a GSE in the event of under-capitalization, and to exercise oversight enforcement powers. By possibly restricting GSE asset growth, if enacted, the bill could potentially limit the availability of advances from the FHLB of Seattle to ASB and sale of loans to Fannie Mae. ASB believes, however, that if this bill is adopted and implemented in these ways, its results will not be materially adversely affected because ASB has access to other funding sources and secondary markets to sell its loans.

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 Bank and Certain factors that may affect future results and financial condition Bank.

Other

(in millions)	**2004**	**% change**	**2003**	**% change**	**2002**
Revenues [1]	$ 9	(32)	$ 13	NM	$ (2)
Operating loss	(8)	(38)	(6)	73	(22)
Net loss	(14)	15	(17)	39	(28)

1 Including writedowns of and net losses from investments.

NM Not meaningful.

The other business segment includes results of operations of HEI Investments, Inc. (HEIII), a company primarily 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 investments; Hawaiian Electric Industries Capital Trust I and its subsidiary (HEI Preferred Funding, LP), which were deconsolidated on January 1, 2004, dissolved in April 2004 and terminated in December 2004, and Hycap Management, Inc. (which is in dissolution), financing entities formed to effect the issuance of 8.36% Trust Originated Preferred Securities that were redeemed in April 2004; The Old Oahu Tug Service, Inc. (TOOTS), a maritime freight transportation company that ceased operations in 1999; HEI and HEIDI, holding companies; and eliminations of intercompany transactions. The first seven months of 2003 also includes the results of operations for ProVision Technologies, Inc., a company formed to sell, install, operate and maintain on-site power generation equipment and auxiliary appliances in Hawaii and the Pacific Rim, which was sold for a nominal loss in July 2003; and two other inactive subsidiaries, HEI Leasing, Inc. and HEI District Cooling, Inc., which were dissolved in October 2003. In August 2004, HEI sold its investments in the income notes it had acquired from ASB in 2001 for a net gain of $5.6 million ($3.6 million after-tax).

HEIII recorded net income of $1.8 million in 2004, $2.3 million in 2003 and $1.5 million in 2002, primarily from leveraged leases.

HEIPI recorded net losses of $0.9 million in 2004, net income of $0.1 million in 2003, and net losses of $0.6 million in 2002, which amounts include income and losses from and/or writedowns of venture capital investments. As of December 31, 2004, HEIPI s venture capital investments amounted to $1.5 million.

HEI Corporate and the other subsidiaries revenues in 2004 include a $5.6 million pretax gain on the sale of the income notes that HEI purchased in May and July 2001 in connection with the termination of ASB s investments in trust certificates. HEI Corporate and the other subsidiaries revenues in 2003 include $9.3 million from the settlement of lawsuits in the fourth quarter of 2003. HEI Corporate and the other subsidiaries revenues in 2002 include $4.5 million of pretax writedowns ($2.9 million, net of taxes) of the income notes.

HEI Corporate operating, general and administrative expenses (including labor, employee benefits, incentive compensation, charitable contributions, legal fees, consulting, rent, supplies and insurance) were $14.9 million in 2004, $15.9 million in 2003 and $15.6 million in 2002. The slightly higher expenses in 2002 and 2003 were due in part to legal expenses incurred in connection with lawsuits and the settlement of lawsuits. HEI Corporate and the other subsidiaries net loss was $15.4 million in 2004, $19.5 million in 2003 and $29.2 million in 2002, the majority of which is comprised of financing costs. The results for 2004 include a $3.6 million after-tax gain on the sale of the income notes, and the results for 2003 include net income of $5.7 million from the settlement of lawsuits in the fourth quarter, which amounts are not expected to be recurring.

The other segment s interest expense and preferred securities distributions of trust subsidiaries were $27.6 million in 2004, $33.3 million in 2003 and $36.4 million in 2002. In 2004, these financing costs decreased 17% compared to the prior year as HEI (1) completed the sale of 2 million shares (pre-split) of common stock, the net proceeds of which were ultimately used, along with other corporate funds, to effect the redemption of $100 million aggregate principal amount of 8.36% Trust Originated Preferred Securities, and (2) completed the sale of $50 million of 4.23% medium-term notes. In 2003, financing costs decreased 9% compared to the prior year due to lower rates and lower average borrowings. In 2003, the amount of outstanding medium-term notes was reduced by $37 million.

Discontinued operations

In 2001, the HEI Board of Directors adopted a plan to exit the international power business. In 2003, HEI Power Corp. (HEIPC) wrote down its investment in Cagayan Electric Power & Light Co., Inc. (CEPALCO) from $7 million to $2 million and increased its reserve for future expenses by $1 million, resulting in a $4 million after-tax loss on disposal. In 2004, the HEIPC Group sold the company that holds its interest in CEPALCO for a nominal gain. Also in 2004, the HEIPC Group transferred its interest in a China joint venture to its partner and another entity and recorded an after-tax gain on disposal of $2 million. See Note 14 of the Notes to Consolidated Financial Statements.

Effects of inflation

U.S. inflation, as measured by the U.S. Consumer Price Index (CPI), averaged 2.7% in 2004, 2.3% in 2003 and 1.6% in 2002. Hawaii inflation, as measured by the Honolulu CPI, averaged 3.3% in 2004, 2.3% in 2003 and 1.2% in 2002. The increase in the Honolulu CPI for 2004 was due in large part to increases in gasoline and housing prices. The rate of inflation over the last two years has been trending upward and, although relatively low throughout this period, 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 generally approved rate increases to cover the effects of inflation. The PUC granted rate increases in 2001 and 2000 for HELCO, and in 1999 for MECO, in part to cover increases in construction costs and operating expenses due to inflation.

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Recent accounting pronouncements

See Recent accounting pronouncements and interpretations in Note 1 of the Notes to Consolidated Financial Statements.

Liquidity and capital resources

Consolidated

Selected contractual obligations and commitments

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

December 31, 2004	**Payment due by period**				
(in millions)	**Less than 1 year**	**1-3 years**	**3-5 years**	**More than 5 years**	**Total**
Contractual obligations					
Deposit liabilities					
Commercial checking	$ 303	$	$	$	$ 303
Other checking	791				791
Savings	1,700				1,700
Money market	303				303
Term certificates	730	321	115	33	1,199
Total deposit liabilities	3,827	321	115	33	4,296
Securities sold under agreements to repurchase	468	233	110		811
Advances from Federal Home Loan Bank	283	349	331	25	988
Long-term debt, net	37	120	50	960	1,167
Operating leases, service bureau contract and maintenance agreements	19	19	12	25	75
Fuel oil purchase obligations (estimate based on January 1, 2005 fuel oil prices)	361	722	722	1,804	3,609
Purchase power obligations minimum fixed capacity charges	118	236	229	1,378	1,961
Total (estimated)	$ 5,113	$ 2,000	$ 1,569	$ 4,225	$ 12,907

December 31, 2004

(in millions)	
Other commercial commitments to ASB customers	
Loan commitments (primarily expiring in 2005)	$ 42
Loans in process	132
Unused lines and letters of credit	748
	$ 922

The tables above do not include other categories of obligations and commitments, such as interest payable, trade payables, obligations under purchase orders, amounts that will become payable in future periods under collective bargaining and other employment agreements and employee benefit plans, and obligations that may arise under indemnities provided to purchasers of discontinued operations. As of December 31, 2004, the fair value of the assets held in trusts to satisfy the obligations of the pension and other postretirement benefit plans exceeded the pension plans accumulated benefit obligation and the accumulated postretirement benefit obligation for retirees. Thus, no minimum funding requirements for retirement benefit plans has been included in the tables above.

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See Note 3 of the 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 forecast capital expenditures and investments, its expected retirement benefit plan contributions and other cash requirements in the foreseeable future.

The Company s total assets were $9.6 billion at December 31, 2004 and $9.2 billion at December 31, 2003.

The consolidated capital structure of HEI (excluding ASB s deposit liabilities, securities sold under agreements to repurchase and advances from the FHLB of Seattle) was as follows:

December 31	**2004**		**2003**	
(in millions)				
Short-term borrowings	$ 77	3%	$	%
Long-term debt, net	1,167	47	1,065	45
HEI- and HECO-obligated preferred securities of trust subsidiaries			200	8
Preferred stock of subsidiaries	34	1	34	1
Common stock equity	1,211	49	1,089	46
	$ 2,489	100%	$ 2,388	100%

As of February 16, 2005, the Standard & Poor s (S&P) and Moody s Investors Service s (Moody s) ratings of HEI and HECO securities were as follows:

	S&P	**Moody s**
HEI		
Commercial paper	A-2	P-2
Medium-term notes	BBB	Baa2
HECO		
Commercial paper	A-2	P-2
Revenue bonds (senior unsecured, insured)	AAA	Aaa
HECO-obligated preferred securities of trust subsidiary	BBB-	Baa2
Cumulative preferred stock (selected series)	NR	Baa3

NR Not rated.

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.

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 and HECO securities. In January 2005, S&P affirmed that its credit ratings of the Company are considered stable.

On March 16, 2004, HEI completed the sale of 2 million shares (pre-split) of common stock. The shares were issued under an omnibus shelf registration statement registering up to $200 million of debt, equity and/or other securities. The net proceeds from the sale of approximately $100 million were ultimately used, along with other corporate funds, to effect the redemption of $100 million aggregate principal amount of 8.36% Trust Originated Preferred Securities of Hawaiian Electric Industries Capital Trust I on April 16, 2004, after which redemption Hawaiian Electric Industries Capital Trust I was dissolved and then terminated. At December 31, 2004, an additional $96 million of debt, equity and/or other securities were available for offering by HEI under the omnibus shelf registration.

On March 17, 2004, HEI completed the sale of $50 million of 4.23% notes, Series D, due March 15, 2011 under its registered medium-term note program. The net proceeds from this sale were ultimately used to make short-term loans to HECO, to assist HECO and HELCO in redeeming the 7.30% Cumulative Quarterly Income Preferred Securities, Series 1998, in April 2004 and for other general corporate purposes. HECO has repaid those short-term loans primarily with funds saved from reducing dividends to HEI in 2004. In 2004, HECO s dividends to HEI were $11.6 million, compared to $57.7 million in 2003.

On March 7, 2003, HEI sold $50 million of its 4.00% notes, Series D, due March 7, 2008, and $50 million of its 5.25% notes, Series D, due March 7, 2013 under its registered medium-term note program. The net proceeds from the sales, along with other corporate funds, were ultimately used to repay $100 million of notes, Series C, (which effectively bore interest at three-month LIBOR plus 376.5 basis points after taking into account two interest rate swaps entered into by HEI with Bank of America) at maturity on April 15, 2003.

At December 31, 2004, an additional $150 million principal amount of Series D notes were available for offering by HEI under its registered medium-term note program.

From time to time, HEI and HECO each utilizes short-term debt, principally commercial paper, to support normal operations and for other temporary requirements. From time to time, HECO also borrows short-term from HEI for itself and on behalf of HELCO and MECO, and HECO may borrow from or loan to HELCO and MECO short-term. At December 31, 2004, HECO had $12.0 million and $7.8 million of short-term borrowings from HEI and MECO, respectively, and HELCO had $34.9 million of short-term borrowings from HECO. HEI had no commercial paper borrowings during 2004. HECO had an average outstanding balance of commercial paper for 2004 of $12.7 million and had $76.7 million of commercial paper outstanding at December 31, 2004. Management believes that if HEI s and HECO s commercial paper ratings were to be downgraded, they might not be able to sell commercial paper under current market conditions.

At December 31, 2004, HEI and HECO maintained bank lines of credit totaling $80 million and $110 million, respectively (all maturing in 2005). In January 2005, HECO increased its total lines of credit to $140 million (all maturing in 2005). These lines of credit are principally maintained by HEI and HECO to support the issuance of commercial paper, but also may be drawn for general corporate purposes. Accordingly, the lines of credit are available for short-term liquidity in the event a rating agency downgrade were to reduce or eliminate access to the commercial paper markets. Lines of credit to HEI totaling $30 million contain provisions for revised pricing in the event of a ratings change (e.g., a ratings downgrade of HEI medium-term notes from BBB/Baa2 to BBB-/Baa3 by S&P and Moody s, respectively, would result in a 25 to 50 basis points higher interest rate; a ratings upgrade from BBB/Baa2 to BBB+/Baa1 by S&P and Moody s, respectively, would result in a 12.5 to 20 basis points lower interest rate). There are no such provisions in the other lines of credit available to HEI and HECO. Further, none of HEI s or HECO s line of credit agreements contain material adverse change clauses that would affect access to the lines of credit in the event of a ratings downgrade or other material adverse events. At December 31, 2004, the lines were unused. To the extent deemed necessary, HEI and HECO anticipate arranging similar lines of credit as existing lines of credit mature. See S&P and Moody s ratings above and Note 5 of the Notes to Consolidated Financial Statements.

Operating activities provided net cash of $244 million in 2004, $241 million in 2003 and $259 million in 2002. Investing activities used net cash of $540 million in 2004, $325 million in 2003 and $616 million in 2002. In 2004, net cash was used in investing activities largely due to banking activities (including the purchase of mortgage-related and investment securities and the origination of loans, net of repayments and sales of such securities) and HECO s consolidated capital expenditures. Financing activities provided net cash of $187 million in 2004, $123 million in 2003 and $151 million in 2002. In 2004, net cash provided by financing activities was affected by several factors, including net increases in deposits and short-term borrowings and proceeds from the issuance of common stock, partly offset by a net decrease in securities sold under agreements to repurchase, advances from the FHLB and long-term debt and preferred securities of trust subsidiaries and by the payment of common stock dividends.

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. However, 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 the Notes to Consolidated Financial Statements.

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Forecast HEI consolidated net cash used in investing activities (excluding investing cash flows from ASB) for 2005 through 2009 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 discussion below), approximately $0.2 billion will be required during 2005 through 2009 to repay maturing HEI long-term debt, which is expected to be repaid with the proceeds from the sale of medium-term notes and issuance of common stock under the stock option and incentive plan, and dividends from subsidiaries (i.e., operating cash flow of subsidiaries). Additional debt and/or equity financing may be required to fund unanticipated expenditures not included in the 2005 through 2009 forecast, such as increases in the costs of or an acceleration of the construction of capital projects of the electric utilities, unbudgeted acquisitions or investments in new businesses, significant increases in retirement benefit funding requirements that might be required if there were significant declines in the market value of pension plan assets or changes in actuarial assumptions and higher tax payments that would result if tax positions taken by the Company do not prevail. 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 Note 8 of the Notes to Consolidated Financial Statements, the Company maintains pension and other postretirement benefit plans. Funding for the pension plans is based upon actuarially determined contributions that take into account the amount deductible for income tax purposes and the minimum contribution required under the Employee Retirement Income Security Act of 1974, as amended (ERISA). The Company was not required to make any contributions to the pension plans to meet minimum funding requirements pursuant to ERISA for 2004 and 2003, but the Company s Pension Investment Committee chose to make tax deductible contributions in both years. Contributions to the pension and postretirement benefit plans totaled $10 million in 2002 and $48 million in 2003 of which $31 million were made by the electric utilities, $15 million by ASB and $2 million by HEI Corporate. Contributions to the pension and postretirement benefit plans totaled $37 million in 2004 of which $34 million were made by the electric utilities, $1 million by ASB and $2 million by HEI Corporate. Contributions are expected to total $17 million in 2005. The electric utilities policy is to comply with directives from the PUC to fund the costs of the postretirement benefit plan. These costs are ultimately collected in rates billed to customers. The Company reserves the right to change, modify or terminate the plans. From time to time in the past, benefits have changed. 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.

Following is a discussion of the liquidity and capital resources of HEI s largest segments.

Electric utility

HECO s consolidated capital structure was as follows:

December 31	2004		2003	
(in millions)				
Short-term borrowings	$ 89	4%	$ 6	%
Long-term debt, net	753	40	699	39
HECO-obligated preferred securities of trust subsidiaries			100	6
Preferred stock	34	2	34	2
Common stock equity	1,017	54	945	53
	$ 1,893	100%	$ 1,784	100%

In 2004, the electric utilities investing activities used $191 million in cash, primarily for capital expenditures. Financing activities provided net cash of $22 million, including an $83 million increase in short-term borrowing, partly offset by the net repayment of $50 million of long-term debt and $13 million for the payment of common and preferred stock dividends. Operating activities provided cash of $169 million.

As of December 31, 2004, approximately $12 million of proceeds from the sale by the Department of Budget and Finance of the State of Hawaii of Series 2002A Special Purpose Revenue Bonds (SPRB) issued for the benefit of HECO remain undrawn. The electric utilities are seeking authorizing legislation for up to $160 million of SPRBs

($100 million for HECO, $40 million for HELCO and $20 million for MECO) for issuance on or after July 1, 2005 through June 30, 2010.

On March 18, 2004, HECO Capital Trust III issued and sold 2 million of its 6.50% Cumulative Quarterly Income Preferred Securities ($50 million aggregate liquidation preference). Also on March 18, 2004, HECO, HELCO and MECO issued 6.50% Junior Subordinated Deferrable Interest Debentures to HECO Capital Trust III in the aggregate principal amount of approximately $51.5 million and directed that the proceeds from the issuance of the debentures be deposited with the trustee for HECO Capital Trust I and ultimately be used in April 2004 to redeem its 8.05% Cumulative Quarterly Income Preferred Securities ($50 million aggregate liquidation preference) and its common securities (owned by HECO) of approximately $1.5 million. The financial statements of HECO Capital Trust III are not consolidated in the HECO consolidated financial statements and the Junior Subordinated Deferrable Interest Debentures are included in Long-term debt, net in the HECO consolidated financial statements. Also in April 2004, HECO Capital Trust II redeemed $50 million aggregate liquidation preference of its 7.30% Cumulative Quarterly Income Preferred Securities primarily using funds from short-term borrowings from HEI and from the issuance of commercial paper by HECO. After redemption of their respective trust preferred securities, HECO Capital Trust I and II were dissolved and terminated.

On May 1, 2003, the Department of Budget and Finance of the State of Hawaii issued, at a small discount, Refunding Series 2003A SPRB in the aggregate principal amount of $14 million with a maturity of approximately 17 years and a fixed coupon interest rate of 4.75% (yield of 4.85%), and loaned the proceeds from the sale to HELCO. Also on May 1, 2003, the Department of Budget and Finance of the State of Hawaii issued, at par, Refunding Series 2003B SPRB in the aggregate principal amount of $52 million with a maturity of approximately 20 years and a fixed coupon interest rate of 5.00% and loaned the proceeds from the sale to HECO and HELCO. On June 2, 2003, the proceeds of these Refunding SPRB, together with additional funds provided by HECO and HELCO, were applied to refund a like principal amount of SPRB bearing higher interest coupons (HELCO s $4 million of 7.60% Series 1990B SPRB and $10 million of 7.375% Series 1990C SPRB with original maturities in 2020, and HECO s and HELCO s aggregate $52 million of 6.55% Series 1992 SPRB with original maturities in 2022).

The electric utilities net capital expenditures for 2005 through 2009 are estimated to total $0.8 billion. HECO s consolidated cash flows from operating activities (net income, adjusted for noncash income and expense items such as depreciation, amortization and deferred taxes), after the payment of common stock and preferred stock dividends, together with a projected increase in short-term borrowings and in long-term debt from the drawdown of revenue bond proceeds that are currently available or that may be available from future issuances of SPRBs, are expected to provide cash to cover the forecast consolidated net capital expenditures. Short-term borrowings are expected to fluctuate during this forecast period. Additional debt and/or equity financing may be required for various reasons, including increases in the costs of, or an 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 that may be required if the market value of pension plan assets does not increase or there are changes in actuarial assumptions and other unanticipated expenditures not included in the 2005 through 2009 forecast.

In January 2005, the Department of Budget and Finance of the State of Hawaii issued, at par, Refunding Series 2005A SPRB in the aggregate principal amount of $47 million with a maturity of January 1, 2025 and a fixed coupon interest rate of 4.80% and loaned the proceeds from the sale to HECO, HELCO and MECO. Proceeds from the sale, along with additional funds, were applied to redeem at a 1% premium a like principal amount of SPRB bearing a higher interest coupon (HECO s, HELCO s, and MECO s aggregate $47 million of 6.60% Series 1995A SPRB with original maturity of January 1, 2025) in February 2005.

The PUC must approve issuances of long-term securities by HECO, HELCO and MECO, including notes or debentures issued by the electric utilities in connection with the issuance of special purpose revenue bonds or trust preferred securities.

Capital expenditures include the costs of projects that are required to meet expected load growth, to improve reliability and to replace and upgrade existing equipment. The consolidated forecast of net capital expenditures for HECO and subsidiaries, which excludes AFUDC and capital expenditures funded by third-party contributions in aid of construction from gross capital expenditures, for the five-year period 2005 through 2009, is currently estimated to total $0.8 billion. Approximately 49% of forecast gross capital expenditures for this period (which includes AFUDC and third-party contributions in aid of construction) is for transmission and distribution projects and 42% for generation projects, with the remaining 9% 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 recently adopted by the U.S. Environmental Protection Agency (EPA), the currently proposed Clear Skies Bill, if adopted by Congress, or the currently proposed environmental regulations relating to nickel emissions, if promulgated by the EPA.

For 2005, electric utility net capital expenditures are estimated to be $173 million. Gross capital expenditures are estimated to be $210 million, including approximately $113 million for transmission and distribution projects, approximately $62 million for generation projects and approximately $35 million for general plant and other projects. Investment in renewable projects through RHI in 2005 is estimated to be $1 million. Drawdowns of $12 million of proceeds from the sale of Series 2002A tax-exempt SPRB, cash flows from operating activities and short-term borrowings are expected to provide the cash needed for the net capital expenditures in 2005.

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 kilowatthour 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 demand-side management 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.

Bank

December 31	**2004**	**% change**	**2003**	**% change**
(in millions)				
Assets	$ 6,767	4	$ 6,515	3
Available-for-sale investment and mortgage-related securities	2,953	9	2,717	(1)
Held-to-maturity investment securities	97	3	95	6
Loans receivable, net	3,249	4	3,122	4
Deposit liabilities	4,296	7	4,026	6
Securities sold under agreements to repurchase	811	(2)	831	25
Advances from FHLB	988	(3)	1,017	(14)

As of December 31, 2004, ASB was the third largest financial institution in Hawaii based on assets of $6.8 billion and deposits of $4.3 billion.

ASB s principal sources of liquidity are customer deposits, borrowings, the sale of mortgage loans into secondary market channels and the maturity and repayment of portfolio loans and securities. ASB s deposits increased by $270 million during 2004. ASB s principal sources of borrowings are advances from the FHLB and securities sold under agreements to repurchase from broker/dealers. At December 31, 2004, 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. At December 31, 2004, ASB s unused FHLB borrowing capacity was approximately $1.4 billion. At December 31, 2004, securities sold under agreements to repurchase totaled $0.8 billion, representing 12% of assets. ASB utilizes growth in 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 make investments. At December 31, 2004, ASB had commitments to borrowers for loan commitments, undisbursed loan funds and unused lines and letters of credit of $0.9 billion. Management believes ASB s current sources of funds will enable it to meet these obligations while maintaining liquidity at satisfactory levels.

In September 2003, ASB entered into an arrangement to have excess funds in its correspondent bank account with Bank of America swept into a Federal Funds Sold facility. Funds earn the overnight fed funds rate and are re-deposited into ASB s correspondent bank account the next day. This automatic sweep facility offers ASB an

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operationally efficient method for investing its liquidity and provides a slightly higher rate of return than methods used in the past (deposits with the FHLB). In addition, efficiencies gained using this method have enabled ASB to expand its wire transfer operating hours.

At December 31, 2004, ASB had $6.4 million of loans on nonaccrual status, or 0.2% of net loans outstanding, compared to $5.4 million, or 0.2%, at December 31, 2003. At December 31, 2004 and 2003, ASB s real estate acquired in settlement of loans was $0.9 million and $7.9 million, respectively.

In 2004, net cash of $382 million was used in investing activities largely for the purchase of mortgage-related and investment securities and the origination of loans, net of repayments and proceeds from sales of securities. Financing activities provided net cash of $196 million due to net increases in deposits, partly offset by net decreases in advances from the FHLB and securities sold under agreements to repurchase and the payment of common and preferred stock dividends. Operating activities provided cash of $81 million.

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, 2004, ASB was well-capitalized.

Off-balance sheet arrangements

The Company 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 registrant 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 registrant in an unconsolidated entity that provides financing, liquidity, market risk or credit risk support to the registrant, or engages in leasing, hedging or research and development services with the registrant.

Certain factors that may affect future results and financial condition

The Company s results of operations and financial condition can be affected by numerous factors, many of which are beyond its control and could cause future results of operations to differ materially from historical results. The following is a discussion of certain of these factors.

Consolidated

Economic conditions. Because its core businesses are providing local electric utility and banking services, HEI s operating results are significantly 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.

Competition. The electric utility and banking industries are competitive and the Company s success in meeting competition will continue to have a direct impact on the Company s financial performance.

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

In 1996, the PUC issued an order instituting a proceeding to identify and examine the issues surrounding electric competition and to determine the impact of competition on the electric utility infrastructure in Hawaii. In October 2003, the PUC closed the competition proceeding and opened investigative dockets on two specific issues

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(competitive bidding and distributed generation (DG)) to move toward a more competitive electric industry environment under cost-based regulation.

Competitive bidding proceeding. The stated purpose of the competitive bidding proceeding is to evaluate competitive bidding as a mechanism for acquiring or building new generating capacity in Hawaii. The PUC stated it would consider related filings on a case-by-case basis pending completion of the competitive bidding and DG dockets.

The current parties/participants in the competitive bidding proceeding include the Consumer Advocate, HECO, HELCO, MECO, Kauai Island Utility Cooperative, the Gas Company, the Counties of Maui and Kauai, a renewable energy organization and vendors of DG equipment and services. In April 2004, the parties and participants entered into and filed a proposed stipulated prehearing order, and the PUC adopted the issues and procedures proposed for consideration in the stipulated order and the proposed schedule with modifications. The issues to be addressed in the proceeding include the benefits and impacts of competitive bidding, whether a competitive bidding system should be developed for acquiring or building new generation, and revisions that should be made to integrated resource planning. If competitive bidding is adopted, the proceeding will address specific bidding guidelines and requirements that encourage broad participation but do not place ratepayers at undue risk. The procedural schedule has been modified and includes statements of position by all parties in March 2005 and evidentiary hearings in a panel format in October 2005. Management cannot predict the ultimate outcome of this proceeding or its effect on the ability of the electric utilities to acquire or build additional generating capacity in the future.

Distributed generation proceeding. Historically, HECO and its subsidiaries have been able to compete by offering customers economic alternatives that, among other things, employ energy efficient electrotechnologies such as the heat pump water heater. However, the number of customer self-generation projects that are being proposed or installed in Hawaii, particularly those involving combined heat and power (CHP) systems, is growing. CHP systems are a form of DG, and produce electricity and thermal energy from gas, propane or diesel-fired engines. In Hawaii, the thermal energy generally is used to heat water and, through an absorption chiller, drive an air conditioning system. The electric energy generated by these systems is usually lower in output than the customer s load, which results in continued connection to the utility grid to make up the difference in electricity demand and to provide back up electricity.

The electric utilities initiated a small CHP demonstration project on Maui in 2002 as part of an on-going evaluation of DG. The electric utilities also have made proposals to customers, subject to PUC review and approval, to install and operate utility-owned CHP systems at the customers sites. The electric utilities have executed a number of letters of intent and one memorandum of understanding to conduct preliminary engineering for potential CHP projects. The electric utilities also signed agreements in 2004 with two customers to install, operate and maintain utility-owned CHP systems, subject to PUC review and approval. Incremental generation from such customer-sited CHP systems, and other DG, is expected to complement traditional central station power, as part of the electric utilities plans to serve their forecast load growth.

In July 2003, three vendors of DG/CHP equipment and services proposed, in an informal complaint to the PUC, that the PUC open a proceeding to investigate the electric utilities provision of CHP services and their teaming agreement with another vendor, and to issue rules or orders to govern the terms and conditions under which the electric utilities will be permitted to engage in utility-owned DG at individual customers sites. In August 2003, the electric utilities responded to the informal complaint, and to information requests from the PUC on the CHP demonstration project and a teaming agreement.

In October 2003, the PUC opened an investigative docket to determine the potential benefits and impact of DG on Hawaii s electric distribution systems and markets and to develop policies and a framework for DG projects deployed in Hawaii. The parties and participants to the proceeding include the Consumer Advocate, HECO, HELCO, MECO, Kauai Island Utility Cooperative, the Counties of Maui and Kauai, a renewable energy organization, a vendor of DG equipment and services and an environmental organization. In April 2004, the PUC issued an order in the proceeding, based in large part on a stipulated order proposed by the parties and participants that includes planning, impact and implementation issues. The planning issues address (1) forms of DG (e.g., renewable energy facilities, hybrid renewable energy systems, generation, cogeneration) that may be feasible and viable for Hawaii, (2) who should own and operate DG projects, and (3) the role of regulated electric utility companies and the PUC in the deployment of DG in Hawaii. The impact issues address (1) the impacts, if any, DG will have on Hawaii s electric transmission and distribution systems and market, (2) the impacts of DG on power quality and reliability, (3) utility costs that can be avoided by DG, (4) external impact costs and benefits of DG, and (5) the potential for DG to reduce the use of fossil fuels. Implementation issues include (1) matters to be considered to allow a DG facility to interconnect with the electric utility s grid, (2) appropriate rate design and cost allocation issues that must be considered with the deployment of DG facilities, (3) revisions that should be made to the integrated resource planning process, and (4) revisions that should be made to PUC rules and utility rules and practices to facilitate the successful deployment of DG. The parties and participants can also address issues raised in the informal complaint, but not specific claims made against any of the parties named in the complaint. Hearings were held in December 2004.

As a result of the docket on DG, the electric utilities cancelled its 2003 teaming agreement for CHP systems with ratings up to 1 MW, and issued a request for qualifications as part of a new equipment procurement process for all CHP systems. Management cannot predict the ultimate outcome of this proceeding.

In October 2003, the electric utilities filed an application for approval of a CHP tariff, under which they would provide CHP services to eligible commercial customers. Under the tariff, the electric utilities would own, operate and maintain customer-sited, packaged CHP systems (and certain ancillary equipment) pursuant to a standard form of contract with the customer. In March 2004, the PUC issued an order in which it suspended the CHP tariff application until, at a minimum, the matters in the investigative docket on DG have been addressed. Pending approval of a CHP tariff, the electric utilities requested approval of its two 2004 agreements for CHP projects. In January 2005, the PUC issued an order suspending the applications for approval of the projects until, at a minimum, the matters in the investigative DG docket have been adequately addressed, which is expected to occur in the second quarter of 2005. One of the agreements was subsequently terminated and the application for approval of the project was withdrawn.

Bank. The banking industry in Hawaii is highly competitive. ASB is the third largest financial institution in Hawaii, based on 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 has been expanding its traditional consumer focus to be a full-service community bank and has been diversifying its loan portfolio from single-family home mortgages to higher-yielding, shorter-duration consumer, business and commercial real estate loans. The origination of consumer, business 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, business and commercial real estate loans.

In recent years, there has been significant bank and thrift merger activity affecting Hawaii, including the merger in 2004 of the holding companies for the state s 4th and 5th largest financial institutions (based on assets). Management cannot predict the impact, if any, of these mergers on the Company s future competitive position, results of operations or financial condition.

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U.S. capital markets and interest rate environment. Changes in the U.S. capital markets can have significant effects on the Company. For example:

The Company estimates that consolidated retirement benefits expense, net of amounts capitalized and income taxes, will be $11 million in 2005 as compared to $7 million in 2004, partly as a result of the impact of lower interest rates on the discount rate used to determine retirement benefit liabilities.

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, 2004, the fair value and carrying value of the investment and mortgage-related securities held by ASB were $3.1 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. Federal government monetary policies and low interest rates have resulted in high mortgage refinancing volume in 2003 and 2004 as well as accelerated prepayments of loans and securities. ASB s interest rate spread, the difference between the yield on interest-earning assets and the cost of funds, has been experiencing compression since the fourth quarter of 2002 as the yields on assets declined more rapidly than the cost of funds. The Federal Reserve began increasing rates in 2004, causing the cost of funds to rise while yields on mortgage assets remained low. As of December 31, 2004, the Company had no floating-rate long-term debt outstanding. As of December 31, 2004, HECO had issued $77 million of commercial paper with a weighted-average interest rate of 2.5% and maturities ranging from 13 to 33 days. See Quantitative and Qualitative Disclosures about Market Risk.

Technological developments. New technological developments (e.g., the commercial development of fuel cells or distributed generation or significant advances in internet banking) may impact the Company s future competitive position, results of operations and financial condition.

Discontinued operations and asset dispositions. The Company discontinued its international power operations in 2001. See Note 14 of the Notes to Consolidated Financial Statements. Problems may be encountered or liabilities may arise in the exit from these operations. For example, in accounting for the discontinuance of operations under accounting standards at the time of discontinuation, estimates were made by management concerning the income tax benefits to be realized upon the disposition of those operations and concerning the costs and liabilities that would be incurred in connection with the discontinuation. Management made these estimates based on the information available, but the amounts finally realized on disposition of the discontinued operations, and the amount of the liabilities and costs ultimately incurred in connection with those operations, may differ materially from the recorded amounts. At December 31, 2004, the net assets of the discontinued international power operations amounted to $10 million, consisting primarily of tax benefits receivable, partly offset by a reserve for future expenses.

In addition, in connection with prior dispositions of operations, additional unrecorded liabilities may arise if claims are asserted under indemnities provided in connection with the dispositions.

It is also possible that the Company may recover amounts relating to claims arising in connection with discontinued operations. For example, HEIPC and its subsidiaries are continuing to pursue recovery of a significant portion of its losses related to a joint venture interest in a China project through arbitration of its claims under a political risk insurance policy. Pursuit of such recoveries, however, may be costly and there can be no assurance that the pursuit of any claims will be successful or that any amounts will be recovered.

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 example, the electric utilities overhead and underground transmission and distribution systems (with the exception of substation buildings and contents) have a replacement value roughly estimated at $3 billion and are uninsured because the amount of transmission and distribution system insurance available is limited and the premiums are cost prohibitive. Similarly, the electric utilities have no business interruption insurance as the premiums for such insurance would be cost prohibitive, particularly since the utilities are not interconnected to other systems. ASB also has no insurance coverage for business interruption nor credit card fraud. If a hurricane or other uninsured catastrophic natural disaster should occur, and the PUC does not allow the Company to recover from ratepayers restoration costs and revenues lost from business interruption, the Company s results of operations and financial condition could be materially adversely impacted. Also, 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 losses in amounts that would have a material adverse effect on its 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, require that certain environmental permits be obtained as a condition to constructing or operating certain facilities, and 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. 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.

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 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. If the Clear Skies Bill is adopted as currently proposed, HECO, and to a lesser extent, HELCO and MECO will likely incur significant capital and operations and maintenance costs beginning one to two years after enactment. In addition, HECO boilers may be affected by the air toxics provisions (Title III) of the CAA when the Maximum Allowable Control Technology (MACT) emission standards are established for those units. HECO believes that, if adopted as currently proposed, the recent EPA proposal to regulate nickel emissions from oil-fired boilers may result in significant capital investments and operations and maintenance costs for HECO s steam generating units within the three-year period after adoption. The EPA has announced that the final rule will be promulgated by March 2005, although it is unclear at this time whether the nickel control requirements will remain in the final rule. HECO has not yet budgeted for such costs in its five-year capital expenditures forecast.

The utility industry is also subject to the federal Clean Water Act. Section 316(b) of the 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 new rule, which the EPA estimates affects approximately 550 facilities across the nation. The rule establishes location, design, construction and capacity standards for existing cooling water intake structures that apply to HECO s Kahe, Waiau and Honolulu generating stations. Strong technology-based performance standards apply unless a facility shows that these standards will result in very high costs or little environmental benefit at the facility site. HECO has until March 2008 to demonstrate compliance. HECO has retained a consultant to develop a cost effective compliance strategy and a preliminary assessment of technologies and operational measures. Although HECO believes that it will be able to cost effectively achieve compliance, if studies show that it cannot develop and implement a compliance strategy short of reconstruction of the affected cooling water intake structures, the capital costs would be significant. HECO has not yet budgeted for such costs in its five-year capital expenditures forecast.

HECO and its subsidiaries, like other utilities, periodically identify leaking petroleum-containing equipment such as underground storage tanks, piping and transformers. The electric utilities report releases from such equipment when and as required by applicable law and address impacts due to the releases in compliance with applicable regulatory requirements.

The Honolulu Harbor environmental investigation, described in Note 3 of the Notes to Consolidated Financial Statements, is an ongoing environmental investigation. Although this investigation is expected to entail significant expense over the next several years, management does not believe, based on information available to the Company at this time, that the costs of this investigation or any other contingent liabilities relating to environmental matters will have a material adverse effect on the Company. However, there can be no assurance that a significant

environmental liability will not be incurred by the electric utilities, including with respect to the Honolulu Harbor environmental investigation.

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.

Electric utility

Regulation of electric utility rates. The PUC has broad discretion in its regulation of the rates charged by HEI s electric utilities and in other matters. Any adverse D&O by the PUC concerning the level or method of determining electric utility rates, the authorized returns on equity or other matters, or any prolonged delay in rendering a D&O in a rate or other proceeding, could have a material adverse effect on the Company s results of operations and financial condition. 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, 2004, HECO and its subsidiaries had recognized $17.4 million of revenues (including interest and revenue taxes) with respect to interim orders regarding certain integrated resource planning costs, which revenues are subject to refund, with interest, 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 $11.0 million of incremental integrated resource planning costs incurred during 1995 through 2003, and the PUC s decision is pending on this matter. In addition, HECO and MECO incurred approximately $0.9 million of incremental integrated resource planning costs for 2004, as to which the Consumer Advocate has not yet stated its position.

Management cannot predict with certainty when D&Os in future rate cases will be rendered or the amount of any interim or final rate increase that may be granted.

The rate schedules of the electric utilities include energy cost adjustment clauses 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. In 1997 PUC decisions approving the electric utilities fuel supply contracts, the PUC noted that, in light of the length of the fuel supply contracts and the relative stability of fuel prices, the need for continued use of energy cost adjustment clauses would be the subject of investigation in a generic docket or in a future rate case. These clauses were continued in the most recent HELCO and MECO rate cases (final D&O s issued in February 2001 and April 1999, respectively). The electric utilities reached agreement with their suppliers on amendments to their existing fuel supply contracts that extend the contracts through December 2014 on substantially the same terms and conditions, including market-related pricing. In December 2004, the PUC approved the amendments to the fuel supply contracts. In approving the amendments, the PUC indicated questions still remain concerning the energy cost adjustment clauses and their continued use to recover fuel contract costs, and indicated that, consistent with its prior decisions, it plans to examine the continued use of the energy cost adjustment clauses to recover the various costs incurred pursuant to the amended fuel contracts in HECO s pending rate case, and in HELCO s and MECO s next respective rate cases. Until such time, the electric utilities will continue to recover their fuel contract costs through their respective energy cost adjustment clauses to the extent the costs are not recovered in their base rates. If the energy cost adjustment clauses were discontinued, the electric utilities results of operations could fluctuate significantly as a result of increases and decreases in fuel oil and purchased energy prices.

Consultants periodically conduct depreciation studies for the electric utilities to determine whether the existing approved rates and methods used to calculate depreciation accruals are appropriate for the production, transmission, distribution and general plant accounts. If it is determined that the existing rates and methods are no longer appropriate, changes to those rates are recommended as part of the study. In October 2002, HECO filed an application with the PUC for approval to change its depreciation rates and to change to vintage amortization accounting for selected plant accounts. See Most recent rate requests above.

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In May 2004, the PUC issued a D&O authorizing an increase from $0.5 million to $2.5 million, effective July 1, 2004, in the threshold for capital improvement projects requiring advance PUC review. This increase generally reflects the cumulative effects of inflation since the review requirement was originally established in 1965.

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 the Notes to Consolidated Financial Statements. The Company estimates that 79% of the net energy generated and purchased by HECO and its subsidiaries in 2005 will be generated from the burning of oil. Purchased KWHs provided approximately 38.2% of the total net energy generated and purchased in 2004 compared to 39.2% in 2003 and 38.0% in 2002.

Failure by the electric utilities oil suppliers to provide fuel pursuant to existing supply contracts, or failure by a major independent power producer to deliver the firm capacity anticipated in its power purchase agreement, 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 s policy, however, is to maintain an inventory of fuel oil equivalent to a 35 day supply. HELCO s and MECO s policies are to maintain approximately a one month s supply of both medium sulfur fuel oil and diesel fuel. The electric utilities major sources of oil, through their suppliers, are in Alaska, Indonesia and the Far East. Some, but not all, of the electric utilities power purchase agreements require that the IPPs maintain minimum fuel inventory levels and all of the firm capacity power purchase agreements 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 7%, 11% and 6% for 2004, 2003 and 2002, respectively, when compared to the prior year. This trend of increased operation and maintenance expenses is expected to continue in 2005 as the electric utilities anticipate: (1) higher demand-side management and integrated resource planning expenses (that are passed on to customers through a surcharge and therefore do not impact net income), (2) higher employee benefits expenses, primarily for retirement benefits, (3) higher production expenses, primarily to meet higher demand and load growth, and (4) higher expenses for new technologies, including broadband over power lines and renewable power sources. 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 the equipment and expenses for technologies may change as emerging technologies prove or disprove themselves. In October 2004, one of HECO s two combustion turbines (CTs) on Oahu experienced a sudden and accidental breakage of a blade that subsequently caused a catastrophic failure of the entire turbine. Greater customer demand resulting in higher usage of the CT contributed to the failure. While partially covered by insurance, the repair costs are significant additional expenses necessary for service reliability. HECO plans to complete this overhaul during the first half of 2005. HECO will then begin preventive overhaul work on its other CT, which has been also used to meet increased customer demand for extended periods. Although it will not be known until the overhaul is fully underway, it is possible that the maintenance costs for this unit will be higher than originally planned. Increased other operation and maintenance expenses is one of the reasons HECO filed a request with the PUC in November 2004 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, have encountered opposition and the Keahole project has been seriously delayed (although full-time operation of CT-4 and CT-5 at Keahole is now expected in the second quarter of 2005). See Note 3 of the Notes to Consolidated Financial Statements.

Bank

Regulation of ASB. ASB is subject to examination and comprehensive regulation by the OTS and the FDIC, and is subject to reserve requirements established by the Board of Governors of the Federal Reserve System. By reason of the regulation of its subsidiary, ASB Realty Corporation, ASB is also subject to regulation by the Hawaii Commissioner of Financial Institutions. 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.

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, 2004, 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) at December 31, 2004 with a tangible capital ratio of 7.1% (1.5%), a core capital ratio of 7.1% (4.0%) and a total risk-based capital ratio of 15.6% (8.0%).

ASB met the capital requirements to be generally considered well-capitalized (noted in parentheses) at December 31, 2004 with a leverage ratio of 7.1% (5.0%), a Tier-1 risk-based capital ratio of 14.6% (6.0%) and a total risk-based capital ratio of 15.6% (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 its shareholders 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 could be required to contribute to ASB up to an additional $28 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.

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 and offering pass-through insurance coverage (i.e., insurance coverage

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that passes through to each owner/beneficiary of the applicable deposit) for the deposits of most employee benefit plans (i.e., $100,000 per individual participant, not $100,000 per plan). As of December 31, 2004, 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, and a failure or inability to comply with those restrictions could effectively result in the required divestiture of ASB. As of December 31, 2004, approximately 89% of its assets were qualified thrift investments.

Federal Thrift Charter. In November 1999, Congress passed the Gramm-Leach-Bliley Act of 1998 (the Gramm Act), under which banks, insurance companies and investment firms can compete directly against each other, thereby allowing one-stop shopping for an array of financial services. Although the Gramm Act further restricts 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

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 in the case of the Company include the amounts reported for investment securities; property, plant and equipment; pension and other postretirement benefit obligations; contingencies and litigation; income taxes; regulatory assets and liabilities; electric utility revenues; VIEs; allowance for loan losses; and reserves for discontinued operations. Management considers an accounting estimate to be material if it requires assumption/s to be made that were uncertain at the time the estimate was made and changes in the assumption/s selected could have a material impact on the estimate and on the Company s results of operations or financial condition. For example, in 2004, a significant change in estimated income taxes occurred as a result of a Tax Appeal Court decision (see ASB state franchise tax dispute and settlement in Note 10 of the Notes to Consolidated Financial Statements).

In accordance with SEC Release No. 33-8040, Cautionary Advice Regarding Disclosure About Critical Accounting Policies, management has identified the following 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. Management has reviewed the material estimates and critical accounting policies with the HEI Audit Committee.

For additional discussion of the Company s accounting policies, see Note 1 of the Notes to Consolidated Financial Statements.

Consolidated

Investment 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 losses excluded from earnings and reported in a separate component of stockholders equity.

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

ASB owns one investment security, private-issue mortgage-related securities and mortgage-related securities issued by the Federal Home Loan Mortgage Corporation (FHLMC), Government National Mortgage Association (GNMA) and Federal National Mortgage Association (FNMA), all of which are classified as available-for-sale. Market prices for the investment security and mortgage-related securities issued by FHLMC, GNMA, and FNMA are available from most third party securities pricing services and ASB obtains market prices for these securities from a third party financial services provider. Market prices for the private-issue mortgage-related securities are not readily available from standard pricing services, so prices are obtained from dealers who are specialists in those markets. The prices of these securities may be influenced by factors such as market liquidity, corporate credit considerations of the underlying collateral, 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. At December 31, 2004, ASB had mortgage-related securities issued by FHLMC, GNMA and FNMA valued at $2.5 billion and private-issue mortgage-related securities valued at $0.4 billion.

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.

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 the Notes to Consolidated Financial Statements concerning costs recorded for CT-4 and CT-5 at Keahole and the East Oahu Transmission Project.

Pension and other postretirement benefits obligations. Pension and other postretirement benefit (collectively, retirement benefits) costs/(returns) are charged/(credited) primarily to expense and electric utility plant.

The Company s reported costs of providing retirement benefits (described in Note 8 of the Notes to Consolidated Financial Statements) are dependent upon numerous factors resulting from actual plan experience and assumptions of 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 and earnings on plan assets. Changes made to the provisions of the plans may also impact current and future costs. (No changes were made to the retirement benefit plans provisions in 2004, 2003 and 2002 that have had a significant impact on recorded retirement benefit plan amounts.) Costs may also be significantly affected by changes in key actuarial assumptions, including the expected return on plan assets and the discount rate used.

As a result of the factors listed above, significant portions of retirement benefits costs recorded in any period do not reflect the actual benefits provided to plan participants. For 2004 and 2003, the Company recorded other postretirement benefit expense, net of amounts capitalized, of approximately $6 million and $7 million, respectively, in accordance with the provisions of SFAS No. 106, Employers Accounting for

Postretirement Benefits Other Than Pensions. Actual payments of such benefits and plan expenses made during 2004 and 2003 were $8 million and $7 million, respectively. In accordance with SFAS No. 87, Employers Accounting for Pensions, changes in pension obligations associated with the factors noted above may not be immediately recognized as pension costs on the income statement, but generally are recognized in future years over the remaining average service period of plan participants. For 2004 and 2003, the Company recorded pension expense, net of amounts capitalized, of approximately $5 million and $13 million, respectively, and paid pension benefits and plan expenses of $41 million and $38 million, respectively.

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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. In selecting an assumed discount rate, the Company benchmarks its discount rate assumption to the Moody s Daily Long-Term Corporate Bond Aa Yield Average (which was 5.66% at December 31, 2004 compared to 6.01% at December 31, 2003) and changes in this rate from period to period. In selecting an assumed rate of return on plan assets, the Company considers economic forecasts for the types of investments held by the plans, the plans asset allocations and the past performance of the plans assets.

As presented in Note 8 of the Notes to Consolidated Financial Statements, the Company has revised its discount rate as of December 31, 2004 compared to December 31, 2003. The change did not have an impact on reported costs in 2004; however, for future years, this change will have a significant impact. Based upon the revised discount rate (decreased 25 basis points to 6.00%) and the plans assets as of December 31, 2004, the Company estimates that retirement benefits expense, net of amounts capitalized and income taxes, will be $11 million in 2005 as compared to $7 million in 2004. Of the $11 million of net retirement benefits expense, it is projected that HECO and its subsidiaries will record an estimated $8 million in 2005 as compared to $4 million in 2004. In determining the retirement benefits costs, assumptions can change from period to period, and such changes could result in material changes to these estimated amounts.

The Company s plan assets are primarily made up of equity and fixed income investments. Fluctuations in actual equity market returns as well as changes in general interest rates may result in increased or decreased retirement benefits costs and contributions in future periods.

The following tables reflect the sensitivities of the projected benefit obligation (PBO) and accumulated postretirement benefit obligation (APBO) as of December 31, 2004, and the sensitivity of 2005 net income, associated with a change in certain actuarial assumptions by the indicated basis points and constitute forward-looking statements. Each sensitivity below reflects an evaluation of the change based solely on a change in that assumption as well as a related change in the contributions to the applicable retirement benefits plan.

Actuarial assumption	Change in assumption in basis points	Impact on PBO/APBO	Impact on 2005 net income
($ in millions)			
Pension benefits			
Discount rate	50	$ (58.5)	$ 3.0
	(50)	65.4	(3.3)
Rate of return on plan assets	50	NA	1.8
	(50)	NA	(1.8)
Other benefits [1]			
Discount rate	50	(11.6)	0.5
	(50)	12.8	(0.6)
Health care cost trend rate	100	7.3	(0.6)
	(100)	(7.3)	0.6
Rate of return on plan assets	50	NA	0.3
	(50)	NA	(0.3)

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

NA Not applicable.

Baseline assumptions: 6% discount rate; 9% asset return rate; 10% medical trend rate for 2005, grading down to 5% for 2010 and thereafter; 5% dental trend rate; and 4% vision trend rate.

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. A determination of the amount of reserves required, if any, for these contingencies is based on a careful analysis of each individual issue 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 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. See Environmental regulation in Note 3 of the 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 periodically evaluates its potential exposures from tax positions taken that have or could be challenged by taxing authorities. These potential exposures result because taxing authorities may take positions that differ from those taken by management in the interpretation and application of statutes, regulations and rules. Management considers the possibility of alternative outcomes based upon past experience, previous actions by taxing authorities (e.g., actions taken in other jurisdictions) and advice from 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.

Reserves for discontinued operations. See Discontinued operations and asset dispositions above.

Electric utility

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 they are probable of future recovery in customer rates. As of December 31, 2004 and 2003, regulatory liabilities, net of regulatory assets, amounted to $88 million and $72 million, respectively. Regulatory assets and regulatory liabilities are itemized in Note 3 of the 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 the regulatory assets as of December 31, 2004 are probable of recovery. 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 liabilities, net of regulatory assets, would be credited to income. 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.

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 customers. At December 31, 2004, revenues applicable to energy consumed, but not yet billed to customers, amounted to $79 million.

Revenue amounts recorded pursuant to a PUC interim order are subject to refund, with interest, pending a final order. Also, the rate schedules of the electric utilities include energy cost adjustment clauses under which electric

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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 Financial Accounting Standards Board (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 is evaluating the impact of applying FIN 46R to its relationships with IPPs with whom the electric utilities execute new power purchase agreements or execute amendments of existing power purchase agreements. 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 consolidation of IPPs could also have a material effect on HECO s credit ratings, and the electric utilities do not know how the consolidation of IPPs would be treated for regulatory purposes.

Bank

Allowance for loan losses. See Note 1 of the Notes to Consolidated Financial Statements. At December 31, 2004, ASB s allowance for loan losses was $33.9 million and ASB had $6.4 million of loans on nonaccrual status. In 2004, ASB s reversal of provision for loan losses was $8.4 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).

HECO:

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

HECO incorporates by reference all of the foregoing electric utility sections and all information related to HECO and its subsidiaries in HEI s MD&A, except for the Selected contractual obligations and commitments table below.

Selected contractual obligations and commitments

The following table presents HECO and subsidiaries-aggregated information about total payments due during the indicated periods under the specified contractual obligations and commercial commitments:

December 31, 2004	Payment due by period				
(in millions)	Less than	1-3 years	3-5 years	More than	Total

	1 year			5 years	
Long-term debt, net	$	$	$	$ 753	$ 753
Operating leases	2	3	2	4	11
Fuel oil purchase obligations (estimate based on January 1, 2005 fuel oil prices)	361	722	722	1,804	3,609
Purchase power obligations minimum fixed capacity charges	118	236	229	1,378	1,961
Total (estimated)	$ 481	$ 961	$ 953	$ 3,939	$ 6,334

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ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

HEI:

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 other segments exposures to these risks are not material as of December 31, 2004.

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 the lending portfolios is controlled through ASB s underwriting standards, loan rating of business and commercial real estate loans, on-going monitoring by loan officers, credit review and quality control functions in the 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 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 its fuel supply and IPP contracts. The Company s commodity price risk is mitigated by the electric utilities energy cost adjustment clauses in their rate schedules. The Company currently has no hedges against its commodity price risk. Because the Company does not have a portfolio of trading assets, the Company is not exposed to market risk from trading activities. The Company s current exposure to foreign currency exchange rate risk is not material.

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

The Company s success is dependent, in part, upon ASB s ability to manage interest rate risk. For ASB, interest-rate risk is the change in net interest income (NII) and change in market value of interest-sensitive assets and liabilities resulting from changes in interest rates. The primary source of interest-rate risk is the mismatch in timing between the maturity or repricing of interest-sensitive assets and liabilities. Large mismatches 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.

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.

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. The fixed-rate residential mortgage loans originated and retained by ASB are characterized by fixed interest rates and long average lives, but also have the potential to prepay at any time without penalty. The option to prepay is usually exercised by borrowers in low interest rate environments, significantly shortening the average lives of these assets. The majority of ASB s liabilities consist of retail deposits. The interest rates paid on many of the retail deposit accounts can be adjusted in response to changes in market interest rates. Other retail deposit accounts with fixed interest rates typically have stated maturities much shorter than that of a 30-year mortgage. As a result, these liabilities will tend to reprice more frequently than the fixed-rate mortgage assets.

The typical result of this combination of assets and liabilities is to create a liability sensitive interest rate risk profile. In a rising interest-rate environment, the average rate on ASB s liabilities will tend to increase faster than the average rate on the assets, causing a reduction in interest rate spread and NII. In a falling interest-rate environment, the opposite happens: the average rate on ASB s liabilities will tend to decrease faster than the

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average rate on ASB s assets, causing an increase in interest rate spread and NII. This volatility in interest rate spread and NII represents one measure of interest rate risk. The degree of volatility is dependent on the magnitude of the mismatch in the amount and timing of maturing or repricing interest-sensitive assets and interest-sensitive liabilities.

Since ASB s primary business of making fixed-rate residential real estate loans and taking in retail deposits does not always result in the optimum mix of assets and liabilities for the management of NII and interest rate risk, other tools must be employed to manage interest rate risk. Chief among these is use of the investment portfolio to secure asset types that may not be available in significant amounts through loan originations, such as adjustable-rate mortgage-related securities, floating LIBOR-based securities, balloon or 15-year mortgage-related securities, and short average life collateralized mortgage obligations (CMOs). On the liability side, a shortage of retail deposits in desired maturities would typically be addressed through FHLB advances and other borrowings to meet asset/liability management needs.

Use of investments, FHLB advances and securities sold under agreements to repurchase, while efficient in managing interest rate risk, are not as profitable as ASB s own lending and deposit taking activities. In this regard, ASB continues to build its portfolio of consumer, business and commercial real estate loans, which generally earn higher rates of interest and have maturities shorter than residential real estate loans. However, the origination of consumer, business and commercial real estate loans involves risks and other considerations different from those associated with originating residential real estate loans. For example, credit risk associated with consumer, business and commercial real estate loans is generally higher than for mortgage loans, the sources and level of competition for such loans differ from residential real estate lending and the making of business and commercial real estate loans is a relatively new business for ASB. These different risk factors are considered in the underwriting and pricing standards established by ASB for its consumer, business and commercial real estate loans.

See Note 4 of the 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 measures interest-rate risk using simulation analysis with an emphasis on measuring changes in 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 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.

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 alternative 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 immediate and sustained parallel shocks of the yield curve 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 and the pricing characteristics of new assets and liabilities.

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. 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, future pricing spreads for assets and liabilities 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, 2004 and 2003 constitute forward-looking statements and were as follows:

December 31	**2004**			**2003**		
	Change in NII	**NPV ratio**	**NPV ratio sensitivity (change from base case in basis points)**	**Change in NII**	**NPV ratio**	**NPV ratio sensitivity (change from base case in basis points)**
Change in interest rates (basis points)						
+300	(7.7)%	7.28%	(367)	(5.8)%	6.30%	(345)
+200	(5.0)	8.69	(226)	(3.2)	7.63	(212)
+100	(2.0)	9.99	(96)	(0.9)	8.82	(93)
Base		10.95			9.75	
-100	(3.9)	11.22	27	(4.3)	10.24	49

Management believes that ASB s interest rate risk position at December 31, 2004 represents a reasonable level of risk. The December 31, 2004 NII profile shows the balance sheet to be liability-sensitive in all rising interest rate scenarios. In rising interest rate environments, the overall rate on liabilities is expected to increase faster than the overall rate on assets. The expectation of slower prepayment speeds as interest rates rise, reduces the runoff of the existing mortgage assets, which reduces the amount available for reinvestment at the higher market rates. This constrains the speed with which the yield on the mortgage assets can adjust upwards to market levels. At the same time, the cost of the liabilities is projected to increase with each increase in the level of rates. As a result, NII falls in each of the rising rate scenarios. The analysis shows ASB s NII profile as of December 31, 2004 to be slightly more sensitive to rising interest rates than in the December 31, 2003 analysis. The change in the NII profile from December 31, 2003 to December 31, 2004 is primarily due to the changes in prepayment expectations. Because of slower prepayment expectations in the base case scenario as of December 31, 2004, the improvement in interest income in rising rate scenarios is less than it was in the December 31, 2003 analysis. As a result, the decrease in NII is greater in the rising rate scenarios as of December 31, 2004 as compared to December 31, 2003.

In the 100 basis point scenario, NII falls relative to the base case because expectations of faster mortgage prepayments and lower reinvestment rates cause the yield on mortgage assets to decline faster than in the base case. Additionally, the cost of liabilities does not fall as much 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. In this analysis, one of the modeling assumptions which impacts the magnitude of the change in NII in response to both rising and falling interest rates is the assumption about the speed and magnitude with which the rate on ASB s core deposits change in response to changes in the overall level of interest rates.

ASB s base NPV ratio as of December 31, 2004 was higher than on December 31, 2003, primarily as a result of changes in the composition of the bank s liabilities. During 2004, the growth in assets was funded primarily by core deposits. Since core deposits are the lowest cost funding source available to the bank, the use of core deposits as a funding source for growth will have a positive impact on the bank s NPV ratio.

ASB s NPV ratio sensitivity measures as of December 31, 2004 were comparable to the measures as of December 31, 2003.

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

Other than bank

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 (primarily fixed-rate debt) and preferred securities. As of December 31, 2004, 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 sections Pension and other postretirement benefits and Pension and other postretirement benefit obligations in Management s discussion and analysis of financial condition and results of operations and Note 8 of the Notes to Consolidated Financial Statements) and the possible effect of interest rates on the electric utilities allowed rates of return (see 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 at December 31, 2004 of $77 million and a hypothetical 10% increase/decrease in interest rates, annual interest expense would have increased/decreased on that commercial paper by $0.2 million.

HECO:

HECO and its subsidiaries general policy is to manage interest rate risk through use of a combination of short-term debt, long-term debt (primarily fixed-rate debt) and preferred securities. As of December 31, 2004, management believes HECO and its subsidiaries are exposed to interest rate risk because of the periodic borrowing requirements, impact of the interest rates on the discount rate used to determine retirement benefits expenses and obligations (see sections Pension and other postretirement benefits and Pension and other postretirement benefit obligations in Management s discussion and analysis of financial condition and results of operations and Note 10 in HECO s Notes to consolidated financial statements) and the possible effect of interest rates on the electric utilities allowed rates of return (see Regulation of electric utility rates in HEI s MD&A). Other than these exposures, management believes its exposure to interest rate risk is not material. Based upon short-term borrowings outstanding at December 31, 2004 of $89 million and a hypothetical 10% increase/decrease in interest rates, annual interest expense would have increased/decreased on those short-term borrowings by $0.2 million.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

HEI (pages 94 to 143):

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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, 2004 and 2003, 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, 2004. 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, 2004 and 2003, and the results of their operations and their cash flows for each of the years in the three-year period ended December 31, 2004, in conformity with U.S. generally accepted accounting principles.

As discussed in notes 1 and 7 to consolidated financial statements, effective January 1, 2004, the Company adopted Financial Accounting Standards Board Interpretation No. 46(R), *Consolidation of Variable Interest Entities*.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of Hawaiian Electric Industries, Inc. s internal control over financial reporting as of December 31, 2004, based on criteria established in Internal Control Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission, and our report dated March 11, 2005 expressed an unqualified opinion on management s assessment of, and the effective operation of, internal control over financial reporting.

/s/ KPMG LLP

Honolulu, Hawaii

March 11, 2005

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Consolidated Statements of Income

Hawaiian Electric Industries, Inc. and Subsidiaries

Years ended December 31	**2004**	**2003**	**2002**
(in thousands, except per share amounts)			
Revenues			
Electric utility	$ 1,550,671	$ 1,396,685	$ 1,257,176
Bank	364,284	371,320	399,255
Other	9,102	13,311	(2,730)
	1,924,057	1,781,316	1,653,701
Expenses			
Electric utility	1,376,768	1,220,120	1,062,220
Bank	259,310	278,565	306,372
Other	17,019	19,064	18,676
	1,653,097	1,517,749	1,387,268
Operating income (loss)			
Electric utility	173,903	176,565	194,956
Bank	104,974	92,755	92,883
Other	(7,917)	(5,753)	(21,406)
	270,960	263,567	266,433
Interest expense other than bank	(77,176)	(69,292)	(72,292)
Allowance for borrowed funds used during construction	2,542	1,914	1,855
Preferred stock dividends of subsidiaries	(1,901)	(2,006)	(2,006)
Preferred securities distributions of trust subsidiaries		(16,035)	(16,035)
Allowance for equity funds used during construction	5,794	4,267	3,954
Income from continuing operations before income taxes	200,219	182,415	181,909
Income taxes	92,480	64,367	63,692
Income from continuing operations	107,739	118,048	118,217
Discontinued operations gain (loss) on disposal, net of income taxes	1,913	(3,870)	
Net income	$ 109,652	$ 114,178	$ 118,217
Basic earnings (loss) per common share			
Continuing operations	$ 1.36	$ 1.58	$ 1.63
Discontinued operations	0.02	(0.05)	
	$ 1.38	$ 1.53	$ 1.63

Diluted earnings (loss) per common share			
Continuing operations	$ 1.36	$ 1.57	$ 1.62
Discontinued operations	0.02	(0.05)	
	$ 1.38	$ 1.52	$ 1.62
Dividends per common share	$ 1.24	$ 1.24	$ 1.24
Weighted-average number of common shares outstanding	79,562	74,696	72,556
Dilutive effect of stock options and dividend equivalents	157	278	398
Adjusted weighted-average shares	79,719	74,974	72,954

See accompanying Notes to Consolidated Financial Statements.

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Consolidated Balance Sheets

Hawaiian Electric Industries, Inc. and Subsidiaries

December 31		2004		2003
(dollars in thousands)				
ASSETS				
Cash and equivalents		$ 132,138		$ 223,310
Federal funds sold		41,491		56,678
Accounts receivable and unbilled revenues, net		208,533		187,716
Available-for-sale investment and mortgage-related securities		2,034,091		1,787,177
Available-for-sale mortgage-related securities pledged for repurchase agreements		919,281		941,571
Held-to-maturity investment securities (estimated fair value $97,365 and $94,624)		97,365		94,624
Loans receivable, net		3,249,191		3,121,979
Property, plant and equipment, net				
Land	$ 46,311		$ 42,943	
Plant and equipment	3,698,539		3,436,352	
Construction in progress	112,293		200,131	
	3,857,143		3,679,426	
Less accumulated depreciation	(1,434,840)	2,422,303	(1,367,538)	2,311,888
Other		414,971		382,228
Goodwill and other intangibles		91,263		93,987
		$ 9,610,627		$ 9,201,158
LIABILITIES AND STOCKHOLDERS EQUITY				
Liabilities				
Accounts payable		$ 153,943		$ 132,780
Deposit liabilities		4,296,172		4,026,250
Short-term borrowings		76,611		
Securities sold under agreements to repurchase		811,438		831,335
Advances from Federal Home Loan Bank		988,231		1,017,053
Long-term debt, net		1,166,735		1,064,420
Deferred income taxes		229,765		226,590
Regulatory liabilities, net		88,459		71,882
Contributions in aid of construction		235,505		233,969
Other		318,418		273,442
		8,365,277		7,877,721
Minority interests				
HEI - and HECO-obligated preferred securities of trust subsidiaries directly or indirectly holding solely HEI and HEI-guaranteed and HECO and HECO-guaranteed subordinated debentures				200,000
Preferred stock of subsidiaries not subject to mandatory redemption		34,405		34,406

		34,405		234,406
Stockholders equity				
Preferred stock, no par value, authorized 10,000,000 shares; issued: none				
Common stock, no par value, authorized 100,000,000 shares; issued and outstanding: 80,687,350 shares and 75,837,588 shares		1,010,090		888,431
Retained earnings		208,998		197,774
Accumulated other comprehensive income (loss), net of income taxes				
Net unrealized gains (losses) on securities	(7,036)		$ 4,274	
Minimum pension liability	(1,107)	(8,143)	(1,448)	2,826
		1,210,945		1,089,031
		$ 9,610,627		$ 9,201,158

See accompanying Notes to Consolidated Financial Statements.

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Consolidated Statements of Changes in Stockholders Equity

Hawaiian Electric Industries, Inc. and Subsidiaries

(in thousands)	**Common stock Shares**	**Common stock Amount**	**Retained earnings**	**Accumulated other comprehensive income (loss)**	**Total**
Balance, December 31, 2001	**71,200**	**$ 787,374**	**$ 147,837**	**$ (5,546)**	**$ 929,665**
Comprehensive income:					
Net income			118,217		118,217
Net unrealized gains on securities:					
Net unrealized gains arising during the period, net of taxes of $14,465				38,346	38,346
Add: reclassification adjustment for net realized losses included in net income, net of tax benefits of $1,440				2,749	2,749
Minimum pension liability adjustment, net of tax benefits of $2,701				(4,870)	(4,870)
Comprehensive income			118,217	36,225	154,442
Issuance of common stock:					
Dividend reinvestment and stock purchase plan	1,326	28,507			28,507
Retirement savings and other plans	1,092	21,407			21,407
Expenses and other, net		2,215			2,215
Common stock dividends ($1.24 per share)			(89,936)		(89,936)
Balance, December 31, 2002	73,618	839,503	176,118	30,679	1,046,300
Comprehensive income:					
Net income			114,178		114,178
Net unrealized losses on securities:					
Net unrealized losses arising during the period, net of tax benefits of $11,538				(29,530)	(29,530)
Less: reclassification adjustment for net realized gains included in net income, net of taxes of $1,082				(2,110)	(2,110)
Minimum pension liability adjustment, net of taxes of $2,027				3,787	3,787
Comprehensive income (loss)			114,178	(27,853)	86,325
Issuance of common stock:					
Dividend reinvestment and stock purchase plan	1,658	36,052			36,052
Retirement savings and other plans	562	11,433			11,433
Expenses and other, net		1,443			1,443
Common stock dividends ($1.24 per share)			(92,522)		(92,522)
Balance, December 31, 2003	75,838	888,431	197,774	2,826	1,089,031
Comprehensive income:					
Net income			109,652		109,652
Net unrealized losses on securities:					

Net unrealized losses arising during the period, net of tax benefits of $4,366				(7,775)	(7,775)
Less: reclassification adjustment for net realized gains included in net income, net of taxes of $2,002				(3,535)	(3,535)
Minimum pension liability adjustment, net of taxes of $197				341	341
Comprehensive income (loss)			109,652	(10,969)	98,683
Issuance of common stock:					
Common stock offering	4,000	103,720			103,720
Dividend reinvestment and stock purchase plan	307	7,999			7,999
Retirement savings and other plans	542	10,128			10,128
Expenses and other, net		(188)			(188)
Common stock dividends ($1.24 per share)			(98,428)		(98,428)
Balance, December 31, 2004	80,687	$ 1,010,090	$ 208,998	$ (8,143)	$ 1,210,945

At December 31, 2004, Hawaiian Electric Industries, Inc. (HEI) had reserved a total of 17,047,249 shares of common stock for future issuance under the HEI Dividend Reinvestment and Stock Purchase Plan, the Hawaiian Electric Industries Retirement Savings Plan, 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.

See accompanying Notes to Consolidated Financial Statements.

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Consolidated Statements of Cash Flows

Hawaiian Electric Industries, Inc. and Subsidiaries

Years ended December 31	**2004**	**2003**	**2002**
(in thousands)			
Cash flows from operating activities			
Income from continuing operations	$ 107,739	$ 118,048	$ 118,217
Adjustments to reconcile income from continuing operations to net cash provided by operating activities			
Depreciation of property, plant and equipment	125,560	120,633	115,597
Other amortization	15,965	29,766	25,396
Provision for loan losses	(8,400)	3,075	9,750
Writedowns of income notes			4,499
Gain on sale of income notes	(5,607)		
Deferred income taxes	12,349	2,838	35,197
Allowance for equity funds used during construction	(5,794)	(4,267)	(3,954)
Changes in assets and liabilities, net of effects from the disposal of businesses			
Increase in accounts receivable and unbilled revenues, net	(20,823)	(11,389)	(12,203)
Increase in prepaid pension benefit cost	(24,539)	(24,681)	(18,445)
Increase (decrease) in accounts payable	21,188	(1,636)	14,566
Increase (decrease) in taxes accrued	46,675	22,045	(38,419)
Changes in other assets and liabilities	(20,161)	(13,100)	8,731
Net cash provided by operating activities	244,152	241,332	258,932
Cash flows from investing activities			
Available-for-sale investment and mortgage-related securities purchased	(1,105,133)	(2,155,980)	(1,605,672)
Principal repayments on available-for-sale investment and mortgage-related securities	803,517	1,860,383	1,182,796
Proceeds from sale of available-for-sale mortgage-related securities	45,207	243,406	77,264
Origination of loans held for investment	(1,232,158)	(1,465,562)	(1,100,961)
Principal repayments on loans held for investment	1,118,167	1,335,357	936,055
Proceeds from sale of real estate acquired in settlement of loans	1,617	7,728	12,013
Capital expenditures	(214,654)	(162,891)	(128,082)
Contributions in aid of construction	8,522	12,963	11,042
Distributions from unconsolidated subsidiaries	24,379		
Other	10,161	(624)	(278)
Net cash used in investing activities	(540,375)	(325,220)	(615,823)
Cash flows from financing activities			
Net increase in deposit liabilities	269,922	225,478	121,186
Net increase in short-term borrowings with original maturities of three months or less	76,611		
Net increase in retail repurchase agreements	25,050	13,085	12,180
Proceeds from securities sold under agreements to repurchase	753,608	1,965,575	1,086,531
Repayments of securities sold under agreements to repurchase	(799,250)	(1,809,945)	(1,116,148)
Proceeds from advances from Federal Home Loan Bank	129,200	373,500	350,100
Principal payments on advances from Federal Home Loan Bank	(158,022)	(532,699)	(206,600)
Proceeds from issuance of long-term debt	103,097	167,935	35,275
Repayment of long-term debt	(224,166)	(210,000)	(64,500)
Preferred securities distributions of trust subsidiaries		(16,035)	(16,035)

Net proceeds from issuance of common stock	110,017	29,824	32,451
Common stock dividends	(93,864)	(75,119)	(73,412)
Other	(4,768)	(8,887)	(9,742)
Net cash provided by financing activities	187,435	122,712	151,286
Net cash provided by (used in) discontinued operations	2,429	(3,361)	(697)
Net increase (decrease) in cash and equivalents and federal funds sold	(106,359)	35,463	(206,302)
Cash and equivalents and federal funds sold, January 1	279,988	244,525	450,827
Cash and equivalents and federal funds sold, December 31	$ 173,629	$ 279,988	$ 244,525

See accompanying Notes to Consolidated Financial Statements.

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Notes to Consolidated Financial Statements

1 Summary of significant accounting policies

General

HEI is a holding company with wholly-owned 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 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), allowance for loan losses; and reserves for discontinued operations.

Consolidation. The consolidated financial statements include the accounts of HEI and its subsidiaries (collectively, the Company). See Note 7 for a discussion of unconsolidated financing entities. All significant intercompany accounts and transactions have been eliminated in consolidation.

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 and 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 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 losses excluded from earnings and reported on a net basis in a separate component of stockholders equity.

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

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

Derivative instruments and hedging activities. Derivatives are recognized at fair value in the balance sheet as an asset or liability. Changes in fair value of derivative instruments not designated as hedging instruments are (and the ineffective portions of hedges, if any in the future, would be) recognized in earnings in the current period. In the future, any changes in the fair value of a derivative designated as a fair value hedge and the hedged item would be recorded in earnings. Also, for a derivative designated as a cash flow hedge, the effective portion of changes in fair value of the derivative would be reported in other comprehensive income and subsequently would be reclassified into earnings when the hedged item affects earnings.

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Equity method. Investments in up to 50%-owned affiliates for 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) since acquisition. Equity in earnings or losses are reflected in operating revenues.

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. 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.

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 3.9% in 2004, 2003 and 2002.

Retirement benefits. Pension and other postretirement benefit costs/(returns) are charged/(credited) primarily to expense and electric utility plant. The Public Utilities Commission of the State of Hawaii (PUC) requires the electric utilities to fund their pension and postretirement benefit costs. The Company s policy is to fund pension costs in amounts that will not be less than the minimum funding requirements of the Employee Retirement Income Security Act of 1974 and will not exceed the maximum tax-deductible amounts. 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 statutory funding limits and targeted funded status as determined with the consulting actuary. 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, while maximizing the use of the most tax advantaged funding vehicles, subject to statutory funding limits, cash flow requirements and reviews of the funded status with the consulting actuary.

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.

Hawaiian Electric Company, Inc. (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 or liabilities 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.

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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.

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 options and dividend equivalents are added to the denominator.

At December 31, 2004, 2003 and 2002, all options to purchase common stock were included in the computation of diluted EPS.

Stock compensation. The Company applies the fair value based method of accounting prescribed by SFAS No. 123, Accounting for Stock-Based Compensation, to account for its stock options and stock appreciation rights (SARs). Beginning in the third quarter of 2005, the Company will apply the fair value based method of accounting prescribed by SFAS No. 123 (Revised 2004) to account for its stock options (see Recent accounting pronouncements and interpretations Share-based payment below).

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

Consolidation of variable interest entities (VIEs). In January 2003, the Financial Accounting Standards Board (FASB) issued Interpretation (FIN) 46, Consolidation of Variable Interest Entities, which addresses the consolidation of VIEs as defined. The Company was required to apply FIN 46 immediately to variable interests in VIEs created after January 31, 2003. For variable interests in VIEs created before February 1, 2003, FIN 46 was to be applied no later than the end of the first reporting period ending after December 15, 2003. The Company adopted the provisions (other than the already adopted disclosure provisions) of FIN 46 relating to VIEs created before February 1, 2003 as of December 31, 2003 with no effect on the Company s financial statements.

In December 2003, the FASB issued revised FIN 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. FIN 46R replaced FIN 46. As of January 1, 2004, the Company adopted the provisions of FIN 46R and deconsolidated Hawaiian Electric Industries Capital Trust I, HEI Preferred Funding, LP, HECO Capital Trust I and HECO Capital Trust II from its consolidated financial statements for the period ended, and as of, March 31, 2004. The Company did not elect to restate previously issued financial statements. See Note 7 for additional information.

As of December 31, 2004, HECO and its subsidiaries had six purchase power agreements (PPAs) for a total of 512 megawatts (MW is defined as megawatt or megawatts, as applicable) of firm capacity, and other PPAs with smaller IPPs and Schedule Q providers that supplied as-available energy. In general, Schedule Q rates are available to customers with cogeneration and/or small power production facilities with a capacity of 100 kilowatthours or less who buy/sell power from/to the electric utility. Approximately 91% of the 512 MW of firm capacity is under PPAs, entered into before December 31, 2003, with AES Hawaii, Kalaeloa Partners, L.P. (Kalaeloa), Hamakua Energy Partners, L.P. (Hamakua) and H-POWER. Purchases from all IPPs for 2004 totaled

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$399 million, with purchases from AES Hawaii, Kalaeloa, Hamakua and H-POWER totaling $134 million, $131 million, $51 million and $31 million, respectively. The primary business activities of these IPPs are the generation and sale of power to HECO and its subsidiaries. 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 is not required to apply FIN 46R to that entity if the enterprise is unable to obtain, after making an exhaustive effort, the information necessary to (1) determine whether the entity is a VIE, (2) determine whether the enterprise is the VIE s primary beneficiary, or (3) perform the accounting required to consolidate the VIE for which it is determined to be the primary beneficiary.

HECO has reviewed its significant PPAs and determined that the IPPs 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 by telephone to explain and repeat its request for information. (HECO and its subsidiaries excluded their Schedule Q providers from the scope of FIN 46R because HECO and its subsidiaries variable interest in the provider would not be significant to HECO and its subsidiaries and they did not participate significantly in the design of the provider.) Some of the IPPs provided sufficient information for HECO and its subsidiaries to determine that the IPP was not a VIE, or was either a business or governmental organization (H-POWER) 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 and its subsidiaries to determine the applicability of FIN 46R, and HECO and its subsidiaries are unable to apply FIN 46R to these IPPs.

In October 2004, Kalaeloa and HECO executed two amendments to their PPA under which, if PUC approval is obtained and other conditions are satisfied, Kalaeloa may make an additional 29 MW of firm capacity available to HECO. Under the first amendment, Kalaeloa agrees to make available to HECO the information HECO needs to (1) determine if HECO must consolidate Kalaeloa under the provisions of FIN 46R, (2) consolidate Kalaeloa if necessary, and (3) comply with Section 404 of the Sarbanes-Oxley Act of 2002. The agreement to make information available is subject to the issuance by the PUC of an acceptable order which, among other things, approves the amendment and orders that HECO may recover the costs resulting from the amendments in HECO s electric rates.

As required under FIN 46R, HECO and its subsidiaries will continue their efforts to obtain the information necessary to make the determinations required under FIN 46R. If the requested information is ultimately received, a possible outcome of future analyses is the consolidation of an IPP 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.

Amendment of SFAS No. 133. In April 2003, the FASB issued SFAS No. 149, Amendment of Statement 133 on Derivative Instruments and Hedging Activities, which amends and clarifies financial accounting and reporting for derivative instruments and hedging activities and will result in more consistent reporting of contracts as either derivatives or hybrid instruments. SFAS No. 149 is effective for contracts entered into or modified after June 30, 2003 (with some exceptions) and for hedging relationships designated after June 30, 2003. The Company adopted the provisions of SFAS No. 149 on July 1, 2003 with no effect on the Company s historical financial statements.

Financial instruments with characteristics of both liabilities and equity. In May 2003, the FASB issued SFAS No. 150, Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity to establish standards for how an issuer classifies and measures these financial instruments. For example, a financial instrument issued in the form of shares that are mandatorily redeemable would be required by SFAS No. 150 to be classified as a liability. SFAS No. 150 was immediately effective for financial instruments entered into or modified after May 31, 2003. SFAS No. 150 was effective for financial instruments existing as of May 31, 2003 at the beginning of the first interim period beginning after June 15, 2003. In October 2003, however, the FASB indefinitely deferred the effective date of the provisions of SFAS No. 150 related to classification and measurement requirements for mandatorily redeemable financial instruments that become subject to SFAS No. 150 solely as a result of consolidation. The Company adopted the non-deferred provisions of SFAS No. 150 for financial

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instruments existing as of May 31, 2003 in the third quarter of 2003 and the adoption had no effect on the Company s financial statements.

Determining whether an arrangement contains a lease. In May 2003, the FASB ratified Emerging Issues Task Force (EITF) Issue No. 01-8, Determining Whether an Arrangement Contains a Lease. Under EITF Issue No. 01-8, companies may need to recognize service contracts, such as power purchase agreements for energy and capacity, or other arrangements as leases subject to the requirements of SFAS No. 13, Accounting for Leases. The Company adopted the provisions of EITF Issue No. 01-8 in the third quarter of 2003. Since EITF Issue No. 01-8 applies prospectively to arrangements agreed to, modified or acquired after June 30, 2003, the adoption of EITF Issue No. 01-8 had no effect on the Company s historical financial statements. If any new power purchase agreement or a reassessment of an existing agreement required under certain circumstances (such as in the event of a material amendment of the agreement) falls under the scope of EITF Issue No. 01-8 and SFAS No. 13, and results in the classification of the agreement as a capital lease, a material effect on the Company s financial statements may result, including the recognition of a significant capital asset and lease obligation.

In October 2004, Kalaeloa and HECO executed two amendments to their PPA under which, if PUC approval is obtained and other conditions are satisfied, Kalaeloa may make an additional 29 MW of firm capacity available to HECO. HECO reassessed the PPA under EITF Issue No. 01-8 due to the amendments and determined that the PPA does not contain a lease because HECO does not control or operate Kalaeloa s property, plant or equipment and another party is purchasing more than a minor amount of the output.

Investments in other than common stock. In July 2004, the FASB ratified EITF Issue No. 02-14, Whether an Investor Should Apply the Equity Method of Accounting to Investments Other Than Common Stock. EITF Issue No. 02-14 requires that companies that have the ability to exercise significant influence over the investee apply the equity method of accounting when it has either common stock or in-substance common stock of a corporation. EITF Issue No. 02-14 was effective in reporting periods beginning after September 15, 2004. The Company adopted EITF Issue No. 02-14 on October 1, 2004 and the adoption had no effect on the Company s financial statements.

Other-than-temporary impairment and its application to certain investments. In March 2004, the FASB ratified EITF Issue No. 03-1, The Meaning of Other-Than-Temporary Impairment and Its Application to Certain Investments. EITF Issue No. 03-1 provides guidance for determining whether an investment in debt or equity securities is impaired, evaluating whether an impairment is other-than-temporary and measuring impairment. EITF Issue No. 03-1 also provides disclosure guidance. The recognition and measurement guidance provided would be applied prospectively to all current and future investments within the scope of EITF Issue No. 03-1, originally effective in reporting periods beginning after June 15, 2004. In September 2004, the FASB issued FASB Staff Position (FSP) EITF 03-1-1 to delay the effective date of the recognition and measurement guidance. A new effective date is expected when the new guidance is issued.

Participating securities and the two-class method under SFAS No. 128. In March 2004, the FASB ratified EITF Issue No. 03-6, Participating Securities and the Two-Class Method under FASB Statement No. 128, Earnings Per Share. EITF Issue No. 03-6 addresses various questions related to calculating EPS in accordance with FASB Statement No. 128, Earnings per Share, including questions related to: (a) the types of securities that should be considered participating, (b) the application of the two-class method, and (c) the allocation of undistributed earnings and losses to participating securities. EITF No. 03-6 was effective for reporting periods beginning after March 31, 2004 and, if its application results in different EPS for prior periods, the previously-reported EPS should be restated. The Company adopted EITF Issue No. 03-6 in the second quarter of 2004 and the adoption had no effect on the Company s financial statements.

Investments in limited liability companies. In March 2004, the FASB ratified EITF Issue No. 03-16, Accounting for Investments in Limited Liability Companies. EITF Issue No. 03-16 requires that an investment in a limited liability company (LLC) that maintains a specific ownership account for each investor (similar to a partnership capital account structure) to be viewed as similar to an investment in a limited partnership for purposes of determining whether a noncontrolling investment in an LLC should be accounted for using the cost method or equity method of accounting. EITF No. 03-16 was effective for reporting periods beginning after June 15, 2004. The

Company adopted EITF Issue No. 03-16 on July 1, 2004 and the adoption had no effect on the Company s financial statements.

Medicare Prescription Drug, Improvement and Modernization Act of 2003. 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 if the participant waives coverage under Medicare Part D.

In May 2004, the FASB issued FSP No. 106-2, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003. When an employer is able to determine that benefits provided by its plan are actuarially equivalent to the Medicare Part D benefits, the FSP requires (a) treatment of the effects of the federal subsidy as an actuarial gain like similar gains and losses, and (b) certain financial statement disclosures related to the impact of the 2003 Act for employers that sponsor postretirement health care plans providing prescription drug benefits. The FASB s related initial guidance, FSP No. 106-1, Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003, was superseded upon the effective date of FSP No. 106-2, which was the first interim or annual period beginning after June 15, 2004.

In the Company s current disclosure, the accumulated postretirement benefit obligation and net periodic postretirement benefit cost do not reflect any amount associated with the federal subsidy because, although the Company has concluded that the benefits the plan provides are actuarially equivalent to Medicare Part D benefits under the 2003 Act, the Company may not be eligible for any employer sponsored qualified plan subsidy, partly due to caps on the Company s costs for these benefits and the sharing of premiums between the Company and retirees. If the Company is eligible, it expects the impact to be immaterial.

The new Medicare legislation could impact the Company s future measures of accumulated postretirement benefit obligation and net periodic postretirement benefit cost in three ways: (1) as described above, the subsidy would reduce the obligation for benefits provided by the postretirement health plan, (2) to the extent election into Medicare Part D coverage causes retirees to elect out of the Company s plan, such measures will be lower, and (3) the Company will review the plan design for alternative ways to capture savings from the 2003 Act.

Share-based payment. In December 2004, the FASB issued SFAS No. 123 (Revised 2004), Share-Based Payment, which requires companies to recognize the grant-date fair value of stock options and other equity-based compensation issued to employees in the income statement. Since the Company adopted the recognition provisions of SFAS No. 123 as of January 1, 2002, the only change the Company expects to make upon adoption is how it accounts for forfeitures. Historically, forfeitures have not been significant. SFAS No. 123 (Revised 2004) is effective as of July 1, 2005 for the Company. The Company will adopt the provisions of SFAS No. 123 (Revised 2004) on July 1, 2005 and expects the impact of adoption to be immaterial.

Tax effects of income from domestic production activities. In December 2004, the FASB issued FSP No. 109-1, Application of FASB Statement No. 109, *Accounting for Income Taxes,* for the Tax Deduction Provided to U.S. Based Manufacturers by the American Jobs Creation Act of 2004, which was effective upon issuance. FSP No. 109-1 clarifies that the new deduction for qualified domestic production activities should be accounted for as a special deduction under SFAS No. 109, and not as a tax-rate reduction, because the deduction is contingent on performing activities identified in the new tax law.

Management is currently reviewing various aspects of the American Jobs Creation Act of 2004 (the 2004 Act), including two notable provisions with potential implications for the Company:

1. Manufacturing tax incentives for the production of electricity beginning in 2005. Taxpayers will be able to deduct a percentage (3% in 2005 and 2006, 6% in 2007 through 2009, and 9% in 2010 and thereafter) of the lesser of their qualified production activities income or their taxable income.

2. Generally for electricity sold and produced after October 22, 2004, the 2004 Act expands the income tax credit for electricity produced from certain sources to include open-loop biomass, geothermal and solar energy, small irrigation power, landfill gas, trash combustion and qualifying refined coal production facilities.

Pending further guidance on these provisions, management has not yet determined the impact of these provisions on the Company s results of operations, financial condition or liquidity.

Common stock split. 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 in the accompanying financial statements and notes has been adjusted to reflect the stock split for all periods presented (unless otherwise noted).

Reclassifications. Certain reclassifications have been made to prior years financial statements to conform to the 2004 presentation.

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 liabilities, net of regulatory assets, would be credited to income. 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.

Accounts receivable. Accounts receivable are recorded at the invoiced amount. The electric utilities 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. At December 31, 2004, customer accounts receivable include unbilled energy revenues of $79 million on a base of annual revenue of $1.5 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 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. In December 2004, the PUC approved amendments to the electric utilities fuel supply contracts. In approving the amendments, the PUC indicated questions still remain concerning the energy cost adjustment clauses and their continued use to recover fuel contract costs, and indicated it plans to examine the continued use of the energy cost adjustment clauses to

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recover the various costs incurred pursuant to the amended fuel contracts in HECO s pending rate case, and in HELCO s and MECO s next respective rate cases.

HECO and its subsidiaries operating revenues include amounts for various revenue taxes. Revenue taxes are 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 2004 and 2003, HECO and its subsidiaries included approximately $136 million and $123 million, respectively, of revenue taxes in operating revenues and in taxes, other than income taxes expense. For 2002, HECO and its subsidiaries included $111 million of revenue taxes in operating revenues and $113 million (including a $2 million nonrecurring PUC fee adjustment) of revenue taxes in taxes, other than income taxes expense.

Repairs and maintenance costs. Repairs and maintenance costs are expensed for overhauls of generating units 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, AFUDC may be stopped.

The weighted-average AFUDC rate was 8.6% in 2004 and 8.7% in 2003 and 2002, 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 costs), commitment fees and purchase premiums and discounts. Interest on loans is credited to income as it is earned. Premiums are amortized and discounts are accreted 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 related loans are 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 rights. 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 rights (MSRs) when the related loans are sold with servicing rights retained. The total cost of the mortgage loans sold is allocated to the MSRs and the mortgage loans without the MSRs based on their relative fair values at the date of sale. The MSRs are included as a component of gain on sale of loans. The MSRs are amortized in proportion to and over the estimated period of net servicing income. Such amortization is reflected as a component of revenues on the consolidated statements of income.

The MSRs are periodically reviewed for impairment based on their fair value. The fair value of the MSRs, for the purposes of impairment, is measured using a discounted cash flow analysis based on market-adjusted discount rates and anticipated prepayment speeds. Market sources are used to determine prepayment speeds and net cost of servicing per loan.

ASB measures MSR impairment 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.

Allowance for loan losses. ASB maintains an allowance for loan losses that it believes is adequate to absorb estimated inherent losses on all loans. 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 loan provisions.

For business 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, by the lending officer. 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, allowance for loan loss allocations are determined based on a historical loss ratio.

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.

Goodwill and other intangibles. Goodwill and intangible assets with indefinite useful lives are 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, was tested for impairment annually in the fourth quarter using data as of September 30. Since January 1, 2002, there has been no impairment of goodwill. The fair value of ASB was estimated by an unrelated third party using a valuation method based on a market approach, which takes into consideration market values of comparable publicly traded companies and recent transactions of companies in the industry.

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Amortized intangible assets.

December 31 (in thousands)	2004 Gross carrying amount	2004 Accumulated amortization	2003 Gross carrying amount	2003 Accumulated amortization
Core deposit intangibles	$ 20,276	$ 15,201	$ 20,276	$ 13,471
Mortgage servicing rights	11,740	7,998	12,953	6,535
	$ 32,016	$ 23,199	$ 33,229	$ 20,006

Changes in the valuation allowance for mortgage servicing rights (MSRs) were as follows:

December 31	2004	2003	2002
(in thousands)			
Valuation allowance, January 1	$ 2,316	$ 2,215	$
Provision for impairment	4	101	2,215
Other than temporary impairment	(1,619)		
Valuation allowance, December 31	$ 701	$ 2,316	$ 2,215

In 2004, 2003 and 2002, aggregate amortization expenses were $3.2 million, $4.0 million and $3.4 million, respectively.

The estimated aggregate amortization expense for ASB s core deposits and MSRs for 2005, 2006, 2007, 2008 and 2009 is $2.4 million, $2.3 million, $2.1 million, $0.4 million and $0.3 million, respectively.

Core deposit intangibles are amortized each year at the greater of the actual attrition rate of such deposit base or 10% of the original value. Core deposit intangibles are reviewed for impairment based on their estimated fair value.

ASB capitalizes MSRs acquired through either the purchase or origination of mortgage loans for sale or securitization with servicing rights retained. Changes in mortgage interest rates impact the value of ASB s MSRs. Rising interest rates typically result in slower prepayment speeds in the loans being serviced for others which increases the value of MSRs, whereas declining interest rates typically result in faster prepayment speeds which decreases the value of MSRs and increases the amortization of the MSRs. In 2004, 2003, and 2002, MSRs acquired through the sale or securitization of loans held for sale totaled $0.4 million, $1.2 million, and $1.3 million, respectively. Amortization expense for ASB s MSRs amounted to $1.5 million, $2.3 million, and $1.7 million for 2004, 2003, and 2002, respectively, and are recorded along with the provision for impairment 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 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, Hawaii Electric Light Company, Inc. (HELCO) and Maui Electric Company, Limited (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 and HECO Capital Trust III, which is an unconsolidated financing entity.

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. By reason of the regulation of its subsidiary, ASB Realty Corporation, ASB is also subject to regulation by the Hawaii Commissioner of Financial Institutions. 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 and other subsidiaries not qualifying as reportable segments and intercompany eliminations.

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(in thousands)	Electric Utility	Bank	Other	Total
2004				
Revenues from external customers	$ 1,550,671	$ 364,284	$ 9,102	$ 1,924,057
Depreciation and amortization	123,700	17,044	781	141,525
Interest expense	49,588	112,787	27,588	189,963
Profit (loss)*	130,656	99,466	(29,903)	200,219
Income taxes (benefit)	49,479	58,404	(15,403)	92,480
Income (loss) from continuing operations	81,177	41,062	(14,500)	107,739
Capital expenditures	201,236	13,085	333	214,654
Assets (at December 31, 2004 **)	2,770,985	6,766,505	73,137	9,610,627
2003				
Revenues from external customers	$ 1,396,683	$ 371,320	$ 13,313	$ 1,781,316
Intersegment revenues (eliminations)	2		(2)	
Revenues	1,396,685	371,320	13,311	1,781,316
Depreciation and amortization	118,792	30,748	859	150,399
Interest expense	44,341	123,324	24,951	192,616
Profit (loss)*	128,735	87,220	(33,540)	182,415
Income taxes (benefit)	49,824	30,959	(16,416)	64,367
Income (loss) from continuing operations	78,911	56,261	(17,124)	118,048
Capital expenditures	146,964	15,798	129	162,891
Assets (at December 31, 2003**)	2,581,256	6,515,208	104,694	9,201,158
2002				
Revenues from external customers	$ 1,257,171	$ 399,255	$ (2,725)	$ 1,653,701
Intersegment revenues (eliminations)	5		(5)	
Revenues	1,257,176	399,255	(2,730)	1,653,701
Depreciation and amortization	116,800	22,784	1,409	140,993
Interest expense	44,232	152,882	28,060	225,174
Profit (loss)*	146,863	87,299	(52,253)	181,909
Income taxes (benefit)	56,658	31,074	(24,040)	63,692

Income (loss) from continuing operations	90,205	56,225	(28,213)	118,217
Capital expenditures	114,558	13,117	407	128,082
Assets (at December 31, 2002**)	2,493,436	6,328,606	111,511	8,933,553

* Income (loss) from continuing operations before income taxes.

** Includes net assets of discontinued operations.

Revenues attributed to foreign countries and long-lived assets located in foreign countries as of the dates and for the periods identified above were not material.

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

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

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3 Electric utility subsidiary

Selected consolidated financial information

Hawaiian Electric Company, Inc. and Subsidiaries

Income Statement Data

Years ended December 31	2004	2003	2002
(in thousands)			
Revenues			
Operating revenues	$ 1,546,875	$ 1,393,038	$ 1,252,929
Other nonregulated	3,796	3,647	4,247
	1,550,671	1,396,685	1,257,176
Expenses			
Fuel oil	483,423	388,560	310,595
Purchased power	398,836	368,076	326,455
Other operation	157,198	155,531	131,910
Maintenance	77,313	64,621	66,541
Depreciation	114,920	110,560	105,424
Taxes, other than income taxes	143,834	130,677	120,118
Other nonregulated	1,244	2,095	1,177
	1,376,768	1,220,120	1,062,220
Operating income from regulated and nonregulated activities	173,903	176,565	194,956
Allowance for equity funds used during construction	5,794	4,267	3,954
Interest and other charges	(50,503)	(52,931)	(52,822)
Allowance for borrowed funds used during construction	2,542	1,914	1,855
Income before income taxes and preferred stock dividends of HECO	131,736	129,815	147,943
Income taxes	49,479	49,824	56,658
Income before preferred stock dividends of HECO	82,257	79,991	91,285
Preferred stock dividends of HECO	1,080	1,080	1,080
Net income for common stock	$ 81,177	$ 78,911	$ 90,205

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Balance Sheet Data

December 31	2004	2003
(in thousands)		
Assets		
Utility plant, at cost		
Property, plant and equipment	$ 3,606,908	$ 3,336,004
Less accumulated depreciation	(1,361,703)	(1,290,929)
Construction in progress	102,949	195,295
Net utility plant	2,348,154	2,240,370
Other	422,831	340,886
	$ 2,770,985	$ 2,581,256
Capitalization and liabilities		
Common stock equity	$ 1,017,104	$ 944,443
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
HECO-obligated mandatorily redeemable trust preferred securities of subsidiary trusts holding solely HECO and HECO-guaranteed debentures (distribution rates of 7.30% and 8.05%)		100,000
Long-term debt, net	752,735	699,420
Total capitalization	1,804,132	1,778,156
Short-term borrowings from nonaffiliates and affiliate	88,568	6,000
Deferred income taxes	189,193	170,841
Regulatory liabilities, net	88,459	71,882
Contributions in aid of construction	235,505	233,969
Other	365,128	320,408
	$ 2,770,985	$ 2,581,256

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 liabilities, net of regulatory assets, would be credited to income. 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.

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Regulatory liabilities represent costs expected to be incurred in the future. 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 accrue and recover interest on their regulatory assets for integrated resource planning costs. Noted in parenthesis are the original PUC authorized amortization or recovery periods and the remaining amortization or recovery periods as of December 31, 2004, if different. Regulatory assets (liabilities) were as follows:

December 31	2004	2003
(in thousands)		
Cost of removal in excess of salvage value (1 to 60 years)	$ (197,089)	$ (178,424)
Income taxes, net (1 to 36 years)	68,780	66,129
Postretirement benefits other than pensions (18 years; 8 years)	14,318	16,108
Unamortized expense and premiums on retired debt and equity issuances (10 to 26 years; 1 to 24 years)	15,509	12,148
Integrated resource planning costs, net (1 year)	1,554	2,731
Vacation earned, but not yet taken (1 year)	5,011	4,750
Other (1 to 5 years; 1 to 2 years)	3,458	4,676
	$ (88,459)	$ (71,882)

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 approximately 10% ($148 million), 10% ($135 million) and 9% ($119 million) of their operating revenues from the sale of electricity to various federal government agencies in 2004, 2003 and 2002, respectively.

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 at January 1, 2005, the estimated cost of minimum purchases under the fuel supply contracts for 2005 is $361 million. The actual cost of purchases in 2005 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 $490 million, $390 million and $317 million of fuel under contractual agreements in 2004, 2003 and 2002, respectively.

Power purchase agreements (PPAs). At December 31, 2004, HECO and its subsidiaries had six PPAs for a total of 512 MW of firm capacity. Of the 512 MW of firm capacity under PPAs, approximately 91% is under PPAs with AES Hawaii, Inc. (since March 1988), Kalaeloa Partners, L.P. (since October 1988), Hamakua Energy Partners, L.P. (since October 1997) and H-Power (since March 1986). The primary business activities of these IPPs are the generation and sale of power to the electric utilities. Current financial information needed to complete a FIN 46R evaluation of these IPPs is not currently available. Purchases from all IPPs totaled $399 million, $368 million and $326 million for 2004, 2003 and 2002, 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 $118 million each in 2005, 2006 and 2007, $116 million in 2008, $113 million in 2009 and a total of $1.4 billion in the period from 2010 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 energy cost adjustment clause in their rate schedules. HECO and its subsidiaries do not operate nor participate in the operation of any of the facilities that provide power under the agreements. Title

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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. At December 31, 2004, HECO and its subsidiaries had recognized $17 million of revenues with respect to interim orders regarding certain integrated resource planning costs, which revenues are subject to refund, with interest, if and to the extent they exceed the amounts allowed in final orders.

HELCO power situation.

Historical context. In 1991, HELCO began planning to meet increased electric generation demand forecast for 1994. HELCO s plans were to install at its Keahole power plant two nominal 20 MW combustion turbines (CT-4 and CT-5), followed by an 18 MW heat steam recovery 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, which HELCO had planned to install in late 1994. In 1995, the PUC allowed HELCO to pursue construction of and commit expenditures for CT-5 and ST-7, but noted in its decision that such costs are not to be included in rate base until the project is installed and is used and useful for utility purposes. The PUC at that time also ordered HELCO to continue negotiating with independent power producers (IPPs) that had proposed generating facilities that they claimed would be a substitute for HELCO s planned expansion of the Keahole plant, stating that the facility to be built should be the one that can be most expeditiously put into service at allowable cost.

Installation of CT-4 and CT-5 was significantly delayed, however, as a result of (a) delays in obtaining an amendment of a land use permit from the Hawaii Board of Land and Natural Resources (BLNR), which was required because the Keahole power plant is located in a conservation district, and a required air permit from the Department of Health of the State of Hawaii (DOH) and the U.S. Environmental Protection Agency (EPA) and (b) lawsuits and administrative proceedings initiated by IPPs and other parties contesting the grant of these permits and objecting to the expansion of the power plant on numerous grounds, including contentions that (i) operation of the expanded Keahole site would not comply with land use regulations (including noise standards) and the conditions of HELCO s land patent; (ii) HELCO cannot operate the plant within current air quality standards; (iii) HELCO could alternatively purchase power from IPPs to meet increased electric generation demand; and (iv) HELCO s land use entitlement expired in April 1999 because it had not completed the project within an alleged three-year construction deadline.

Status of installation. In November 2003, HELCO entered into a conditional settlement agreement intended in part to permit HELCO to complete CT-4 and CT-5 (see The Settlement Agreement below). Subsequently, CT-4 and CT-5 were installed and put into limited commercial operation in May 2004 and June 2004, respectively. Under the Settlement Agreement, CT-4 and CT-5 must have noise mitigation measures completed before they can be operated full-time. Noise mitigation equipment has been installed and noise mitigation work is expected to be completed in the second quarter of 2005 so that full-time operation of both CT-4 and CT-5 may then be achieved.

IPP complaints; related PPAs. Three IPPs Kawaihae Cogeneration Partners (KCP), which is an affiliate of Waimana, Enserch Development Corporation (Enserch) and Hilo Coast Power Company (HCPC) filed separate complaints with the PUC in 1993, 1994 and 1999, respectively, alleging that they were each entitled to a PPA to provide HELCO with additional capacity. KCP and Enserch each claimed that the generation capacity they would provide under their proposed PPAs would be a substitute for HELCO s planned expansion of the Keahole plant.

The Enserch and HCPC complaints were resolved by HELCO s entry into PPAs with each of these parties. The term of the PPA with Enserch is 30 years from December 31, 2000. The PPA with HCPC terminated in December 2004. HELCO believes that KCP s proposal for a PPA is not viable.

Air permit. Following completion of all appeals from an air permit issued by the DOH in 1997 and then reissued in July 2001, a final air permit from the DOH became effective on November 27, 2001.

Land use permit amendment and related proceedings. The Third Circuit Court ruled in 1997 that, because the BLNR had failed to render a valid decision on HELCO s application to amend its land use permit before the statutory deadline in April 1996, HELCO was entitled to use its Keahole site for the expansion project (HELCO s default entitlement). The Third Circuit Court s 1998 final judgment on this issue was appealed to the Hawaii Supreme Court by several parties. On July 8, 2003, the Hawaii Supreme Court issued its opinion affirming the Third

Circuit Court s final judgment on the basis that the BLNR failed to render the necessary four votes either approving or rejecting HELCO s application.

While the Hawaii Supreme Court s July 2003 decision validated the Third Circuit Court s 1998 final judgment confirming HELCO s default entitlement, construction of the expansion project had been delayed for much of the intervening period that had followed the 1998 final judgment, first because HELCO had not yet obtained its final air permit and then because of other rulings made by the Third Circuit Court in several related proceedings.

The Third Circuit Court s 1998 final judgment confirming HELCO s default entitlement provided that HELCO must comply with the conditions in its application and with the standard land use conditions insofar as those conditions were not inconsistent with the default entitlement. Numerous proceedings were commenced before the Third Circuit Court and the BLNR in which parties opposed to the project claimed that HELCO had not or could not comply with the conditions applicable to its default entitlement. The Third Circuit Court issued a number of rulings in these proceedings which further delayed or otherwise adversely affected HELCO s ability to construct and efficiently operate CT-4 and CT-5:

Based on a change by the DOH in its interpretation of the noise rules it promulgated under the Hawaii Noise Pollution Act, the Third Circuit Court ruled that a stricter noise standard applied to HELCO s Keahole plant. In the November 2003 Settlement Agreement (described below), HELCO agrees that the Keahole plant will comply during normal operations with the stricter noise standards and that it will not begin full-time operations of CT-4 and CT-5 until it has installed noise mitigation equipment to meet these standards. See Status of installation above. In accordance with the Settlement Agreement, the parties filed a stipulation to dismiss HELCO s appeal of the Noise Standards Judgment and the stipulation was approved in January 2004.

In other litigation in the Third Circuit Court brought by Keahole Defense Coalition (KDC) and two individuals (Individual Plaintiffs), the Third Circuit Court denied plaintiff s motions made on several grounds to enjoin construction of the Keahole plant and plaintiffs appealed these rulings to the Hawaii Supreme Court in June 2002. Pursuant to the Settlement Agreement, KDC filed a motion in the Hawaii Supreme Court to dismiss this appeal and the motion was granted on April 12, 2004.

In November 2000, the Third Circuit Court entered an order that, absent an extension authorized by the BLNR, the three-year construction period during which expansion of the Keahole plant should have been completed under the standard land use conditions of the Department of Land and Natural Resources of the State of Hawaii (DLNR) expired in April 1999. In December 2000, the Third Circuit Court granted a motion to stay further construction of the Keahole plant until an extension of the construction deadline was obtained. After an administrative hearing, in March 2002, the BLNR granted HELCO an extension of the construction deadline through December 31, 2003 (the March 2002 BLNR Order), subject to a number of conditions. In April 2002, based on the March 2002 BLNR Order, the Third Circuit Court lifted the stay it had imposed on construction and construction activities on CT-4 and CT-5 were restarted.

KDC and the Individual Plaintiffs appealed the March 2002 BLNR Order to the Third Circuit Court, as did the Department of Hawaiian Home Lands (DHHL). In September 2002, the Third Circuit Court issued a letter to the parties indicating its decision to reverse the March 2002 BLNR Order and the Third Circuit Court issued a final judgment to this effect in November 2002 (November 2002 Final Judgment). As a result of the letter ruling and November 2002 Final Judgment, the construction of CT-4 and CT-5 was once again suspended. HELCO appealed this ruling to the Hawaii Supreme Court.

The Settlement Agreement. With installation of CT-4 and CT-5 halted, the parties that opposed the Keahole power plant expansion project (other than Waimana, which did not participate in the settlement discussions and opposes the settlement), including KDC, the Individual Plaintiffs and DHHL, engaged in a mediation process with HELCO and several Hawaii regulatory agencies that led to an agreement in principle ultimately embodied in the Settlement Agreement. Subject to satisfaction of several conditions (some of which remain to be satisfied), HELCO was permitted under the Settlement Agreement to proceed with installation of CT-4 and CT-5, and, in the future, ST-7. In addition to KDC, the

Individual Plaintiffs, DHHL and HELCO, parties to the Settlement Agreement also include the DOH, the Director of the DOH, the DLNR and the BLNR.

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In connection with efforts to implement the agreement in principle and Settlement Agreement:

On October 10, 2003, the BLNR conditionally approved a 19-month extension of the previous December 31, 2003 construction deadline, but subject to court action allowing construction to proceed (BLNR 2003 Construction Period Extension).

On October 14, 2003, the Hawaii Supreme Court granted a motion to remand the pending appeal of the November 2002 Final Judgment (which was halting construction) in order to permit the Third Circuit Court to consider a motion to vacate that judgment.

On October 17, 2003, a motion to vacate the November 2002 Final Judgment was filed in the Third Circuit Court by KDC and DHHL.

On November 12, 2003, the motion to vacate the November 2002 Final Judgment was granted by the Third Circuit Court, over Waimana s objections, and, on November 28, 2003, the Third Circuit Court entered its first amended final judgment (November 2003 Final Judgment) vacating the November 2002 Final Judgment.

On November 17, 2003, HELCO resumed construction of CT-4 and CT-5.

On January 13, 2004, the Hawaii Supreme Court granted, over Waimana s objection, HELCO s motion to dismiss HELCO s original appeal of the November 2002 Final Judgment (since that judgment had been vacated).

Full implementation of the Settlement Agreement is conditioned on obtaining final dispositions of all litigation and proceedings pending at the time the Settlement Agreement was entered into. While substantial progress continues to be made, final dispositions of all such proceedings have not yet been obtained. If the remaining dispositions are obtained, as HELCO believes they will be, then HELCO has agreed in the Settlement Agreement that it will undertake a number of actions, in addition to complying with the stricter noise standards, to mitigate the impact of the power plant in terms of air pollution and potable water and aesthetic concerns. These actions relate to providing additional landscaping, expediting efforts to obtain the permits and approvals necessary for installation of ST-7 with selective catalytic reduction (SCR) emissions control equipment, operating existing CT-2 at Keahole within existing air permit limitations rather than the less stringent limitations in a pending air permit revision, using primarily brackish instead of potable water resources, assisting DHHL in installing solar water heating in its housing projects and in obtaining a major part of HELCO s potable water allocation from the County of Hawaii, supporting KDC s participation in certain PUC cases, paying legal expenses and other costs of various parties to the lawsuits and other proceedings, and cooperating with neighbors and community groups, including a Hot Line service for communications with neighboring DHHL beneficiaries.

Since the time construction activities resumed in November 2003, HELCO has begun implementation of many of its commitments under the Settlement Agreement. However, despite the numerous rulings against Waimana described above, Waimana has continued to pursue efforts to stop or delay the Keahole project and to interfere with implementation of the Settlement Agreement, including (a) filing a notice of appeal to the Hawaii Supreme Court of the Third Circuit Court s November 2003 Final Judgment (vacating the November 2002 Final Judgment), (b) appealing to the Third Circuit Court the BLNR 2003 Construction Period Extension, (c) appealing to the Third Circuit Court the BLNR s approval, on December 12, 2003, of HELCO s request for a revocable permit to use brackish well water as the primary source of water for operating the Keahole plant and (d) along with a group representing DHHL beneficiaries, appealing to the Third Circuit Court the BLNR s approval in March 2004 of HELCO s request for a long-term water lease to use the brackish well water (subject to conditions including a public auction of qualified bidders, which occurred on July 1, 2004 with HELCO the sole and prevailing bidder). In January 2004, the Third Circuit Court denied Waimana s motion to stay the effectiveness of the BLNR 2003 Construction Period Extension, and granted HELCO s motion (joined in by the BLNR) to dismiss Waimana s appeal of that extension. On April 15, 2004, Waimana appealed that ruling to the Supreme Court. In February 2004, the Third Circuit Court denied Waimana s motion to stay the effectiveness of the revocable permit to use brackish water, and granted HELCO s motion (joined in by the BLNR) to dismiss Waimana s appeal of that permit. The final judgment was entered on April 7, 2004. Waimana appealed that judgment to the Supreme Court on April 22, 2004. With regard to the appeal of the water lease, which was fully executed in July 2004 and took effect on August 1, 2004, both Waimana and the other party filed motions to stay the effectiveness of the lease, which motions were denied. On October 28, 2004, the Circuit Court granted HELCO s motion to dismiss Waimana from the case based on lack of standing. On November 3, 2004, the Circuit Court issued findings affirming the BLNR s action in granting the water lease. The final judgment was issued on February 4, 2005. The three Supreme Court appeals described in this paragraph are fully briefed and ready for decision.

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Land Use Commission petition. HELCO submitted to the Hawaii State Land Use Commission (LUC) on November 25, 2003 a new petition to reclassify the Keahole plant site from conservation land use to urban land use. The installation of ST-7, with SCR as contemplated by the Settlement Agreement, is dependent upon this reclassification. In December 2003, Waimana filed a Notice of Intent to Intervene in the LUC proceeding. On February 5, 2004, the LUC issued an order, with which HELCO concurred, that an environmental impact statement (EIS) be prepared in connection with the reclassification petition. Work on the EIS was already in progress before the ruling was issued. A draft EIS was submitted and published on November 8, 2004, starting a 45-day comment period. A final EIS was submitted to the LUC on January 24, 2005. The final EIS was accepted by the LUC on February 10, 2005. Further hearings on this petition are scheduled in 2005.

The entire reclassification process could take several years. The County of Hawaii s just approved General Plan, however, has classified the lands under the plant as urban, which could help the County zoning process following any land use reclassification.

Management s evaluation; costs incurred. Although (1) additional steps must be completed under the Settlement Agreement to satisfy its remaining conditions, (2) HELCO must obtain the further permits necessary to eventually allow installation and operation of ST-7 and (3) three appeals to the Hawaii Supreme Court by Waimana await final resolution, management believes that the prospects are good that those conditions will be satisfied, that any further necessary permits will be obtained and that the appeals will be favorably resolved.

Based on management s expectation that the remaining conditions under the Settlement Agreement will be satisfied, HELCO recorded, as expenses in November 2003, approximately $3.1 million of legal fees and other costs required to be paid under the Settlement Agreement. If the Settlement Agreement is implemented and ST-7 is installed, HELCO will have incurred approximately $24 million of capital expenditures relating to noise mitigation, visual mitigation and air pollution control at the Keahole power plant site (approximately $9 million for CT-4 and CT-5, approximately $10 million for ST-7, when installed, and approximately $5 million for other existing units). Other miscellaneous incidental expenses may also be incurred.

As of December 31, 2004, HELCO s capitalized costs incurred in its efforts to put CT-4 and CT-5 into service and to support existing units (excluding costs the PUC permitted to be transferred to plant-in-service for pre-air permit facilities) amounted to approximately $103 million, including $40 million for equipment and material purchases, $43 million for planning, engineering, permitting, site development and other costs and $20 million for AFUDC up to November 30, 1998, after which date management decided not to continue to accrue AFUDC in light of the delays that had been experienced, even though management believes that it has acted prudently with respect to the Keahole project. As of December 31, 2004, estimated additional capital costs of approximately $6 million will be required to complete the installations of CT-4 and CT-5, including the costs necessary to satisfy the requirements of the Settlement Agreement pertaining to those units. To date, HELCO has reclassified $103 million of capital costs for CT-4, CT-5 (excluding related pre-air permit facilities) from construction in progress to plant and equipment and depreciation has been recorded since January 1, 2005. The majority of the costs are being depreciated over 20 years. HELCO s electric rates, however, will not change specifically as a result of including CT-4 and CT-5 in HELCO s plant and equipment until HELCO files a rate increase application and the PUC grants HELCO rate relief.

The recovery of costs relating to CT-4 and CT-5 is subject to the rate-making process governed by the PUC. Management believes no adjustment to costs incurred to put CT-4 and CT-5 into service is required as of December 31, 2004. However, if it becomes probable that the PUC will disallow some or all of the incurred costs for rate-making purposes, HELCO may be required to write off a material portion of the costs incurred in its efforts to put these units into service.

HELCO s plans for ST-7 are pending until it obtains the contemplated reclassification of the Keahole plant site from conservation to urban and obtains the necessary permits, which HELCO has agreed to seek promptly. The costs of ST-7 will be higher than originally planned, not only by reason of the change in schedule in its installation, but also by reason of additional costs that will be incurred to satisfy the requirements of the Settlement Agreement.

<u>East Oahu transmission system</u>. HECO s power sources are located primarily in West Oahu, but the bulk of HECO s system load is in the Honolulu/East Oahu area. Accordingly, HECO transmits bulk power to the Honolulu/East Oahu area over two major transmission corridors (Northern and Southern). HECO had planned to construct a part underground/part overhead 138 kilovolt (kV) transmission line from the Kamoku substation to the

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Pukele substation in order to close the gap between the Southern and Northern corridors and provide a third 138 kV transmission line to the Pukele substation. Construction of the proposed transmission line in its originally proposed location required the BLNR to approve a Conservation District Use Permit (CDUP) for the overhead portion of the line that would have been in conservation district lands. Several community and environmental groups opposed the project, particularly the overhead portion of the line and, in June 2002, the BLNR denied HECO s request for a CDUP.

HECO continues to believe that the proposed project (the East Oahu Transmission Project) is needed to improve the reliability of the Pukele substation, which serves approximately 16% of Oahu s electrical load, including Waikiki, and to address future potential line overloads under certain contingencies. In 2003, HECO completed its evaluation of alternative ways to accomplish the project (including using 46 kV transmission lines). As part of its evaluation, HECO conducted a community-based process to obtain public views of the alternatives. In December 2003, HECO filed an application with the PUC requesting approval to commit funds (currently estimated at $55 million, which amount includes $23 million of costs already incurred and disclosed below) for its revised East Oahu Transmission Project. In March 2004, the PUC granted intervenor status to an environmental organization and three elected officials, granted a more limited participant status to four community organizations, and denied intervention sought by two individuals in the PUC proceeding.

At HECO s request, the PUC agreed to be the accepting agency for an environmental assessment (EA) of HECO s East Oahu Transmission Project prepared by HECO. The PUC issued a preliminary determination based on the draft EA that it intends to issue a Finding of No Significant Impacts unless it determines based on public comment and subsequent analysis of the final EA that an EIS is necessary. In September 2004, public notice of the availability of the draft EA for the revised project was published in the Environmental Notice. On January 7, 2005, HECO submitted the Final EA to the PUC. The Final EA, which incorporated and responded to all public comments received on the draft EA, is currently being reviewed by the PUC. Although HECO anticipates that the PUC will issue a Finding of No Significant Impacts based on the Final EA, the possibility that the PUC will require an EIS cannot be ruled out.

Under a stipulated order modified and adopted by the PUC in May 2004, the testimonies of the other parties and the evidentiary hearing before the PUC are scheduled to follow the completion of an environmental review process. That process will be deemed to be complete when the PUC reviews the final EA and either determines that an EIS is not required or, if an EIS is required, when the final EIS is accepted.

Subject to PUC approval, the revised project, none of which is in conservation district lands, will be built in two phases. Completion of the first phase, currently projected for 2007, will address future potential transmission line overloads in the Northern and Southern corridors and improve the reliability of service to many customers in the Pukele substation service area, including Waikiki. The second phase, projected to take an additional two years to complete, will improve service to additional customers in the Pukele substation service area by minimizing the duration of service interruptions that could occur under certain contingencies.

On March 3, 2004, approximately 40,000 of HECO s customers in the Honolulu/East Oahu area, including Waikiki, lost power. The Pukele substation serves the affected areas. One of the two transmission lines serving the Pukele substation was out for scheduled maintenance when the second transmission line went out of service and resulted in the power outage. Management believes that the sustained outage would have been prevented if the East Oahu Transmission Project had been completed. Many of the customers affected on March 3, 2004 would not have seen any interruption in service, while the other affected customers would have experienced a momentary interruption in service lasting only seconds.

As of December 31, 2004, the accumulated costs related to the East Oahu Transmission Project amounted to $23 million, including $15 million for planning, engineering and permitting costs and $8 million for AFUDC. These costs are recorded in construction in progress. The recovery of costs relating to the project is subject to the rate-making process administered by the PUC. Management believes no adjustment to project costs incurred is required as of December 31, 2004. 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.

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State of Hawaii, *ex rel*., Bruce R. Knapp, *Qui Tam* Plaintiff, and Beverly Perry, on behalf of herself and all others similarly situated, Class Plaintiff, vs. The AES Corporation, AES Hawaii, Inc., HECO and HEI. In April 2002, HECO and HEI were served with an amended complaint filed in the Circuit Court for the First Circuit of Hawaii alleging that the State of Hawaii and HECO s other customers have been overcharged for electricity as a result of alleged excessive prices in the amended PPA between defendants HECO and AES Hawaii, Inc. (AES Hawaii). AES Hawaii is a subsidiary of The AES Corporation (AES), which guarantees certain obligations of AES Hawaii under the amended PPA.

The amended PPA, which has a 30-year term, was approved by the PUC in December 1989, following contested case hearings in October 1988 and November 1989. The PUC proceedings addressed a number of issues, including whether the terms and conditions of the amended PPA were reasonable.

The amended complaint alleged that HECO s payments to AES Hawaii for power, based on the prices, terms and conditions in the PUC-approved amended PPA, have been excessive by over $1 billion since September 1992, and included various claims for relief and causes of action.

As a result of rulings by the First Circuit Court in 2003, the only remaining claims were under the Hawaii False Claims Act based on allegations that false bills or claims were submitted to the State after May 26, 2000. On August 25, 2003, the First Circuit Court issued an order dismissing with prejudice the amended complaint, including all of the Plaintiffs remaining claims against the defendants for violations under the Hawaii False Claims Act after May 26, 2000. The final judgment was entered on September 17, 2003. On October 15, 2003, plaintiff Beverly Perry filed a notice of appeal to the Hawaii Supreme Court and the Intermediate Court of Appeals, on the grounds that the Circuit Court erred in its reliance on the doctrine of primary jurisdiction and the statute of limitations. By order filed on July 16, 2004, the Supreme Court retained jurisdiction of the appeal (rather than assign it to the Intermediate Court of Appeals for disposition). In the opinion of management, the ultimate disposition of these matters will not have a material adverse effect on the Company s consolidated financial position, results of operations or liquidity.

Environmental regulation. HECO, HELCO and MECO, like other utilities, periodically identify leaking petroleum-containing equipment and other releases into the environment from its generation plants and other facilities. Each subsidiary reports these releases when and as required by applicable law and addresses impacts due to the releases in compliance with applicable regulatory requirements. Except as otherwise disclosed herein, the Company believes that each subsidiary s costs of responding to any such releases to date will not have a material adverse effect, individually and in the aggregate, on the Company s or consolidated HECO s financial statements.

Honolulu Harbor investigation. In 1995, the DOH issued letters indicating that it had identified a number of parties, including HECO, Hawaiian Tug & Barge Corp. (HTB) and Young Brothers, Limited (YB), who appear to be potentially responsible for the contamination and/or operated their facilities upon contaminated land at or near Honolulu Harbor. Certain of the identified parties formed a work group, which entered into a voluntary agreement with the DOH to determine the nature and extent of any contamination, the potentially responsible parties and appropriate remedial actions. The work group submitted reports and recommendations to the DOH and engaged a consultant who identified 27 additional potentially responsible parties (PRPs). The EPA became involved in the investigation in June 2000. Later in 2000, the DOH issued notices to additional PRPs. A new voluntary agreement and a joint defense agreement were signed by the parties in the work group and some of the new PRPs, which parties are known as the Iwilei District Participating Parties (Participating Parties). The Participating Parties agreed to fund remediation work using an interim cost allocation method (subject to a final allocation) and have organized a limited liability company to perform the work.

Under the terms of the 1999 agreement for the sale of assets of HTB and the stock of YB, HEI and The Old Oahu Tug Service, Inc. (TOOTS, formerly HTB) have specified indemnity obligations, including obligations with respect to the Honolulu Harbor investigation. In 2003, TOOTS paid $250,000 (for TOOTS and HEI) to the Participating Parties to fund response activities in the Iwilei Unit of the Honolulu Harbor site, as a one-time cash-out payment in lieu of continuing with further response activities.

Since 2001, subsurface investigation and assessment has 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. Currently, the Participating Parties are preparing a Remediation Alternatives Analysis which will identify and recommend remedial technologies and will further analyze the anticipated costs to be incurred.

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In addition to routinely maintaining its facilities, HECO had previously investigated its operations and ascertained that they were not releasing petroleum in the Iwilei Unit. In October 2002, HECO and three other companies (the Operating Companies) entered into a voluntary agreement with the DOH to evaluate their facilities to determine whether they are currently releasing petroleum to the subsurface in the Iwilei Unit. Pursuant to the agreement, the Operating Companies retained an independent consultant to conduct the evaluation. Based on available data, its own evaluation, as well as comments by the EPA, DOH and Operating Companies, the independent consultant issued a final report in the fourth quarter of 2003 that confirmed that HECO s facilities in the Iwilei Unit are functioning properly, not leaking, operating in compliance with all regulatory requirements and not contributing to contamination in the Iwilei District. In view of the final report, HECO does not anticipate that further work will be necessary under the 2002 voluntary agreement.

Management developed a preliminary estimate of HECO s share of costs primarily from 2002 through 2005 for continuing investigative work, remedial activities and monitoring at the Iwilei Unit of approximately $1.1 million (of which $0.4 million has been incurred through December 31, 2004). The $1.1 million estimate was expensed in 2001. Also, individual companies have incurred costs to remediate their facilities which will not be allocated to the Participating Parties. Because (1) the full scope and extent of additional investigative work, remedial activities and monitoring are unknown at this time, (2) the final cost allocation method has not yet been determined and (3) management cannot estimate the costs to be incurred (if any) for the sites other than the Iwilei Unit (including its Honolulu power plant site), the cost estimate may be subject to significant change and additional material investigative and remedial costs may be incurred.

Maalaea Units 12 and 13 notice and finding of violation. On September 5, 2003, MECO received a Notice of Violation (NOV) issued by the DOH alleging violations of opacity conditions in permits issued under the DOH s Air Pollution Control Law for two generating units at MECO s Maalaea Power Plant. The NOV ordered MECO to immediately take corrective action to prevent further opacity incidents. The NOV also ordered MECO to pay a penalty of $1.6 million, unless MECO submitted a written request for a hearing. In September 2003, MECO submitted a request for hearing and accrued $1.6 million for the potential penalty.

In December 2003, the DOH and MECO reached a conditional settlement of the NOV (reducing the penalty to approximately $0.8 million) and MECO reduced the initial September 2003 accrual of $1.6 million to $0.8 million. In late March 2004, after a public notice and comment period, the Consent Order was formally signed and approved by both the DOH and MECO, and MECO paid the settlement amount of $0.8 million. MECO came into full compliance with the opacity rules for the units by December 31, 2004 as required by the Consent Order. The Consent Order resolves all civil liability of MECO to the DOH for all opacity violations from February 1, 1999 to December 31, 2004. By letter dated January 12, 2005, the DOH informed MECO that it had closed the docket for the NOV.

Collective bargaining agreements. On November 7, 2003, members of the International Brotherhood of Electrical Workers (IBEW), AFL-CIO, Local 1260, Unit 8, ratified new collective bargaining and benefit agreements with HECO, HELCO and MECO. Of the electric utilities 2,013 employees, 1,179 are members of IBEW, AFL-CIO, Local 1260, Unit 8, which is the only union representing employees of the Company. The new collective bargaining and benefit agreements cover a four-year term, from November 1, 2003 to October 31, 2007, and provide for non-compounded wage increases (3% on November 1, 2003, 1.5% on November 1, 2004, 1.5% on May 1, 2005, 1.5% on November 1, 2005, 1.5% on May 1, 2006, and 3% on November 1, 2006) and include changes to medical, drug, vision and dental plans and increased employee contributions.

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4 Bank subsidiary

Selected consolidated financial information

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

Income statement data

Years ended December 31	2004	2003	2002
(in thousands)			
Interest and dividend income			
Interest and fees on loans	$ 184,773	$ 198,948	$ 203,082
Interest on mortgage-related securities	116,471	107,496	135,252
Interest and dividends on investment securities	5,876	6,384	7,896
	307,120	312,828	346,230
Interest expense			
Interest on deposit liabilities	47,184	53,808	73,631
Interest on Federal Home Loan Bank advances	43,301	48,280	58,608
Interest on securities sold under agreements to repurchase	22,302	21,236	20,643
	112,787	123,324	152,882
Net interest income	**194,333**	**189,504**	**193,348**
Provision for loan losses	(8,400)	3,075	9,750
Net interest income after provision for loan losses	**202,733**	**186,429**	**183,598**
Other income			
Fees from other financial services	23,560	22,817	21,254
Fee income on deposit liabilities	17,820	16,971	15,734
Fee income on other financial products	10,184	9,920	10,063
Fee income on loans serviced for others, net	252	155	(164)
Gain (loss) on sale of securities	(70)	4,085	(640)
Other income	5,418	4,544	6,778
	57,164	58,492	53,025
General and administrative expenses			
Compensation and employee benefits	65,052	65,805	59,594
Occupancy	16,996	16,579	15,508
Equipment	13,756	13,967	14,578
Consulting and other services	12,863	12,529	12,946
Data processing	11,794	10,668	11,167

Office supplies, printing and postage	4,699	4,850	4,746
Marketing	3,987	3,973	3,967
Communication	2,879	4,072	3,465
Amortization of goodwill and core deposit intangibles	1,730	1,730	1,731
Other	21,167	17,993	16,038
	154,923	152,166	143,740
Income before minority interests and income taxes	**104,974**	**92,755**	**92,883**
Minority interests	97	124	173
Income taxes	58,404	30,959	31,074
Income before preferred stock dividends	**46,473**	**61,672**	**61,636**
Preferred stock dividends	5,411	5,411	5,411
Net income for common stock	**$ 41,062**	**$ 56,261**	**$ 56,225**

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Balance sheet data

December 31	2004	2003
(in thousands)		
Assets		
Cash and equivalents	$ 120,295	$ 209,598
Federal funds sold	41,491	56,678
Available-for-sale investment and mortgage-related securities	2,034,091	1,775,053
Available-for-sale mortgage-related securities pledged for repurchase agreements	919,281	941,571
Held-to-maturity investment securities	97,365	94,624
Loans receivable, net	3,249,191	3,121,979
Other	213,528	221,718
Goodwill and other intangibles	91,263	93,987
	$ 6,766,505	$ 6,515,208
Liabilities and stockholders equity		
Deposit liabilities noninterest-bearing	$ 558,958	$ 469,272
Deposit liabilities interest-bearing	3,737,214	3,556,978
Securities sold under agreements to repurchase	811,438	831,335
Advances from Federal Home Loan Bank	988,231	1,017,053
Other	110,938	97,429
	6,206,779	5,972,067
Minority interests	3,415	3,417
Preferred stock		75,000
	3,415	78,417
Common stock	320,501	244,568
Retained earnings	243,001	221,109
Accumulated other comprehensive loss	(7,191)	(953)
	556,311	464,724
	$ 6,766,505	$ 6,515,208

Investment and mortgage-related securities

ASB owns one investment security-federal agency obligation, 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). At December 31, 2004, ASB s available-for-sale federal agency obligation had a contractual due date in November 2008. Contractual maturities are not presented for mortgage-related securities because these securities are not due at a single maturity date. Expected maturities will differ from contractual maturities because borrowers have the right to prepay the underlying mortgages.

Market prices for the investment security and mortgage-related securities issued by FHLMC, GNMA and FNMA are available from most third party securities pricing services. ASB obtains market prices for these securities from a third party financial services provider. Market prices for the private-issue mortgage-related securities are not readily available from standard pricing services, so prices are obtained from dealers who are specialists in those markets. The prices of these securities may be influenced by factors such as market liquidity, corporate credit considerations of the underlying collateral, 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.

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December 31, 2004

					Gross unrealized losses					
					Less than 12 months			12 months or longer		
($ in thousands)	Amortized cost	Gross unrealized gains	Gross unrealized losses	Estimated fair value	Count	Fair Value	Amount	Count	Fair Value	Amount
Available-for-sale										
Investment security-federal agency obligation	$ 24,953	$	$ (88)	$ 24,865	1	$ 24,865	$ (88)		$	$
Mortgage-related securities:										
FNMA	1,434,861	8,970	(12,245)	1,431,586	57	668,745	(6,017)	23	247,090	(6,228)
FHLMC	890,658	1,494	(5,365)	886,787	35	593,658	(3,514)	7	95,663	(1,851)
GNMA	218,501	1,094	(1,928)	217,667	5	83,558	(775)	5	46,735	(1,153)
Private issue	393,518	1,063	(2,114)	392,467	9	169,374	(1,199)	13	63,645	(915)
	$ 2,962,491	$ 12,621	$ (21,740)	$ 2,953,372	107	$ 1,540,200	$ (11,593)	48	$ 453,133	$ (10,147)

December 31, 2003

					Gross unrealized losses					
					Less than 12 months			12 months or longer		
($ in thousands)	Amortized cost	Gross unrealized gains	Gross unrealized losses	Estimated fair value	Count	Fair Value	Amount	Count	Fair Value	Amount
Available-for-sale										
Investment security-federal agency obligation	$ 49,833	$ 172	$	$ 50,005		$	$		$	$
Mortgage-related securities:										
FNMA	1,377,300	16,317	(9,297)	1,384,320	45	668,981	(9,297)			
FHLMC	754,514	3,376	(4,098)	753,792	24	447,629	(4,098)			
GNMA	227,584	1,958	(3,016)	226,526	10	150,947	(3,016)			
Private issue	306,583	1,595	(6,197)	301,981	7	88,156	(1,339)	30	88,517	(4,858)
	$ 2,715,814	$ 23,418	$ (22,608)	$ 2,716,624	86	$ 1,355,713	$ (17,750)	30	$ 88,517	$ (4,858)

December 31, 2002

(in thousands)	Amortized cost	Gross unrealized gains	Gross unrealized losses	Estimated fair value
Available-for-sale				
Mortgage-related securities:				
FNMA	$ 1,043,407	$ 37,207	$ (34)	$ 1,080,580
FHLMC	539,041	7,784	(76)	546,749
GNMA	225,002	7,136		232,138
Private issue	876,561	8,373	(7,722)	877,212
	$ 2,684,011	$ 60,500	$ (7,832)	$ 2,736,679

As of December 31, 2004, 2003 and 2002, ASB s held-to-maturity investment securities consisted of stock in the FHLB of Seattle. ASB did not sell held-to-maturity investment securities in 2004, 2003 or 2002.

The weighted-average interest rate of mortgage-related securities at December 31, 2004 and 2003 was 4.59% and 4.67%, respectively.

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In 2004, 2003 and 2002, proceeds from sales of available-for-sale mortgage-related securities were $45 million, $243 million and $77 million resulting in gross realized gains of $0.2 million, $4.2 million and $0.4 million and gross realized losses of $0.3 million, $0.1 million and $1.0 million, respectively.

ASB pledged mortgage-related securities with a carrying value of approximately $125 million and $71 million at December 31, 2004 and 2003, respectively, as collateral to secure public funds and deposits in ASB s treasury, tax, and loan account with the Federal Reserve Bank of San Francisco. At December 31, 2004 and 2003, mortgage-related securities with a carrying value of $919 million and $942 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, 2004 and 2003, all securities in the portfolio with unrealized losses are not other-than-temporarily impaired. 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 intends and believes it has the 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	2004	2003
(in thousands)		
Real estate loans		
One-to-four unit residential and commercial	$ 2,690,527	$ 2,638,178
Construction and development	202,466	100,986
	2,892,993	2,739,164
Loans secured by savings deposits	6,525	7,572
Consumer loans	217,221	206,748
Commercial loans	310,999	286,068
	3,427,738	3,239,552
Undisbursed portion of loans in process	(132,211)	(69,915)
Deferred fees and discounts, including net purchase accounting discounts	(21,223)	(20,765)
Allowance for loan losses	(33,857)	(44,285)
Loans held to maturity	3,240,447	3,104,587
Loans held for sale	8,744	17,392
	$ 3,249,191	$ 3,121,979

At December 31, 2004, ASB had impaired loans totaling $24 million, which consisted of $6 million of commercial real estate loans and $18 million of business loans. At December 31, 2003, ASB had impaired loans totaling $19 million, which consisted of $7 million of commercial real estate loans and $12 million of business loans. At December 31, 2004 and 2003, impaired loans totaling $1 million and $7 million, respectively, had related allowances for loan losses of $0.2 million and $1.0 million, respectively. At December 31, 2004 and 2003, ASB had

$23 million and $12 million of impaired loans, respectively, for which there were no related allowances for loan losses. ASB realized $1.3 million, $1.7 million and $2.3 million of interest income on impaired loans in 2004, 2003 and 2002, respectively. The average balances of impaired loans during 2004, 2003 and 2002 were $20 million, $23 million and $26 million, respectively.

At December 31, 2004 and 2003, ASB had nonaccrual and renegotiated loans of $12 million and $13 million, respectively.

ASB realized $0.4 million, $0.1 million and $0.4 million of interest income on nonaccrual loans in 2004, 2003 and 2002, respectively. If these loans would have earned interest in accordance with their original contractual terms ASB would have realized $0.6 million, $0.5 million and $0.9 million in 2004, 2003 and 2002, respectively. ASB had no loans that were 90 days or more past due on which interest was being accrued at December 31, 2004 and 2003.

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At December 31, 2004 and 2003, commitments not reflected in the consolidated balance sheets consisted of commitments to originate loans, other than the undisbursed portion of loans in process, of $42 million and $47 million, respectively. Of such commitments at December 31, 2004, $22 million was for variable-rate loans and $20 million was for fixed-rate loans. Commitments to extend credit are agreements to lend to a customer as long as there is no violation of any condition established in the contract. 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.

At December 31, 2004 and 2003, ASB had commitments to sell residential loans of $0.3 million and $16 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, 2004, there were no rate lock commitments made on loans to be held for sale. At December 31, 2003, rate lock commitments were made on loans totaling $8.0 million. 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 sale 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 on the balance sheet in Other assets or liabilities. As of December 31, 2004 and 2003, the notional amounts for forward sales contracts were $0.3 million and $16 million, respectively. Valuation models are applied using current market information to estimate fair value. For 2004 and 2003, the net loss on derivatives was nil and less than $40,000, respectively.

ASB had commitments to sell education loans of $8.4 million as of December 31, 2004 and 2003.

At December 31, 2004 and 2003, standby, commercial and banker s acceptance letters of credit totaled $40 million and $13 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. At December 31, 2004 and 2003, unused lines of credit totaled $708 million and $653 million, respectively.

ASB services real estate loans owned by third parties ($0.5 billion, $0.6 billion and $0.9 billion at December 31, 2004, 2003 and 2002, 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.

At December 31, 2004 and 2003, ASB had pledged loans with an amortized cost of approximately $1.2 billion as collateral to secure advances from the FHLB of Seattle.

At December 31, 2004 and 2003, 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 $74 million and $95 million, respectively. The $21 million decrease in such loans in 2004 was attributed to repayments of $21 million, new loans of $5 million and closed lines of credit of $5 million. At December 31, 2004 and 2003, $58 million and $83 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.

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

Years ended December 31,	2004	2003	2002
(dollars in thousands)			
Allowance for loan losses, January 1	$ 44,285	$ 45,435	$ 42,224
Provision for loan losses	(8,400)	3,075	9,750
Charge-offs, net of recoveries			
Real estate loans	(868)	(604)	1,876
Other loans	2,896	4,829	4,663
Net charge-offs	2,028	4,225	6,539
Allowance for loan losses, December 31	$ 33,857	$ 44,285	$ 45,435
Ratio of allowance for loan losses, December 31, to average loans outstanding	1.08%	1.44%	1.60%
Ratio of provision for loan losses to average loans outstanding	NM	0.10%	0.34%
Ratio of net charge-offs to average loans outstanding	0.06%	0.14%	0.23%

NM Not meaningful.

Real estate acquired in settlement of loans. At December 31, 2004 and 2003, ASB s real estate acquired in settlement of loans was $0.9 million and $7.9 million, respectively.

Deposit liabilities

December 31	2004		2003	
(in thousands)	Weighted-average stated rate	Amount	Weighted-average stated rate	Amount
Savings	0.40%	$ 1,700,211	0.46%	$ 1,497,146
Other checking				
Interest-bearing	0.06	534,464	0.04	516,500
Noninterest-bearing		256,346		184,059
Money market	0.58	303,162	0.40	342,845
Commercial checking		302,612		285,213
Term certificates	3.26	1,199,377	3.52	1,200,487

	1.12%	$ 4,296,172	1.26%	$ 4,026,250

At December 31, 2004 and 2003, deposit accounts of $100,000 or more totaled $1.2 billion and $1.0 billion, respectively.

The approximate amounts of term certificates outstanding at December 31, 2004 with scheduled maturities for 2005 through 2009 were $730.1 million in 2005, $194.0 million in 2006, $126.9 million in 2007, $38.0 million in 2008 and $76.7 million in 2009.

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Interest expense on savings deposits by type of deposit was as follows:

Years ended December 31	2004	2003	2002
(in thousands)			
Term certificates	$ 38,935	$ 43,413	$ 51,968
Savings	6,525	7,524	14,512
Money market	1,448	2,424	6,092
Interest-bearing checking	276	447	1,059
	$ 47,184	$ 53,808	$ 73,631

Securities sold under agreements to repurchase

December 31, 2004

Maturity	Repurchase liability	Weighted-average interest rate	Collateralized by mortgage-related securities fair value plus accrued interest
(in thousands)			
Overnight	$ 72,980	1.38%	$ 103,328
1 to 29 days	68,923	2.84	86,339
30 to 90 days	198,715	3.89	233,066
Over 90 days	470,820	3.66	500,070
	$ 811,438	3.44%	$ 922,803

At December 31, 2004, securities sold under agreements to repurchase consisted of mortgage-related securities sold under fixed-coupon agreements. The FHLMC, GNMA and FNMA mortgage-related securities are book-entry securities and were delivered by appropriate entry into the counterparties accounts at the Federal Reserve System. The remaining securities underlying the agreements were delivered to the brokers/dealers who arranged the transactions. 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. At December 31, 2004, the agreements include transactions with public (governmental) entities, primarily the state of Hawaii, amounting to $213.8 million with a weighted average maturity of 64 days. At December 31, 2004 and 2003, ASB had agreements to repurchase identical securities totaling $811 million and $831 million, respectively. At December 31, 2004 and 2003, the weighted-average rate on securities sold under agreements to repurchase was 3.4% and 2.5%, respectively, and the weighted-average remaining days to maturity was 500 days and 640 days, respectively. During 2004, 2003 and 2002, securities sold under agreements to repurchase averaged $842 million, $807 million and $663 million, respectively, and the maximum amount outstanding at any month-end was $990 million, $958 million and $751 million, respectively.

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Advances from Federal Home Loan Bank

December 31	2004		2003	
(in thousands)	Weighted-average stated rate	Amount	Weighted-average stated rate	Amount
Due in				
2004	NA	NA	3.39%	$ 123,822
2005	4.77%	$ 282,731	4.40	282,731
2006	3.58	183,500	3.63	168,500
2007	3.90	166,000	3.90	166,000
2008	5.45	168,000	5.45	168,000
2009	4.60	163,000	4.91	83,000
Thereafter	4.43	25,000	4.43	25,000
	4.48%	$ 988,231	4.28%	$ 1,017,053

NA Not applicable.

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 at December 31, 2004 and 2003.

ASB restructured a total of $389 million of FHLB advances during 2003. The restructurings involved paying off existing, higher rate FHLB advances with advances that have lower rates and longer maturities. The restructurings were executed in two transactions, with $258 million of advances restructured in April 2003 and $131 million of advances restructured in June 2003. In the April 2003 restructuring, the FHLB advances that were paid off had an average rate of 7.17% and an average remaining maturity of 2.02 years. The new advances had an average rate of 5.57% and an average maturity of 4.80 years at the time of the restructuring. In the June 2003 restructuring, the FHLB advances that were paid off had an average rate of 5.21% and an average remaining maturity of 0.93 years. The new advances had an average rate of 3.21% and an average remaining maturity of 4.12 years at the time of the restructuring.

Common stock equity. As of December 31, 2004, 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. As of December 31, 2004, 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 million.

In December 2004, ASB s capital structure changed when ASB redeemed its preferred stock held by HEIDI ($75 million) and HEIDI infused common equity into ASB ($75 million).

The change in accumulated other comprehensive income (loss) from December 31, 2003 to December 31, 2004 was primarily due to the change in the market value of the available-for-sale mortgage-related securities. 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.

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5 Short-term borrowings

Short-term borrowings consisted of commercial paper issued by HECO at December 31, 2004 and had a weighted-average interest rate of 2.5%. No commercial paper was outstanding at December 31, 2003.

At December 31, 2004 and 2003, HEI maintained bank lines of credit which totaled $80 million ($20 million maturing in April 2005, $15 million in June 2005, $15 million in October 2005 and $30 million in December 2005) and $90 million, respectively, and HECO maintained bank lines of credit which totaled $110 million ($80 million maturing in April 2005 and $30 million in June 2005) and $90 million, respectively. In January 2005, HECO increased its total lines of credit to $140 million, thereby increasing to $90 million and $50 million the HECO lines maturing in April 2005 and June 2005, respectively. HEI maintains lines of credit (at a base rate (Prime, Fed Funds, Bank Base, Eurodollar or LIBOR rate) plus a margin ranging from 0 to 125 basis points) and HECO maintains lines of credit (at a base rate (Prime, Fed Funds, Bank Base, Bank Quoted or LIBOR rate) plus a margin ranging from 0 to 81 basis points) to support the issuance of commercial paper and for other general corporate purposes. Fees to maintain the lines of credit are not material. Lines of credit maintained by HEI have covenants, including covenants related to capitalization ratios, consolidated net worth, maintaining 100% ownership of HECO and its subsidiaries and ASB remaining well-capitalized. Lines of credit to HEI totaling $30 million contain provisions for revised pricing in the event of a ratings change. Lines of credit maintained by HECO have covenants, including covenants related to capitalization ratios. None of the lines are secured. There were no borrowings under any line of credit during 2004 and 2003.

6 Long-term debt

December 31	**2004**	**2003**
(in thousands)		
6.50% Junior Subordinated Deferrable Interest Debentures, Series 2004, due 2034 (see Note 7)	$ 51,546	$
Obligations to the State of Hawaii for the repayment of special purpose revenue bonds (SPRB) issued on behalf of electric utility subsidiaries		
4.95%, due 2012	57,500	57,500
4.75-5.70%, due 2020-2023	232,000	232,000
5.65-6.60%, due 2025-2027	272,000	272,000
5.50-6.20%, due 2014-2029	116,400	116,400
5.10%, due 2032	40,000	40,000
	717,900	717,900
Less funds on deposit with trustees	(12,462)	(14,013)
Less unamortized discount	(4,249)	(4,467)
	701,189	699,420
HEI promissory notes 4.00-7.56%, due in various years through 2014	414,000	365,000
	$ 1,166,735	$ 1,064,420

At December 31, 2004, the aggregate principal payments required on long-term debt for 2005 through 2009 are $37 million in 2005, $110 million in 2006, $10 million in 2007, $50 million in 2008 and nil in 2009.

In January 2005, the Department of Budget and Finance of the State of Hawaii issued, at par, Refunding Series 2005A SPRB in the aggregate principal amount of $47 million with a maturity of January 1, 2025 and a fixed coupon interest rate of 4.80% and loaned the proceeds from the sale to HECO, HELCO and MECO. The proceeds of such bonds, along with additional funds, were applied to redeem at a 1% premium a like principal amount of SPRB bearing a higher interest coupon (HECO s, HELCO s, and MECO s aggregate $47 million of $6.60% Series 1995A SPRB with original maturity of January 1, 2025) in February 2005.

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7 HEI- and HECO-obligated preferred securities of trust subsidiaries

December 31	2004	2003	Liquidation value per security
(in thousands, except per security amounts and number of securities)			
Hawaiian Electric Industries Capital Trust I* 8.36% Trust Originated Preferred Securities (4,000,000 securities)**	$	$ 100,000	$ 25
HECO Capital Trust I* 8.05% Cumulative Quarterly Income Preferred Securities, Series 1997 (2,000,000 securities)***		50,000	25
HECO Capital Trust II* 7.30% Cumulative Quarterly Income Preferred Securities, Series 1998 (2,000,000 securities)***		50,000	25
HECO Capital Trust III* 6.50% Cumulative Quarterly Income Preferred Securities, Series 2004 (2,000,000 securities)****	50,000		25
	$ 50,000	$ 200,000	

* Delaware grantor trust.

** Fully and unconditionally guaranteed by HEI and redeemed in April 2004 without premium.

*** Fully and unconditionally guaranteed by HECO and redeemed in April 2004 without premium

**** Fully and unconditionally guaranteed by HECO; 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 redeemable at the issuer s option without premium beginning on March 18, 2009.

Hawaiian Electric Industries Capital Trust I (the Trust) was a financing entity, which issued, in 1997, $100 million of 8.36% Trust Originated Preferred Securities to the public. As of January 1, 2004, the Trust became an unconsolidated subsidiary of HEI under FIN 46R. In March 2004, HEI completed the issuance and sale of 2 million shares of its common stock (pre-split) in a registered public offering. HEI used the net proceeds from the sale, along with other corporate funds, to effect the redemption of the 8.36% Trust Originated Preferred Securities in April 2004. The Trust was dissolved in April 2004 and terminated in late 2004.

HECO Capital Trust I (Trust I) was a financing entity, which issued, in 1997, $50 million of 8.05% Cumulative Quarterly Income Preferred Securities, Series 1997 (1997 Trust Preferred Securities) to the public. As of January 1, 2004, Trust I became an unconsolidated subsidiary of HECO under FIN 46R. In March 2004, HECO, HELCO and MECO issued 6.50% Junior Subordinated Deferrable Interest Debentures, Series 2004 (2004 Debentures) to HECO Capital Trust III and, in April 2004, used the proceeds, along with other corporate funds, to effect the redemption of the 1997 Trust Preferred Securities. Trust I was dissolved in April 2004 and terminated in late 2004.

HECO Capital Trust II (Trust II) was a financing entity, which issued, in 1998, $50 million of 7.30% Cumulative Quarterly Income Preferred Securities, Series 1998 (1998 Trust Preferred Securities) to the public. As of January 1, 2004, Trust II became an unconsolidated subsidiary of

HECO under FIN 46R. In April 2004, the electric utilities used funds primarily from short-term borrowings from HEI and from the issuance of commercial paper by HECO to effect the redemption of the 1998 Trust Preferred Securities. Trust II was dissolved in April 2004 and terminated in late 2004.

HECO Capital Trust III (Trust III) exists for the exclusive purposes of (i) issuing in 2004 trust securities, consisting of 6.50% Cumulative Quarterly Income Preferred Securities, Series 2004 (2004 Trust Preferred Securities) ($50 million) issued to the public and trust common securities ($1.5 million) issued to HECO, (ii) investing the proceeds of the 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 2004 Trust Preferred Securities and trust common securities and (iv) engaging in only those other activities necessary or incidental thereto. The 2004 Debentures, together with the obligations of HECO, MECO and HELCO under an expense agreement and HECO s obligations under its trust guarantee and its guarantee of the obligations of MECO and HELCO under their respective debentures, are the sole assets of Trust III. Trust III is an unconsolidated subsidiary of HECO. Trust III s balance sheet as of December 31, 2004 consisted of $51.5 million of 2004 Debentures; $50.0 million of 2004 Trust Preferred Securities; and $1.5 million of

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Trust Common Securities. Trust III s income statement for 2004 consisted of $2.6 million of interest income received from the 2004 Debentures; $2.5 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 on the Trust Common Securities, and in certain circumstances, HECO s right to receive such distributions is subordinate to the right of the holders to receive distributions on their 2004 Trust Preferred 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.

8 Retirement benefits

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 and substantially all of the employees of ASB and its subsidiaries participate in the American Savings Bank Retirement Plan (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 Employee Retirement Income Security Act of 1974, as amended (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 Plans and the Supplemental/Excess/Directors Plans were adopted with the expectation that they will continue indefinitely, but the continuation of these plans and the payment of any contribution thereunder is not assumed as a contractual obligation 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.

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.

The participating employers contribute amounts to a master pension trust for the Plans in accordance with the funding requirements of ERISA and considering the deductibility of contributions under the Internal Revenue Code. The funding of the Plans is based on actuarial assumptions adopted by the Pension Investment Committee administering the Plans on the advice of an enrolled actuary.

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. Health benefits are also provided to dependents of eligible employees. The contribution for health benefits paid by the participating employers is based on 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 Retirement Plan for Employees of Hawaiian Electric Industries, Inc. and Participating Subsidiaries.

Among other provisions, the 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. See Medicare Prescription Drug, Improvement and Modernization Act of 2003 under General Recent accounting pronouncements and interpretations in Note 1.

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The postretirement benefits other than pensions plan was adopted with the expectation that it will continue indefinitely, but the continuation of the 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.

Pension and other postretirement benefit plans information. The changes in the pension and other postretirement benefit defined benefit plans obligations and plan assets, the funded status of the plans and the unrecognized and recognized amounts reflected in the Company s balance sheet were as follows:

	Pension benefits		Other benefits	
(in thousands)	**2004**	**2003**	**2004**	**2003**
Benefit obligation, January 1	$ 828,300	$ 728,780	$ 180,108	$ 159,430
Service cost	26,454	22,918	4,530	3,580
Interest cost	50,654	47,970	10,770	10,408
Amendments	83	19	(1,261)	
Actuarial loss	28,679	66,483	14,083	13,936
Benefits paid and expenses	(40,532)	(37,870)	(8,048)	(7,246)
Benefit obligation, December 31	893,638	828,300	200,182	180,108
Fair value of plan assets, January 1	723,854	589,092	98,189	75,926
Actual return on plan assets	70,700	134,829	9,993	19,212
Employer contribution	27,736	37,803	9,350	10,297
Benefits paid and expenses	(40,532)	(37,870)	(8,048)	(7,246)
Fair value of plan assets, December 31	781,758	723,854	109,484	98,189
Funded status	(111,880)	(104,446)	(90,698)	(81,919)
Unrecognized net actuarial loss	226,936	197,238	40,505	26,724
Unrecognized net transition obligation	23	27	25,104	29,503
Unrecognized prior service cost (gain)	(5,695)	(6,365)	170	183
Net amount recognized, December 31	$ 109,384	$ 86,454	$ (24,919)	$ (25,509)
Amounts recognized in the balance sheet consist of:				
Prepaid benefit cost	$ 119,552	$ 95,020	$	$
Accrued benefit liability	(12,136)	(11,005)	(24,919)	(25,509)
Intangible asset	151	67		
Accumulated other comprehensive income	1,817	2,372		
Net amount recognized, December 31	$ 109,384	$ 86,454	$ (24,919)	$ (25,509)

The defined benefit pension plans accumulated benefit obligations, which do not consider projected pay increases, as of December 31, 2004 and 2003 were $750 million and $691 million, respectively. Depending on the performance of the pension plan assets, the status of interest rates and numerous other factors, the Company could be required to recognize an additional minimum liability as prescribed by SFAS No. 87, Employers Accounting for Pensions, in the future. If recognizing a liability is required, the liability would largely be recorded as a reduction to stockholders equity through a non-cash charge to accumulated other comprehensive income, and would result in the removal of the prepaid pension asset

($120 million as of December 31, 2004) from the Company s balance sheet.

The measurement dates used to determine pension and other postretirement benefit measurements for the defined benefit plans were December 31, 2004, 2003 and 2002.

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The weighted-average asset allocation of pension and other postretirement benefit defined benefit plans was as follows:

	Pension benefits				Other benefits			
			Investment policy				Investment policy	
December 31	2004	2003	Target	Range	2004	2003	Target	Range
Asset category								
Equity securities	75%	76%	74%	67-80%	74%	77%	75%	70-80%
Debt securities	25	22	25	20-30%	26	22	25	20-30%
Other		2	1	0-3%		1		
	100%	100%	100%		100%	100%	100%	

In July 2004, the Company s Pension Investment Committee (PIC) approved a new target weighted-average asset allocation of pension and other postretirement benefit defined benefit plans as follows: equity securities 70%, and debt securities 30%. Subsequently, a plan to move toward these targets was developed by the plans investment consultants and approved by the PIC. The plan is currently being implemented. As a result, the investment policy (target and range shown above) will be amended in the future.

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 pension and other postretirement benefit defined benefit 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 was based on an asset/liability study performed by the plans actuarial and investment consultants, which projected the return over the long term to be in excess of 9%, based on the target asset allocation.

The Company s current estimate of contributions to the retirement benefit plans in 2005 is $17 million.

As of December 31, 2004, the benefits expected to be paid under the retirement benefit plans in 2005, 2006, 2007, 2008, 2009 and 2010 through 2014 amounted to $51 million, $54 million, $57 million, $59 million, $62 million and $357 million, respectively.

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

	Pension benefits	Other benefits

December 31	2004	2003	2002	2004	2003	2002
Benefit obligation						
Discount rate	6.00%	6.25%	6.75%	6.00%	6.25%	6.75%
Expected return on plan assets	9.0	9.0	9.0	9.0	9.0	9.0
Rate of compensation increase	4.6	4.6	4.6	4.6	4.6	4.6
Net periodic benefit cost (years ended)						
Discount rate	6.25	6.75	7.25	6.25	6.75	7.25
Expected return on plan assets	9.0	9.0	10.0	9.0	9.0	10.0
Rate of compensation increase	4.6	4.6	4.6	4.6	4.6	4.6

At December 31, 2004, the assumed health care trend rates for 2005 and future years were as follows: medical, 10.00%, grading down to 5.00% for 2010 and thereafter; dental, 5.00%; and vision, 4.00%. At December 31, 2003, the assumed health care trend rates for 2004 and future years were as follows: medical, 10.00%, grading down to 4.25% for 2011 and thereafter; dental, 4.25%; and vision, 3.25%.

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The components of net periodic benefit cost (return) were as follows:

	Pension benefits			Other benefits		
Years ended December 31	**2004**	**2003**	**2002**	**2004**	**2003**	**2002**
(in thousands)						
Service cost	$ 26,454	$ 22,918	$ 20,215	$ 4,531	$ 3,580	$ 3,135
Interest cost	50,654	47,970	45,806	10,770	10,408	10,158
Expected return on plan assets	(72,880)	(59,790)	(80,958)	(9,691)	(7,639)	(10,023)
Amortization of unrecognized transition obligation	4	954	2,270	3,138	3,278	3,278
Amortization of prior service cost (gain)	(587)	(614)	(505)	13	13	13
Recognized actuarial loss (gain)	1,160	4,035	(3,489)			(716)
Net periodic benefit cost (return)	$ 4,805	$ 15,473	$ (16,661)	$ 8,761	$ 9,640	$ 5,845

Of the net periodic pension benefit costs (returns), the Company recorded expense of $5 million in 2004 and $13 million in 2003 and income of $11 million in 2002, and charged or credited the remaining amounts primarily to electric utility plant. Of the net periodic other than pension benefit costs, the Company expensed $6 million, $7 million and $4 million in 2004, 2003 and 2002, 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 $15 million, $12 million and nil, respectively, as of December 31, 2004 and $13 million, $11 million and nil, respectively, as of December 31, 2003.

The health care cost trend rate assumptions can have a significant effect on the amounts reported for other benefits. At December 31, 2004, a one-percentage-point increase in the assumed health care cost trend rates would have increased the total service and interest cost by $0.5 million and the postretirement benefit obligation by $7.3 million, and a one-percentage-point decrease would have reduced the total service and interest cost by $0.5 million and the postretirement benefit obligation by $7.3 million.

9 Stock compensation

Under the 1987 Stock Option and Incentive Plan, as amended, HEI may issue an aggregate of 9,300,000 shares of common stock (5,702,914 shares unissued as of December 31, 2004) to officers and key employees as incentive stock options, nonqualified stock options, restricted stock, stock appreciation rights (SARs), stock payments or dividend equivalents. HEI has issued nonqualified stock options, SARs, restricted stock and dividend equivalents. The restricted stock generally becomes 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 method of accounting in the amounts of $172,000 in 2004, $112,000 in 2003 and $58,000 in 2002.

For the nonqualified stock options and SARs, the exercise price of each option or SAR generally equals the market price of HEI s stock on or near the date of grant. Options and SARs 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. In general, options and SARs include dividend equivalents over the four-year vesting period. The Company recorded stock option and SARs compensation expense of $1.6 million in 2004, $2.0 million in 2003 and $1.5 million in 2002.

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Information about HEI s nonqualified stock options are summarized as follows:

	2004		2003		2002	
	Shares	(1)	Shares	(1)	Shares	(1)
Outstanding, January 1	1,476,600	$ 19.02	1,266,050	$ 18.31	1,628,500	$ 17.79
Granted			456,000	20.49	294,000	21.68
Exercised	(348,100)	16.67	(241,450)	18.08	(656,450)	18.54
Forfeited or expired	(6,000)	19.86	(4,000)	19.14		
Outstanding, December 31	1,122,500	19.74	1,476,600	$ 19.02	1,266,050	$ 18.31
Options exercisable, December 31	568,000	19.06	591,100	$ 17.60	545,550	$ 17.47

(1) Weighted-average exercise price

	Outstanding				Exercisable	
Year of grant	Range of exercise prices	Number of options at 12/31/04	Weighted-average remaining contractual life	Weighted-average exercise price	Number of options at 12/31/04	Weighted-average exercise price
1997	$ 17.31	6,000	2.3	$ 17.31	6,000	$ 17.31
1998	20.50	16,000	3.3	20.50	16,000	20.50
1999	17.61 17.63	65,000	4.5	17.62	65,000	17.62
2000	14.74 16.72	54,500	5.4	14.83	54,500	14.83
2001	17.96 20.00	277,000	6.3	18.19	197,000	18.19
2002	21.68	264,000	7.3	21.68	127,000	21.68
2003	20.49	440,000	8.3	20.49	102,500	20.49
	14.74 21.68	1,122,500	7.1	19.74	568,000	19.06

The weighted-average fair value of each option granted was $4.11 and $4.91 (at grant date) in 2003 and 2002, respectively. The weighted-average assumptions used to estimate fair value include: risk-free interest rate of 3.0% and 4.6%; expected volatility of 18.4% and 17.5%; expected dividend yield of 6.6% and 7.0% for 2003 and 2002, respectively, and expected life of 4.5 years for each of the two years. The weighted-average fair value of each option grant is estimated on the date of grant using a Binomial Option Pricing Model. At December 31, 2004, unexercised stock options have exercise prices ranging from $14.74 to $21.68 per common share.

SARs in the amount of 349,000 were granted in 2004 and are outstanding at December 31, 2004, none of which are exercisable. The weighted-average fair value of each of the SARs granted during 2004 was $5.11 (at grant date). For 2004, the weighted-average assumptions used to estimate fair value include: risk-free interest rate of 3.4%, expected volatility of 16.7%, expected dividend yield of 5.8% and expected life of 4.5 years. The weighted-average fair value of each SARs grant is estimated on the date of grant using a Binomial Option Pricing Model. At December 31, 2004, unexercised SARs have an exercise price of $26.02 per SAR and a weighted-average remaining contractual life of 9.3 years.

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10 Income taxes

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

Years ended December 31	2004	2003	2002
(in thousands)			
Federal			
Current	$ 42,142	$ 58,763	$ 24,791
Deferred	15,670	3,032	35,614
Deferred tax credits, net	(1,446)	(1,504)	(1,557)
	56,366	60,291	58,848
State			
Current	32,809	2,213	2,668
Deferred	(1,875)	1,307	1,139
Deferred tax credits, net	5,180	556	1,037
	36,114	4,076	4,844
	$ 92,480	$ 64,367	$ 63,692

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	2004	2003	2002
(in thousands)			
Amount at the federal statutory income tax rate	$ 70,077	$ 63,845	$ 63,668
Increase (decrease) resulting from:			
State income taxes, net of effect on federal income taxes and excluding cumulative bank franchise taxes through December 31, 2003	3,133	2,649	3,149
Cumulative bank franchise taxes through December 31, 2003	20,340		
Other, net	(1,070)	(2,127)	(3,125)
	$ 92,480	$ 64,367	$ 63,692

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

December 31	2004	2003
(in thousands)		
Deferred tax assets		
Cost of removal in excess of salvage value	$ 76,687	$ 69,425
Contributions in aid of construction and customer advances	39,159	42,179
Allowance for loan losses	13,841	14,711
Other	40,847	30,804
	170,534	157,119
Deferred tax liabilities		
Property, plant and equipment	249,790	237,778
Leveraged leases	29,920	32,911
Pension	42,240	27,990
Real estate investment trust dividends (federal income taxes only)	9,775	19,396
Net unrealized gains on available-for-sale mortgage-related securities		1,573
Regulatory assets, excluding amounts attributable to property, plant and equipment	26,756	25,514
FHLB stock dividend	21,690	18,645
Other	20,128	19,902
	400,299	383,709
Net deferred income tax liability	$ 229,765	$ 226,590

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. As of December 31, 2004, the valuation allowance for deferred tax benefits is not significant.

ASB state franchise tax dispute and settlement. In March 1998, ASB formed a subsidiary, ASB Realty Corporation, which elected to be taxed as a real estate investment trust. This reorganization had reduced Hawaii bank franchise taxes, net of federal income tax benefits, recognized on the financial statements of HEI Diversified, Inc. and ASB by $21 million (through March 31, 2004) as a result of ASB taking a dividends received deduction on dividends paid to it by ASB Realty Corporation. The State of Hawaii Department of Taxation (DOT) challenged ASB s position on the dividends received deduction and issued notices of tax assessment for 1999 through 2001. In October 2002, ASB filed an appeal with the State Board of Review, First Taxation District (Board). In May 2003, the Board issued its decision in favor of the DOT and ASB filed a notice of appeal with the Hawaii Tax Appeal Court. As required under Hawaii law, ASB paid the bank franchise taxes and interest assessed at that time ($17 million) in June 2003, but recorded this payment as a deposit rather than an expense for financial statement purposes.

In June 2004, the Hawaii Tax Appeal Court issued its decision in favor of the DOT and against ASB for tax assessed years 1999 through 2001. ASB appealed the decision to the Hawaii Supreme Court, which appeal was dismissed as part of a settlement described below. As a result of the Hawaii Tax Appeal Court s decision, ASB wrote off the deposit recorded in June 2003 and expensed the related bank franchise taxes and interest for subsequent periods through March 31, 2004 related to this issue, resulting in a cumulative after-tax charge to net income in the second quarter of 2004 of $24 million ($21 million for the bank franchise taxes and $3 million for interest).

On December 31, 2004, ASB agreed to settle its dispute with the DOT and close the tax years 1999 through 2004 (relating to the financial performance of ASB for the calendar years 1998 through 2003) for purposes of audit, examination, assessment, refund and judicial review. Under the terms of the settlement, ASB agreed to pay the DOT $12 million, in addition to the $17 million previously paid under protest, dismiss its appeal to the Hawaii Supreme Court and not take the dividends received deduction in future years. As a result, ASB recognized $3 million in additional net income in the fourth quarter of 2004, representing a partial reversal of the $24 million previously charged against net income. A plan for the dissolution of ASB Realty Corporation has been submitted for regulatory approval. The plan contemplates that ASB Realty Corporation would satisfy all obligations to creditors and then distribute its assets to shareholders. ASB holds substantially all of the preferred and common stock of ASB Realty Corporation.

11 Cash flows

Supplemental disclosures of cash flow information. In 2004, 2003 and 2002, the Company paid interest amounting to $185 million, $196 million and $222 million, respectively.

In 2004, 2003 and 2002, the Company paid income taxes amounting to $42 million, $53 million and $60 million, respectively.

Supplemental disclosures of noncash activities. Under the HEI Dividend Reinvestment and Stock Purchase Plan, common stock dividends reinvested by shareholders in HEI common stock in noncash transactions amounted to $5 million in 2004, $17 million in 2003 and $17 million in 2002. Beginning in March 2004, HEI began satisfying the requirements of the HEI DRIP and the Hawaiian Electric Industries Retirement Savings Plan by acquiring for cash its common shares through open market purchases rather than the issuance of additional shares.

Other noncash increases in common stock for director and officer compensatory plans were $2.9 million in 2004, $2.8 million in 2003 and $2.1 million in 2002.

In 2004, 2003 and 2002, HECO and its subsidiaries capitalized as part of the cost of electric utility plant an allowance for equity funds used during construction amounting to $6 million, $4 million and $4 million, respectively.

The estimated fair value of noncash contributions in aid of construction amounted to $5 million, $14 million and $4 million in 2004, 2003 and 2002, respectively.

In 2004, ASB financed $6 million of sales of real estate acquired in settlement of loans.

In 2003, ASB restructured a total of $389 million of FHLB advances with lower rate, longer maturity advances.

In 2002, HECO assigned account receivables totaling $10 million to a creditor, without recourse, in full settlement of HECO s $10 million notes payable to that creditor.

12 Regulatory restrictions on net assets

At December 31, 2004, HECO and its subsidiaries could not transfer approximately $424 million of net assets to HEI in the form of dividends, loans or advances without regulatory approval.

ASB is required to file a notice with the OTS 30 days 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. At December 31, 2004, ASB could transfer approximately $143 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 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. At December 31, 2004, 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, 2004, various securities rating agencies rated the private-issue mortgage-related securities held by ASB as investment grade.

14 Discontinued operations

HEI Power Corp. (HEIPC). On October 23, 2001, the HEI Board of Directors adopted a formal plan to exit the international power business (engaged in by HEIPC and its subsidiaries, the HEIPC Group). HEIPC management has been carrying out a program to dispose of all of the HEIPC Group s remaining projects and investments. Accordingly, the HEIPC Group has been reported as a discontinued operation in the Company s consolidated statements of income.

China project. In 1998 and 1999, the HEIPC Group acquired what became a 75% interest in a joint venture, Baotou Tianjiao Power Co., Ltd., formed to construct, own and operate a 200 MW (net) coal-fired power plant to be located in Inner Mongolia. The power plant was intended to be built inside the fence for Baotou Iron & Steel (Group) Co., Ltd. The project received approval from both the national and Inner Mongolia governments. However, the Inner Mongolia Power Company, which owns and operates the electricity grid in Inner Mongolia, caused a delay of the project by failing to enter into a satisfactory interconnection arrangement with the joint venture. The Inner Mongolia Power Company was seeking to limit the joint venture s load, which is inconsistent with the terms of the project approvals and the power purchase contract. Upon appeal to the Inner Mongolia government, the Inner Mongolia Economic and Trade Committee (the regulator of the electric utility industry) refused to enforce the HEIPC Group s rights associated with the approved project. The HEIPC Group determined that a satisfactory interconnection arrangement could not be obtained and is not proceeding with the project. In the third quarter of 2001, the HEIPC Group wrote off its remaining investment of approximately $24 million in the project. In 2004, the HEIPC Group transferred its interest in the China joint venture to its partner and another entity for $3 million and recorded a gain on disposal, net of income taxes, of $2 million. The HEIPC Group is continuing to pursue recovery of a significant portion of its losses through arbitration of its claims under a political risk insurance policy, but management cannot predict the outcome of those claims.

Philippines investment. In 1998 and 1999, the HEIPC Group invested $9.7 million to acquire shares in Cagayan Electric Power & Light Co., Inc. (CEPALCO), an electric distribution company in the Philippines. The HEIPC Group recognized impairment losses of approximately $3 million in 2001 and $5 million in 2003 to adjust this investment to its estimated net realizable value at the time of approximately $7 million and $2 million, respectively. In the first quarter of 2004, the HEIPC Group sold HEIPC Philippine Development, LLC, the HEIPC Group company that held an interest in CEPALCO, for a nominal gain.

Summary financial information for the discontinued operations of the HEIPC Group is as follows:

Years ended December 31	**2004**	**2003**	**2002**
(in thousands)			
Disposal			
Gain (loss), including a provision of $1 million for losses from operations during phase-out period in 2004 and 2003	$ 2,878	$ (6,017)	$
Income tax benefits	(965)	2,147	
Gain (loss) on disposal	$ 1,913	$ (3,870)	$

As of December 31, 2004, the remaining net assets of the discontinued international power operations, after the write-offs and writedowns described above, amounted to $10 million (included in Other assets) and consisted primarily of the deferred taxes receivable, reduced by a reserve for losses from operations during the phase-out period (primarily for legal fees). HEIPC increased its reserve for future expenses by $1 million in 2003 and 2004. If the HEIPC Group is successful in pursuing its insurance claims in connection with its China joint venture interest, any such recovery would be recorded as a gain on disposal of discontinued operations. Further losses may be sustained if the expenditures made in pursuing its insurance claims in connection with the China joint venture interest exceed the total of any recovery ultimately achieved and the amount provided for in HEI s reserve for discontinued operations.

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15 Fair value of financial instruments

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 quoted market prices or dealer quotes or estimated by discounting the expected future cash flows using current market rates for similar investments.

Loans receivable. For certain homogenous categories of loans, such as residential real estate loans, an asset/liability simulation model was used to estimate fair value. Whenever possible, observable market prices for securities backed by similar loans were used as benchmarks to calibrate the model. The fair value of other types of loans was estimated by discounting the future cash flows using the current rates at which similar loans would be made to borrowers with similar credit ratings and for the same remaining maturities.

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.

Securities sold under agreements to repurchase. Fair value was estimated by discounting future cash flows using the current rates available for repurchase agreements with similar terms and remaining maturities.

Advances from Federal Home Loan Bank and long-term debt. Fair value was estimated by discounting the future cash flows using the current rates available for borrowings with similar remaining maturities.

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

Off-balance sheet financial instruments. The fair value of the mortgage servicing asset was estimated as the net present value of expected net income streams generated from 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.

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

December 31	2004		2003	
(in thousands)	Carrying or notional amount	Estimated fair value	Carrying or notional amount	Estimated fair value
Financial assets				
Cash and equivalents	$ 132,138	$ 132,138	$ 223,310	$ 223,310
Federal funds sold	41,491	41,491	56,678	56,678
Available-for-sale investment and mortgage-related securities	2,953,372	2,953,372	2,728,748	2,728,748
Held-to-maturity investment securities	97,365	97,365	94,624	94,624
Loans receivable, net	3,249,191	3,278,170	3,121,979	3,179,392
Financial liabilities				
Deposit liabilities	4,296,172	4,297,681	4,026,250	4,057,267
Securities sold under agreements to repurchase	811,438	813,897	831,335	842,272
Advances from Federal Home Loan Bank	988,231	1,016,188	1,017,053	1,066,697
Long-term debt	1,166,735	1,160,280	1,064,420	1,113,163
HEI- and HECO-obligated preferred securities of trust subsidiaries	NA	NA	200,000	205,120
Off-balance sheet items				
Loans serviced for others	452,724	5,292	568,807	4,378
HECO-obligated preferred securities of trust subsidiary	50,000	52,400	NA	NA

NA Not applicable.

At December 31, 2004 and 2003, loan commitments and unused lines and letters of credit had carrying amounts of $922 million and $783 million and the estimated fair value was $0.3 million and nil, respectively. For purposes of comparability, the fair value amount at December 31, 2003 was restated.

Limitations. The Company makes fair value estimates at a specific point in time, based on relevant market information and information about the financial instrument. 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 significant portion of the Company s financial instruments, fair value estimates cannot be determined with precision. Changes in assumptions 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.

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16 Quarterly information (unaudited)

Selected quarterly information was as follows:

(in thousands, except per share amounts)	Quarters ended March 31	June 30	Sept. 30	Dec. 31	Years ended December 31
2004					
Revenues	$ 437,110	$ 461,798	$ 506,759	$ 518,390	$ 1,924,057
Operating income [1]	67,837	66,946	81,686	54,491	270,960
Net income [1]					
Continuing operations	30,932	11,238	40,759	24,810	107,739
Discontinued operations			1,913		1,913
	30,932	11,238	42,672	24,810	109,652
Basic earnings (loss) per common share [3]					
Continuing operations	0.40	0.14	0.51	0.31	1.36
Discontinued operations			0.02		0.02
	0.40	0.14	0.53	0.31	1.38
Diluted earnings (loss) per common share [4]					
Continuing operations	0.40	0.14	0.51	0.31	1.36
Discontinued operations			0.02		0.02
	0.40	0.14	0.53	0.31	1.38
Dividends per common share	0.31	0.31	0.31	0.31	1.24
Market price per common share [5]					
High	26.88	26.28	26.75	29.55	29.55
Low	23.55	22.96	24.89	26.48	22.96
2003					
Revenues	$ 424,636	$ 448,756	$ 453,703	$ 454,221	$ 1,781,316
Operating income [2]	59,088	61,453	68,235	74,791	263,567
Net income [2]					
Continuing operations	24,327	25,760	30,522	37,439	118,048
Discontinued operations		(3,870)			(3,870)
	24,327	21,890	30,522	37,439	114,178
Basic earnings (loss) per common share [3]					
Continuing operations	0.33	0.34	0.41	0.50	1.58
Discontinued operations		(0.05)			(0.05)
	0.33	0.29	0.41	0.50	1.53

Diluted earnings (loss) per common share [4]					
Continuing operations	0.33	0.34	0.41	0.49	1.57
Discontinued operations		(0.05)			(0.05)
	0.33	0.29	0.41	0.49	1.52
Dividends per common share	0.31	0.31	0.31	0.31	1.24
Market price per common share [5]					
High	23.06	23.30	22.98	24.00	24.00
Low	19.10	19.77	20.63		