HAWAIIAN ELECTRIC INDUSTRIES INC
Form 10-K
March 07, 2006
Table of Contents

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, 2005

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 if Registrant Hawaiian Electric Industries, Inc. is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x No ¨

Indicate by check mark if Registrant Hawaiian Electric Company, Inc. is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes ¨ No x

Indicate by check mark if Registrant Hawaiian Electric Industries, Inc. is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No x

Indicate by check mark if Registrant Hawaiian Electric Company, Inc. is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No x

Indicate by check mark whether Registrant Hawaiian Electric Industries, Inc. (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 whether Registrant Hawaiian Electric Company, Inc. (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. x

Indicate by check mark whether Registrant Hawaiian Electric Industries, Inc. is a large accelerated filer, an accelerated filer, or a non-accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Large accelerated filer x Accelerated filer ¨ Non-accelerated filer ¨

Indicate by check mark whether Registrant Hawaiian Electric Company, Inc. is a large accelerated filer, an accelerated filer, or a non-accelerated filer (as defined in Rule 12b-2 of the Exchange Act). Large accelerated filer ¨ Accelerated filer ¨ Non-accelerated filer x

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

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

	Aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrants as of	**Number of shares of common stock outstanding of the registrants as of**	
	June 30, 2005	**June 30, 2005**	**February 28, 2006**
Hawaiian Electric Industries, Inc. (HEI)	$2,169,840,781.29	80,934,009 (Without par value)	81,059,892 (Without par value)
Hawaiian Electric Company, Inc. (HECO)	None	12,805,843 ($6 2/3 par value)	12,805,843 ($6 2/3 par value)

DOCUMENTS INCORPORATED BY REFERENCE

HECO Consolidated 2005 Financial Statements Parts I, II, III and IV

HECO Consolidated Selected Financial Data Part II

Portions of Proxy Statement of Hawaiian Electric Industries, Inc. for the 2006 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.

TABLE OF CONTENTS

Table of Contents

GLOSSARY OF TERMS

Defined below are certain terms used in this report:

Terms	Definitions
1935 Act	Public Utility Holding Company Act of 1935
2005 Act	Public Utility Holding Company Act of 2005
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.) and AdCommunications, Inc. Former subsidiaries include American Savings Mortgage Co., Inc. (dissolved in July 2003) and ASB Service Corporation (dissolved in January 2004) and ASB Realty Corporation (dissolved in May 2005).
BIF	Bank Insurance Fund
BLNR	Board of Land and Natural Resources of the State of Hawaii
Btu	British thermal unit
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 and terminated in 2004)*, HECO Capital Trust II (dissolved and terminated in 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 and terminated in 2004)*, HEI Preferred Funding, LP (dissolved and terminated in 2004)*, Malama Pacific Corp. (discontinued operations, dissolved in June 2004), ASB Service Corporation (dissolved in January 2004) and dissolved HEIPC subsidiaries (discontinued operations). (*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 and terminated in 2004)* and HECO Capital Trust II (dissolved and terminated in 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
D&O	Decision and order
DOD	Department of Defense federal
DOH	Department of Health of the State of Hawaii

DSM	Demand-side management
DTCC	Dual-train combined-cycle
ECA	Energy cost adjustment
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
FERC	Federal Energy Regulatory Commission
FHLB	Federal Home Loan Bank
FICO	Financing Corporation

Table of Contents

GLOSSARY OF TERMS *(continued)*

Terms	Definitions
FIRREA	Financial Institutions Reform, Recovery, and Enforcement Act of 1989
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 and terminated in 2004)* and HECO Capital Trust II (dissolved and terminated in 2004)*. (*unconsolidated subsidiaries as of January 1, 2004)
HECO s Consolidated Financial Statements	Hawaiian Electric Company, Inc. s Consolidated Financial Statements incorporated into Parts I, II, III and IV of this Form 10-K, which is filed as HECO Exhibit 99.4 and incorporated into this Form 10-K by reference
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 and terminated in 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
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 2006 Proxy Statement	Portions of Hawaiian Electric Industries, Inc. s 2006 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 since 2002, 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.
HEP	Hamakua Energy Partners, L.P., formerly known as Encogen Hawaii, L.P.
HITI	Hawaiian Interisland Towing, Inc.

HRD	Hawi Renewable Development, LLC
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.

GLOSSARY OF TERMS *(continued)*

Terms	Definitions
kV	kilovolt
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.
MSFO	Medium sulfur fuel oil
MW	Megawatt/s (as applicable)
NA	Not applicable
NM	Not meaningful
NOV	Notice of Violation
O&M	operation and maintenance
OPA	Federal Oil Pollution Act of 1990
OTS	Office of Thrift Supervision, Department of Treasury
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
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
See	Means the referenced material is incorporated by reference
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.

Table of Contents

Forward-Looking Statements

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

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

- the effects of international, national and local economic conditions, including the state of the Hawaii tourist and construction industries, the strength or weakness of the Hawaii and continental U.S. real estate markets (including the fair value of collateral underlying loans and mortgage-related securities) and decisions concerning the extent of the presence of the federal government and military 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 (e.g., increased self-generation of electricity may have an adverse impact on HECO s revenues and increased price competition for deposits, or an outflow of deposits to alternative investments, may have an adverse impact on American Savings Bank, F.S.B. s (ASB s) cost of funds);
- capacity and supply constraints or difficulties, especially if generating units (utility-owned or independent power producer (IPP)-owned) fail or measures such as demand-side management (DSM), distributed generation (DG), combined heat and power (CHP) or other firm capacity supply-side resources fall short of achieving their forecasted benefits or are otherwise insufficient to reduce or meet peak demand;

increased risk to generation reliability as generation reserve margins on Oahu are lower than considered desirable;

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 IPPs to deliver the firm capacity anticipated in their power purchase agreements (PPAs);

the ability of the electric utilities to negotiate, periodically, favorable fuel supply and collective bargaining agreements;

new technological developments that could affect the operations and prospects of HEI and its subsidiaries (including HECO and its subsidiaries and ASB and its subsidiaries) or their competitors;

federal, state and international governmental and regulatory actions, such as changes in laws, rules and regulations applicable to HEI, HECO 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, restrictions and penalties (that may arise with respect to environmental conditions, capital adequacy and business practices);

increasing operations and maintenance expenses for the electric utilities and the possibility of more frequent rate cases;

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 (SFAS) No. 71 (Accounting for the Effects of Certain Types of Regulation), and the possible effects of applying Financial Accounting Standards Board (FASB) Interpretation No. (FIN) 46R (Consolidation of Variable Interest Entities) and Emerging Issues Task Force (EITF) Issue No. 01-8 (Determining Whether an Arrangement Contains a Lease) to 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 and the results of financing efforts;

faster than expected loan prepayments that can cause an acceleration of the amortization of premiums on loans and investments and the impairment of mortgage servicing rights of ASB;

changes in ASB s loan portfolio credit profile and asset quality which may increase or decrease the required level of allowance for loan losses;

the final outcome of tax positions taken by HEI, HECO and their subsidiaries;

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

the risks of suffering losses and incurring liabilities that are uninsured; and other risks or uncertainties described elsewhere in this report (e.g., Item 1A. Risk Factors) 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.

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 95% of Hawaii s population. 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, is the third largest financial institution in the State of Hawaii based on total assets as of December 31, 2005. ASB has subsidiaries involved in the sale and distribution of insurance products and an inactive advertising agency for ASB and its subsidiaries. Former ASB subsidiary, ASB Realty Corporation, which had elected to be taxed as a real estate investment trust, was dissolved in May 2005 (see Note 10 to HEI s Consolidated Financial Statements under ASB state franchise tax dispute and settlement).

HEIPI, whose predecessor company was formed in February 1998, holds venture capital investments (in companies based in Hawaii and the U.S. mainland) with a carrying value of $6.9 million as of December 31, 2005.

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

Hycap Management, Inc., 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 and will terminate in 2007.

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 to its former operations and the operations of its former subsidiary.

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 regulated under the Investment Company Act of 1940. In February 2000, HEIII became a subsidiary of HEIPC. HEIII s long-term investments currently consist primarily of investments in leveraged leases accounted for in the Company s continuing operations. In 2005, HEIII sold its approximate 25% interest in a trust that is the owner/lessor of a 60% undivided interest in a coal-fired electric generating plant in Georgia for a pretax gain of $14 million.

For information about the Company s discontinued international power operations formerly conducted by HEIPC and its subsidiaries, see Note 14 to HEI s Consolidated Financial Statements.

Table of Contents

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 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. MECO acquired the Lanai City power plant on the island of Lanai in 1988 and all the outstanding common stock of Molokai Electric Company, Limited (currently a division of MECO) in 1989. In 2005, the electric utilities revenues and net income from continuing operations amounted to approximately 82% and 57%, respectively, of HEI s consolidated amounts, compared to approximately 81% and 75% in 2004 and approximately 78% and 67% in 2003, respectively.

The islands of Oahu, Maui, Lanai, Molokai and Hawaii have a combined population currently estimated at 1,212,000, or approximately 95% of the Hawaii population, 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 HECO s MD&A, HECO s Quantitative and Qualitative Disclosures about Market Risk and HECO s Consolidated Financial Statements.

Sales of electricity

The following table sets forth the number of electric customer accounts as of December 31, 2005, 2004 and 2003 and electric sales revenues by company for each of the years then ended:

Years ended December 31	2005	2004	2003

(dollars in thousands)	Customer accounts*	Electric sales revenues	Customer accounts*	Electric sales revenues	Customer accounts*	Electric sales revenues
HECO	291,580	$ 1,201,156	288,456	$ 1,050,388	286,677	$ 960,717
MECO	63,901	301,755	61,996	250,750	61,423	213,806
HELCO	73,835	293,739	71,594	240,947	68,893	213,268
	429,316	$ 1,796,650	422,046	$ 1,542,085	416,993	$ 1,387,791

* As of December 31.

Revenues from the sale of electricity in 2005 were from the following types of customers in the proportions shown:

	HECO	MECO	HELCO	Total
Residential	32%	37%	40%	34%
Commercial	32	34	41	34
Large light and power	35	29	18	32
Other	1		1	
	100%	100%	100%	100%

Kilowatthour (KWH) sales of HECO and its subsidiaries follow a seasonal pattern, but they do not experience the extreme seasonal variation due to extreme weather variations like some electric utilities on the U.S. mainland. KWH sales in Hawaii tend to increase in the warmer summer months, probably as a result of increased demand for air conditioning.

HECO and its subsidiaries derived approximately 10% of their operating revenues from the sale of electricity to various federal government agencies in each of 2005, 2004 and 2003.

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, mandated 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 was measured relative to the agency s 1985 energy use. The Energy Policy Act of 2005 further mandated that federal buildings reduce energy consumption by up to 20% in fiscal year 2015 relative to base fiscal year 2003 consumption to the extent that these measures are cost effective. The Act also establishes energy conservation goals at the state level for federally funded programs; stricter conservation measures for a variety of large energy consuming products; tax credits for energy efficient homes, solar energy, fuel cells and microturbine power plants; and includes other energy-related provisions. HECO continues to work with various federal agencies to implement demand-side management programs that will help them achieve their energy reduction objectives. Neither HEI nor HECO management can predict with certainty the impact of federal mandates on HEI s or HECO s future financial condition, results of operations or liquidity.

Table of Contents

Selected consolidated electric utility operating statistics

Years ended December 31,	2005	2004	2003	2002	2001
KWH sales (millions)					
Residential	3,008.0	3,000.6	2,875.9	2,778.5	2,665.2
Commercial	3,288.5	3,247.3	3,168.3	3,073.6	3,016.1
Large light and power	3,742.0	3,762.6	3,676.5	3,639.2	3,636.5
Other	51.4	52.8	54.4	53.0	52.6
	10,089.9	10,063.3	9,775.1	9,544.3	9,370.4
KWH net generated and purchased (millions)					
Net generated	6,485.3	6,572.5	6,280.2	6,249.7	6,042.4
Purchased	4,167.5	4,066.5	4,054.3	3,829.6	3,861.6
	10,652.8	10,639.0	10,334.5	10,079.3	9,904.0
Losses and system uses (%)	5.1	5.2	5.2	5.1	5.2
Energy supply (December 31)					
Net generating capability MW	1,644	1,642	1,606	1,606	1,608
Firm purchased capability MW	540	529	531	510	531
	2,184	2,171	2,137	2,116	2,139
Net peak demand MW[1]	1,641	1,694	1,638	1,583	1,564
Btu per net KWH generated	10,873	10,767	10,663	10,673	10,675
Average fuel oil cost per Mbtu (cents)	908.6	684.3	580.5	466.4	539.3
Customer accounts (December 31)					
Residential	372,638	366,217	362,400	356,244	352,132
Commercial	54,647	53,854	52,659	51,386	50,974
Large light and power	559	555	549	551	542
Other	1,472	1,420	1,385	1,374	1,344
	429,316	422,046	416,993	409,555	404,992
Electric revenues (thousands)					
Residential	$ 607,031	$ 527,970	$ 471,697	$ 426,291	$ 425,287
Commercial	611,403	522,230	474,017	425,595	436,751
Large light and power	569,016	483,737	434,319	389,312	409,977
Other	9,200	8,148	7,758	7,028	7,349
	$ 1,796,650	$ 1,542,085	$ 1,387,791	$ 1,248,226	$ 1,279,364
Average revenue per KWH sold (cents)	17.81	15.32	14.20	13.08	13.65
Residential	20.18	17.60	16.40	15.34	15.96
Commercial	18.59	16.08	14.96	13.85	14.48
Large light and power	15.21	12.86	11.81	10.70	11.27
Other	17.92	15.44	14.26	13.26	13.98

Residential statistics

Average annual use per customer account (KWH)	8,141	8,239	8,004	7,840	7,620
Average annual revenue per customer account	$ 1,643	$ 1,450	$ 1,313	$ 1,203	$ 1,216
Average number of customer accounts	369,495	364,225	359,288	354,419	349,782

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

Table of Contents

Generation statistics

The following table contains certain generation statistics as of, and for the year ended, December 31, 2005. The capability available for operation at any given time may be more or less than 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) as of December 31, 2005[1]						
Conventional oil-fired steam units	1,106.8	35.9			62.2	1,204.9
Diesel	14.8	82.5	10.3	9.6	30.8	148.0
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]	434.0	16.0			90.0	540.0
	1,657.4	232.8	10.3	11.8	271.9	2,184.2
Net peak demand (MW)	1,230.0	202.1	5.1	6.3	197.0	1,640.5[3]
Reserve margin	36.0%	15.2%	101.9%	89.1%	38.0%	34.0%
Annual load factor	75.2%	71.3%	65.9%	71.8%	70.5%	74.1%[3]
KWH net generated and purchased (millions)	8,104.3	1,262.2	29.4	39.4	1,217.5	10,652.8

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

2 Nonutility generators HECO: 208 MW (Kalaeloa Partners, L.P., oil-fired), 180 MW (AES Hawaii, Inc., coal-fired) and 46 MW (HPower, refuse-fired); MECO: 16 MW (Hawaiian Commercial & Sugar Company, primarily bagasse-fired); HELCO: 30 MW (Puna Geothermal Venture, geothermal) and 60 MW (Hamakua Energy Partners, L.P., oil-fired).

3 Noncoincident and nonintegrated.

Generating reliability and reserve margin

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. HECO, HELCO and MECO have isolated electrical systems that are not interconnected to each other or to any other electrical grid and thus, each maintain a higher level of reserve generation than is typically carried by interconnected mainland U.S. 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 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, HECO is below preferred levels of reserve margin and has made several public calls for energy conservation when reserves were especially narrow. See Integrated resource planning, requirements for additional generating capacity and adequacy of supply in HEI s MD&A.

Integrated resource planning and requirements for additional generating capacity

The PUC issued an order in 1992 requiring the energy utilities in Hawaii to develop integrated resource plans (IRPs), which may be approved, rejected or modified by the PUC. The goal of integrated resource planning is the identification of demand- and supply-side resources and the integration of these resources for meeting near- and long-term consumer energy needs in an efficient and reliable manner at the lowest reasonable cost. The PUC adopted a framework, which established the process and guidelines for developing IRPs and directed that each plan cover a 20-year planning horizon with a five-year program implementation schedule and that the planning cycle will be repeated every three years.

The utilities are entitled to recover all appropriate and reasonable integrated resource planning and implementation costs, including the costs of DSM programs. The PUC has approved IRP cost recovery provisions for HECO, MECO and HELCO, pursuant to which the utilities have recovered the costs for approved DSM programs (including DSM program lost margins and shareholder incentives), and IRP costs incurred by the utilities and approved by the PUC, either through a surcharge or through their base rates.

Table of Contents

See Other regulatory matters Demand-side management programs agreements with the Consumer Advocate in HEI s MD&A, which includes a discussion of the electric utilities residential and commercial and industrial load management programs and of the agreements between the utilities and the Consumer Advocate concerning caps on the recovery of lost margins and shareholders incentives.

Incremental IRP costs are deferred until approved for recovery, at which time they are amortized to expense. Procedural schedules for the IRP cost proceedings have been established with respect to the 2000-2005 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 decision and order (D&O) approving recovery of the costs. HECO completed recovery of its 2004 incremental IRP costs in August 2005 and MECO is scheduled to complete recovery of its 2004 costs in June 2006. In HECO s 2005 test year rate case, the parties to the rate case reached a settlement agreement to include $0.6 million for IRP costs in base rates. The PUC issued its interim D&O in HECO s rate case granting an increase effective September 28, 2005, at which time HECO s IRP costs will be recovered through base rates, and the separate surcharge for recovery is discontinued, pending the PUC s final D&O. The Consumer Advocate has objected to the recovery of $3.2 million (before interest) of the $11.8 million of incremental IRP costs incurred during the 1995-2004 period, and the PUC s decision is pending on this matter. As of December 31, 2005, 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 $18 million. HECO and MECO expect to begin recovering their incremental 2005 IRP costs incurred through September 28, 2005 and December 31, 2005, respectively, subject to refund with interest, following the filing of actual 2005 costs (which is expected to occur in late March or early April 2006).

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 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. 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.

In September 2003, the PUC opened a docket to commence HECO s third IRP (IRP-3). 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 were requested in HECO s rate increase application, which was filed in November 2004. The energy efficiency

DSM programs were bifurcated from the rate case into a separate Energy Efficiency Docket, which is still pending**.** 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 (see Certain factors that may affect future results and financial condition-Consolidated-Competition-Distributed generation proceeding in HEI s MD&A). Also on the supply-side, HECO and Kalaeloa Partners, L.P. (Kalaeloa) executed amendments to the Kalaeloa PPA, under which Kalaeloa now provides

Table of Contents

28 megawatts (MW) of additional firm capacity (see FIN 46R discussion in Note 1 to HECO s Consolidated Financial Statements).

HECO s gross peak demand was 1,250 MW in 2002, 1,284 MW in 2003 and 1,327 MW in 2004. The gross peak demand of 1,327 MW in 2004 was 20 MW higher than the projected peak for 2004. Although the gross peak demand in 2005 decreased to 1,273 MW, demand for electricity on Oahu is projected to increase. In October 2004, November 2005 and January 2006, HECO issued a public request that its customers voluntarily conserve energy as generating units were out for scheduled maintenance or were unexpectedly unavailable. In addition to making the requests, in November 2005 and January 2006, HECO remotely turned off water heaters of a number of residential customers who participate in its Energy Scout load-control program.

For a discussion of HECO s 2005 and 2006 Adequacy of supply letters, see Integrated resource planning, requirements for additional generating capacity and adequacy of supply in HEI s MD&A.

On October 28, 2005, HECO filed its IRP-3, which proposes multiple solutions to meet Oahu s future energy needs, including renewable energy resources, energy efficiency, conservation, technology (such as CHP and DG) and central station generation. IRP-3 included a potential wind energy project above HECO s Kahe power plant. However, HECO currently is reviewing other potential sites, such as Kahuku, due to the Mayor of Honolulu s opposition to the Kahe project site.

In June 2005, HECO filed with the PUC an application for approval of funds to build a new nominal 100 MW simple cycle combustion turbine generating unit at Campbell Industrial Park on Oahu, the site of three other existing power plants, each owned and operated by an IPP (AES Hawaii, Inc., Kalaeloa and HPower). Plans are for the combustion turbine to be run primarily as a peaking unit beginning in 2009, operating mainly between the weekday peak electricity demand periods or during times when other generating units are not available. The air permit application for the unit, filed in October 2003 and currently under review by the Department of Health of the State of Hawaii (DOH), requests approval to burn naphtha or diesel and specifies that the unit will have the ability to convert to using biofuels, such as ethanol, when they are commercially available. On December 15, 2005, HECO signed a contract with Siemens for the right to purchase up to two combustion turbine units. The contract allows the Company to terminate the contract at a specified payment amount if necessary combustion turbine (CT) project approvals are not obtained.

The generating unit application also requests approval to build an additional 138 kilovolt (kV) transmission line approximately two miles long, within and adjacent to Campbell Industrial Park, to more reliably transmit power from the new and existing generating units to the Oahu electric grid. Preliminary costs for the new generating unit and transmission line, as well as related substation improvements, are estimated at $137 million. As of December 31, 2005 accumulated project costs for planning, engineering, permitting and AFUDC amounted to $2.7 million. HECO has prepared a draft Environmental Impact Statement (EIS) for the proposed project. Notice of the availability of the draft EIS was published on February 8, 2006 and the public comment period ends on March 25, 2006.

In a related application filed with the PUC in June 2005, HECO requested approval for an approximately $11.5 million package of community benefit measures to mitigate the impact of the new generating unit on communities near the proposed generating unit site. These measures include a base electric rate discount for those who live near the proposed generation site, additional air-quality monitoring stations, a fish monitoring program and the use of recycled instead of potable water in Kahe power plant s operations.

In July 2005, the Consumer Advocate filed Preliminary Statements of Position on HECO s Campbell Industrial Park generating unit and transmission line additions application and community benefits application. Also in July 2005, HECO filed memoranda in response opposing the Consumer Advocate s recommendations to suspend the two applications, suspend the start of the procedural schedule for both applications until after the filing of the IRP-3 (which was filed on October 28, 2005), and consolidate the applications.

In September 2005, the PUC suspended HECO s Campbell Industrial Park generating unit and transmission line additions application to allow more time to review the application. Also in September 2005, the PUC ordered HECO and the Consumer Advocate to submit a stipulated prehearing order for the community benefits application. In January 2006, the PUC granted an environmental group s motion to intervene and a neighboring business entity s motion to participate in the generating unit and transmission line application, and ordered HECO, the Consumer Advocate and the other parties (the environmental group and the business entity) to submit a stipulated prehearing order by March 13, 2006.

Table of Contents

In addition to the 100 MW simple-cycle combustion turbine anticipated to be added in 2009, IRP-3 also includes plans to build a 180 MW coal unit in 2022. However, the report notes there is flexibility to allow HECO to modify its plan in response to changing market conditions and to also consider alternative generation technologies should they 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 (2006-2025).

MECO s IRP. MECO filed its second IRP with the PUC in May 2000. In April 2004 and 2005, MECO filed with the PUC its IRP evaluation reports, updating the second IRP to reflect the latest sales and fuel forecasts and updated key planning assumptions.

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 (currently planned to be added in 2011), 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). 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 December 2005, Maalaea Unit 13, a 12.34 MW diesel generator suffered an equipment failure. The unit is not expected to be available for service until approximately June 2007. MECO s Maui system should have sufficient installed capacity to meet the forecasted loads, except that the Maui system may not have sufficient capacity at times in the event of an unexpected outage of its largest unit, until Maalaea Unit 13 returns to service. MECO intends to implement appropriate mitigation measures to overcome insufficient reserve capacity situations.

MECO s third IRP is scheduled to be filed with the PUC in October 2006.

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

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 CTs at its Keahole power plant site and proceeding in parallel with a PPA with Hamakua Energy Partners, L.P. (HEP, formerly Encogen Hawaii, L.P.) for a 60 MW (net) dual-train combined-cycle (DTCC) facility.

The HEP 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 and HELCO power situation in Note 11 to HECO s Consolidated Financial Statements. HELCO has deferred the retirements of some of its older generating units. Subject to obtaining zoning approval and obtaining all other necessary permits and approvals, HELCO s current plans are to install an 18 MW heat recovery steam generator (ST-7) in 2009 or earlier. 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) and HEP.

HELCO s third IRP is scheduled to be filed with the PUC by December 31, 2006.

Table of Contents

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 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 abandonment. 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.

Significant capital projects include HELCO s Keahole power plant expansion project, including ST-7, HECO s East Oahu Transmission Project (see discussion in Note 11 to HECO s Consolidated Financial Statements), MECO s Maalaea and Waena power plant expansion projects, and HECO s $25 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 has also requested approval from the PUC to install a new generating unit in Campbell Industrial Park (an approximately 100 MW combustion turbine scheduled for commercial operation in 2009) and a two mile long 138 kV overhead transmission line to provide additional transmission capacity for the new generating unit as well as for existing units at Campbell Industrial Park. See preceding discussion in Integrated resource planning and requirements for additional generating capacity.

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, 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 utilizes a clean coal technology and 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. In 2003, HECO consented to AES Hawaii s proposed refinancing and received consideration for its consent, primarily in the form of a PPA amendment that reduced the cost of firm capacity retroactive to June 1, 2003, which benefit is being passed on to ratepayers through a reduction in rates. AES Hawaii also 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.

In October 1988, HECO entered into an agreement with Kalaeloa, a limited partnership whose sole general partner was an indirect, wholly-owned subsidiary of ASEA Brown Boveri, Inc. (ABB), which through affiliates, contracted to design, build, operate and maintain the facility. The ownership of Kalaeloa was subsequently restructured. 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 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, and is designed to sell sufficient steam to be a QF. On October 12, 2004, HECO and Kalaeloa executed two amendments to the PPA: 1) Confirmation Agreement Concerning Section 5.2B(2) Of PPA And Amendment No. 5 To PPA (Amendment No. 5), and 2) Agreement For Increment Two Capacity And Amendment No. 6 To PPA (Amendment No. 6). Amendment No. 5 confirms that Kalaeloa s facility is able to deliver 189 MW of capacity and sets the capacity payment rate for capacity above 180 MW at $112 per kilowatt per year.

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. Amendment Nos. 5 and 6 became

Table of Contents

effective on September 28, 2005, when HECO received an interim D&O allowing the recovery of the costs of the additional 29 MW (subsequently revised to 28 MW) of additional capacity (see FIN 46R discussion in Note 1 to HECO s Consolidated Financial Statements). Kalaeloa currently supplies HECO with 208 MW of firm capacity.

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 (HPower). The HPower facility currently supplies HECO with 46 MW of firm capacity. Under the amendment, 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.

The PUC has allowed rate recovery for the firm capacity and purchased energy costs related to HECO s three major PPAs that provide a total of 434 MW of firm capacity, representing 26% of HECO s total net generating and firm purchased capacity on Oahu as of December 31, 2005. The PUC also has allowed rate recovery for the purchased energy costs related to HECO s as-available energy PPAs.

HELCO and MECO PPAs. As of December 31, 2005, HELCO and MECO had PPAs for 90 MW and 16 MW (includes 4 MW of system protection) of currently available firm capacity, which PPAs have been approved by the PUC.

HELCO has a 35-year PPA with PGV for 30 MW of firm capacity from its geothermal steam facility expiring on December 31, 2027. Since April 2002, PGV s output has been reduced. In 2005, PGV generally exported to HELCO between 25 MW and 30 MW. If PGV does not provide the contracted 30 MW of capacity, the PPA provides for annual availability sanctions, which amounted to $0.7 million, $0.2 million, $0.1 million, and $0.1 million for 2002, 2003, 2004 and 2005, respectively. In 2005, PGV re-drilled an existing well, and drilled for a new production and a new injection well. As a result, PGV can export 30 MW to HELCO with all of its wells and converters in service. PGV has indicated its intent to pursue improvements to the plant to increase its capacity by 8 MW, and to pursue negotiations with HELCO for a new or amended PPA.

On October 4, 1999, HELCO entered into a PPA with Hilo Coast Power Company (HCPC) effective January 1, 2000 through December 31, 2004, whereby HELCO purchased 22 MW of firm capacity from HCPC s coal-fired facility. HELCO terminated the PPA as of January 1, 2005.

In October 1997, HELCO entered into an agreement with Encogen, which has been succeeded by HEP. 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. In 2000, HEP began providing HELCO with firm capacity. In June 2001, HEP demonstrated 60 MW of output from the facility. Subsequently, the output deteriorated due to technical problems, but returned to providing 60 MW in 2003.

HELCO purchases energy on an as-available basis from a number of nonutility generators. Wailuku River Hydroelectric L.P., the owner of a 12.1 MW run-of-the-river hydroelectric facility, has an existing contract to provide HELCO with as-available power through May 2023.

Apollo Energy Corporation (Apollo), the owner of a 7 MW 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). HELCO and Apollo reached agreement on a PPA on October 13, 2004. The PPA enables Apollo to repower its existing facility, and install an additional 13.5 MW of capacity, for a total windfarm capacity of 20.5 MW. The PUC approved the PPA on March 10, 2005. On September 7, 2005, Apollo informed HELCO that its wind turbine supplier will not be able to supply any wind turbines to the project in 2005 or 2006, and any delivery in 2007 is not yet known. Apollo is claiming an event of force majeure under the PPA, since the PPA requires that Apollo s windfarm meet an in-service date which is two years following the date of receipt of a non-appealable PUC approval order. HELCO is seeking information from Apollo regarding its claim of force majeure.

On December 30, 2003, HELCO and Hawi Renewable Development, LLC (HRD) entered into a PPA under which HRD would sell energy from an expanded wind farm (approximately 10.6 MW) at HRD s 5 MW wind farm site. 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. HELCO expects to purchase as-available energy from the HRD wind farm beginning in 2006.

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

Table of Contents

constraints. On June 28, 2005, MECO and HC&S agreed to extend the PPA through December 31, 2011, and from year to year thereafter, subject to termination on or after December 31, 2011 on not less than two years prior written notice by either party. MECO informed the PUC of the PPA extension by letter dated July 27, 2005.

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 PUC approved the PPA on March 18, 2005.

On May 10, 2005, MECO entered into a PPA with Makila Hydro, LLC (Makila) for the purchase of as-available energy from an existing 0.5 MW hydro electric plant, which Makila is refurbishing. The PPA was submitted to the PUC for approval on June 28, 2005.

The PUC has 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.

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 of rates and issues relating to the ECA clause below under Rates, and Certain factors that may affect future results and financial condition Electric utility Regulation of electric utility rates and Material estimates and critical accounting policies Electric utility 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 Chinese, Vietnamese 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 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 Products Company (Chevron) and Tesoro Hawaii Corp. (Tesoro) with no material changes in the primary commercial arrangements including volumes and pricing formulas. The PUC approved these contract extensions in December 2004. The PUC 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 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.

In March and April of 2004, HECO, HELCO and MECO executed 10-year extensions of 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 electric utilities pay market-related prices for diesel and MSFO supplied under these agreements.

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. This agreement has been informally extended on a year-by-year basis since a second amendment to the contract is currently being negotiated.

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

11

Table of Contents

The following table sets forth the average cost of fuel oil used by HECO, MECO and HELCO to generate electricity in the years 2005, 2004 and 2003:

	HECO		MECO		HELCO		Consolidated	
	$/Barrel	¢/MBtu	$/Barrel	¢/MBtu	$/Barrel	¢/MBtu	$/Barrel	¢/MBtu
2005	52.61	833.1	70.88	1,188.3	57.44	935.4	56.61	908.6
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

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 2005, 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 36% of HELCO s fuel consumption. MSFO made up the remainder of the fuel consumption of MECO and HELCO. 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. By the spring of 2005, the prices of LSFO, MSFO and diesel rose above the levels reached at the end of 2004, reflecting demand supported by continued strong economic growth in the U.S. and China, and continued geopolitical uncertainty. Elevated price levels continued into the later part of the year as hurricanes Katrina and Rita seriously damaged U.S. Gulf crude oil and natural gas production facilities and caused a significant, if temporary, loss in regional refinery processing capability. Thus, the average prices paid by the utilities in 2005 for LSFO, MSFO and diesel averaged approximately 30%, 33% and 37%, respectively, above the average price paid for that grade of fuel in 2004. 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.

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. The contracts provide for the employment of a double-hull bulk petroleum barge (since 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 HPower, 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. HEP energy prices vary primarily with HELCO s diesel costs.

The Company estimates that 79.5% of the net energy generated and purchased by HECO and its subsidiaries in 2006 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 generally maintains an average system fuel inventory level equivalent to 35 days of forward consumption. HELCO and MECO generally maintain an average system fuel inventory level equivalent to approximately one month s supply of both MSFO and diesel. The PPAs with AES Hawaii and HEP require that they maintain certain minimum fuel inventory levels.

Table of Contents

Transmission systems

HECO has 138 kV transmission and 46 kV sub-transmission lines. HELCO has 69 kV transmission and 34.5 kV transmission and sub-transmission lines. MECO has 69 kV transmission and 23 kV sub-transmission 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 sub-transmission 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 (as of December 31, 2005) located in West Oahu (1,055 MW); Waiau, adjacent to Pearl Harbor (481 MW); and Honolulu (107 MW). HECO also leases nine 1.64 MW generating units that provide a total of 14.8 MW (net) of firm power and are located at two substation sites and at HECO s Iwilei tank farm. HECO s non-firm power sources (approximately 28 MW) are located primarily in West Oahu. HECO transmits power to its service areas on Oahu through approximately 220 miles of overhead and underground 138 kV transmission lines (of which approximately 8 miles are underground) and approximately 521 miles of overhead and underground 46 kV sub-transmission lines. See East Oahu Transmission Project (EOTP) in Note 11 to HECO s Consolidated Financial Statements for a further discussion of the transmission system and the EOTP.

HELCO system. HELCO serves the island of Hawaii s electricity requirements with firm capacity (net) generating units (as of December 31, 2005) located in West Hawaii (77 MW) and East Hawaii (195 MW). HELCO s non-firm power sources total 24 MW, but are expected to increase in 2006 from additional wind power. 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 (as of December 31, 2005) located on the island of Maui (233 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), which was approved by the PUC in March 2005. 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 86 miles of 23 kV overhead lines.

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 Electric utility Results of operations Most recent rate requests, Certain factors that may affect future results and financial condition Electric utility Regulation of electric utility rates and Material estimates and critical accounting policies Electric utility Electric utility revenues in HEI s MD&A.

Public Utilities Commission of the State of Hawaii

Carlito P. Caliboso (an attorney previously in private practice) continues to serve as Chairman of the PUC (term expiring June 30, 2010). Also serving as commissioners are Janet E. Kawelo (whose term expires June 30, 2006 and who previously served as the Deputy Director for the State Department of Land and Natural Resources) and Wayne H. Kimura (whose term expires June 30, 2008 and who previously served as State Comptroller with the State Department of Accounting and General Services).

13

Table of Contents

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.

Competition

See Certain factors that may affect future results and financial condition Consolidated Competition Electric utility 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.

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 a policy of prudent avoidance, 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 Electric utility Results of operations 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, Item 1A. Risk Factors, 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, AES Hawaii, 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 claims that it has liability for the incident and responded to the demand asserting its defenses. In addition, HECO has insurance coverage (over a deductible amount).

Table of Contents

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, 2005, ASB was the third largest financial institution in the State of Hawaii based on total assets of $6.8 billion and deposits of $4.6 billion. In 2005, ASB s revenues and net income from continuing operations amounted to approximately 18% and 51%, respectively, of HEI s consolidated amounts, compared to approximately 19% and 38% in 2004 and approximately 21% and 48% in 2003, 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 to insure that ASB would have a capital level required by the OTS was limited to a maximum aggregate amount of approximately $65.1 million. As of December 31, 2005, HEI s maximum obligation to contribute additional capital has been reduced to approximately $28.3 million. ASB is subject to OTS regulations on dividends and other distributions applicable to financial institutions and ASB must receive a letter of non-objection from the OTS 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 earning assets (loans receivable and investment and mortgage-related securities) and the interest expense incurred on costing 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 affecting ASB s operating results include fee income, provision for loan losses, gains or losses on sales of securities available-for-sale, and noninterest expenses.

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		
	2005	**2004**	**2003**
Common equity to assets ratio			
Average common equity divided by average total assets [1]	8.15%	7.10%	7.20%
Return on assets			
Net income for common stock divided by average total assets [1]	0.95	0.62	0.88
Return on common equity			
Net income for common stock divided by average common equity [1]	11.7	8.7	12.2
Tangible efficiency ratio			

Total noninterest expense divided by net interest income and noninterest income	61	61	61

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

ASB s tangible efficiency ratio the cost of earning $1 of revenue remained flat at 61% from 2003 to 2005 as ASB has been undergoing a transformation, involving four major lines of business, to become a full-service community bank serving both consumer and commercial business customers. The transformation project will require continued investment in people and technology. ASB s ongoing challenge is to increase revenues faster than expenses.

Table of Contents

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

	Years ended December 31		
(in thousands)	**2005**	**2004**	**2003**
Assets			
Investment securities	$ 207,258	$ 240,466	$ 200,891
Mortgage-related securities	2,755,736	2,799,303	2,707,395
Loans receivable, net	3,411,389	3,121,878	3,071,877
Other	442,368	424,464	418,296
	$ 6,816,751	$ 6,586,111	$ 6,398,459
Liabilities and stockholder s equity			
Deposit liabilities	$ 4,453,762	$ 4,114,070	$ 3,888,145
Other borrowings	1,703,353	1,819,598	1,851,258
Other	104,009	109,544	123,167
Stockholder s equity	555,627	542,899	535,889
	$ 6,816,751	$ 6,586,111	$ 6,398,459

In 2005, the average loans receivables increased by $289.5 million, or 9.3%, over 2004 average loans receivable due to the continued strength in the Hawaii economy and real estate market. The average residential mortgage portfolio for 2005 grew by $139.8 million, or 5.6%, over the 2004 average residential mortgage portfolio. Average commercial real estate loans, net of undisbursed loan funds, increased $51.1 million, or 24.2%, over 2004 primarily due to commercial construction real estate loans originated in 2005 of $39.8 million. ASB s average commercial portfolio increased by $65.6 million, or 23.1%, during 2005 primarily due to higher commercial loan originations. The average consumer loan portfolio increased $22.5 million, or 10.3%, from 2004. ASB s average deposit balances increased by $339.7 million, or 8.3%, during 2005, enabling ASB to replace other borrowings and to help fund loan growth.

In 2004, the low interest rate environment and continued strength in the Hawaii real estate market also resulted in an increase in average loans receivables. The average residential mortgage portfolio for 2004 grew by $37.7 million, or 1.5%, over the 2003 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 commercial 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 deposits increased during the year as ASB continued to attract deposits. Average other borrowings also decreased during 2004 as the increase in average deposits enabled ASB to repay some of its higher costing other borrowings.

Asset/liability management

See HEI s Quantitative and Qualitative Disclosures about Market Risk.

Table of Contents

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 earning assets and costing liabilities for the years ended December 31, 2005, 2004 and 2003.

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.

(in thousands)	2005 vs. 2004			2004 vs. 2003		
Increase (decrease) due to	**Rate**	**Volume**	**Total**	**Rate**	**Volume**	**Total**
Income from earning assets						
Loans receivable, net	$ 2,861	$ 17,450	$ 20,311	$ (17,381)	$ 3,206	$ (14,175)
Mortgage-related securities	7,206	(1,830)	5,376	5,250	3,725	8,975
Investment securities	(1,048)	(751)	(1,799)	(1,637)	1,129	(508)
	9,019	14,869	23,888	(13,768)	8,060	(5,708)
Expense from costing liabilities						
Deposit liabilities	(15)	4,895	4,880	(5,349)	(1,275)	(6,624)
FHLB advances and other borrowings	8,091	(4,332)	3,759	(2,739)	(1,174)	(3,913)
	8,076	563	8,639	(8,088)	(2,449)	(10,537)
Net interest income	$ 943	$ 14,306	$ 15,249	$ (5,680)	$ 10,509	$ 4,829

Noninterest income

In addition to net interest income, ASB has various sources of noninterest income, including fee income from credit and debit cards and fee income from deposit liabilities and other financial products and services. Noninterest income totaled approximately $56.9 million in 2005, $57.2 million in 2004 and $58.5 million in 2003. Noninterest income for 2005 was relatively stable when compared to 2004. The decrease in noninterest 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.

Lending activities

General. Loans and mortgage-related securities of $6.2 billion represented 90.3% of total assets as of December 31, 2005, compared to $6.2 billion, or 91.3%, and $5.8 billion, or 88.8%, as of December 31, 2004 and 2003, respectively. ASB s loan portfolio consists primarily of conventional residential mortgage loans.

Table of Contents

The following table sets forth the composition of ASB s loan and mortgage-related securities portfolio as of the dates indicated:

	December 31									
	2005		2004		2003		2002		2001	
(dollars in thousands)	Balance	% of total	Balance	% of total	Balance	% of total	Balance	% of total	Balance	% of total
Real estate loans [1]										
Conventional (1-4 unit residential)	$ 2,617,194	42.4	$ 2,464,133	39.9	$ 2,438,573	42.1	$ 2,347,446	40.9	$ 2,242,329	43.0
Commercial	229,430	3.7	226,699	3.6	208,683	3.6	193,627	3.4	196,515	3.8
Construction and development	241,311	3.9	202,466	3.3	100,986	1.8	46,150	0.8	52,043	1.0
	3,087,935	50.0	2,893,298	46.8	2,748,242	47.5	2,587,223	45.1	2,490,887	47.8
Less:										
Deferred fees and discounts	(21,484)	(0.3)	(20,701)	(0.3)	(20,268)	(0.4)	(18,937)	(0.3)	(17,946)	(0.3)
Undisbursed loan funds	(140,271)	(2.3)	(132,208)	(2.1)	(69,884)	(1.2)	(21,412)	(0.4)	(22,910)	(0.5)
Allowance for loan losses	(16,212)	(0.3)	(15,663)	(0.3)	(14,734)	(0.3)	(23,708)	(0.4)	(26,085)	(0.5)
Total real estate loans, net	2,909,968	47.1	2,724,726	44.1	2,643,356	45.6	2,523,166	44.0	2,423,946	46.5
Other loans										
Consumer and other	259,048	4.2	232,189	3.8	222,743	3.9	245,853	4.3	252,487	4.8
Commercial	412,816	6.7	310,999	5.0	286,068	4.9	247,114	4.3	197,333	3.8
	671,864	10.9	543,188	8.8	508,811	8.8	492,967	8.6	449,820	8.6
Less:										
Deferred fees and discounts	(613)		(526)		(606)		(416)			
Undisbursed loan funds	(2)		(3)		(31)		(1)		(5)	
Allowance for loan losses	(14,383)	(0.2)	(18,194)	(0.3)	(29,551)	(0.5)	(21,727)	(0.4)	(16,139)	(0.3)
Total other loans, net	656,866	10.7	524,465	8.5	478,623	8.3	470,823	8.2	433,676	8.3
Mortgage-related securities, net	2,604,920	42.2	2,928,507	47.4	2,666,619	46.1	2,736,679	47.8	2,354,849	45.2
Total loans and mortgage-related securities, net	$ 6,171,754	100.0	$ 6,177,698	100.0	$ 5,788,598	100.0	$ 5,730,668	100.0	$ 5,212,471	100.0

[1] Includes renegotiated loans.

The following table summarizes ASB s loan portfolio, excluding loans held for sale and undisbursed commercial real estate construction and development loan funds as of December 31, 2005 and 2004, based upon contractually scheduled principal payments and expected prepayments allocated to the indicated maturity categories:

	December 31							
	2005				2004			
Due (in millions)	In 1 year or less	After 1 year through 5 years	After 5 years	Total	In 1 year or less	After 1 year through 5 years	After 5 years	Total
Residential loans - Fixed	$ 361	$ 920	$ 1,120	$ 2,401	$ 427	$ 890	$ 855	$ 2,172
Residential loans - Adjustable	82	142	82	306	115	208	63	386
	443	1,062	1,202	2,707	542	1,098	918	2,558
Commercial real estate loans - Fixed	4	19	42	65	5	11	20	36
Commercial real estate loans - Adjustable	107	38	65	210	73	41	87	201
	111	57	107	275	78	52	107	237
Consumer loans Fixed	11	19	14	44	12	19	14	45
Consumer loans Adjustable	52	106	47	205	50	93	36	179
	63	125	61	249	62	112	50	224
Commercial loans Fixed	109	104	51	264	89	69	38	196
Commercial loans Adjustable	107	38	4	149	63	47	5	115
	216	142	55	413	152	116	43	311
Total loans - Fixed	485	1,062	1,227	2,774	533	989	927	2,449
Total loans - Adjustable	348	324	198	870	301	389	191	881
	$ 833	$ 1,386	$ 1,425	$ 3,644	$ 834	$ 1,378	$ 1,118	$ 3,330

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, 2005, approximately $7.8 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 2005, 2004, 2003, 2002 and 2001 were $1.4 billion, $1.4 billion, $1.6 billion, $1.2 billion and $1.0 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 compared to 2003 was due to a slowdown in residential refinancing activity. The increase in loan originations in 2003 and 2002 was due to the strength in the Hawaii real estate market and low interest rates which had resulted in increased affordability of housing for consumers and higher loan refinancings.

Residential mortgage lending. ASB s 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, construction and development loans are generally 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, 2005, 2004 and 2003, ASB had commercial real estate construction and development loans of $149 million, $108 million and $35 million and residential construction and development loans of $93 million, $94 million and $66 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 2005, 2004 and 2003, ASB originated $77 million, $153 million and $81 million, respectively, of loans secured by multifamily or commercial and industrial properties. 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 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 2005, 2004 and 2003, ASB originated $189 million, $156 million and $138 million, respectively, of consumer loans.

Commercial lending. ASB provides both secured and unsecured commercial 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 commercial checking deposits. In 2005, 2004 and 2003, gross commercial loan originations of $436 million, $351 million and $195 million, respectively, accounted for approximately 30%, 26% and 12%, respectively, of ASB s total loan originations.

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

19

action, the property securing the delinquent debt is sold at a public auction in which ASB may participate as a bidder to protect its interest. If ASB is the successful bidder, the property is classified as real estate owned until it is sold. ASB s real estate acquired in settlement of loans represented nil, 0.01% and 0.12% of total assets as of December 31, 2005, 2004 and 2003, 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). 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				
(dollars in thousands)	**2005**	**2004**	**2003**	**2002**	**2001**
Nonaccrual loans					
Real estate					
One-to-four unit residential	$ 1,394	$ 2,240	$ 2,784	$ 9,783	$ 22,495
Commercial		235		983	10,129
Total real estate	1,394	2,475	2,784	10,766	32,624
Consumer	377	411	341	1,382	1,965
Commercial	598	3,510	2,236	3,633	3,018
Total nonaccrual loans	$ 2,369	$ 6,396	$ 5,361	$ 15,781	$ 37,607
Nonaccrual loans to total net loans	0.1%	0.2%	0.2%	0.5%	1.3%
Renegotiated loans not included above					
Real estate					
One-to-four unit residential	$ 731	$ 1,243	$ 2,148	$	$
Commercial	3,446	3,653	3,877	7,582	3,874
Commercial	790	427	1,919	2,175	2,681
Total renegotiated loans	$ 4,967	$ 5,323	$ 7,944	$ 9,757	$ 6,555
Nonaccrual and renegotiated loans to total net loans	0.2%	0.4%	0.4%	0.9%	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 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 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. In 2005, the decrease in nonaccrual loans of $4.0 million was primarily due to a $2.9 million payoff of a commercial loan and lower delinquencies in residential loans.

Table of Contents

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

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

(dollars in thousands)	2005	2004	2003	2002	2001
Allowance for loan losses, January 1	$ 33,857	$ 44,285	$ 45,435	$ 42,224	$ 37,449
Provision (reversal of allowance) for loan losses	(3,100)	(8,400)	3,075	9,750	12,500
Charge-offs					
Residential real estate loans		40	892	2,345	4,651
Commercial real estate loans			174	441	315
Consumer loans	1,558	1,790	3,027	3,479	3,644
Commercial loans	456	2,479	2,601	1,479	1,013
Total charge-offs	2,014	4,309	6,694	7,744	9,623
Recoveries					
Residential real estate loans	459	346	1,244	858	1,210
Commercial real estate loans		562	426	52	342
Consumer loans	525	549	586	257	313
Commercial loans	868	824	213	38	33
Total recoveries	1,852	2,281	2,469	1,205	1,898
Allowance for loan losses, December 31	$ 30,595	$ 33,857	$ 44,285	$ 45,435	$ 42,224
Ratio of allowance for loan losses, December 31, to average loans outstanding	0.90%	1.08%	1.44%	1.60%	1.42%
Ratio of provision for loan losses during the year to average loans outstanding	NM	NM	0.10%	0.34%	0.42%
Ratio of net charge-offs during the year to average loans outstanding	NM	0.06%	0.14%	0.23%	0.26%

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 as of the dates indicated:

	December 31				
	2005	2004	2003	2002	2001

(dollars in thousands)	Balance	% of total	Balance	% of total	Balance	% of total	Balance	% of total	Balance	% of total
Residential real estate	$ 8,613	72.1%	$ 10,137	74.4%	$ 4,031	76.9%	$ 6,246	77.6%	$ 9,933	78.0%
Commercial real estate	7,450	10.0	5,355	9.7	6,008	7.5	6,343	6.4	9,031	6.7
Consumer	3,111	6.9	4,008	6.8	6,540	6.8	8,489	8.0	8,538	8.6
Commercial	11,139	11.0	13,986	9.1	14,758	8.8	12,118	8.0	6,388	6.7
Unallocated	282	NA	371	NA	12,948	NA	12,239	NA	8,334	NA
	$ 30,595	100.0%	$ 33,857	100.0%	$ 44,285	100.0%	$ 45,435	100.0%	$ 42,224	100.0%

NA Not applicable.

In 2005, ASB s allowance for loan losses decreased by $3.3 million compared to a decrease of $10.4 million in 2004. Continued strength in real estate and business conditions in 2005 resulted in lower historical loss ratios and lower net charge-offs as a result of lower delinquencies which enabled ASB to record a reversal of allowance for loan losses of $3.1 million.

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 record a reversal of allowance for loan losses of $8.4 million. 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.

Table of Contents

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.

Investment activities

Currently, ASB s investment portfolio consists primarily of mortgage-related securities, stock of the FHLB of Seattle and a federal agency obligation. ASB owns private-issue mortgage-related securities as well as mortgage-related securities issued by the Federal National Mortgage Association (FNMA), Federal Home Loan Mortgage Corporation (FHLMC) and Government National Mortgage Association (GNMA). As of December 31, 2005, 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 2005, 2004 or 2003.

As of December 31, 2005, 2004 and 2003, ASB s investment in stock of FHLB of Seattle amounted to $97.8 million, $97.4 million and $94.6 million, respectively. The weighted-average yield on investments during 2005, 2004 and 2003 was 1.13%, 3.29% and 5.45%, 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.

As of December 31, 2005, ASB owned private-issue mortgage related securities issued by Countrywide Financial with an aggregate book value of $187.3 million and aggregate market value of $184.1 million.

The following table summarizes ASB s investment portfolio (excluding stock of the FHLB of Seattle, which has no contractual maturity), as of December 31, 2005, based upon contractually scheduled principal payments and expected prepayments allocated to the indicated maturity categories:

Due **(dollars in millions)**	**In 1 year or less**	**After 1 year through 5 years**	**After 5 years through 10 years**	**After 10 years**	**Total**

Federal agency obligation	$	$ 24	$	$	$ 24
FNMA, FHLMC and GNMA	419	1,228	433	96	2,176
Private issue	108	266	54	1	429
	$ 527	$ 1,518	$ 487	$ 97	$ 2,629
Weighted average yield	4.10%	4.16%	4.88%	5.07%	

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

Table of Contents

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 deposits.

Deposits. ASB s deposits are obtained primarily from residents of Hawaii. Net deposit inflow in 2005, 2004 and 2003 was $261.2 million, $269.9 million and $225.5 million, respectively.

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								
	2005			2004			2003		
(dollars in thousands)	Average balance	% of total deposits	Weighted average rate %	Average balance	% of total deposits	Weighted average rate %	Average balance	% of total deposits	Weighted average rate %
Savings	$ 1,721,988	38.7%	0.51%	$ 1,613,856	39.2%	0.40%	$ 1,352,507	34.8%	0.56%
Checking	1,151,345	25.8	0.05	1,019,464	24.8	0.03	913,228	23.5	0.05
Money market	288,731	6.5	0.89	322,806	7.8	0.45	397,590	10.2	0.61
Certificate	1,291,698	29.0	3.10	1,157,944	28.2	3.36	1,224,820	31.5	3.54
Total deposits	$ 4,453,762	100.0%	1.17%	$ 4,114,070	100.0%	1.15%	$ 3,888,145	100.0%	1.38%

As of December 31, 2005, ASB had $406.5 million in certificate accounts of $100,000 or more, maturing as follows:

(in thousands)	Amount
Three months or less	$ 152,803
Greater than three months through six months	63,879
Greater than six months through twelve months	88,741
Greater than twelve months	101,066

	$ 406,489

Deposit-insurance premiums and regulatory developments. In general, ASB s deposits are insured by the Savings Association Insurance Fund (SAIF) or the Bank Insurance Fund (BIF), which assess quarterly insurance premiums to thrifts and commercial banks, respectively. In addition to deposit insurance premiums, Financing Corporation (FICO) imposes a quarterly assessment on SAIF and BIF deposits to service the interest on FICO bond obligations. As a well capitalized thrift, ASB s base deposit insurance premium effective for the December 31, 2005 quarterly payment is zero and its annual FICO assessment is 1.32 cents per $100 of SAIF and BIF deposits as of September 30, 2005.

For a discussion of recent changes to the deposit insurance system, see Bank regulation Deposit insurance coverage.

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.

As of December 31, 2005, 2004 and 2003, advances from the FHLB amounted to $0.9 billion, $1.0 billion and $1.0 billion, respectively. The weighted-average rates on the advances from the FHLB outstanding as of December 31, 2005, 2004 and 2003 were 4.53%, 4.48% and 4.28%, respectively. The maximum amount outstanding at any month-end during 2005, 2004 and 2003 was $1.1 billion, $1.0 billion and $1.1 billion, respectively. Advances from the FHLB averaged $1.0 billion during each of 2005, 2004 and 2003 and the approximate weighted-average rate on the advances was 4.48%, 4.43% and 4.62%, respectively.

See Securities sold under agreements to repurchase in Note 4 of HEI s Consolidated Financial Statements.

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

	December 31		
(dollars in thousands)	2005	2004	2003
Advances from the FHLB	$ 935,500	$ 988,231	$ 1,017,053
Securities sold under agreements to repurchase	686,794	811,438	831,335
Total borrowings	$ 1,622,294	$ 1,799,669	$ 1,848,388
Weighted-average rate	4.23%	4.01%	3.48%

Competition

The banking industry in Hawaii is highly competitive. ASB is the third largest financial institution in Hawaii based on total assets and is in direct competition for deposits and loans, not only with the two larger institutions, but also with smaller institutions that are heavily promoting their services in certain niche areas, such as providing financial services to small and medium-sized businesses. 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 7 FDIC-insured financial institutions, of which 2 were thrifts and 5 were commercial banks, and approximately 100 credit unions as of December 31, 2005. 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 commercial and commercial real estate lines of business in 2002. The origination of commercial 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 commercial 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. Changes to two lines of business commercial real estate and mortgage banking have been completed, and a third is nearing completion commercial banking. The remaining transformation involving retail banking is intended to make ASB s retail area more customer-centric, rather than product-centric. In addition to these transformation projects, ASB will continue to invest in projects and opportunities that will build core franchise value and add to earnings growth and returns. Additionally, the banking industry is constantly changing and ASB is continuously making the changes and investments necessary to adapt and remain competitive.

Table of Contents

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.

Regulation and other matters

Holding company regulation. HEI and HECO were exempt from the comprehensive regulation of the SEC under the Public Utility Holding Company Act of 1935 (1935 Act) except for Section 9(a)(2) (relating to the acquisition of securities of other public utility companies) through compliance with the requirement to file annually Form U-3A-2 under the 1935 Act for holding companies which own utility businesses that are intrastate in character. The 1935 Act was repealed, effective February 8, 2006, and was essentially replaced by the Public Utility Holding Company Act of 2005 and implementing regulations (2005 Act). HEI and HECO are each holding companies within the meaning of the 2005 Act and filed a required notification of that status on February 21, 2006. The 2005 Act makes holding companies and certain of their subsidiaries subject to certain rights of the Federal Energy Regulatory Commission (FERC) to have access to books and records relating to FERC s jurisdictional rates, and also imposes certain record retention, accounting and reporting requirements. HEI and HECO filed a FERC Form 65B on February 21, 2006, seeking a waiver of these record retention, accounting and reporting requirements. If FERC takes no action within 60 days of such filing, this waiver will be automatically granted.

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. 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 met the QTL test at all times during 2005, 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.

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.

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. As of December 31, 2005, the consolidated common stock equity of HEI s electric utility subsidiaries was 56% of their total capitalization (as previously defined). As of December 31, 2005, HECO and its subsidiaries had common stock equity of $1.0 billion, of which approximately $431 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.

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 discussion under Electric utility Rates and the discussions under Electric utility Results of operations Most recent rate requests and Certain factors that may affect future results and financial condition Electric utility 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 proceedings on two specific issues (competitive bidding and distributed generation (DG)) to move toward a more competitive electric industry environment under cost-based regulation. For a discussion of the D&O issued by the PUC in the DG proceeding in January 2006, see Certain factors that may affect future results and financial condition Consolidated Competition Electric utility 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)

Table of Contents

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 made a similar presentation in its current rate case, which was accepted pending the final D&O. See also Holding company regulation above.

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 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 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.

Table of Contents

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. See Holding company regulation above. 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.

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). As of December 31, 2005, ASB was well capitalized .

On February 8, 2006, federal deposit insurance reform became law. Among other things, this major reform: merges the BIF and the SAIF; indexes the $100,000 deposit insurance to inflation beginning in 2010 and every five years thereafter; gives the FDIC and the National Credit Union Administration authority to determine whether raising the standard $100,000 deposit insurance limit is warranted; increases to $250,000 the deposit insurance limit for certain retirement accounts; and authorizes the FDIC to assess risk-based premiums. Although ASB believes that this insurance deposit reform may eventually result in a decrease in its premiums, proposed implementing regulations have not yet been issued for comment and it is too soon to evaluate the impact of this reform on ASB.

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) imposed 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. 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.

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 UVEST Financial Services 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. Since October 1, 2003, financial institutions have been required to fully implement a customer identification program. 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.

The Fair and Accurate Credit Transactions Act of 2003 (the FACT Act) 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 the type and number of solicitations they receive, and to restrict the use and distribution of sensitive medical information.

The agencies have implemented provisions of the FACT Act to, among other things, 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.

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, 2005, ASB was in compliance with all of the minimum standards with a core capital ratio of 7.4% (compared to a 4.0% requirement), a tangible capital ratio of 7.4% (compared to a 1.5% requirement) and total risk-based capital ratio of 15.1% (based on risk-based capital of $536.8 million, $251.8 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 certain types of loans and investments and core capital requirements. Under the new rules, an institution with a composite rating of 1 under the Uniform Financial Institution Rating System (i.e., 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, 2005, ASB met the applicable minimum core capital requirement of the revised OTS regulations.

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 new regulations have had a slight positive impact on ASB s risk-based capital.

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 (Basel II) 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 Basel II. 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 Basel II. The Advance Notice describes the purpose of Basel II 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 most recently announced time table is to issue a notice of proposed rule making during the first quarter of 2006, with parallel running anticipated during calendar year 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.

The review of U.S. risk-based capital requirements given impetus by Basel II resulted in the agencies issuance on October 20, 2005 of an advanced notice of rule making addressing the risk-based capital requirements of those financial institutions that will not come within the scope of the yet-to-be-proposed Basel II-inspired rules. The proposed changes described in this advanced notice would increase the number of risk-weight categories from five to nine in an effort to improve the risk sensitivity of the capital rules. ASB believes that the proposals would, if implemented in their current form, result in some improvement in its risk-based capital ratios. The agencies announced intention is to issue a notice of proposed rule making with respect to these proposals in a similar timeframe as the notice of rule making for the Basel II-inspired rules (currently scheduled for the first quarter of 2006) in order to allow the comparative evaluation of the two sets of risk-based capital standards.

Table of Contents

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 December 12, 2002, the OTS issued an interim final rule which applies Regulation W of the Federal Reserve Board (FRB) 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. ASB is subject to OTS rules relating to derivatives activities, including interest rate swaps. Currently ASB does not use interest rate swaps to manage interest rate risk, but may do so in the future. Generally speaking, the OTS 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 rules require ASB to have certain internal procedures for handling financial derivative transactions, including involvement of the ASB Board of Directors.

OTS Thrift Bulletin 13a (TB 13a) provides guidance on the management of interest rate risks, investment securities and derivatives activities. TB 13a also describes the guidelines OTS examiners 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 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 to the original TB 13. 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 $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. TB 13a 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, borrowings, the maturity and repayment of portfolio loans and securities and the sale of loans into secondary market channels. 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. As of December 31, 2005, ASB s unused FHLB borrowing capacity was approximately $1.5 billion. ASB utilizes growth in

30

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. As of December 31, 2005, ASB had loan commitments, undisbursed loan funds and unused lines and letters of credit of $1.1 billion. Management believes ASB s current sources of funds will enable it to meet these obligations while maintaining liquidity at satisfactory levels.

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, 2005, 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, 2005, 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. Failure to satisfy the QTL test would subject ASB to various penalties, including limitations on its activities, and would also bring into operation restrictions on the activities that may be engaged in by HEI, HEIDI and their other subsidiaries, which could effectively result in the required divestiture of ASB. At all times during 2005, ASB was in compliance with the QTL test. As of December 31, 2005, 86.5% 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. As of December 31, 2005, ASB was required under the capital plan to own capital stock in the FHLB of Seattle in the amount of $62 million and owned capital stock in the amount of $98 million, or $36 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.

Congress is considering legislation to revamp oversight of government-sponsored enterprises (GSEs). This legislation 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, this legislation 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.

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.

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 (see Certain factors that may affect future results and financial condition Consolidated Environmental matters in HEI s MD&A and Note 11 to HECO s Consolidated Financial Statements, which are incorporated herein by reference), the Company believes that each subsidiary has appropriately responded to environmental conditions requiring action and 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 utility subsidiaries facilities 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.

Table of Contents

For a discussion of section 316(b) of the federal Clean Water Act, related EPA rules and their possible application to the electric utilities, see Environmental regulation in Note 11 to HECO s Consolidated Financial Statements.

In 2000, the EPA introduced new regulations that required all large capacity cesspools to be permanently closed by April 2005. The regulations affected HECO s Kahe generating station, HELCO s Kanoelehua Base Yard, MECO s Maalaea and Kahului generating stations. MECO completed its cesspool replacement projects in late 2003. HECO and HELCO closed their cesspools in 2005 prior to the April deadline.

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 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 HELCO successfully completed arbitration in 2005 whereby it recovered a substantial portion of its costs from the third party contractor. The second incident took place on September 13, 2004 at Pier 3 in Hilo Harbor when a pipeline beneath a pier jointly owned by HELCO and Chevron leaked fuel oil owned by HELCO beneath a pier at storage facilities owned by Chevron. Cleanup activities at the pier were completed on October 9, 2004. Costs associated with pipeline maintenance, repair and replacement, as well as cleanup costs are shared 50%-50% between Chevron and HELCO.

During 2005 and up through March 7, 2006, HECO, HELCO and MECO did not experience any significant petroleum releases. 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 certain facilities that store petroleum to 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. In July 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. Since 2002, the EPA issued four extensions of the compliance dates for the amended regulations. The most recent extension, issued on February 17, 2006, requires that existing facilities that started operation prior to August 16, 2002, must maintain or amend, and implement SPCC plans by October 31, 2007. Regulated facilities that start operations after August 16, 2002, also must prepare and implement an SPCC Plan by October 31, 2007. 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 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.

Effective March 29, 2005, the EPA delisted coal-fired and oil-fired utility boilers from regulation under Title III of the CAA (the Delisting Rule). On the same date, the EPA issued a rule designed to control mercury emissions from coal-fired utility units. The preamble to the mercury control rule stated that the EPA would not require control of nickel emissions from oil-fired utility boilers. Subsequently, on October 21, 2005, the EPA issued a notice that it would reconsider the Delisting Rule (the Notice of Reconsideration). Based on the EPA comments accompanying

Table of Contents

the Notice of Reconsideration, HECO does not anticipate that the agency will relist oil-fired utility units for regulation under Title III. Further, because a decision by the EPA to relist oil-fired utility units would require the EPA to determine whether it should propose rules to control nickel emissions from existing oil-fired utility units, HECO believes that attempts to evaluate the impact of such regulations, if any, are both premature and speculative.

For a discussion of the July 1999 Regional Haze Rule amendments, see Environmental regulation in Note 11 to HECO s Consolidated Financial Statements.

CAA operating permits (Title V permits) have been issued for all affected generating units. The installation of the planned noise mitigation equipment measures for Keahole CT-4 was completed in November 2004. The installation of the planned noise mitigation equipment measures for Keahole CT-5 was completed in January 2005.

Hazardous waste and toxic substances controls. The operations of the electric utility and former freight transportation subsidiaries are subject to EPA regulations that implement provisions of the Resource Conservation and Recovery Act (RCRA), the Superfund Amendments and Reauthorization Act (SARA) 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.

Both federal and state 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 RCRA 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 RCRA. This determination 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.

The Emergency Planning and Community Right-to-Know Act under SARA Title III requires HECO, MECO and HELCO to report potentially hazardous chemicals present in their facilities in order to provide the public with information 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 some 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 their systems. 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 in August 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.

In July 2002, personnel at MECO s Maalaea Generating Station discovered a leak in an underground diesel fuel line. MECO notified DOH, instituted temporary corrective measures, and 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 located south of the Maalaea facility. MECO constructed a sump to remove fuel from the subsurface, installed soil borings and groundwater monitoring wells to assess impacts of the fuel release, and, with the guidance and consent of the USFWS and the DOH, installed an interception trench in the buffer zone and in a small part of the Wildlife Refuge. Based on the results of the subsurface investigation the operation of the interception trench, it appears that the fuel release has not affected and will not affect wildlife, sensitive wildlife habitat or the ocean, which lies approximately one-quarter mile south of the Maalaea facility. Total costs incurred as of December 31, 2005 were approximately $0.96 million. An estimated $0.2 million is expected to be expended during 2006-2007 to address ongoing response 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 developed a Monitoring and Closure Plan, which DOH approved in December 2004. Continued monitoring occasionally reveals a groundwater sample that exceeds DOH groundwater action levels. 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.

ASB may be subject to the provisions of the 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 great for ASB.

Securities ratings

See the Standard & Poor s (S&P) and Moody s Investors Service s (Moody s) ratings of HEI s and HECO s securities under Liquidity and capital resources (both Consolidated and Electric utility) in HEI s MD&A. 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.

Table of Contents

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 $3.9 million, $3.3 million and $3.1 million in 2005, 2004 and 2003, 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 and environmental and emissions controls.

Employees

As of December 31, 2005 and 2004, the Company had full-time employees as follows:

December 31	2005	2004
HEI	42	45
HECO and its subsidiaries	2,066	2,013
ASB and its subsidiaries	1,272	1,291
Other subsidiaries	3	5
	3,383	3,354

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 2,066 full time employees of HECO and its subsidiaries as of December 31, 2005, 58% were covered by collective bargaining agreements. See the discussion of Collective bargaining agreements in Note 11 to HECO s Consolidated Financial Statements.

ITEM 1A. RISK FACTORS

Holding Company and Company-Wide Risks

For additional information for certain risk factors enumerated below, see Forward-Looking Statements, HEI s MD&A, Quantitative and Qualitative Disclosures about Market Risk, and HEI s Consolidated Financial Statements.

HEI is a holding company that derives its income from its operating subsidiaries and depends on the ability of those subsidiaries to pay dividends or make other distributions to HEI and on its own ability to raise capital.

HEI is a legal entity separate and distinct from its various subsidiaries. As a holding company with no significant operations of its own, HEI s cash flows and consequent ability to service its obligations and pay dividends on its common stock is dependent upon its receipt of dividends or other distributions from its operating subsidiaries and its ability to issue common stock or other equity securities and to incur additional debt. The ability of HEI s subsidiaries to pay dividends or make other distributions to HEI is, in turn, subject to the risks associated with their operations and to contractual and regulatory restrictions, including:

- the provisions of an HEI agreement with the PUC, which could limit the ability of HEI s principal electric public utility subsidiary, HECO, to pay dividends to HEI in the event that the consolidated common stock equity of the electric public utility subsidiaries falls below 35% of total electric utility capitalization;

- the provisions of an HEI agreement entered into with federal bank regulators in connection with its acquisition of its bank subsidiary, ASB, which require HEI to contribute additional capital to ASB (up to a maximum amount of additional capital of $28.3 million as of December 31, 2005) upon request of the regulators in order to maintain ASB s regulatory capital at the level required by regulation;

- the minimum capital and capital distribution regulations of the OTS that are applicable to ASB;

Table of Contents

the receipt of a letter from the OTS stating it has no objection to the payment of any dividend ASB proposes to declare and pay to HEI; and

the provisions of preferred stock resolutions and debt instruments of HEI and its subsidiaries.

The Company is subject to risks associated with the Hawaii economy, volatile U.S. capital markets and changes in the interest rate environment that could result in higher retirement benefits expenses, declines in electric utility kilowatthour sales, declines in ASB s interest rate margins, higher delinquencies and charge-offs in ASB s loan portfolio and restrictions on the ability of HEI or its subsidiaries to borrow money.

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

A decline in the Hawaii economy, or the U.S. or Asian economies, could lead to a decline in kilowatthour sales and an increase in uncollected billings of HECO and its subsidiaries, higher delinquencies in ASB s loan portfolio and other adverse effects on HEI s businesses. If S&P or Moody s were to downgrade HEI s or HECO s long-term debt ratings because of these adverse effects, or if future events were to adversely affect the availability of capital to the Company, HEI s and HECO s ability to borrow could be constrained and their future borrowing costs would likely increase with resulting reductions in HEI s consolidated net income in future periods. Further, if HEI s or HECO s ratings were to be downgraded, HEI and HECO might not be able to sell commercial paper under current market conditions and might be required to draw on more expensive bank lines of credit or to defer capital or other expenditures.

Changes in the U.S. capital markets can also have significant effects on the Company. For example, pension income or expense is affected by the market performance of the assets in the master pension trust maintained for pension plans, and by the discount rate used to determine the service and interest cost components of net periodic pension cost (returns).

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

HEI and its subsidiaries may incur higher retirement benefits expenses and could be required to recognize a substantial additional minimum liability for pension benefits.

Retirement benefits expenses and cash funding requirements could increase in future years depending on numerous factors, including the performance of the U.S. equity markets and trends in interest rates and health care costs. Retirement benefits expenses based on net periodic pension and other postretirement benefit costs have been an allowable expense for rate-making, and higher retirement benefits expenses, along with other factors, may affect the need to request a rate increase.

Depending on investment results at each year end from the assets held in trust to satisfy retirement benefit plan obligations and the status of interest rates, the Company, like many sponsors of defined benefit pension plans, could be required in future years to recognize an additional minimum liability as prescribed by Statement of Accounting Standards (SFAS) No. 87, Employers Accounting for Pensions. The recognition of an additional minimum liability is required if the accumulated benefit obligation exceeds the fair value of plan assets on the measurement date. The electric utilities recognition of the liability would also require the removal of the prepaid pension asset ($106 million as of December 31, 2005) from their consolidated balance sheet and from their rate bases and the sum of these amounts (net of taxes) would be recorded as a reduction to stockholders equity through a non-cash charge to accumulated other comprehensive income (AOCI), and would not affect net income. By application filed on December 8, 2005, the electric utilities have requested the PUC to permit them to record, as a regulatory asset pursuant to SFAS No. 71, Accounting for the Effects of Certain Types of Regulation, and include in rate base, any amount that would otherwise be charged to AOCI as a result of recording a minimum pension liability, but no assurance can be given concerning how or when the PUC will act on this request.

The amount of additional minimum liability and charge to AOCI, if any, that might be recorded could be material and will depend upon a number of factors, including the year-end discount rate assumption, asset returns experienced during the year, any changes to actuarial assumptions or plan provisions, and contributions made by the Company to the plans during the year. In addition, retirement benefits expenses and cash funding requirements could increase in future years depending on the performance of the U.S. equity markets and trends in interest rates. Retirement benefits expenses based on net periodic pension and other postretirement benefit costs have been an allowable expense for rate-making, and higher retirement benefits expenses, along with other factors, may affect the need to request an electric rate increase. If HEI and its subsidiaries are required to record substantially greater charges to AOCI in the future, the consolidated financial ratios of HEI and its subsidiaries may deteriorate, which could result in security ratings downgrades and difficulty (or greater expense) in obtaining future financing. In addition, there may be possible financial covenant violations (although there are no advances currently outstanding under any credit facility subject to financial covenants). For example, certain of HECO s bank lines of credit require that it maintain a minimum ratio of consolidated common equity to consolidated capitalization of 35% (actual ratio was 56% as of December 31, 2005). In addition, the rates of return for the electric utilities could increase if they were required to record significant charges to AOCI and could impact the rates the electric utilities are allowed to charge, which may ultimately result in reduced revenues and lower earnings.

The Company is subject to the risks associated with the geographic concentration of its businesses and lack of interconnections that could result in service interruptions at the electric utilities or higher default rates on loans held by ASB.

The business of HECO and its electric utility subsidiaries is concentrated on the individual islands they serve in the State of Hawaii. The operations of HEI s electric utility subsidiaries are more vulnerable to service interruptions than are many U.S. mainland utilities because none of the systems of HECO and its subsidiaries are interconnected with the systems on the other islands they serve. Because of this lack of interconnections, it is necessary to maintain higher generation reserve margins than are typical for U.S. mainland utilities to help ensure reliable service. The reserve margins on Oahu are currently below desirable levels and this condition will likely continue and be exacerbated by projected load growth until additional generation is brought on line, which is not expected until 2009. Service interruptions, including in particular extended interruptions that could result from a natural disaster or terrorist activity, could adversely impact the kilowatthour sales of some or all of the electric utility subsidiaries.

Certain geographic regions of the U.S. may from time-to-time experience natural disasters or weaker regional economic conditions and housing markets and, consequently, may experience higher rates of loss and delinquency on loans. Substantially all of ASB s consumer loan customers are Hawaii residents. A significant portion of the commercial loan customers are located in Hawaii. Substantially all of the real estate underlying ASB s residential and commercial real estate loans are located in Hawaii. These assets may be subject to a greater risk of default than other comparable assets held by financial institutions with other geographic concentrations in the event of adverse economic, political or business developments or natural hazards that may affect Hawaii and the ability of ASB s customers to make payments of principal and interest on their loans.

Increasing competition and technological advances could cause HEI s businesses to lose customers or render their operations obsolete.

The banking industry in Hawaii, and certain aspects of the electric utility industry, are competitive. The success of HEI s subsidiaries in meeting competition will continue to have a direct impact on HEI s consolidated financial performance. For example:

ASB, which is the third largest financial institution in the state based on total assets, is in direct competition for deposits and loans not only with two larger institutions that have substantial capital, technology and marketing resources, but also with smaller Hawaii institutions and other U.S. institutions, including credit unions, mutual funds, mortgage brokers, finance companies and investment banking firms. Larger financial institutions may have greater access to capital at lower costs, which could impair ASB s ability to compete effectively. Significant advances in technology could render the operations of ASB less competitive or obsolete.

HECO and its subsidiaries face competition from independent power producers (IPPs), including alternate energy providers, and customer self-generation, with or without cogeneration. The PUC has an ongoing investigative proceeding on competitive bidding as a mechanism for acquiring or building new electric generating capacity. New technological developments, such as the commercial development of fuel cells or distributed generation, may render the operations of HEI s electric utility subsidiaries less competitive or obsolete. The PUC recently issued a decision in its ongoing distributed generation (DG) investigative proceeding, in which it set policies for DG interconnection agreements and standby rates, and established conditions under which electric utilities can provide DG services on customer-owned sites as a regulated service. The utilities have requested that the PUC clarify how the conditions will be administered. The electric utilities cannot predict the ultimate outcome of the PUC s competitive bidding and DG investigations, the impact they will have on competition from IPPs and customer self-generation, or the rate at which technological developments facilitating non-utility generation of electricity will occur.

HEI s businesses could suffer losses that are uninsured due to a lack of insurance coverage or limitations on the insurance coverage the Company does have.

In the ordinary course of business, HEI and its subsidiaries purchase insurance coverages (e.g., property and liability coverages) to protect against loss of, or damage to, their 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, there is no coverage. Certain of the insurance has substantial deductibles or has limits on the maximum amounts that may be recovered. For example:

The electric utilities overhead and underground transmission and distribution systems (with the exception of substation buildings and contents) have an estimated replacement cost of approximately $3 billion and are not insured against loss or damage 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. If a hurricane or other uninsured catastrophic natural disaster were to occur, and if the PUC were not to allow the affected electric utilities to recover from ratepayers restoration costs and revenues lost from business interruption, the lost revenues and repair expenses could result in a significant decrease in HEI s consolidated net income or in significant net losses for the affected periods.

ASB generally does not obtain credit enhancements such as mortgagor bankruptcy insurance but does require standard hazard and hurricane insurance and may require flood insurance for certain properties. ASB is subject to the risks of borrower defaults and bankruptcies and special hazard losses not covered by the required insurance.

Events like the September 11, 2001 terrorist attacks and financial failures of Enron and other companies have resulted generally in a decreased availability of insurance and higher deductibles, higher premiums and more restrictive policy terms.

Increased federal and state environmental regulation will require an increasing commitment of resources and funds and could result in construction delays or penalties and fines for non-compliance.

HEI and its subsidiaries are subject to federal and state environmental laws and regulations relating to air quality, water quality, waste management, natural resources and health and safety, which 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. Compliance with these legal requirements requires HEI s utility subsidiaries to commit significant resources and funds toward environmental monitoring, installation of pollution control equipment and payment of emission fees. These laws and regulations, among other things, require that certain environmental permits be obtained in order to construct or operate 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. For example, emission and/or discharge limits may be tightened, more extensive permitting requirements may be imposed and additional substances may become regulated.

If HEI or its subsidiaries fail to comply with environmental laws and regulations, even if caused by factors beyond their control, that failure may result in civil or criminal penalties and fines. At the present time, HECO is a named party in an ongoing environmental investigation to determine the nature and extent of actual or potential release of hazardous substances, oil, pollutants or contaminants at or near Honolulu Harbor and management cannot predict the ultimate cost or outcome of that investigation.

Adverse tax rulings or developments could result in significant increases in tax payments and/or expense.

Governmental taxing authorities could challenge a tax return position taken by HEI or its subsidiaries and, if the taxing authorities prevail, HEI s consolidated tax payments and/or expense, including applicable penalties and interest, could increase significantly. Further, the ability of HEI and its subsidiaries to generate capital gains and utilize capital loss carryforwards on future tax returns could impact future earnings.

The Company could be subject to the risk of uninsured losses in excess of its accruals for litigation matters.

HEI and its subsidiaries are involved in routine litigation in the ordinary course of their businesses, most of which is covered by insurance (subject to policy limits and deductibles). However, other litigation may arise that is not routine or involves claims that may not be covered by insurance. For example, HECO is a defendant in a suit, brought as a purported qui tam and class action, which claims that the State of Hawaii and HECO s other customers have been overcharged for electricity as a result of allegedly excessive prices charged under a power purchase agreement between defendants HECO and AES Hawaii, Inc. The complaint asserted that HECO s payments to AES Hawaii, Inc. for power have been excessive by over $1 billion since September 1992, and that approval of the power purchase agreement by the PUC in 1989 was wrongfully obtained through alleged misrepresentations or material omissions by the defendants of the estimated future costs under the power purchase agreement compared to the costs that would have been incurred if HECO-owned units had been constructed instead. Although a final judgment dismissing this complaint with prejudice was entered in HECO s favor on September 17, 2003, one of the plaintiffs has appealed from this dismissal. On July 16, 2004, the Hawaii Supreme Court retained jurisdiction over the appeal (rather than assign the appeal to the Intermediate Court of Appeals) and the matter has been fully briefed and is awaiting decision. Because of the uncertainties associated with litigation, there is a risk that litigation against HEI and its subsidiaries, even if vigorously defended, could result in costs of defense and judgment or settlement amounts not covered by insurance and in excess of reserves established in HEI s consolidated financial statements.

Changes in accounting principles and estimates could affect the reported amounts of the Company s assets and liabilities or revenues and expenses.

HEI s consolidated financial statements are prepared in accordance with accounting principles generally accepted in the United States of America. Changes in these principles or the Company s application of existing accounting principles could materially affect HEI s consolidated financial position or results of operations. Further, 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; and allowance for loan losses.

In accordance with SFAS No. 71, Accounting for the Effects of Certain Types of Regulation, HECO and its subsidiaries financial statements reflect assets and costs based on cost-based rate-making regulations. Continued accounting in this manner requires that certain criteria relating to the recoverability of such costs through rates be met. If events or circumstances should change so that the criteria are no longer satisfied, the electric utilities regulatory assets (amounting to approximately $111 million as of December 31, 2005) may need to be charged to expense, which could result in significant reductions in the electric utilities net income, and the electric utilities regulatory liabilities (amounting to $219 million as of December 31, 2005) may need to be refunded to ratepayers.

Changes in accounting principles can also impact HEI s consolidated financial statements. For example, if a PPA falls within the scope of FASB FIN No. 46 (FIN 46R), Consolidation of Variable Interest Entities and results in the consolidation of the IPP in HECO s consolidated financial statements, the consolidation 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. Also, if a PPA falls within the scope of Emerging Issues Task Force (EITF) Issue No. 01-8, Determining Whether an Arrangement Contains a Lease and results in the classification of the agreement as a capital lease, a material effect on HEI s consolidated balance sheet may result, including the recognition of significant capital assets and lease obligations.

Electric Utility Risks

Actions of the PUC are outside the control of the electric utility subsidiaries and could result in inadequate or untimely rate relief, in rate reductions or refunds or in unanticipated delays, expenses or writedowns in connection with the construction of new projects.

The rates the electric utilities are allowed to charge for their services and the timeliness of permitted rate increases, are among the most important items influencing the electric utilities financial condition, results of operations and liquidity. The PUC has broad discretion over the rates that the electric utilities charge their customers. HECO currently has a rate case pending before the PUC in which it is seeking rate increases largely to recover the costs of capital improvements since its last rate case, the purchase of additional firm capacity and energy from Kalaeloa, the cost of measures taken to address peak load increases until generation capacity can be added on Oahu and increased operation and maintenance (O&M) expenses. In addition, HELCO has notified the PUC of its intention to file a request for a rate increase in spring 2006 intended to recover the cost of improvements to its transmission and distribution lines and the two generating units at its Keahole generating plant that became available for commercial operation since its last rate case in 2000. The increased level of the electric utilities O&M expenses (including increased retirement benefits expenses), which management expects will continue in 2006, increased capital expenditures, or other factors could result in the electric utilities seeking rate relief more often than in the past. Any adverse decision by the PUC concerning the level or method of determining electric utility rates, the returns on equity or rate base found to be reasonable, the potential consequences of exceeding or not meeting such returns, or any prolonged delay in rendering a decision in a rate or other proceeding, could have a material adverse effect on HECO s consolidated financial condition, results of operations and liquidity.

The electric utilities could be required to refund to their customers, with interest, revenues received under interim rate orders if and to the extent they exceed the amounts allowed in final rate orders. At the end of September 2005, HECO received and implemented an interim general rate increase of $53.3 million in annual base revenues granted by the PUC in HECO s current rate case. As of December 31, 2005, HECO had recognized an aggregate of $32 million of revenues with respect to this interim general rate increase and other interim orders regarding certain integrated resource planning costs.

The rate schedules of each of HEI s 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 2004 PUC decisions approving the electric utilities fuel supply contracts, the PUC affirmed the electric utilities right to include in their respective energy cost adjustment clauses the stated costs incurred pursuant to their respective new fuel supply contracts, to the extent that these costs are not included in their respective base rates, and restated its intention to examine the need for continued use of energy cost adjustment clauses in rate cases. While there was no opposition to the continuation of the clause by the parties in the pending HECO rate case, there can be no assurance concerning actions the PUC may take in its final order in the pending HECO rate case or otherwise in the future with respect to these clauses.

Many public utility projects require PUC approval and various permits (e.g., environmental and land use permits) from other governmental agencies. Difficulties in obtaining, or the inability to obtain, the necessary approvals or permits, or any adverse decision or policy made or adopted, or any prolonged delay in rendering a decision, by an agency with respect to such approvals and permits, can result in significantly increased project costs or even cancellation of projects. For example, two major capital improvement projects HECO s East Oahu Transmission

Project and the expansion of HELCO s Keahole generating plant have encountered substantial opposition and consequent delay and increased cost. In the event a project does not proceed, or if the PUC disallows cost recovery for all or part of the project, project costs may need to be written off in amounts that could result in significant reductions in HECO s consolidated net income.

Electric utility operations are significantly influenced by weather conditions.

The electric utilities results of operations can be affected by changes in the weather. Weather conditions, particularly temperature and humidity, directly influence the demand for electricity. In addition, severe weather can be destructive, causing outages and property damage and requiring the utilities to incur significant additional expenses that may not be recoverable.

Electric utility operations depend heavily on third party suppliers of fuel oil and purchased power.

The electric utilities rely on fuel oil suppliers and shippers and independent power producers to deliver fuel oil and power, respectively, in accordance with contractual agreements. Approximately 79.5% of the net energy generated or purchased by the electric utilities in 2005 was generated from the burning of oil, and purchases of power by the electric utilities provided about 39.1% of their total net energy generated and purchased for the same period. Failure or delay by oil suppliers and shippers to provide fuel pursuant to existing contracts, or failure by a major IPP to deliver the firm capacity anticipated in its power purchase agreement, could disrupt the ability of the electric utilities to deliver electricity and require the electric utilities to incur additional expenses to meet the needs of their customers that may not be recoverable. In addition, as these contractual agreements end, the electric utilities may not be able to purchase fuel and power on terms equivalent to the current contractual agreements.

Electric utility generating facilities are subject to operational risks that could result in unscheduled plant outages, unanticipated and/or increased operation and maintenance expenses and increased power purchase costs.

Operation of electric generating facilities involves certain risks which can adversely affect energy output and efficiency levels. Included among these risks are facility shutdowns or power interruptions due to insufficient generation or a breakdown or failure of equipment or processes or interruptions in fuel supply, inability to negotiate satisfactory collective bargaining agreements when existing agreements expire or other labor disputes, inability to comply with regulatory or permit requirements, disruptions in delivery of electricity, operator error and catastrophic events such as fires, explosions, floods or other similar occurrences affecting the electric utilities generating facilities or transmission and distribution systems. For example, as a result of load growth on Oahu and other factors, there currently is an increased risk to generation reliability. Generation reserve margins are lower than considered desirable in light of circumstances. Existing units are running harder, resulting in more frequent and more extensive maintenance, at times requiring temporary shut downs of these units. HECO has taken a number of steps to mitigate the risk of outages, including securing additional purchased power, adding distributed generation at some of substations and encouraging energy conservation. The marginal costs of supplying growing demand, however, is increasing because of HECO s decreasing reserve margin situation and the rate of this increase is not likely to lessen until after HECO adds its proposed new generating unit on Oahu in 2009.

The electric utilities may be adversely affected by new legislation.

Congress and the Hawaii Legislature periodically consider legislation that could have positive or negative effects on the electric utilities and their customers. For example, Congress adopted the Energy Policy Act of 2005, which will provide $14.5 billion in tax incentives over a 10-year period designed to boost conservation efforts, increase domestic energy production and expand the use of alternative energy sources, such as solar, wind, ethanol, biomass, hydropower and clean coal technology. The incentives include tax credits and shorter depreciable lives for many assets associated with energy production and transmission. The primary impact of these incentives on the electric utilities will be the reduction in the depreciable tax life, from 20 years to 15 years, of certain electric transmission equipment placed into service after April 11, 2005. The Energy Policy Act of 2005 also replaced the Public Utility Holding Company Act of 1935 with the Public Utility Holding Company Act of 2005. On February 8, 2006, HEI and HECO became holding companies under the Public Utility Holding Company Act of 2005. The Public

Utility Holding Company Act of 2005 provides for FERC access to the books and records of utility holding companies and, absent exemptions or waivers, imposes certain record retention and accounting requirements on public utility holding companies. HEI and HECO have filed a notification claiming a waiver of such requirements as single-state public utility holding companies. There can be no assurance that the waiver will be obtained.

A number of bills on energy were introduced in the 2006 Hawaii State legislative session. While the majority of measures contained in these bills do not negatively affect the electric utilities, the electric utilities are actively engaged in deliberations before the Legislature on matters that may affect them if adopted, such as bills that would direct the PUC to review and consider alternatives to the current energy cost adjustment clause, require the outsourcing of demand-side management programs, require the use of long-term fixed-price power purchase contracts for renewable energy generators, or modify the renewable portfolio standards law. At this time, it is not possible to predict the outcome of those deliberations.

The 2001 Hawaii Legislature passed a law establishing renewable portfolio standard (RPS) goals for the electric utilities, on a consolidated basis, of 7% by December 31, 2003, 8% by December 31, 2005 and 9% by December 31, 2010. The law was amended in 2004 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. It may be difficult for the electric utilities to attain the renewables percentages in the future (although they have in the past), and management cannot predict the future consequences of failure to do so.

The renewable standards law also required the PUC to develop and implement a utility ratemaking structure, which may include performance-based ratemaking, to provide incentives that encourage Hawaii s electric utilities to use cost-effective renewable energy resources found in Hawaii to meet the RPS goals, 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. In November 2004, the PUC initiated a process, consisting of three sets of workshops (two sets of which have been completed) that are intended to lead to the creation of a document forming the basis of a set of rules to be adopted in a rule-making process relating to electric utility rate design. The electric utilities cannot predict the ultimate outcome of this process.

Bank Risks

Fluctuations in interest rates could result in lower net interest income, impair ASB s ability to originate new loans or impair the ability of ASB s adjustable-rate borrowers to make increased payments.

Interest rate risk is a significant risk of ASB s operations. ASB s net interest income consists primarily of interest income received on fixed-rate and adjustable-rate loans, mortgage-related securities and investments and interest expense consisting primarily of interest paid on deposits and borrowings. Interest rate risk arises when earning assets mature or when their interest rates change in a time frame different from that of the costing liabilities. Changes in market interest rates, including changes in the relationship between short-term and long-term market interest rates or between different interest rate indices, can impact ASB s net interest margin. Although ASB pursues an asset-liability management strategy designed to control its risk from changes in market interest rates, unfavorable movements in interest rates could result in lower net interest income.

Increases in market interest rates could have an adverse impact on ASB s cost of funds. Higher market interest rates could lead to higher interest rates paid on deposits and other borrowings.

Significant increases in market interest rates, or the perception that an increase may occur, could adversely affect ASB s ability to originate new loans and grow. An increase in market interest rates, especially a sudden increase, could also adversely affect the ability of ASB s adjustable-rate borrowers to meet their higher payment obligations. If this occurred, it could cause an increase in nonperforming assets and charge-offs. Conversely, a decrease in interest rates or a mismatching of maturities of interest sensitive financial instruments could result in an acceleration in the prepayment of loans and mortgage-related securities and impact ASB s ability to reinvest its liquidity in similar yielding assets.

ASB s operations are affected by many disparate factors, some of which are beyond its control, that could result in lower net interest income or decreased demand for its products and services.

ASB s results of operations depend primarily on the level of net interest income generated by ASB s earning assets and costing liabilities and the supply of and demand for its products and services (i.e., loans and deposits). ASB s net income may also be adversely affected by various other factors, such as:

- local and other economic and political conditions that could result in declines in employment and real estate values, which in turn could adversely affect the ability of borrowers to make loan payments and the ability of ASB to recover the full amounts owing to it under defaulted loans;

- the ability of borrowers to obtain insurance and the ability of ASB to place insurance where borrowers fail to do so, particularly in the event of catastrophic damage to collateral securing loans made by ASB;

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 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;

increases in operating costs, due to its strategic transformation to a full-service community bank, inflation and other factors, that exceed increases in ASB s net interest, fee and other income;

the ability of ASB to maintain or increase the level of deposits, ASB s lowest cost funds; and

the ability of ASB to execute its strategy to transform itself to a full-service community bank.

Banking and related regulations could result in significant restrictions being imposed on ASB s business.

ASB is subject to examination and comprehensive regulation by the Department of Treasury, the OTS and the Federal Deposit Insurance Corporation, and is subject to reserve requirements established by the Board of Governors of the Federal Reserve System. As ASB s primary regulator, the OTS regularly conducts examinations to assess the safety and soundness of ASB s operations and activities and ASB s compliance with applicable banking laws and regulations. Because ASB is an indirect subsidiary of HEI, federal regulatory authorities have the right to examine HEI and its activities.

Under certain circumstances, including any determination that ASB s relationship with HEI results in an unsafe and unsound banking practice, these regulatory authorities have the authority to restrict the ability of ASB to transfer assets and to make distributions to its stockholders (including payment of dividends to HEI), or they could seek to require HEI to sever its relationship with or divest its ownership of ASB. Payment by ASB of dividends to HEI may also be restricted by the OTS under its prompt corrective action regulations or its capital distribution regulations if ASB s capital position deteriorates. In order to maintain its status as a QTL, ASB is required to maintain at least 65% of its assets in qualified thrift investments. 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 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. In the event of a required divestiture, federal law substantially limits the entities that could acquire ASB.

ASB s strategy to expand its commercial and commercial real estate lending activities may result in higher service costs and greater credit risk than residential lending activities due to the unique characteristics of these markets.

ASB has been aggressively pursuing a strategy that includes expanding its commercial and commercial real estate lines of business. These types of loans generally entail higher underwriting and other service costs and present greater credit risks than traditional residential mortgages.

Generally, both commercial and commercial real estate loans have shorter terms to maturity and earn higher rates than residential mortgage loans. Only the assets of the business typically secure commercial loans. In such cases, upon default, any collateral repossessed may not be sufficient to repay the outstanding loan balance. In addition, loan collections are dependent on the borrower s continuing financial stability and, thus, are more likely to be affected by current economic conditions and adverse business developments.

Commercial real estate properties tend to be unique and are more difficult to value than residential real estate properties. Commercial real estate loans may not be fully amortizing, meaning that they may have a significant principal balance or balloon payment due at maturity. In addition, commercial real estate properties, particularly industrial and warehouse properties, are generally subject to relatively greater environmental risks than noncommercial properties and to the corresponding burdens and costs of compliance with environmental laws and regulations. Also, there may be costs and delays involved in enforcing rights of a property owner against tenants in default under the terms of leases with respect to commercial properties. For example, tenants may seek the protection of bankruptcy laws, which could result in termination of such tenant s lease.

In addition to the inherent risks of commercial and commercial real estate lending described above, the expansion of these new lines of business present execution risks including the ability of ASB to attract personnel experienced in underwriting such loans and the ability of ASB to appropriately evaluate credit risk associated with such loans in determining the adequacy of the allowance for loan losses.

Table of Contents

ITEM 1B. UNRESOLVED STAFF COMMENTS

HEI has not received, prior to July 4, 2005, written comments from the SEC staff regarding its periodic or current reports under the Securities Exchange Act of 1934, which remain unresolved.

HECO has not received, prior to July 4, 2005, written comments from the SEC staff regarding its periodic or current reports under the Securities Exchange Act of 1934, which remain unresolved.

ITEM 2. PROPERTIES

HEI leases office space from nonaffiliated lessors in downtown Honolulu under leases that expire in May 2007 and March 2011. HEI also subleases office space in a downtown Honolulu building leased by HECO under a lease that expires in November 2021. The properties of HEI s subsidiaries are as follows:

Electric utility

See Generation statistics and Transmission systems in Item 1 and Limited insurance in HEI s MD&A.

Electric lines are located over or under public and nonpublic properties. See HECO and subsidiaries and service areas in Item 1 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. These plants, along with distributed generators at two substation sites and at HECO s Iwilei tank farm, have an aggregate net generating capability of 1,223.4 MW as of December 31, 2005. 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 122 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 6,734,855 kilovoltamperes as of December 31, 2005.

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 expires in November 2021, with an option to extend through 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 underground fuel pipelines that transport fuel from HECO s tank farm at Campbell Industrial Park to HECO s power plants at Waiau and Kahe. HECO also owns a fuel storage facility at its Iwilei site with a maximum usable capacity of 79,203 barrels, and an underground pipeline that transports fuel from that site to its Honolulu power plant.

HELCO owns and operates five generating plants on the island of Hawaii. These plants at Hilo (2), Waimea, Kona and Puna, along with distributed generators at substation sites, have an aggregate net generating capability of 181.9 MW as of December 31, 2005 (excluding a small run-of-river hydro unit and a 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, 2005), 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 216.8 MW as of December 31, 2005. The plants are situated on MECO-owned land 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 on a month-to-month basis until the area is required for development by MECO for utility purposes or September 30, 2007, 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, 2005) and fuel storage facilities on the islands of Lanai and Molokai, primarily on land owned by MECO.

Bank

ASB owns or 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, 2005	**Owned**	**Leased**	**Total**
Oahu	8	36	44
Maui	3	5	8
Kauai	3	2	5
Hawaii	2	4	6
Molokai		1	1
	16	48	64

In January 2006, ASB opened a new leased branch on the island of Oahu bringing the total number of branches to 65.

As of December 31, 2005, the net book value of branches and office facilities is approximately $44 million. Of this amount, $34 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 2006 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 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.

Table of Contents

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

HEI and HECO:

During the fourth quarter of 2005, 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 6, 2006 and their years of company service are given as of December 31, 2005. 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 May 2, 2006) 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 63	
Chairman of the Board, President and Chief Executive Officer	9/98 to date
Director	4/89 to date
(Company service: 18 years)	
Eric K. Yeaman, age 38	
Financial Vice President, Treasurer and Chief Financial Officer	01/03 to date
Eric K. Yeaman, prior to joining HEI, served as Chief Operating and Financial Officer of Kamehameha Schools from 4/02 to 1/03 and Chief Financial Officer of Kamehameha Schools from 7/00 to 4/02).	
(Company service: 3 years)	
Patricia U. Wong, age 49	
Vice President Administration and Corporate Secretary	4/05 to date
Vice President	1/05 to 4/05
Vice President Corporate Excellence, HECO	3/98 to 12/04
(Company service: 15 years)	
Charles F. Wall, age 66	
Vice President and Corporate Information Officer	7/90 to date
(Company service: 15 years)	
Andrew I. T. Chang, age 66	
Vice President Government Relations	4/91 to date
(Company service: 20 years)	
Curtis Y. Harada, age 50	
Controller	1/91 to date
(Company service: 16 years)	
T. Michael May, age 59	
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: 13 years)	

Constance H. Lau, age 53	
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: 21 years)	

HEI s executive officers, with the exception of Charles F. Wall and Andrew I. T. Chang, 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.

Robert F. Clarke will relinquish his title as Chairman, President and CEO of HEI, effective at HEI s Annual Meeting of Shareholders on May 2, 2006 and will not be renominated as a director of HEI. He will retire on May 31, 2006. HEI s board of directors has named Constance H. Lau, President and CEO of ASB, to succeed Mr. Clarke on May 2, 2006, as HEI President and CEO, as well as Chairman of HECO. Ms. Lau will also retain her position as

Table of Contents

President and CEO of ASB and will add the title of Chairman of the ASB board. She will also be nominated to be elected by the shareholders as a director of HEI. There are no arrangements or understandings between her and any person, pursuant to which she was selected. Also, effective in May 2006, Charles F. Wall, Vice President and Corporate Information Officer, will retire.

PART II

ITEM 5. MARKET FOR REGISTRANTS COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

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 of this Form 10-K. 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 and that description is incorporated herein by reference. 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 March 1, 2006, was 12,568.

In 2005, HEI issued an aggregate of 28,200 shares of unregistered common stock pursuant to the HEI 1990 Nonemployee Director Stock Plan, as amended and restated effective March 8, 2005 (the HEI Nonemployee Director Plan). Under the HEI Nonemployee Director Plan, each HEI nonemployee director receives, in addition to an annual cash retainer, an annual stock grant of 1,400 shares of HEI common stock (2,000 shares for the first time grant to a new HEI director) and each nonemployee subsidiary director who is not also an HEI nonemployee director receives an annual stock grant of 1,000 shares of HEI common stock (600 shares for the first time grant to a new subsidiary director). 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.

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). In 2003, HEI issued an aggregate of 16,200 shares (split-adjusted) of unregistered common stock pursuant to the HEI 1990 Nonemployee Director Stock Plan, as amended and restated effective May 1, 2002 (the HEI Nonemployee Director Plan).

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.

Table of Contents

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, 2005	110,054	$ 26.24		NA
November 1 to 30, 2005	45,761	26.27		NA
December 1 to 31, 2005	267,176	26.28		NA
	422,991	$ 26.27		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), 78,654 of the 110,054 shares, 45,761 of the 45,761 shares and 231,676 of the 267,176 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 a 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 quarters ended March 31, 2005, June 30, 2005, September 30, 2005 and December 31, 2005 were $9,933,000, $9,289,000, $14,733,000 and $16,940,000, respectively. The dividends declared and paid on HECO s common stock for the quarter ended March 31, 2004 was $11,613,000. There were no dividends declared and paid on HECO s common stock for the quarters ended June 30, 2004, September 30, 2004 and December 31, 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 and the discussion of Restrictions on dividends and other distributions under Regulation and other matters in Item 1. Business.

ITEM 6. SELECTED FINANCIAL DATA

HEI:

Table of Contents

Selected Financial Data

Hawaiian Electric Industries, Inc. and Subsidiaries

Years ended December 31	2005	2004	2003	2002	2001
(dollars in thousands, except per share amounts)					
Results of operations					
Revenues	$ 2,215,564	$ 1,924,057	$ 1,781,316	$ 1,653,701	$ 1,727,277
Net income (loss)					
Continuing operations	$ 127,444	$ 107,739	$ 118,048	$ 118,217	$ 107,746
Discontinued operations	(755)	1,913	(3,870)		(24,041)
	$ 126,689	$ 109,652	$ 114,178	$ 118,217	$ 83,705
Basic earnings (loss) per common share					
Continuing operations	$ 1.58	$ 1.36	$ 1.58	$ 1.63	$ 1.60
Discontinued operations	(0.01)	0.02	(0.05)		(0.36)
	$ 1.57	$ 1.38	$ 1.53	$ 1.63	$ 1.24
Diluted earnings per common share	$ 1.56	$ 1.38	$ 1.52	$ 1.62	$ 1.23
Return on average common equity-continuing operations *	10.5%	9.4%	11.1%	12.0%	12.2%
Return on average common equity	10.4%	9.5%	10.7%	12.0%	9.5%
Financial position **					
Total assets	$ 9,951,577	$ 9,719,257	$ 9,307,700	$ 9,039,121	$ 8,663,417
Deposit liabilities	4,557,419	4,296,172	4,026,250	3,800,772	3,679,586
Securities sold under agreements to repurchase	686,794	811,438	831,335	667,247	683,180
Advances from Federal Home Loan Bank	935,500	988,231	1,017,053	1,176,252	1,032,752
Long-term debt, net	1,142,993	1,166,735	1,064,420	1,106,270	1,145,769
HEI- and HECO-obligated preferred securities of trust subsidiaries			200,000	200,000	200,000
Preferred stock of subsidiaries not subject to mandatory redemption	34,293	34,405	34,406	34,406	34,406
Stockholders equity	1,216,630	1,210,945	1,089,031	1,046,300	929,665
Common stock					
Book value per common share **	$ 15.02	$ 15.01	$ 14.36	$ 14.21	$ 13.06
Market price per common share					
High	29.79	29.55	24.00	24.50	20.63
Low	24.60	22.96	19.10	17.28	16.78
December 31	25.90	29.15	23.69	21.99	20.14
Dividends per common share	1.24	1.24	1.24	1.24	1.24
Dividend payout ratio	79%	90%	81%	76%	100%
Dividend payout ratio-continuing operations	78%	91%	78%	76%	78%

Market price to book value per common share **	172%	194%	165%	155%	154%
Price earnings ratio ***	16.4x	21.4x	15.0x	13.5x	12.6x
Common shares outstanding (thousands) **	80,983	80,687	75,838	73,618	71,200
Weighted-average	80,828	79,562	74,696	72,556	67,508
Shareholders ****	35,645	35,292	34,439	34,901	37,387
Employees **	3,383	3,354	3,197	3,220	3,189

* 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. The principal trading market for HEI s common stock is the New York Stock Exchange (NYSE).

**** At December 31. Registered shareholders plus participants in the HEI Dividend Reinvestment and Stock Purchase Plan who are not registered shareholders. As of March 1, 2006, HEI had 35,624 registered shareholders and participants.

The Company discontinued its international power operations in 2001. 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 and factors that affected reported results of operations (e.g., bank franchise taxes).

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.

Table of Contents

HECO:

The information required by this item is incorporated herein by reference to Selected Financial Data on page 1 of Exhibit 99 to HECO s Form 8-K dated March 7, 2006.

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

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 of the electric utilities and the bank that follow.

HEI Consolidated

Executive overview and strategy

The Company s three strategic objectives, currently, 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 HECO and its electric utility subsidiaries, Hawaii Electric Light Company, Inc. (HELCO) and Maui Electric Company, Limited (MECO), 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 2005, income from continuing operations was $127 million, compared to $108 million in 2004. Basic earnings per share from continuing operations were $1.58 per share in 2005, up 16% from $1.36 per share in 2004 due primarily to a 2004 after-tax charge of $20 million, or $0.25 per share, as a result of a June 2004 tax ruling and subsequent settlement (see Bank franchise taxes sections below). Also impacting results in 2005 were lower electric utility earnings, partly offset by $8 million higher net gains on investments and lower financing costs in the other segment. The Company s operations will be heavily influenced by Hawaii s economy, which is driven by tourism, the federal government (including the military), real estate and construction. Per the State of Hawaii Department of Business, Economic Development and Tourism (DBEDT), Hawaii real gross state product grew by a forecasted 3.5% in 2005 and is expected to grow by a forecasted 2.8% in 2006.

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 as of December 31, 2005 was 4.8%. HEI s Board believes that HEI should achieve a 65% payout ratio on a sustainable basis and that cash flows should support an increase before it considers increasing the common stock dividend above its current level. The dividend payout ratios based on net income for 2005, 2004 and 2003 were 79%, 90% and 81% (payout ratios of 78%, 91% and 78% 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.

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

See the Electric Utility and Bank sections for their respective executive overviews and strategies.

Economic conditions

Note: The statistical data in this section is from public third party sources (e.g., DBEDT, U.S. Census Bureau and Bloomberg).

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. The state s economic growth, which is fueled by the two largest components of Hawaii s economy (tourism and the federal government), is forecast by the DBEDT to be a moderate 3.0% in 2006.

It was a record year for tourism in Hawaii with visitor days exceeding the 2004 record by 6.6%. In 2005, visitor expenditures were $11.8 billion, which is an 8.7% increase over 2004. State economists expect continued growth in 2006 with projected increases of 3.1% in visitor days and 4.6% in visitor expenditures.

Hawaii was the fifth ranking state in federal government expenditures per capita in the latest available data. For the federal fiscal year ended September 30, 2004 (latest available data), total federal government expenditures in Hawaii, including military expenditures, were $12.2 billion or $9,651 per capita, increasing 8% and 7%, respectively, over fiscal year 2003. Military spending, which is 39% of federal expenditures in Hawaii, increased 6% in 2004 compared to 2003.

The real estate and construction industries in Hawaii also influence HEI s core businesses. After five years of increases, real estate prices climbed again in 2005, resulting in $6 billion in total dollar residential resale volumes on Oahu, a 25.8% increase over 2004.

The construction industry continues to remain healthy indicated by a 28.1% increase in building permits in 2005 compared with 2004. Local economists forecast contracting receipts to grow by 5% in 2006.

Overall, the outlook for the Hawaii economy remains positive. However, economic growth is affected by the rate of expansion in the mainland U.S. and Japan economies and the growth in military spending, and is vulnerable to uncertainties in the world s geopolitical environment.

Management also monitors (1) oil prices because of their impact on the rates the utilities charge for electricity and the potential effect of increased prices of electricity on usage and (2) interest rates because of their potential impact on ASB s earnings, HEI s and HECO s cost of capital, pension costs and HEI s stock price. Crude oil prices rose considerably during 2005 as strong demand from the U.S. and China and geopolitical uncertainty continued. Futures prices began 2005 near $27 per barrel and spiked to a high of $69.81 per barrel in August 2005 in the wake of Hurricane Katrina. Prices moved down in the last quarter of the year as regional production in the Gulf was restored. More recently, however, prices are climbing due to political tension and uncertainty in oil producing countries such as Iran and Nigeria. On February 3, 2006, crude oil futures closed at $65.37 per barrel.

For most of 2005, long-term interest rates fluctuated in the 4.0% to 4.5% trading range and the short-end of the yield curve continued to increase. This resulted in a flattening yield curve throughout the year which is indicative of a difficult earning environment for ASB. As of December 31, 2005, the yield curve was inverted with a spread between the 10-year and 2-year Treasuries of (0.02)%, compared to the yield curve as of December 31, 2004 with a spread of 1.16%.

Table of Contents

Results of Operations

(dollars in millions, except per share amounts)	2005	% change	2004	% change	2003
Revenues	$ 2,216	15	$ 1,924	8	$ 1,781
Operating income	271		271	3	264
Income from continuing operations	$ 128	18	$ 108	(9)	$ 118
Loss from discontinued operations	(1)	NM	2	NM	(4)
Net income	$ 127	16	$ 110	(4)	$ 114
Electric utility	$ 73	(10)	$ 81	3	$ 79
Bank	65	58	41	(27)	56
Other	(10)	NM	(14)	NM	(17)
Income from continuing operations	$ 128	18	$ 108	(9)	$ 118
Basic earnings (loss) per share					
Continuing operations	$ 1.58	16	$ 1.36	(14)	$ 1.58
Discontinued operations	(0.01)	NM	0.02	NM	(0.05)
	$ 1.57	14	$ 1.38	(10)	$ 1.53
Dividends per share	$ 1.24		$ 1.24		$ 1.24
Weighted-average number of common shares outstanding (millions)	80.8	2	79.6	7	74.7
Dividend payout ratio	79%		90%		81%
Dividend payout ratio continuing operations	78%		91%		78%

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.

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 income from continuing operations to income from continuing operations 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 income from its real estate investment trust (REIT) subsidiary. The Company 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 defined under accounting principles generally accepted in the United States of America (GAAP) and may not be comparable to presentations used by other companies or more useful than the GAAP presentation included in HEI s consolidated financial statements.

Table of Contents

Years ended December 31	2005	2004	2003
(dollars in thousands, except per share amounts)			
Income from continuing operations	$ 127,444	$ 107,739	$ 118,048
Basic earnings per share - continuing operations	$ 1.58	$ 1.36	$ 1.58
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)
As adjusted			
Income from continuing operations	$ 127,444	$ 128,079	$ 114,255
Basic earnings per share - continuing operations	$ 1.58	$ 1.61	$ 1.53
Return on average common equity [1]	10.5%	11.2%	10.9%

[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 2005 consolidated income from continuing operations would have been flat compared to 2004.

Retirement benefits (pension and other postretirement benefits)

The Company s reported costs of providing retirement benefits 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, earnings and realized and unrealized gains and losses on plan assets and changes made to the provisions of the plans. (No changes were made to the retirement benefit plans provisions in 2005, 2004 and 2003 that have had a significant impact on costs.) Costs may also be significantly affected by changes in key actuarial assumptions, including the expected return on plan assets and the discount rate. The Company accounts for retirement benefits in accordance with SFAS No. 87, Employers Accounting for Pensions and SFAS No. 106, Employers Accounting for Postretirement Benefits Other Than Pensions, and thus, changes in obligations associated with the factors noted above may not be immediately recognized as costs on the income statement, but generally are recognized in future years over the remaining average service period of plan participants.

The assumptions used by management in making benefit and funding calculations are based on current economic conditions. Changes in economic conditions will impact the underlying assumptions in determining retirement benefits costs on a prospective basis. In selecting an assumed discount rate, the Company considers the Moody s Daily Long-Term Corporate Bond Aa Yield Average (which was 5.41% as of December 31, 2005 compared to 5.66% as of December 31, 2004) and changes in this rate from period to period. In addition, the plans actuarial consultant prepared a cashflow matching analysis based upon bond information provided by Standard & Poors for all high quality bonds (i.e., rated AA- or better) as of December 31, 2005, which supports the 5.75% discount rate adopted as of December 31, 2005. In selecting an assumed rate of return on plan assets, the Company considers economic forecasts for the types of investments held by the plans (primarily equity and fixed income investments), the plans asset allocations and the past performance of the plans assets.

For 2005, the Company s retirement benefit plans assets generated a total return, net of investment management fees, of 7.2%, resulting in realized and unrealized gains of $65 million, compared to $82 million for 2004 and $154 million for 2003. The market value of the retirement benefit plans assets as of December 31, 2005 was $931 million. The Company made cash contributions to the retirement benefit plans totaling $25 million in 2005, $37 million in 2004 and $48 million in 2003. Contributions are expected to total $14 million in 2006 ($11 million by the utilities and $3 million by ASB), but actual contributions may differ. Fluctuations in actual equity market returns as well as changes in general interest rates will result in changes in the market value of plan assets and may result in increased or decreased retirement benefits costs and contributions in future periods.

Table of Contents

Based on various assumptions in Note 8 of the Notes to Consolidated Financial Statements 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; retirement benefits expense, net of income taxes; and retirement benefits paid and plan expenses were, or are estimated to be, as follows as of the dates or for the periods indicated:

	AOCI balance, net of tax benefits,		Retirement benefits expense, net of income tax benefits				Retirement benefits paid and expenses		
	December 31		Years ended December 31				Years ended December 31		
			(Estimated)						
(dollars in millions)	2005	2004	2006 [1]	2005 [2]	2004 [2]	2003 [2]	2005	2004	2003
Consolidated HEI	$ (1)	$ (1)	$ 18	$ 11	$ 7	$ 12	$ 51	$ 49	$ 45
Consolidated HECO			14	8	4	9	50	47	43
ASB			3	2	2	3	1	1	1

1 Forward-looking statements subject to risks and uncertainties, including the impact of plan changes during the year, if any, and the impact of actual information when received (e.g., actual participant demographics as of January 1, 2006).

2 Does not include impact of the Medicare Prescription Drug, Improvement and Modernization Act of 2003. See Recent accounting pronouncements and interpretations in Note 1 of the Notes to Consolidated Financial Statements.

If the Company and consolidated HECO are required to record significant charges to AOCI (and the prepaid pension assets that the electric utilities have been allowed to include in their rate bases for ratemaking purposes are eliminated) in the future, the electric utilities returns on average rate base (RORs) could increase and if the utilities exceeded the RORs found by the PUC to be reasonable, the rates the electric utilities are allowed to charge could be impacted, which may ultimately result in reduced revenues and lower earnings. In December 2005, the electric utilities submitted a request to the PUC for approval to record and include in rate base the amount that would otherwise be charged to AOCI and reduce stockholder s equity (see Note 8 of the Notes to Consolidated Financial Statements). If the relief requested from the PUC is not granted and the electric utilities are 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, 2005); 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, 2005); 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, 2005).

Table of Contents

The following tables reflect the sensitivities of the projected benefit obligation (PBO) and accumulated postretirement benefit obligation (APBO) as of December 31, 2005, and the sensitivity of 2006 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 other postretirement benefits contributions to the applicable retirement benefits plan.

Actuarial assumption	Change in assumption in basis points	Impact on PBO/APBO	Impact on 2006 net income
(dollars in millions)			
Pension benefits			
Discount rate	+/ 50	$ (63)/$71	$ 3/$(4)
Rate of return on plan assets	+/ 50	NA	2/(2)
Other benefits			
Discount rate	+/ 50	(11)/12	/(1)
Health care cost trend rate	+/ 100	4/(5)	(1)/1
Rate of return on plan assets	+/ 50	NA	/( )

NA Not applicable.

Baseline assumptions: 5.75% discount rate; 9% asset return rate; 10% medical trend rate for 2006, grading down to 5% for 2011 and thereafter; 5% dental trend rate; and 4% vision trend rate.

Other segment

(dollars in millions)	2005	% change	2004	% change	2003
Revenues [1]	$ 21	134	$ 9	(32)	$ 13
Operating income (loss)	5	NM	(8)	(38)	(6)
Net loss	(10)	NM	(14)	NM	(17)

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

The other business segment includes results of operations of HEI Investments, Inc. (HEIII), a company 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; The Old Oahu Tug Service, Inc. (TOOTS), a maritime freight transportation company that ceased operations in 1999; HEI and HEI Diversified, Inc. (HEIDI), holding companies; and eliminations of intercompany transactions. The other business segment also includes results of operations of financing entities formed to effect the issuance of 8.36% Trust Originated Preferred Securities that were redeemed in April 2004: 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). The first seven months of 2003 also include 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.

HEIII recorded net income of $16.2 million in 2005, including a gain of $14 million on the sale of its approximate 25% interest in a trust that is the owner/lessor of a 60% undivided interest in a coal-fired electric generating plant in Georgia. Most of the approximately $5 million of income taxes on the sale were recorded at HEI in accordance with the Company s stand-alone tax allocation policy. HEIII recorded net income of $1.8 million in 2004 and $2.3 million in 2003, primarily from leveraged leases.

HEIPI recorded net income of $3.5 million in 2005, net losses of $0.9 million in 2004 and net income of $0.1 million in 2003, which amounts include income and losses from and/or writedowns of venture capital investments. In 2005, HEIPI recognized a $4.6 million unrealized gain ($2.9 million after-tax) on its investment in Hoku Scientific, Inc. (Hoku), a Hawaii fuel cell technology startup company that completed its initial public offering and became a public company in August 2005. Also in 2005, HEIPI recorded lower writedowns of another venture capital investment in a nonpublic company. As of December 31, 2005, HEIPI s venture capital investments (including Hoku) amounted to $6.9 million.

HEI Corporate and the other subsidiaries revenues in 2004 include a $5.6 million pretax gain ($3.6 million after-tax) 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 operating, general and administrative expenses (including labor, employee benefits, incentive compensation, charitable contributions, legal fees, consulting, rent, supplies and insurance) were $14.8 million in 2005, $14.9 million in 2004 and $15.9 million in 2003. The slightly higher expenses in 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 $30.0 million in 2005, $15.4 million in 2004 and $19.5 million in 2003, the majority of which is comprised of financing costs. The loss for 2005 includes most of the $5 million of income taxes on the $14 million gain on sale by HEIII described above. Also, the results for 2005 did not include $5.4 million of dividends on ASB preferred stock held by HEIDI, as it had in 2004 and 2003, due to the redemption of ASB s preferred stock in December 2004, which was followed by a $75 million infusion into ASB of common equity by HEIDI. 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 in 2003) were $25.9 million in 2005, $27.6 million in 2004 and $33.3 million in 2003. 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 in March 2004, 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 2005, financing costs continued to decrease due to lower interest rates and lower average borrowing balances.

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. In 2005, HEIPC increased its reserve for future expenses by $1 million primarily due to higher than expected arbitration costs in connection with HEI and HEIPC claims under a political risk insurance policy; the arbitration concluded unsuccessfully in 2005. 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 3.4% in 2005, 2.7% in 2004, and 2.3% in 2003. Hawaii inflation, as measured by the Honolulu CPI, averaged 3.8% in 2005, 3.3% in 2004 and 2.3% in 2003. 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 2005 for HECO, 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.

Table of Contents

Recent accounting pronouncements

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

Liquidity and capital resources

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, 2005	Payment due by period				
(in millions)	1 year or less	2-3 years	4-5 years	More than 5 years	Total
Contractual obligations					
Deposit liabilities					
Commercial checking	$ 315	$	$	$	$ 315
Other checking	883				883
Savings	1,724				1,724
Money market	257				257
Term certificates	801	306	253	18	1,378
Total deposit liabilities	3,980	306	253	18	4,557
Securities sold under agreements to repurchase	373	264	50		687
Advances from Federal Home Loan Bank	206	467	263		936
Long-term debt, net	110	60		973	1,143
Operating leases, service bureau contract and maintenance agreements	27	43	33	37	140
Fuel oil purchase obligations (estimate based on January 1, 2006 fuel oil prices)	542	1,084	1,083	2,167	4,876
Power purchase obligations minimum fixed capacity charges	118	240	236	1,279	1,873
Total (estimated)	$ 5,356	$ 2,464	$ 1,918	$ 4,474	$ 14,212

December 31, 2005 (in millions)	
Other commercial commitments to ASB customers	
Loan commitments (primarily expiring in 2006)	$ 76
Loans in process	140
Unused lines and letters of credit	892

	$ 1,108

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, 2005, the fair value of the assets held in trusts to satisfy the obligations of the pension plans exceeded the pension plans accumulated benefit obligation. Thus, no minimum funding requirements for retirement benefit plans have been included in the tables above.

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 forecasted capital expenditures and investments, its expected retirement benefit plan contributions and other cash requirements in the foreseeable future.

Table of Contents

The Company s total assets were $10.0 billion as of December 31, 2005 and $9.7 billion as of December 31, 2004.

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

December 31	2005		2004	
(dollars in millions)				
Short-term borrowings	$ 142	6%	$ 77	3%
Long-term debt, net	1,143	45	1,167	47
Preferred stock of subsidiaries	34	1	34	1
Common stock equity	1,217	48	1,211	49
	$ 2,536	100%	$ 2,489	100%

As of March 6, 2006, the Standard & Poor s (S&P) and Moody s Investors Service s (Moody s) ratings of HEI securities were as follows:

	S&P	Moody s
Commercial paper	A-2	P-2
Medium-term notes	BBB	Baa2

The above ratings are not recommendations to buy, sell or hold any securities; such ratings may be subject to revision or withdrawal at any time by the rating agencies; and each rating should be evaluated independently of any other rating.

HEI s overall S&P corporate credit rating is BBB/Negative/A-2.

The rating agencies use a combination of qualitative measures (i.e., assessment of business risk that incorporates an analysis of the qualitative factors such as management, competitive positioning, operations, markets and regulation) as well as quantitative measures (e.g., cash flow, debt, interest coverage and liquidity ratios) in determining the ratings of HEI securities. In April 2005, S&P affirmed its corporate credit ratings of HEI, but revised its outlook from stable to negative, citing HECO s need for a rate increase to cover its growing expenses and yet to be recovered investments. See Electric utility Liquidity and capital resources below.

As of December 31, 2005, $96 million of debt, equity and/or other securities were available for offering by HEI under an omnibus shelf registration and an additional $150 million principal amount of Series D notes were available for offering by HEI under its registered medium-term note program.

HEI periodically utilizes short-term debt, principally commercial paper, to support normal operations and for other temporary requirements. HEI also periodically makes short-term loans to HECO to meet HECO s cash requirements and on behalf of HELCO and MECO. HEI had an average outstanding balance of commercial paper for 2005 of $3 million and had $6 million outstanding as of December 31, 2005. Management believes that if HEI s commercial paper ratings were to be downgraded, it might not be able to sell commercial paper under current market conditions.

As of December 31, 2005, HEI maintained bank lines of credit with four different banks totaling $80 million (all maturing in 2006). These lines of credit are maintained by HEI principally 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 12.5 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 HEI s other lines of credit. While each of the lines contain customary conditions that must be met in order to draw on them, none of HEI s line of credit agreements contain clauses that would affect access to the lines by reason of a ratings downgrade, nor do they have broad material adverse change clauses that could affect access to the lines in the event of any material adverse event so long as any such event is timely disclosed. As of December 31, 2005, the lines were undrawn. To manage future liquidity needs, including short-term liquidity for general corporate purposes and the refinancing of maturing long-term debt, the Company may seek to enter into new lines of credit, including multi-year credit, syndicated and/or bilateral facilities. The Company may also seek to increase the amount of credit available under such facilities as management deems appropriate. See S&P and Moody s ratings above and Note 6 of the Notes to Consolidated Financial Statements.

Table of Contents

Noteholders of $100 million of HEI 6.51% notes, due May 5, 2014, have a one-time option to redeem the notes on May 5, 2006 at 98.10% of the principal amount plus accrued interest.

Operating activities provided net cash of $218 million in 2005, $244 million in 2004 and $241 million in 2003. Investing activities used net cash of $202 million in 2005, $540 million in 2004 and $325 million in 2003. In 2005, net cash was used in investing activities primarily for HECO s consolidated capital expenditures, net of contributions in aid of construction, and net increases in loans held for investment, partly offset by repayments and sales of mortgage-related securities, net of purchases. Financing activities provided net cash of $22 million in 2005, $187 million in 2004 and $123 million in 2003. In 2005, 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 net decreases in securities sold under agreements to repurchase, advances from the FHLB and long-term debt 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. One of the conditions of the merger and corporate restructuring of HECO and HEI requires that HECO maintain a consolidated common equity to total capitalization ratio of not less than 35%, and restricts HECO from making distributions to HEI to the extent it would result in that ratio being less than 35%. In the absence of an unexpected material adverse change in the financial condition of the electric utilities or ASB, such restrictions are not expected to significantly affect the operations of HEI, its ability to pay dividends on its common stock or its ability to meet its debt or other cash obligations. See Note 12 of the Notes to Consolidated Financial Statements.

Forecasted HEI consolidated net cash used in investing activities (excluding investing cash flows from ASB) for 2006 through 2008 consists primarily of the net capital expenditures of HECO and its subsidiaries. In addition to the funds required for the electric utilities construction program (see Electric utility Liquidity and capital resources), approximately $0.2 billion will be required during 2006 through 2008 to repay maturing HEI medium-term notes, which is expected to be repaid with the proceeds from the sale of medium-term notes, issuance of commercial paper, issuance of common stock under the stock option and incentive plan and dividends from subsidiaries. Additional debt and/or equity financing may be required to fund unanticipated expenditures not included in the 2006 through 2008 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. In addition, existing debt may be refinanced prior to maturity (potentially at more favorable rates) with additional debt or equity financing (or both).

As further explained in Note 8 of the Notes to Consolidated Financial Statements, the Company maintains pension and other postretirement benefit plans. Funding for the qualified pension plans is based upon actuarially determined contributions that consider 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 qualified pension plans to meet minimum funding requirements pursuant to ERISA for 2005, 2004 and 2003, but the Company s Pension Investment Committee chose to make tax deductible contributions in those years. 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.

Contributions to the retirement benefit plans totaled $25 million in 2005 (comprised of $18 million made by the electric utilities, $6 million by ASB and $1 million by HEI Corporate), $37 million in 2004 and $48 million in 2003. Contributions to the retirement benefits plans are expected to total $14 million in 2006 ($11 million by the utilities and $3 million by ASB). 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.

Table of Contents

Following are discussions of the results of operations, liquidity and capital resources of the electric utility and bank segments. Additional segment information is shown in Note 2 of the Notes to Consolidated Financial Statements.

Electric utility

Executive overview and strategy

The electric utilities are vertically integrated and regulated by the PUC. The island utility systems are not interconnected, which requires that additional reliability be built into the systems, but also means that the utilities are not exposed to the risks of inter-ties. The electric utilities strategic focus has been to meet Hawaii s growing energy needs through a combination of diverse activities modernizing and adding needed infrastructure through capital investment, placing emphasis on energy efficiency and conservation, pursuing renewable energy options and technology opportunities (such as CHP and DG) and taking the necessary steps to secure regulatory support for their plans.

Reliability projects, including projects to increase generation reserves to meet growing peak demand, remain a priority for HECO and its subsidiaries. On Oahu, HECO is in the early permitting stages for a new generating unit, which is projected to be placed in service in 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 $25 million. PUC approvals have been obtained for the new Outage Management and Customer Information Systems, which 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, construction is proceeding on the installation of an 18 MW steam turbine at the Maalaea power plant site and the turbine is expected to be operational later in 2006. Further, the utilities are seeking PUC approval for additional DSM rebate programs and considering additional DG at utility-owned sites (e.g., substations) as another measure to potentially help meet growing peak demand.

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

With large power users in the electric utilities service territories, such as the U.S. military, hotels and state and local government, management believes that retaining customers by maintaining customer satisfaction is a critical component in achieving 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, primarily for (1) costs relating to existing and proposed energy conservation and efficiency programs (demand-side management (DSM) programs), (2) costs of capital improvement projects, (3) the proposed purchase of additional firm capacity and energy, (4) costs of other measures taken to address peak load increases, and (5) increased operation and maintenance expenses. Interim rate relief was granted in late September 2005. The PUC issued a bifurcation order separating HECO s requests for approval and/or modification of its existing and proposed DSM programs from the rate case proceeding into a new docket (EE DSM Docket) and HECO is continuing its existing DSM programs and cost recovery mechanisms pending the resolution of the EE DSM Docket. See Most recent rate requests HECO and Other regulatory matters Demand-side management programs agreements with the Consumer Advocate. In December 2005, HELCO notified the PUC that it intends to file a request for an electric rate increase in spring 2006. See Most recent rate requests HELCO.

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

Net income for HECO and its subsidiaries was $73 million in 2005 compared to $81 million in 2004 and $79 million in 2003. The decrease in 2005 was primarily due to increased operation and maintenance expenses (including more extensive maintenance on generating units, which are getting older and are being run harder to meet the higher demand for electricity, and higher retirement benefits expense) and higher depreciation expense due to investments in capital projects, partly offset by the impact of HECO s interim rate increase in late September 2005.

Results of Operations

(dollars in millions, except per barrel amounts)	2005	% change	2004	% change	2003
Revenues [1]	$ 1,806	16	$ 1,551	11	$ 1,397
Expenses					
Fuel oil	640	32	483	24	389
Purchased power	458	15	399	8	368
Other	546	11	495	7	463
Operating income	162	(7)	174	(2)	177
Allowance for funds used during construction	7	(15)	8	35	6
Net income	73	(10)	81	3	79
Return on average common equity	7.1%		8.3%		8.5%
Average price per barrel of fuel oil [1]	$ 56.61	33	$ 42.67	18	$ 36.23
Kilowatthour sales (millions)	10,090		10,063	3	9,775
Cooling degree days (Oahu)	4,971	(3)	5,107	2	5,010
Number of employees (at December 31)	2,066	3	2,013	8	1,862

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 2005, the electric utilities revenues increased by 16%, or $256 million, from 2004 primarily due to higher fuel prices ($235 million), interim rate relief granted by the PUC in late September 2005 ($10 million) and increased shareholder incentives and lost margins ($6 million), including the surcharge transferred to base rates in the interim rate relief granted in September 2005. KWH sales increased 0.3% from 2004 primarily due to new load growth (i.e., increase in number of customers), largely offset by the impacts of cooler and less humid weather and major commercial repair and renovation projects. Cooling degree days for Oahu were 2.7% lower in 2005 compared to 2004. In addition, customers may have been moderating their energy usage in response to the electric utilities campaign to promote conservation and efficiency and possibly reacting to higher fuel prices reflected in electric bills. The higher fuel prices are also reflected in the higher amount of customer accounts receivable and accrued unbilled revenues.

Operating income in 2005 was $12 million lower than in 2004 mainly due to higher other expenses, including higher maintenance and retirement benefit expenses.

Fuel oil and purchased power expenses in 2005 increased by 32% and 15%, respectively, due primarily to higher fuel prices, which are generally passed on to customers.

Other expenses increased 11% in 2005 due to a 10% (or $16 million) increase in other operation expense; a 6% (or $5 million) increase in maintenance expense; a 7% (or $8 million) increase in depreciation expense; and a 16% (or $23 million) increase in taxes, other than income taxes, primarily due to the increase in revenues. Other operation expenses increased 10% in 2005 when compared to 2004 due primarily to higher expenses for production operations (including higher environmental expenses as there was a DOH emission fee waiver in 2004, which was not repeated in 2005), transmission and distribution operations and retirement benefits. Pension and other postretirement benefit expenses for the electric utilities increased $6.7 million over the same period in 2004 due in part to the HEI Pension Investment Committee s adoption of a 25 basis points lower discount rate as of December 31, 2004. Maintenance expenses increased 6% due to higher production maintenance expense (primarily due to generating plant maintenance and generating unit overhauls) and higher transmission and distribution maintenance expense. Higher depreciation expense was attributable to additions to plant in service in 2004 (including HELCO s CT-4 and CT-5 and HECO s Waiau fuel oil pipeline), offset in part by lower depreciation expense resulting from the PUC s approval in September 2004 of rates and accounting methodology applicable to HECO s depreciable assets on Oahu.

62

The trend of increased other operation and maintenance (O&M) expenses is expected to continue in 2006 as the electric utilities expect (1) higher demand side management expenses (that are generally passed on to customers through a surcharge and are being considered in the EE DSM Docket) and integrated resource planning expenses, (2) higher employee benefit expenses, primarily for retirement benefits and (3) higher production expense, primarily to meet higher demand levels and load growth achieved in 2004 and sustained in 2005. As a result of load growth on Oahu and other factors, there currently is an increased risk to generation reliability. Existing units are running harder, resulting in more frequent and more extensive maintenance, at times requiring temporary shut downs of these units. Generation reserve margins during peak periods are lower than considered desirable in light of these circumstances. The electric utilities have taken a number of steps to mitigate the risk of outages, including securing additional purchased power, adding distributed generation at some substations and encouraging energy conservation. The marginal costs of supplying growing demand, however, are increasing because of the decreasing reserve margin situation, and the rate of cost increases is not likely to lessen until a proposed new generating unit on Oahu is added in 2009. Increased O&M expense was one of the reasons HECO filed a request with the PUC in November 2004 to increase base rates. In late September 2005, HECO received interim rate relief (see Most recent rate requests).

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 greater 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.

Most recent rate requests

The electric utilities initiate PUC proceedings from time to time to request electric rate increases to cover rising operating costs and the cost of plant and equipment, including the cost of new capital projects to maintain and improve service reliability. As of March 6, 2006, 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 & order (D&O) issued on December 11, 1995, based on a 1995 test year), 11.50% for HELCO (D&O issued on February 8, 2001, based on a 2000 test year) and 10.94% for MECO (amended D&O issued on April 6, 1999, based on a 1999 test year). However, the ROACE used for purposes of the interim rate increase in HECO s current rate case was 10.7%. For 2005, the simple average ROACEs (calculated under the rate-making method and reported to the PUC) for HECO, HELCO and MECO were 6.92%, 6.86% and 9.81%, respectively. HECO s actual ROACE is significantly lower than its allowed ROACE primarily because of increased O&M expenses, which are expected to continue and

Table of Contents

could result in HECO seeking rate relief more often than in the past. The interim rate relief granted to HECO by the PUC in September 2005 (see below), which was based in part on increased costs of operating and maintaining HECO s system. 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 (currently planned for spring 2006) and the PUC grants HELCO rate relief.

As of March 6, 2006, the 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). However, the ROR used for purposes of the interim D&O in the current HECO rate case is 8.66%. For 2005, the simple average RORs (calculated under the rate-making method and reported to the PUC) for HECO, HELCO and MECO were 6.20%, 6.08% and 8.21%, respectively.

If, as discussed above, the utilities are required to record significant charges to AOCI related to a minimum liability for retirement benefits, the electric utilities RORs would increase and could impact the rates the electric utilities are allowed to charge, which may ultimately result in reduced revenues and lower earnings. In December 2005, the electric utilities submitted a request to the PUC for approval to record as a regulatory asset and include in rate base the amount that would otherwise be charged to AOCI and reduce stockholder s equity (see Note 8 of the Notes to Consolidated Financial Statements).

HECO. In November 2004, HECO filed a request with the PUC to increase base rates 9.9%, or $99 million in annual base revenues, based on a 2005 test year, a 9.11% return on rate base and an 11.5% return on average common equity. HECO requested approval of its proposed new energy efficiency (EE) DSM programs (Enhanced EE DSM programs), and associated utility incentive mechanism, in its rate case application. The requested increase included (1) transferring the cost of existing DSM programs from a surcharge line item on electric bills into base electricity charges, (2) the costs of Enhanced EE DSM programs, (3) the costs of capital improvement projects completed since the last rate case, (4) the proposed purchase of up to an additional 29 MW of firm capacity and energy from Kalaeloa Partners, L.P., (5) the cost of other measures taken to address peak load increases arising out of economic growth and increasing electricity use, and (6) increased O&M expenses. Excluding the surcharge transfer amount, the requested net increase to customers was 7.3%, or $74 million.

In March 2005, the PUC issued a bifurcation order separating HECO s requests for approval and/or modification of its existing and proposed DSM programs from the rate case proceeding into a new docket. The preliminary issues identified by the PUC for the new EE DSM Docket include (1) whether, and if so, what, energy efficiency goals should be established, (2) whether the proposed and/or other DSM programs will achieve the established energy efficiency goals and be implemented in a cost-effective manner, (3) what market structures are most appropriate for providing these or other DSM programs, and (4) for utility-incurred costs, what cost recovery mechanisms and cost levels are appropriate. The original parties/participants in this docket included HECO, the Consumer Advocate, the DOD, the County of Maui, two renewable energy organizations, an energy efficiency organization, and an environmental organization. In June 2005, however, the PUC, on its own initiative, included HELCO, MECO, Kauai Island Utility Cooperative and The Gas Company as parties to the docket, provided their participation is limited solely to the issues dealing with statewide energy policies. The procedural schedule for this docket calls for the parties to file final statements of position with the PUC in April 2006. Panel hearings are scheduled to take place in June 2006.

As a result of the bifurcation order, HECO is continuing its existing DSM programs and cost recovery mechanisms (under which program costs, shareholder incentives, and lost margins between rate cases are covered through a DSM surcharge). Relevant provisions of the stipulations under which the existing DSM programs have been extended continue to apply, including an agreement to cap the recovery of lost margins and shareholder incentives, if such recovery would cause HECO to exceed the ROR found to be reasonable by the PUC. The PUC used a ROR of 8.66% in its interim D&O discussed below. An estimated $32 million in revenue requirements for DSM program costs related to both the Enhanced EE DSM programs and to the extent recovered through the DSM surcharge, the existing DSM programs, were thus removed from HECO s rate increase request.

Table of Contents

In September 2005, HECO, the Consumer Advocate and the DOD reached agreement among themselves on most of the issues in the rate case proceeding, subject to PUC approval. The remaining significant issue among the parties was the appropriateness of including in rate base approximately $50 million related to HECO s prepaid pension asset, net of deferred income taxes.

Later in the same month, the PUC issued its interim D&O (with tariff changes effective September 28, 2005 and amounts collected refundable, with interest, to ratepayers to the extent they exceed the amount approved in the final D&O). For purposes of the interim D&O, the PUC included HECO s prepaid pension asset in rate base (with a rate increase impact of approximately $7 million).

The following amounts were included in HECO s rebuttal, the Consumer Advocate s and the DOD s testimonies and exhibits (as adjusted to exclude the transferred surcharge amount of $12 million); the settlement agreement (described below); and the PUC s interim D&O:

	Pre-Settlement				
(dollars in millions)	HECO rebuttal	Consumer Advocate	Department of Defense	HECO (per settlement)	Interim increase[1]
Net additional revenues [2]	$ 51	$ 11	$ 7	$ 42	$ 41
ROACE	11%	8.5-10%	9%	10.7%	10.7%
ROR	8.83%	7.85%	7.71%	8.66%	8.66%
Average rate base	$ 1,109	$ 1,065	$ 1,062	$ 1,109	$ 1,109

1 Effective September 28, 2005, subject to refund with interest pending the final outcome of the case.
2 Excludes $12 million transferred from a surcharge to base rates for existing energy efficiency programs.

The adoption of revenue, expense, rate base and cost of capital amounts (including the ROACE and ROR) for purposes of an interim rate increase does not commit the PUC to accept any such amounts in its final D&O.

HELCO. In December 2005, HELCO notified the PUC that it intends to file a request for an electric rate increase in spring 2006. Preliminary estimates of the request are approximately 10%, however, it is expected that by using a proposed new tiered rate structure, most residential users would see smaller increases in the range of 3% to 7%. The tiered rate structure is designed to minimize the increase for residential customers using less electricity and is expected to encourage customers to take advantage of solar water heating programs and other energy management options. The proposed rate increase would pay for improvements made to increase reliability, including transmission and distribution line improvements and the two generating units at the Keahole power plant (CT-4 and CT-5). With energy efficiency and conservation, distributed generation and renewable energy options, management expects that CT-4 and CT-5 should be the last fossil fuel-burning units on the island of Hawaii for the foreseeable future. The next planned generating unit to provide firm power (available 24 hours) for the island will be the last phase of the combined cycle plant at Keahole, which will use waste heat from existing units and no additional fossil fuel.

Among the renewable energy projects on the island of Hawaii is the 10 MW Hawi Renewable Development wind farm and the planned expansion of the Apollo wind farm from 7 MW to approximately 20 MW (which may be delayed). Future projects for firm renewable purchased energy potentially include an expansion of a geothermal plant, a woodchip-burning plant, a County waste-to-energy plant and a pumped storage hydro plant. Other renewable sources include photovoltaics and, when commercially available, ethanol.

The earliest any increase, if allowed, may go into effect is expected to be in early 2007.

Depreciation rates and accounting

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, which the PUC approved 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, resulting in slightly lower depreciation in the remainder of 2004 than would have been recorded under the previous rates and method.

Table of Contents

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 forecasted 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 a portion of the impact evaluation report for the 2000-2003 period with the PUC in November 2004 and adjusted the lost margin recovery in the second quarter of 2005. The study methodology for the remaining portion of the impact evaluation report (which evaluates the level of the DSM Programs free-ridership and corresponding energy and demand impacts that would have occurred anyway in the absence of the DSM Programs), is under discussion with the Consumer Advocate. To date, 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 October 2001, HELCO and MECO reached similar agreements with the Consumer Advocate and filed requests to continue their four existing DSM programs.

As previously discussed, as a result of the bifurcation order in HECO s rate case, HECO is continuing its existing DSM programs and cost recovery mechanisms, including the recovery of program costs, shareholder incentives and lost margins through a surcharge mechanism, pending the resolution of the EE DSM Docket. In the EE DSM Docket, HECO has requested PUC approval on an interim basis for certain modifications to its existing DSM programs, and a new interim DSM program (Interim DSM Proposals). HECO did not request shareholder incentives and lost margins for its proposed new interim DSM program, but did so for its existing programs. On January 10, 2006, the Consumer Advocate filed comments on HECO s Interim DSM Proposals, which included an objection to the continued recovery of shareholder incentives and lost margins. HECO filed its response to the Consumer Advocate s comments on January 31, 2006, reaffirming its position that the continuation of shareholder incentives and lost margins is appropriate and in conformance with the PUC s order allowing the continuation of its existing DSM programs pending the resolution of the EE DSM Docket. The issue of the continuation of shareholder incentives and lost margins, or alternative incentive mechanisms, will be determined by the PUC as part of the EE DSM Docket. At this time the PUC has not issued a decision on HECO s Interim DSM Proposals.

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

Table of Contents

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 the first half of 2006, HELCO and MECO plan to file a request to confirm that the bifurcation order in HECO s rate case had the effect of postponing the deadline for the recovery of HELCO and MECO s lost margins and shareholder incentives until resolution of the EE DSM Docket or, in the alternative, a request for extension of the recovery period for another year.

One of the conditions to the interim 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 2003 and 2005, none of the electric utilities exceeded their respective authorized RORs. In 2004, only 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). 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 ratepayers in August 2004.

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.

<u>Avoided cost generic docket</u>. In May 1992, the PUC instituted a generic investigation, including all of Hawaii s electric utilities, to examine the proxy method and formula used by the electric utilities to calculate their avoided energy costs and Schedule Q rates. In general, Schedule Q rates are available to customers with cogeneration and/or small power production facilities with a capacity of 100 KWHs or less who buy/sell power from/to the electric utility. The parties to the 1992 docket include the electric utilities, the Consumer Advocate, the DOD, and representatives of existing or potential 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. In July 2004, the PUC ordered the parties to review and update the agreements, information and data contained in the stipulation and file such information. The parties have until May 31, 2006 to file.

<u>Integrated resource planning, requirements for additional generating capacity and adequacy of supply</u>. The 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. 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 PUC s IRP framework, the utilities are required to submit annual evaluations of their plans (including a revised five-year program implementation schedule) and to submit new plans on a three-year cycle, subject to changes approved by the PUC. Prior to proceeding with the DSM programs, separate PUC approval proceedings must be completed. See Demand-side management programs agreements with the Consumer Advocate above, which includes a discussion of the electric utilities residential and commercial and industrial load management programs.

The utilities are entitled to recover all appropriate and reasonable integrated resource planning and implementation costs, including the costs of DSM programs, either through a surcharge or through their base rates. Incremental IRP costs are deferred until approved for recovery, at which time they are amortized to expense. Under procedural schedules for the IRP cost proceedings, the utilities can begin recovering their incremental IRP costs in the month following the filing of their actual costs incurred for the year, subject to refund with interest pending the PUC s final D&O approving recovery of the costs.

Table of Contents

The Consumer Advocate has objected to the recovery of $3.2 million (before interest) of the $11.8 million of incremental IRP costs incurred during the 1995-2004 period, and the PUC s decision is pending on this matter. As of December 31, 2005, 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 $18 million.

HECO s IRP. In October 2005, HECO filed its third IRP (IRP-3), which proposes multiple solutions to meet Oahu s future energy needs, including renewable energy resources, energy efficiency, conservation, technology (such as CHP and DG) and central station generation.

In June 2005, HECO filed with the PUC an application for approval of funds to build a new nominal 100 MW simple cycle combustion turbine generating unit at Campbell Industrial Park and an additional 138 kilovolt transmission line to transmit power from the new unit and existing generating units at Campbell Industrial Park to the Oahu electric grid. Plans are for the combustion turbine to be run primarily as a peaking unit beginning in 2009, and to burn naphtha or diesel, but will have the ability to convert to using biofuels, such as ethanol, when they are commercially available. On December 15, 2005, HECO signed a contract with Siemens for the right to purchase up to two combustion turbine units. The contract allows the Company to terminate the contract at a specified payment amount if necessary combustion turbine (CT) project approvals are not obtained.

Preliminary costs for the new generating unit and transmission line, as well as related substation improvements, are estimated at $137 million. As of December 31, 2005 accumulated project costs for planning, engineering, permitting and AFUDC amounted to $2.7 million. HECO is now preparing an Environmental Impact Statement for the proposed project.

In a related application filed with the PUC in June 2005, HECO requested approval for an approximately $11.5 million package of community benefit measures to mitigate the impact of the new generating unit on communities near the proposed generating unit site. These measures include a base electric rate discount for those who live near the proposed generation site, additional air-quality monitoring stations, a fish monitoring program and the use of recycled instead of potable water in Kahe power plant s operations.

In September 2005, the PUC suspended HECO s Campbell Industrial Park generating unit and transmission line additions application to allow more time to review the application. Also in September 2005, the PUC ordered HECO and the Consumer Advocate to submit a stipulated prehearing order for the community benefits application. In January 2006, the PUC granted an environmental group s motion to intervene and a neighboring business entity s motion to participate in the generating unit and transmission line application, and ordered HECO, the Consumer Advocate and the other parties (the environmental group and the business entity) to submit a stipulated prehearing order by March 13, 2006.

IRP-3 also includes plans to build a 180 MW coal unit in 2022. In addition, all existing generating units are currently planned to be operated (future environmental considerations permitting) beyond the 20-year IRP planning period (2006-2025).

MECO s IRP. MECO filed its second IRP with the PUC in May 2000, and updated it in 2004 and 2005. 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 (currently planned to be added in 2011), 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). 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.

MECO s third IRP is scheduled to be filed with the PUC in October 2006.

HELCO s IRP. In September 1998, HELCO filed its second IRP with the PUC, and updated it in 1999 and 2004 . On the supply side, HELCO s second IRP focused on the planning for generating unit additions after near-term additions. The near-term additions proposed in HELCO s second IRP included installing two 20 MW CTs at its Keahole power plant site (the installation of which were delayed, but were put into limited commercial operation in May and June 2004) and proceeding in parallel with a PPA with Hamakua Energy Partners, L.P. (HEP) for a 60 MW (net) dual-train combined-cycle (DTCC) facility (which was completed in December 2000). HELCO has deferred the retirements of some of its older generating units. HELCO s current plans are to install an 18 MW heat recovery steam generator (ST-7) in 2009 or earlier. After the installation of ST-7, the target date for the next firm capacity addition is the 2017 timeframe.

HELCO s third IRP is scheduled to be filed with the PUC by December 31, 2006.

Adequacy of supply.

HECO. As a result of load growth and other factors, HECO s 2005 Adequacy of Supply letter filed in March 2005 concluded that generation reserve margins, although substantial, were lower than is considered desirable on Oahu under the circumstances, and that there currently was an increased risk to generation reliability. Also, the letter stated that the risk of having generation-related customer outages would be higher if the peak reduction impacts of planned energy efficiency DSM programs, load management programs or CHP installations fall short of achieving their forecasted benefits. This situation is expected to continue, if the peak demand continues to grow as forecasted, at least until 2009, which is the earliest that HECO expects to be able to install its planned combustion turbine. The letter also indicated that HECO was 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 (which were installed in the fourth quarter of 2005) and initiating a customer demand response program to supplement its load management programs (for which HECO plans to request approval in the first half of 2006). HECO did not experience actual generation shortfalls causing customer load shedding in 2005, in part because peak loads were lower than forecast in the second half of 2005.

HECO s 2006 Adequacy of Supply letter filed in March 2006 indicates that HECO s latest analysis estimates the reserve capacity shortfall to be between 170 MW and 200 MW in the 2006 to 2009 period, which is significantly larger than the 50 to 70 MW reserve capacity shortfall projected in the 2005 Adequacy of Supply letter. The increase in projected reserve capacity shortfall is largely due to the lower projected availability of existing generating units, and a reduction in the projected impacts from planned peak reduction measures. Generating units may be entirely or partially unavailable to serve load during scheduled overhaul periods and other planned maintenance outages, or when they trip or are taken out of operation or their output is de-rated due to equipment failure or other causes. While the availability rates for generating units on Oahu remain better than those of comparable units on the U.S. mainland, the availability rates have declined in 2004 and 2005. Based on this experience, the manner in which the units must be operated when there is a reserve capacity shortfall, and the increasing ages of the units, HECO expects this situation to continue in the near-term and is forecasting lower availability rates than were used in the 2005 analyses.

To mitigate the projected reserve capacity shortfalls and to increase generating unit availability going forward, HECO is continuing to plan and implement mitigation measures, such as installing additional distributed generators at substations or other sites, seeking approval for additional load management and other demand reduction measures, and pursuing efforts to improve the availability of generating units. HECO will operate at lower than desired reliability levels and take steps to mitigate the reserve capacity shortfall situation until the next generating unit is installed. Until sufficient generating capacity can be added to the system, HECO will experience a higher risk of generation related customer outages. Given the magnitude of the projected reserve capacity shortfall, HECO also will evaluate the need to file an application with the PUC for approval to add more firm capacity (over and above the PUC application filed in June 2005 for a simple-cycle combustion turbine).

MECO. MECO s 2006 Adequacy of Supply letter filed in March 2006 indicated that MECO s Maui island system should have sufficient installed capacity to meet the forecasted loads. However, in December 2005, MECO s Maalaea unit 13, a 12.34 MW diesel generator suffered an equipment failure and the unit is not expected to be available for service until approximately June 2007. Until Maalaea unit 13 returns to service, the Maui island system at times may not have sufficient capacity in the event of an unexpected outage of the largest unit. MECO will implement appropriate mitigation measures to overcome insufficient reserve capacity situations.

HELCO. HELCO s 2006 Adequacy of Supply letter filed in February 2006 indicated that HELCO s generation capacity for the next three years, 2006 through 2008, is sufficiently large to meet all reasonably expected demands for service and provide reasonable reserves for emergencies.

Table of Contents

Collective bargaining agreements

Each of the electric utilities entered into a new four-year collective bargaining agreement in 2003 with the union which represents approximately 58% of electric utility employees. See Collective bargaining agreements in Note 3 of the Notes to Consolidated Financial Statements.

Legislation and regulation

Congress and the Hawaii legislature periodically consider legislation that could have positive or negative effects on the utilities and their customers. 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.

Energy Policy Act of 2005. On August 8, 2005, the President signed into law the Energy Policy Act of 2005 (the Act). The Act provides $14.5 billion in tax incentives over a 10-year period designed to boost conservation efforts, increase domestic energy production and expand the use of alternative energy sources, such as solar, wind, ethanol, biomass, hydropower and clean coal technology. Ocean energy sources, including wave power, are identified as renewable technologies. Section 355 of the Act authorizes a study by the U.S. Department of Energy of Hawaii s dependence on oil; however, that provision is subject to appropriation, as is $9 million authorized under Section 208 for a sugar cane ethanol program in Hawaii. Incentives also include tax credits and shorter depreciable lives for many assets associated with energy production and transmission. The Act s primary direct impact on HECO and its subsidiaries is currently expected to be the reduction in the depreciable tax life, from 20 years to 15 years, of certain electric transmission equipment placed into service after April 11, 2005.

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

Renewable Portfolio Standard. The 2001 Hawaii Legislature adopted a law that required the utilities to meet a renewable portfolio standard (RPS) of 7% by December 31, 2003. HECO, HELCO and MECO are permitted to aggregate their renewable portfolios in order to achieve these standards. The electric utilities met this standard with over 8% of the utilities consolidated electricity sales for 2003 from renewable resources (as defined under the 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. In 2005, the electric utilities attained over 11% of sales from renewable sources. 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 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, Electric Utility Rate Design in Hawaii, describing the PUC s intended methodology for fulfilling the legislative mandate to formulate an electric utility rate design by December 31, 2006, that (1) enables the achievement of RPS, (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 (two sets of which have been completed), and the creation of a document that forms the basis of a set of rules to be adopted in a conventional rulemaking process to follow, providing input to the PUC s decisions on electric utility ratemaking. On July 26, 2005, the PUC transmitted a Second Concept Paper (SCP) authored by Economists Incorporated (EI), Proposals for Implementing Renewable Portfolio Standards in Hawaii, which identified incentive regulation (IR) mechanisms, including renewable energy credit trading, alternative compliance fees, penalties and positive incentives. Subsequently, other IR mechanisms were proposed. Management cannot predict the outcome of this process.

The electric utilities continue to pursue a three-pronged 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 and the electronic shock absorber for wind generation). 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).

HECO filed and received a patent in February 2005 for an electronic shock absorber (ESA) that addresses power fluctuations from wind resources. An ESA demonstration system has been installed and is currently being tested at HELCO s Lalamilo wind farm. HECO has sought protection of intellectual property rights in its ESA technology, including a portfolio of U.S. and international patents and patent filings. HECO has an intellectual property license agreement with the party constructing the ESA demonstration system. Management cannot predict the amount of royalties HECO may receive from the sale of ESAs in the future.

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 greater than 1 MW in Hawaii. Since 2003, RHI has periodically solicited competitive proposals for investment opportunities in qualified projects. To date, RHI has signed a Conditional Investment Agreement for a small-scale landfill gas-to-energy project on Oahu. RHI has also signed a Framework Agreement for evaluation of three wind projects and two pumped storage hydroelectric projects on three islands. Project investments by RHI will generally be made only after developers secure the necessary approvals and permits and independently execute a PPA with HECO, HELCO or MECO, approved by the PUC.

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

Other legislation. A number of bills on energy were introduced in the 2006 Hawaii State legislative session. The majority of measures contained in these bills do not negatively affect the electric utilities, and the electric utilities support many of the measures that would encourage the more efficient use of energy and the use of Hawaii s renewable energy resources. The electric utilities also are actively engaged in deliberations before the Legislature on matters that may affect them if adopted, such as bills that would direct the PUC to review and consider alternatives to the current energy cost adjustment clause, require the outsourcing of demand-side management programs, require the use of long-term fixed-price power purchase contracts for renewable energy generators, or modify the renewable portfolio standards law. At this time, it is not possible to predict the outcome of those deliberations.

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

Other developments

To evaluate the technical feasibility of the Broadband over Power Line (BPL) technology and its applications, HECO completed a small-scale trial of the BPL technology. Based on the favorable results of the trial, HECO is proceeding with a pilot in an expanded residential/commercial area in Honolulu, which is expected to run through at least the second quarter of 2006. BPL-enabled utility applications being evaluated include distribution system line monitoring, advanced remote metering, residential direct load control and monitoring of distribution substation equipment. Although its evaluation will be focused primarily on utility applications of BPL, HECO is also evaluating broadband information services that might potentially be provided by other service providers.

In October 2004, the Federal Communications Commission (FCC) released a Report and Order that amended and adopted new rules for Access Broadband over Power Line systems (Access BPL) and stated that an FCC goal 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.

Liquidity and capital resources

HECO s consolidated capital structure was as follows:

December 31	**2005**		**2004**	
(dollars in millions)				
Short-term borrowings	$ 136	7%	$ 89	4%
Long-term debt, net	766	38	753	40
Preferred stock	34	2	34	2
Common stock equity	1,039	53	1,017	54
	$ 1,975	100%	$ 1,893	100%

As of March 6, 2006, the Standard & Poor s (S&P) and Moody s Investors Service s (Moody s) ratings of HECO securities were as follows:

	S&P	**Moody s**

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)	Not rated	Baa3

The above ratings are not recommendations to buy, sell or hold any securities; such ratings may be subject to revision or withdrawal at any time by the rating agencies; and each rating should be evaluated independently of any other rating. HECO s overall S&P corporate credit rating is BBB+/Negative/A-2.

The rating agencies use a combination of qualitative measures (i.e., assessment of business risk that incorporates an analysis of the qualitative factors such as management, competitive positioning, operations, markets and regulation) as well as quantitative measures (e.g., cash flow, debt, interest coverage and liquidity ratios) in determining the ratings of HECO securities. In April 2005, S&P affirmed its corporate credit ratings of HECO, but revised its outlook from stable to negative, citing HECO s need for a rate increase, rising operating expenses and yet to be recovered investments. S&P s ratings outlook assesses the potential direction of a long-term credit rating over the intermediate term (typically six months to two years). In response to the PUC s interim rate decision for HECO, S&P stated a final order that closely mirrors the interim ruling appears to be sufficient to lift key financial metrics to levels that are marginally suitable for Standard & Poor s guideposts for the BBB rating category. However, S&P will reconsider its negative outlook when the PUC issues its final order. Moody s maintains a stable outlook on HECO. In May 2005, S&P revised HECO s business profile from 6 to 5 . S&P ranks business profiles from 1 (strong) to 10 (weak).

Table of Contents

HECO periodically utilizes short-term debt, principally commercial paper, to support normal operations and for other temporary requirements. HECO also periodically borrows short-term from HEI for itself and on behalf of HELCO and MECO, and HECO may borrow from or loan to HELCO and MECO short-term. HECO had an average outstanding balance of commercial paper for 2005 of $95 million and had $136 million of commercial paper outstanding as of December 31, 2005. Management believes that if HECO s commercial paper ratings were to be downgraded, they might not be able to sell commercial paper under current market conditions.

As of December 31, 2005, HECO maintained bank lines of credit totaling $180 million with six different banks (all expiring in 2006). These lines of credit are principally maintained by 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. While each of the lines contain customary conditions that must be met in order to draw on them, none of HECO s line of credit agreements contain clauses that would affect access to the lines by reason of a ratings downgrade, nor do they have broad material adverse change clauses that could affect access to the lines in the event of any material adverse event so long as any such event is timely disclosed. As of December 31, 2005, the lines were unused. To manage HECO s future liquidity needs, HECO anticipates restructuring its lines of credit arrangements, including arranging a multi-year syndicated credit facility at a level consistent with the current level of lines of credit arrangements.

In 2005, the electric utilities investing activities used $195 million in cash, primarily for capital expenditures, net of contributions in aid of construction. Financing activities provided net cash of $10 million, including a $48 million net increase in short-term borrowings and a $12 million net increase in long-term debt, partly offset by $52 million for the payment of common and preferred stock dividends. Operating activities provided cash of $185 million.

In May 2005, up to $160 million of Special Purpose Revenue Bonds (SPRBs) ($100 million for HECO, $40 million for HELCO and $20 million for MECO) were authorized by the Hawaii legislature for issuance, with PUC approval, through June 30, 2010 to finance the electric utilities capital improvement projects.

In January 2005, the Department of Budget and Finance of the State of Hawaii issued, at par, Refunding Series 2005A SPRBs 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 in February 2005 to redeem at a 1% premium a like principal amount of SPRBs bearing a higher interest coupon (HECO s, HELCO s, and MECO s aggregate $47 million of 6.60% Series 1995A SPRBs with an original stated maturity of January 1, 2025).

In December 2005, an application was filed with the PUC requesting approval to issue up to a total of $165 million in taxable unsecured notes for HECO, MECO and HELCO (up to $100 million for HECO, up to $50 million for HELCO and up to $15 million for MECO). On January 20, 2006, a Registration Statement on Form S-3 was filed with the SEC covering $100 million, $50 million and $15 million aggregate principal amount, respectively, for HECO, HELCO and MECO of their respective taxable unsecured notes due 2036. It is anticipated that the net proceeds from the sale of the notes will be used for capital expenditures and/or to repay short-term borrowings (including borrowings from affiliates) incurred for capital expenditures or to refinance short-term borrowings used for capital expenditures. The HELCO and MECO bonds will be fully and unconditionally guaranteed by HECO.

For the five-year period 2006 through 2010, approximately 51% of forecasted gross capital expenditures is for transmission and distribution projects and 41% for generation projects, with the remaining 8% for general plant and other projects. These estimates do not include expenditures, which could be material, that would be required to comply with cooling water intake structure regulations adopted by the U.S. Environmental Protection Agency (EPA) in 2004, the July 1999 Regional Haze Rule amendments or the proposed Clear Skies Bill, if adopted by Congress. The electric utilities net capital expenditures (which exclude AFUDC and capital expenditures funded by third-party contributions in aid of construction) for 2006 through 2010 are currently estimated to total approximately $0.8 billion. HECO s consolidated cash flows from operating activities (net income, adjusted for non-cash income and expense items such as depreciation, amortization and deferred taxes), after the payment of common stock and preferred stock dividends are currently not expected to provide sufficient cash to cover the forecasted net capital expenditures and to reduce the level of short-term borrowings, which level is expected to fluctuate during this forecast period. Long-tem debt financing is expected to be required to fund this shortfall as well as any unanticipated expenditures not included in the 2006 through 2010 forecast, such as 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 and significant increases in contributions to the retirement benefit plans. The PUC must approve issuances of long-term securities for HECO, HELCO and MECO, including notes or debentures issued by the electric utilities in connection with the issuance of taxable unsecured notes, special purpose revenue bonds or trust preferred securities.

Proceeds from the anticipated sale of the taxable unsecured notes, cash flows from operating activities and temporary increases in short-term borrowings are expected to provide the forecasted $166 million needed for the net capital expenditures in 2006. For 2006, gross capital expenditures are estimated to be $207 million, including approximately $114 million for transmission and distribution projects, approximately $65 million for generation projects and approximately $28 million for general plant and other projects. Investment in renewable projects through RHI in 2006 is estimated to be $0.4 million. Consolidated net capital expenditures for HECO and subsidiaries for 2005, 2004 and 2003 were $194 million, $187 million and $131 million, respectively.

Funding for the electric utilities qualified pension plans is based upon actuarially determined contributions that consider the amount deductible for income tax purposes and the funding requirements under the Employee Retirement Income Security Act of 1974, as amended (ERISA). Although the electric utilities were not required to make any contributions to the qualified pension plans to meet minimum funding requirements pursuant to ERISA for 2005, 2004 and 2003, they made voluntary contributions in those years. With respect to the postretirement benefit plans, the electric utilities policy is to comply with directives from the PUC to fund the costs. Contributions by the electric utilities to the retirement benefit plans for 2005, 2004 and 2003 totaled $18 million, $34 million and $31 million, respectively, and are expected to total $11 million in 2006. Additional contributions to the retirement benefit plans may be required, or may be made even if not required, and such contributions could be in amounts substantially in excess of the amounts currently included in the electric utilities forecast of their consolidated financing requirements for the period 2006 through 2010.

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

Executive overview and strategy

When ASB was acquired by HEI in 1988, it was a traditional thrift with assets of $1 billion and net income of about $13 million. ASB has grown by both acquisition and internal growth since 1988 and ended 2005 with assets of $6.8 billion and net income of $65 million, compared to assets of $6.8 billion as of December 31, 2004 and net income of $41 million in 2004. Excluding a $20 million after-tax charge for franchise taxes for prior years due to an adverse tax ruling, net income would have been $61 million in 2004 (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.

Due to improved asset quality resulting from the strength in the Hawaii economy and the real estate market, ASB recognized a $2 million after-tax reversal of allowance for loan losses during 2005 despite a $0.3 billion increase in its average balances of loans. ASB s allowance as a percentage of average loans was 0.90% at the end of 2005, compared to 1.08% and 1.44% at the end of 2004 and 2003, respectively. 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 commercial 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.

Table of Contents

ASB has been facing a challenging interest rate environment that has pressured its net interest margin. 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, resulting in an inverted yield curve at year-end. 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 margin. If the current interest rate environment persists, the potential for compression of ASB s margin will continue to be a concern. As part of its interest rate risk management process, ASB uses simulation analysis to measure net interest income sensitivity to changes in interest rates (see Quantitative and Qualitative Disclosures about Market Risk). ASB then employs strategies to limit the impact of changes in interest rates on net interest income. ASB s key strategies include:

(1) attracting and retaining low cost deposits, which enables ASB to replace other borrowings and reduce funding costs;

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

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

(4) lengthening the maturities of costing liabilities in a lower interest-rate environment, which has stabilized the cost of other borrowings as interest rates have risen.

ASB has been undergoing a transformation, involving four major lines of business, to become a full service community bank serving both consumer and commercial customers. Two have been completed commercial real estate and mortgage banking, and a third is nearing completion commercial banking. The remaining transformation involving retail banking is intended to make ASB s retail area more customer-centric, rather than product-centric. The transformation project will require continued investment in people and technology. In addition to these transformation projects, ASB will continue to invest in projects and opportunities that will build core franchise value and add to earnings growth and returns. Additionally, the banking industry is constantly changing and ASB is continuously making the changes and investments necessary to adapt and remain competitive. ASB s ongoing challenge is to increase revenues faster than expenses.

Results of Operations

(dollars in millions)	2005	% change	2004	% change	2003
Revenues	$ 388	6	$ 364	(2)	$ 371
Net interest income	210	8	194	3	190
Operating income	105		105	13	93
Net income	65	58	41	(27)	56
Return on average common equity [1]	11.7%		8.0%		12.1%
Earning assets					
Average balance [2]	$ 6,374	3	$ 6,162	3	$ 5,980
Weighted-average yield	5.19%	4	4.98%	(5)	5.23%
Costing liabilities					
Average balance [2]	$ 6,157	4	$ 5,934	3	$ 5,739
Weighted-average rate	1.97%	4	1.90%	(12)	2.15%
Interest rate spread	3.22%	5	3.08%		3.08%
Net interest margin [3]	3.29%	4	3.15%	(1)	3.17%

[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.

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

Table of Contents

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 income from 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 defined under GAAP and may not be comparable to other companies or more useful than the GAAP presentation included in HEI s consolidated financial statements.

Years ended December 31	**2005**	**2004**	**2003**
(dollars in thousands)			
Net income	$ 64,883	$ 41,062	$ 56,261
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)
Net income as adjusted	$ 64,883	$ 61,402	$ 52,468
ROACE as adjusted[1]	11.7%	13.3%	11.7%

[1] Calculated using adjusted net income divided by the simple average adjusted common equity (excluding the $75 million common equity infusion in December 2004 from equity as of December 31, 2004).

Taking into account the adjustments in the table above, ASB s 2005 net income would have increased 6% compared to 2004.

Bank operations

Earnings of ASB depend primarily on net interest income, which is the difference between interest earned on earning assets and interest paid on costing liabilities. As discussed above, if the current interest rate environment persists, the potential for compression of ASB s net interest margin will continue to be a concern. ASB s loan volumes and yields are affected by market interest rates, competition, demand for financing, availability of funds and management s responses to these factors. As of December 31, 2005, ASB s loan portfolio mix, net, consisted of 74% residential loans, 11% commercial loans, 8% commercial real estate loans and 7% consumer loans. As of December 31, 2004, ASB s loan portfolio mix, net, consisted of 77% residential loans, 9% commercial loans, 7% commercial real estate loans and 7% consumer loans. ASB s mortgage-related securities portfolio consists primarily of shorter-duration assets and is affected by market interest rates and demand.

Deposits continue to be the largest source of funds for ASB and are affected by market interest rates, competition and management s responses to these factors. Advances from the FHLB of Seattle and securities sold under agreements to repurchase continue to be significant sources of funds, but the amount of advances has trended downward over the last few years. As of December 31, 2005, ASB s costing liabilities consisted of 74% deposits and 26% FHLB advances and other borrowings. As of December 31, 2004, ASB s costing liabilities consisted of 71% deposits and 29% FHLB advances and other borrowings.

Other factors primarily affecting ASB s operating results include fee income, provision (or reversal of allowance) for loan losses, gains or losses on sales of securities available-for-sale and expenses from operations.

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. As of December 31, 2005 and 2004, the unrealized losses, net of tax benefits, on available-for-sale mortgage-related securities (including securities pledged for repurchase agreements) in AOCI was $37 million and $7 million, respectively, reflecting the impact of higher interest rates in 2005. See Quantitative and qualitative disclosures about market risk.

Table of Contents

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

	Years ended December 31		
(dollars in thousands)	**2005**	**2004**	**2003**
Loans receivable			
Average balances [1]	$ 3,411,389	$ 3,121,878	$ 3,071,877
Interest income [2]	205,084	184,773	198,948
Weighted-average yield	6.01%	5.92%	6.48%
Mortgage-related securities			
Average balances	$ 2,755,736	$ 2,799,303	$ 2,707,395
Interest income	121,847	116,471	107,496
Weighted-average yield	4.42%	4.16%	3.97%
Investments [3]			
Average balances	$ 207,258	$ 240,466	$ 200,891
Interest and dividend income	4,077	5,876	6,384
Weighted-average yield	1.97%	2.44%	3.18%
Total earning assets			
Average balances	$ 6,374,383	$ 6,161,647	$ 5,980,163
Interest and dividend income	331,008	307,120	312,828
Weighted-average yield	5.19%	4.98%	5.23%
Deposit liabilities			
Average balances	$ 4,453,762	$ 4,114,070	$ 3,888,145
Interest expense	52,064	47,184	53,808
Weighted-average rate	1.17%	1.15%	1.38%
Borrowings			
Average balances	$ 1,703,353	$ 1,819,598	$ 1,851,258
Interest expense	69,362	65,603	69,516
Weighted-average rate	4.07%	3.61%	3.76%
Total costing liabilities			
Average balances	$ 6,157,115	$ 5,933,668	$ 5,739,403
Interest expense	121,426	112,787	123,324
Weighted-average rate	1.97%	1.90%	2.15%
Net average balance	$ 217,268	$ 227,979	$ 240,760
Net interest income	209,582	194,333	189,504
Interest rate spread	3.22%	3.08%	3.08%
Net interest margin [4]	3.29%	3.15%	3.17%

1 Includes nonaccrual loans.

2 Includes interest accrued prior to suspension of interest accrual on nonaccrual loans, together with loan fees of $6.4 million, $6.1 million and $8.6 million for 2005, 2004 and 2003, respectively.

3

Includes stock in the FHLB of Seattle ($98 million as of December 31, 2005). In 2005, ASB received a stock dividend with a par value of $0.4 million, compared to $2.7 million in 2004 and $ 5.1 million in 2003. See FHLB of Seattle business and capital plan below.

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

Net interest income before reversal of allowance for loan losses for 2005 increased by $15 million, or 7.8%, when compared to 2004. Strong organic growth in loans and deposits and the ability to keep deposit cost low enabled ASB to offset margin compression pressure from a flattening yield curve, which inverted near year-end. Net interest margin increased from 3.15% in 2004 to 3.29% in 2005 due to growth in the loan portfolio and higher yields in the loan and mortgage-related securities portfolios funded by strong deposit growth. The increase in the average loan portfolio balance was helped by the continued strength in the Hawaii economy and real estate market. The decrease in the average investment and mortgage-related securities portfolios was due to the reinvestment of excess liquidity into loans. Average deposit balances grew by $340 million, enabling ASB to replace other borrowings and helping fund loan growth. The shift in liability mix enabled ASB to keep down its weighted average rate on costing liabilities.

Table of Contents

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 reversal of allowance for loan losses of $3 million ($2 million, net of tax) in 2005. This compares with a reversal of allowance for loan losses of $8 million ($5 million, net of tax) in 2004.

Noninterest income remained stable for 2005 when compared to 2004.

Noninterest expense for 2005 increased by $10 million, or 6.3%, over 2004, primarily due to higher compensation and employee benefits expense related to strategic initiatives, increased pension costs, Sarbanes-Oxley Act of 2002 (SOX) compliance costs and the charge for prepayment of a high cost Federal Home Loan Bank advance.

Net interest income before the reversal of allowance 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 as net interest margin decreased slightly from 3.17% in 2003 to 3.15% in 2004 due to faster growth in costing liabilities compared to earning assets. Growth in the loan portfolio and mortgage-related securities were funded by strong 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 was due to the reinvestment into short-term investments of excess liquidity resulting from an inflow of deposits. 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 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. Average deposit balances grew by $226 million in 2004 compared to 2003. The higher deposit balances enabled ASB to repay some of its 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 reversal of allowance 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.

Noninterest 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.

Noninterest expense for 2004 increased by $3 million, or 1.8%, over 2003, primarily due to SOX compliance costs.

During 2005, 2004 and 2003, ASB s allowance for loan losses decreased by $3 million, $10 million and $1 million, respectively.

ASB s nonaccrual and renegotiated loans represented 0.2%, 0.4% and 0.4% of total loans outstanding as of December 31, 2005, 2004 and 2003, respectively. See Note 4 of the Notes to Consolidated Financial Statements.

FHLB of Seattle business and capital plan

In December 2004, the FHLB of Seattle signed an agreement with its regulator, the Federal Housing Finance Board (Finance Board), to adopt a business and capital plan to strengthen its risk management, capital structure and governance. In April 2005, the FHLB of Seattle delivered a proposed three-year business plan and capital management plan to the Finance Board, and issued a press release stating that it anticipates minimal to no dividends in the next few years while it implements its new business model. No dividends were received by ASB from the FHLB of Seattle during the fourth quarter of 2004 and the last three quarters of 2005. Subject to the impact of legislation being considered by Congress (discussed below under Legislation and regulation), member access to the FHLB of Seattle funding and liquidity is expected to continue unimpeded during implementation of the three-year plan.

Table of Contents

Legislation and regulation

Congress is considering legislation to revamp oversight of government-sponsored enterprises (GSEs). This legislation 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, this legislation 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 legislation 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 and Certain factors that may affect future results and financial condition Bank.

Liquidity and capital resources

December 31	2005	% change	2004	% change
(dollars in millions)				
Assets	$ 6,835	1	$ 6,767	4
Available-for-sale investment and mortgage-related securities	2,629	(11)	2,953	9
Investment in stock of Federal Home Loan Bank of Seattle	98		97	3
Loans receivable, net	3,567	10	3,249	4
Deposit liabilities	4,557	6	4,296	7
Securities sold under agreements to repurchase	687	(15)	811	(2)
Advances from FHLB	936	(5)	988	(3)

As of December 31, 2005, ASB was the third largest financial institution in Hawaii based on assets of $6.8 billion and deposits of $4.6 billion.

ASB s principal sources of liquidity are customer deposits, borrowings, the maturity and repayment of portfolio loans and securities and the sale of loans into secondary market channels. ASB s deposits increased by $261 million during 2005. ASB s principal sources of borrowings are advances from the FHLB and securities sold under agreements to repurchase from broker/dealers. As of December 31, 2005, FHLB borrowings totaled approximately $0.9 billion, representing 14% of assets. ASB is approved to borrow from the FHLB up to 35% of ASB s assets to the extent it provides qualifying collateral and holds sufficient FHLB stock. As of December 31, 2005, ASB s unused FHLB borrowing capacity was approximately $1.5 billion. As of December 31, 2005, securities sold under agreements to repurchase totaled $0.7 billion, representing 10% of assets. ASB utilizes deposits, advances from the FHLB and securities sold under agreements to repurchase to fund maturing and withdrawable deposits, repay maturing borrowings, fund existing and future loans and make investments. As of December 31, 2005, ASB had commitments to borrowers for undisbursed loan funds, loan commitments and unused lines and letters of credit of $1.1 billion. Management believes ASB s current sources of funds will enable it to meet these commitments and obligations while maintaining liquidity at satisfactory levels.

As of December 31, 2005, ASB had $2.4 million of loans on nonaccrual status, or 0.1% of net loans outstanding, compared to $6.4 million, or 0.2%, as of December 31, 2004. As of December 31, 2005 and 2004, ASB s real estate acquired in settlement of loans was $0.2 million and $0.9 million, respectively.

In 2005, net cash of $40 million was used in investing activities primarily due to net increases in loans held for investment, partly offset by repayments and sales of mortgage-related securities, net of purchases. Financing activities provided net cash of $44 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 stock dividends. Operating activities provided cash of $42 million.

Table of Contents

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, 2005, ASB was well-capitalized (see Regulation of ASB for ASB s capital ratios).

Off-balance sheet arrangements

Although the Company has off-balance sheet arrangements, management has determined that it has no off-balance sheet arrangements that either have, or are reasonably likely to have, a current or future effect on the 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. See also Forward-Looking Statements above and Item 1A. Risk 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 proceedings on two specific issues (competitive bidding and DG) to move toward a more competitive electric industry environment under cost-based regulation.

Competitive bidding proceeding. 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 current parties/participants in the competitive bidding proceeding include the Consumer Advocate, HECO, HELCO, MECO, Kauai Island Utility Cooperative and a renewable energy organization. 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 it is determined that a competitive bidding system should be developed, issues include how a fair system can be developed that ensures that competitive benefits result from the system and ratepayers are not placed at undue risk , what the guidelines and requirements for prospective bidders should be, and how such a system can encourage broad participation. The PUC stated it would consider related matters on a case-by-case basis pending completion of the competitive bidding and DG proceedings. Statements of position by, information requests to, and responses by the parties/participants were filed in March through August 2005. The PUC held panel hearings in December 2005. The parties will engage in working sessions to discuss a competitive bidding framework and file a joint submission by March 31, 2006 identifying areas of agreement and disagreement for the PUC s review and consideration. After the filing of briefs, oral arguments are expected to be presented to the PUC in May 2006. 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. The electric utilities have been expanding their use and consideration of DG resources to meet the energy needs of the utility systems. Utility-sited DG has been deployed to provide peaking capacity and to defer the need for transmission system infrastructure. The utilities have also been pursuing the possibility of offering utility-owned, customer-sited combined heat and power (CHP) systems to large customers to produce electricity and thermal energy, which is generally used in Hawaii 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 the customer s continued connection to the utility grid to make up the difference in electricity demand and to provide back up electricity. Incremental generation from such customer-sited CHP systems and other forms of DG is intended to complement traditional central station power, as part of the electric utilities plans to meet their forecasted load growth.

In October 2003, the PUC opened the DG proceeding 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.

In April 2004, the PUC issued an order in the DG proceeding defining issues related to planning (e.g., who should own and operate projects and the roles of the electric utilities and PUC), impacts (e.g., on the transmission and distribution systems, power quality and reliability, the use of fossil fuels and utility costs) and implementation (e.g., issues concerning matters to be considered to allow a DG facility s interconnection with the utility s grid, appropriate rate design and cost allocation issues, and revisions that should be made to PUC and utility rules and practices). Hearings were held in December 2004.

Prior to opening of the investigative DG proceeding, the electric utilities filed an application for approval of CHP tariffs, under which they would own, operate and maintain customer-sited, packaged CHP systems (and certain ancillary equipment) pursuant to standard form contracts with eligible commercial customers. This CHP tariff application and a HELCO application for approval of an agreement with a customer for a utility CHP project were suspended by the PUC until, at a minimum, the matters in the DG proceeding were adequately addressed.

On January 27, 2006, the PUC issued its D&O in the DG proceeding. In the D&O the PUC indicated that its policy is to promote the development of a market structure that assures DG is available at the lowest feasible cost, DG that is economical and reliable has an opportunity to come to fruition and DG that is not cost-effective does not enter the system.

With regard to DG ownership, the D&O affirmed the ability of the electric utilities to procure and operate DG for utility purposes at utility sites. The PUC also indicated its desire to promote the development of a competitive market for customer-sited DG. In weighing the general advantages and disadvantages of allowing a utility to provide DG services on a customer s site, the PUC found that the disadvantages outweigh the advantages. However, the PUC also found that the utility is the most informed potential provider of DG and it would not be in the public interest to exclude the HECO Utilities from providing DG services at this early stage of DG market development.

Therefore, the D&O allows the utility to provide DG services on a customer-owned site as a regulated service when (1) the DG resolves a legitimate system need; (2) the DG is the least cost alternative to meet that need; and (3) it can be shown that, in an open and competitive process acceptable to the PUC, the customer operator was unable to find another entity ready and able to supply the proposed DG service at a price and quality comparable to the utility s offering.

The D&O also requires the electric utilities to establish reliability and safety requirements for DG, establish a non-discriminatory DG interconnection policy, develop a standardized interconnection agreement to streamline the DG application review process, establish standby rates based on unbundled costs associated with providing each

Table of Contents

service (i.e., generation, distribution, transmission and ancillary services), and establish detailed affiliate requirements should the utility choose to sell DG through an affiliate.

On March 1, 2006, the electric utilities filed a Motion for Clarification and/or Partial Reconsideration requesting that the PUC clarify how the three conditions under which electric utilities are allowed to provide regulated DG services at customer-owned sites will be administered, in order to better determine the impacts the conditions may have on the electric utilities DG plans.

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, commercial and commercial real estate loans. The origination of consumer, commercial and commercial real estate loans involves risks and other considerations different from those associated with originating residential real estate loans. For example, the sources and level of competition may be different and credit risk is generally higher than for mortgage loans. These different risk factors are considered in the underwriting and pricing standards and in the allowance for loan losses established by ASB for its consumer, commercial and commercial real estate loans.

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.

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

Volatility in U.S. capital markets can affect the fair values of assets available to satisfy retirement benefits obligations. The Company estimates that consolidated retirement benefits expense, net of amounts capitalized and income taxes, will be $17.8 million in 2006 as compared to $11.3 million in 2005, 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, 2005, the fair value and carrying value of the investment and mortgage-related securities held by ASB were $2.6 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. The Federal Reserve began increasing rates in 2004, while longer-term interest rates have not increased significantly, causing a flattening of the yield curve. This type of interest rate environment typically puts downward pressure on ASB s net interest margin. As of December 31, 2005, the Company had no floating-rate long-term debt outstanding. As of December 31, 2005, consolidated HEI had $142 million of commercial paper outstanding with a weighted-average interest rate of 4.47% and maturities ranging from 13 to 21 days. See Quantitative and Qualitative Disclosures about Market Risk.

Table of Contents

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.

Limited insurance. In the ordinary course of business, the Company purchases insurance coverages (e.g., property and liability coverages) to protect itself against loss of or damage to its properties and against claims made by third-parties and employees for property damage or personal injuries. However, the protection provided by such insurance is limited in significant respects and, in some instances, the Company has no coverage. For electric utility examples, see Limited insurance in Note 3 of the Notes to Consolidated Financial Statements. ASB also has no insurance coverage for business interruption nor credit card fraud. Certain of the Company s insurance has substantial deductibles or has limits on the maximum amounts that may be recovered. Insurers also have exclusions or limitations of coverage for claims related to certain perils including, but not limited to, mold and terrorism. If a series of losses occurred, such as from a series of lawsuits in the ordinary course of business each of which were subject to the deductible amount, or if the maximum limit of the available insurance were substantially exceeded, the Company could incur 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. 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 2004 legislature passed legislation that clarifies that the accepting agency or authority for an environmental impact statement is not required to be the approving agency for the permit or approval and also requires an environmental assessment for proposed waste-to-energy facilities, landfills, oil refineries, power-generating facilities greater than 5 MW and wastewater facilities, except individual wastewater systems. This legislation could result in an increase in project costs.

The entire electric utility industry has been affected by the 1990 amendments to the Clean Air Act (CAA), changes to the National Ambient Air Quality Standard (NAAQS) for ozone, and adoption of a NAAQS for fine particulate matter. Further significant impacts may occur if currently proposed legislation, rules and standards are adopted.

For discussions of the ongoing Honolulu Harbor environmental investigation, the July 1999 Regional Haze Rule amendments and section 316(b) of the federal Clean Water Act, see Environmental regulation in Note 3 of the Notes to Consolidated Financial Statements. There can be no assurance that a significant environmental liability will not be incurred by the electric utilities.

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 rates the electric utilities are allowed to charge for their services, and the timeliness of permitted rate increases, are among the most important items influencing their financial condition, results of operations and liquidity. The PUC has broad discretion over the rates the electric utilities charge and other matters. Any adverse decision by the PUC concerning the level or method of determining electric utility rates, the authorized returns on equity or rate base found to be reasonable, the potential consequences of exceeding or not meeting such returns, or any prolonged delay in rendering a decision in a rate or other proceeding could have a material adverse

Table of Contents

affect on the Company s and HECO s consolidated results of operations, financial condition and liquidity. Upon a showing of probable entitlement, the PUC is required to issue an interim D&O in a rate case within 10 months from the date of filing a completed application if the evidentiary hearing is completed (subject to extension for 30 days if the evidentiary hearing is not completed). There is no time limit for rendering a final D&O. Interim rate increases are subject to refund with interest, pending the final outcome of the case. Through December 31, 2005, HECO and its subsidiaries had recognized $32 million of revenues with respect to interim orders regarding certain integrated resource planning costs and an Oahu general rate increase, which revenues are subject to refund, with interest, if and to the extent they exceed the amounts allowed in final orders. The Consumer Advocate has objected to the recovery of $3.2 million (before interest) of the $11.8 million of incremental IRP costs incurred by the utilities during the 1995-2004 period, and the PUC s decision is pending on this matter. In addition, HECO and MECO incurred approximately $1.0 million of incremental integrated resource planning costs for 2005, for which the Consumer Advocate has not yet stated its position. See Most recent rate requests HECO above for a discussion of the status of the current HECO rate case.

Management cannot predict with certainty when the final D&O in the current HECO rate case or when D&Os in future rate cases will be rendered or the amount of any interim or final rate increase that may be granted. Further, the increasing levels of O&M expenses (including increased retirement benefit costs), increased capital expenditures, or other factors could result in the electric utilities seeking rate relief more often than in the past.

The rate schedules of each 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 2004 PUC decisions approving the electric utilities fuel supply contracts, the PUC affirmed the electric utilities right to include in their respective energy cost adjustment clauses the stated costs incurred pursuant to their respective new fuel supply contracts, to the extent that these costs are not included in their respective base rates, and restated its intention to examine the need for continued use of energy cost adjustment clauses in rate cases. While there was no opposition to the continuation of the clause by the parties in the pending HECO rate case, there can be no assurance concerning actions the PUC may take in its final order in the pending HECO rate case or otherwise in the future with respect to these clauses. In addition, the State Legislature is currently considering legislation which would direct the PUC to review and consider alternatives to the current energy cost adjustment clause and, at this time, it is not possible to predict the outcome of those deliberations. 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.

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 79.5% of the net energy generated and purchased by HECO and its subsidiaries in 2006 will be generated from the burning of oil. Purchased KWHs provided approximately 39.1% of the total net energy generated and purchased in 2005 compared to 38.2% in 2004 and 39.2% in 2003.

Failure or delay by the electric utilities oil suppliers and shippers to provide fuel pursuant to existing supply contracts, or failure by a major independent power producer to deliver the firm capacity anticipated in its 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 generally maintains an average system fuel inventory level equivalent to 35 days of forward consumption. HELCO and MECO generally maintain an inventory level equivalent to one month s supply of both medium sulfur fuel oil and diesel fuel. The electric utilities major sources of oil, through their suppliers, are in China, Vietnam 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 9%, 7% and 11% for 2005, 2004 and 2003, respectively, when compared to the prior year. This trend of increased operation and maintenance expenses is expected to continue in 2006 as the electric utilities anticipate: (1) higher demand-side management expenses (that are passed on to customers through a surcharge and therefore do not impact net income) and integrated resource planning expenses, (2) higher employee benefits expenses, primarily for retirement benefits and (3) higher production expenses, primarily to meet higher demand levels and load growth set in 2004 and sustained in 2005. 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 aging equipment, which has experienced heavier usage as demand has increased to current levels. Until an overhaul is fully underway, it is possible that the maintenance costs for a generating unit may be significantly higher than originally planned. Increased operation and maintenance expenses were among the reasons HECO filed a request with the PUC in November 2004 to increase base rates. In September 2005, HECO received interim rate relief (see Most recent rate requests).

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 have been seriously delayed (although CT-4 and CT-5 at Keahole are now operating). See Note 3 of the Notes to Consolidated Financial Statements.

Bank

Regulation of ASB. ASB is subject to examination and comprehensive regulation by the Department of Treasury, OTS and the FDIC, and is subject to reserve requirements established by the Board of Governors of the Federal Reserve System. Regulation by these agencies focuses in large measure on the adequacy of ASB s capital and the results of periodic safety and soundness examinations conducted by the OTS. ASB s insurance product sales activities, including those conducted by ASB s insurance agency subsidiary, Bishop Insurance Agency of Hawaii, Inc., are subject to regulation by the Hawaii Insurance Commissioner.

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, 2005, ASB was in compliance with OTS minimum regulatory capital requirements and was well-capitalized within the meaning of OTS prompt corrective action regulations and FDIC capital regulations, as follows:

ASB met applicable minimum regulatory capital requirements (noted in parentheses) as of December 31, 2005 with a tangible capital ratio of 7.4% (1.5%), a core capital ratio of 7.4% (4.0%) and a total risk-based capital ratio of 15.1% (8.0%).

ASB met the capital requirements to be generally considered well-capitalized (noted in parentheses) as of December 31, 2005 with a leverage ratio of 7.4% (5.0%), a Tier-1 risk-based capital ratio of 14.2% (6.0%) and a total risk-based capital ratio of 15.1% (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 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, 2005, 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, 2005, approximately 87% of its assets were qualified thrift investments.

Federal Thrift Charter. The Gramm-Leach-Bliley Act of 1998 (the Gramm Act) permitted banks, insurance companies and investment firms to compete directly against each other, thereby allowing one-stop shopping for an array of financial services. Although the Gramm Act further restricted the creation of so-called unitary savings and loan holding companies (i.e., companies such as HEI whose subsidiaries include one or more savings associations and one or more nonfinancial subsidiaries), the unitary savings and loan holding company relationship among HEI, HEIDI and ASB is grandfathered under the Gramm Act so that HEI and its subsidiaries will be able to continue to engage in their current activities so long as ASB maintains its QTL status. Under the Gramm Act, any proposed sale of ASB would have to satisfy applicable statutory and regulatory requirements and potential acquirers of ASB would most likely be limited to companies that are already qualified as, or capable of qualifying as, either a traditional savings and loan association holding company or a bank holding company, or as one of the newly authorized financial holding companies permitted under the Gramm Act.

Material estimates and critical accounting policies

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

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

For securities that are not trading securities, declines in value determined to be other than temporary are included in earnings and result in a new cost basis for the investment. The specific identification method is used in determining realized gains and losses on the sales of securities.

ASB owns one investment security (a federal agency obligation), 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. ASB obtains market prices for investment and mortgage-related securities from a third party financial services provider. The prices of these securities may be influenced by factors such as market liquidity, corporate credit considerations of the underlying collateral, the levels of interest rates, expectations of prepayments and defaults, limited investor base, market sector concerns, and overall market psychology. Adverse changes in any of these factors may result in additional losses. As of December 31, 2005, ASB had mortgage-related securities issued by FHLMC, GNMA and FNMA valued at $2.2 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.

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

Management believes that the PUC will allow recovery of property, plant and equipment in its electric rates. If the PUC does not allow recovery of any such costs, the electric utility would be required to write off the disallowed

Table of Contents

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 benefits (collectively, retirement benefits) costs are material estimates accounted for in accordance with SFAS No. 87, Employers Accounting for Pensions and SFAS No. 106, Employers Accounting for Postretirement Benefits Other Than Pensions. For a discussion of retirement benefits (including costs, major assumptions, plan assets, other factors affecting costs, AOCI charges and sensitivity analyses), see Retirement benefits (pension and other postretirement benefits) in Consolidated Results of Operations above and Note 8 of the Notes to Consolidated Financial Statements.

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

In general, environmental contamination treatment costs are charged to expense, unless it is probable that the PUC would allow such costs to be recovered 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. See Note 10 of the Notes to Consolidated Financial Statements.

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, 2005, regulatory liabilities and regulatory assets amounted to $219 million and $111 million, respectively. Regulatory liabilities and regulatory assets 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, 2005 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 assets would be charged to income and the regulatory liabilities would be credited to income or refunded to ratepayers. In the event of unforeseen regulatory actions or other circumstances, however, management believes that a material adverse effect on the Company s results of operations and financial position may result if regulatory assets have to be charged to expense without an offsetting credit for regulatory liabilities or if regulatory liabilities are required to be refunded to ratepayers.

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. As of December 31, 2005, revenues applicable to energy consumed, but not yet billed to customers, amounted to $91 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 rates are adjusted for changes in the weighted-average price paid for fuel oil and certain components of purchased power, and the relative amounts of company-generated power and purchased power. See Regulation of electric utility rates above.

Consolidation of VIEs. In December 2003, the FASB issued revised FIN No. 46 (FIN 46R), Consolidation of Variable Interest Entities, which addresses how a business enterprise should evaluate whether it has a controlling financial interest in an entity through means other than voting rights and accordingly should consolidate the entity. The Company evaluates the impact of applying FIN 46R to its relationships with IPPs with whom the electric utilities execute new 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 electric utilities do not know how the consolidation of IPPs would be treated for regulatory or credit ratings purposes. See General Consolidation Consolidation of VIEs in Note 1 of the Notes to Consolidated Financial Statements.

Bank

Allowance for loan losses. See Note 1 of the Notes to Consolidated Financial Statements. As of December 31, 2005, ASB s allowance for loan losses was $30.6 million and ASB had $2.4 million of loans on nonaccrual status. In 2005, ASB s reversal of allowance for loan losses was $3.1 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), and material increases in those amounts could have a material adverse affect on the Company s results of operations and financial position.

Table of Contents

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 HEI s Selected contractual obligations and commitments table.

Selected contractual obligations and commitments

The following table presents HECO and subsidiaries-aggregated information as of December 31, 2005 about total payments due during the indicated periods under the specified contractual obligations and commercial commitments:

December 31, 2005	Payment due by period				
(in millions)	1 year or less	2-3 years	4-5 years	More than 5 years	Total
Long-term debt, net	$	$	$	$ 766	$ 766
Operating leases	4	6	4	14	28
Fuel oil purchase obligations (estimate based on January 1, 2006 fuel oil prices)	542	1,084	1,083	2,167	4,876
Purchase power obligations minimum fixed capacity charges	118	240	236	1,279	1,873
Total (estimated)	$ 664	$ 1,330	$ 1,323	$ 4,226	$ 7,543

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 two risks are not material as of December 31, 2005.

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 commercial and commercial real estate loans, on-going monitoring by loan officers, credit review and quality control functions in these lending areas and adequate allowance for loan losses. Credit risk associated with the securities portfolio is mitigated by ASB s asset/liability management process, experienced staff working with analytical tools, monthly fair value analysis and on-going monitoring and reporting such as investment watch reports and loss sensitivity analysis. See 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 substantially mitigated so long as the electric utilities have their current energy cost adjustment clauses in their rate schedules. See discussion of the energy cost adjustment clauses in Certain factors that may affect future results and financial condition Electric utility Regulation of electric utility rates. The Company currently has no hedges against its commodity price risk. Because the Company does not have a large portfolio of trading assets, the Company is not exposed to significant market risk from trading activities. However, until the Company sell its shares of Hoku (a Hawaii fuel cell company that completed its initial public offering in August 2005), fluctuations in the market price of the shares will impact the Company s net income. 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.

Table of Contents

Bank interest rate risk

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

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

See Note 4 of 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 net interest income (NII) and the market value of interest-sensitive assets and liabilities in different interest-rate environments. The simulation analysis is performed using a dedicated asset/liability management software system enhanced with a mortgage prepayment model and a collateralized mortgage obligation (CMO) database. The simulation software is capable of generating scenario-specific cash flows for all instruments using the specified contractual information for each instrument and product specific prepayment assumptions for mortgage loans and mortgage-related securities.

NII sensitivity analysis measures the change in ASB s twelve-month, pre-tax NII in alternate interest rate scenarios. NII sensitivity is measured as the change in NII in the alternate interest-rate scenarios as a percentage of the base case NII. The base case interest-rate scenario is established using the current yield curve and assumes interest rates remain constant over the next twelve months. The alternate scenarios were created by assuming immediate and sustained parallel shocks of the yield curve in increments of +/- 100 basis points. At the end of 2005, the timing of the interest rate changes in the alternate scenarios for NII sensitivity analysis was modified from instantaneous interest rate changes to rate ramps or gradual interest changes. While the magnitude of the interest rate changes in the alternate scenarios remains the same, the timing of the changes is gradual, and accomplished by moving the yield curve in a parallel fashion, over the next twelve month period. This change was made because gradual rate changes more closely reflect historical patterns of interest rate movements, and are therefore more useful in measuring and managing NII sensitivity. As of December 31, 2005, NII sensitivity results are shown under both instantaneous rate shocks and rate ramps. The simulation model forecasts scenario-specific principal and interest cash flows for the interest-bearing assets and liabilities, and the NII is calculated for each scenario. Key balance sheet modeling assumptions used in the NII sensitivity analysis include: the size of the balance sheet remains relatively constant over the simulation horizon and maturing assets or liabilities are reinvested in similar instruments in order to maintain the current mix of the balance sheet. In addition, assumptions are made about the prepayment behavior of mortgage-related assets, future pricing spreads for new assets and liabilities, and the speed and magnitude with which deposit rates change in response to changes in the overall level of interest rates.

ASB s net portfolio value (NPV) ratio is a measure of the economic capitalization of ASB. The NPV ratio is the ratio of the net portfolio value of ASB to the present value of expected net cash flows from existing assets. Net portfolio value represents the theoretical market value of ASB s net worth and is defined as the present value of expected net cash flows from existing assets minus the present value of expected cash flows from existing liabilities plus the present value of expected net cash flows from existing off-balance sheet contracts. The NPV ratio is calculated by ASB pursuant to guidelines established by the OTS in Thrift Bulletin 13a. 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

Table of Contents

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, 2005 and 2004 constitute forward-looking statements and were as follows:

December 31	2005				2004		
	Change in NII	Change in NII	NPV ratio	NPV ratio sensitivity*	Change in NII	NPV ratio	NPV ratio sensitivity*
	Gradual change	Instantaneous change			Instantaneous change		
Change in interest rates (basis points)							
+300	(2.7)%	(8.1)%	8.12%	(332)	(7.7)%	7.28%	(367)
+200	(1.8)	(5.5)	9.34	(210)	(5.0)	8.69	(226)
+100	(0.9)	(2.8)	10.49	(95)	(2.0)	9.99	(96)
Base			11.44			10.95	
-100	1.5	2.2	11.91	47	(3.9)	11.22	27
-200	1.0	(5.0)	11.62	17	**	**	**

* Change from base case in basis points.

** Not performed due to the low level of interest rates as of December 31, 2004.

Management believes that ASB s interest rate risk position as of December 31, 2005 represents a reasonable level of risk. Under the instantaneous rate shock scenarios, the December 31, 2005 NII profile is slightly more sensitive to changes in interest rates compared to the NII profile on December 31, 2004.

In the 200 basis point scenario, NII falls relative to the base case because expectations of faster prepayments and lower reinvestment rates causes the yield on assets to decline faster than the cost of liabilities, which do not fall as much because the current low level of rates on existing liabilities limits the amount by which they can decline.

ASB s base NPV ratio as of December 31, 2005 was higher than on December 31, 2004, primarily as a result of changes in the composition of the balance sheet and changes in the level and shape of the yield curve. During 2005, ASB s funding mix shifted, as higher costing wholesale borrowings were replaced with lower cost deposits. This contributed to the increase in ASB s NPV ratio.

ASB s NPV ratio sensitivity measures as of December 31, 2005 were comparable to the measures as of December 31, 2004.

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

Table of Contents

Other than bank interest rate risk

The Company s general policy is to manage other than bank interest rate risk through use of a combination of short-term debt, long-term debt (primarily fixed-rate debt) and preferred securities. As of December 31, 2005, management believes the Company is exposed to other than bank interest rate risk because of their periodic borrowing requirements, the impact of interest rates on the discount rate and the market value of plan assets used to determine retirement benefits expenses and obligations (see Retirement benefits (pension and other postretirement benefits) in Management s discussion and analysis of financial condition and results of operations and Note 8 of 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 as of December 31, 2005 of $142 million and a hypothetical 10% increase/decrease in interest rates, annual interest expense would have increased/decreased on that commercial paper by $0.6 million.

HECO:

HECO and its subsidiaries manage various market risks in the ordinary course of business, including credit risk and liquidity risk, but management believes their exposures to these two risks are not material as of December 31, 2005.

HECO and its subsidiaries are exposed to some commodity price risk primarily related to its fuel supply and IPP contracts. HECO and its subsidiaries commodity price risk is substantially mitigated so long as they have their current energy cost adjustment clauses in their rate schedules. See discussion of the energy cost adjustment clauses in Item 1A. Risk factors (Electric Utility Risks) and Certain factors that may affect future results and financial condition Electric utility Regulation of electric utility rates. HECO and its subsidiaries currently have no hedges against their commodity price risk.

Because HECO and its subsidiaries do not have a portfolio of trading assets, they are not exposed to market risk from trading activities.

See Other than bank interest rate risk above and Note 10 of HECO s Notes to Consolidated Financial Statements. Based upon short-term borrowings outstanding as of December 31, 2005 of $136 million and a hypothetical 10% increase/decrease in interest rates, annual interest expense would have increased/decreased on those short-term borrowings by $0.6 million.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Table of Contents

Consolidated Financial Statements

Consolidated Statements of Income

Hawaiian Electric Industries, Inc. and Subsidiaries

Years ended December 31	2005	2004	2003
(in thousands, except per share amounts)			
Revenues			
Electric utility	$ 1,806,384	$ 1,550,671	$ 1,396,685
Bank	387,910	364,284	371,320
Other	21,270	9,102	13,311
	2,215,564	1,924,057	1,781,316
Expenses			
Electric utility	1,644,681	1,376,768	1,220,120
Bank	283,009	259,310	278,565
Other	16,452	17,019	19,064
	1,944,142	1,653,097	1,517,749
Operating income (loss)			
Electric utility	161,703	173,903	176,565
Bank	104,901	104,974	92,755
Other	4,818	(7,917)	(5,753)
	271,422	270,960	263,567
Interest expense other than bank	(75,309)	(77,176)	(69,292)
Allowance for borrowed funds used during construction	2,020	2,542	1,914
Preferred stock dividends of subsidiaries	(1,894)	(1,901)	(2,006)
Preferred securities distributions of trust subsidiaries			(16,035)
Allowance for equity funds used during construction	5,105	5,794	4,267
Income from continuing operations before income taxes	201,344	200,219	182,415
Income taxes	73,900	92,480	64,367
Income from continuing operations	127,444	107,739	118,048
Discontinued operations gain (loss) on disposal, net of income taxes	(755)	1,913	(3,870)
Net income	$ 126,689	$ 109,652	$ 114,178
Basic earnings (loss) per common share			
Continuing operations	$ 1.58	$ 1.36	$ 1.58
Discontinued operations	(0.01)	0.02	(0.05)

	$ 1.57	$ 1.38	$ 1.53
Diluted earnings (loss) per common share			
Continuing operations	$ 1.57	$ 1.36	$ 1.57
Discontinued operations	(0.01)	0.02	(0.05)
	$ 1.56	$ 1.38	$ 1.52
Dividends per common share	$ 1.24	$ 1.24	$ 1.24
Weighted-average number of common shares outstanding	80,828	79,562	74,696
Dilutive effect of stock-based compensation	372	157	278
Adjusted weighted-average shares	81,200	79,719	74,974

See accompanying Notes to Consolidated Financial Statements.

Table of Contents

Consolidated Balance Sheets

Hawaiian Electric Industries, Inc. and Subsidiaries

December 31		2005		2004
(dollars in thousands)				
ASSETS				
Cash and equivalents		$ 151,513		$ 132,138
Federal funds sold		57,434		41,491
Accounts receivable and unbilled revenues, net		249,473		208,533
Available-for-sale investment and mortgage-related securities		2,629,351		2,953,372
Investment in stock of Federal Home Loan Bank of Seattle (estimated fair value $97,764 and $97,365)		97,764		97,365
Loans receivable, net		3,566,834		3,249,191
Property, plant and equipment, net				
Land	$ 46,350		$ 46,311	
Plant and equipment	3,884,886		3,698,539	
Construction in progress	150,376		112,293	
	4,081,612		3,857,143	
Less accumulated depreciation	(1,538,836)	2,542,776	(1,434,840)	2,422,303
Regulatory assets		110,718		108,630
Other		456,134		414,971
Goodwill and other intangibles		89,580		91,263
		$ 9,951,577		$ 9,719,257
LIABILITIES AND STOCKHOLDERS EQUITY				
Liabilities				
Accounts payable		$ 183,336		$ 147,054
Deposit liabilities		4,557,419		4,296,172
Short-term borrowings		141,758		76,611
Securities sold under agreements to repurchase		686,794		811,438
Advances from Federal Home Loan Bank		935,500		988,231
Long-term debt, net		1,142,993		1,166,735
Deferred income taxes		207,997		229,765
Regulatory liabilities		219,204		197,089
Contributions in aid of construction		256,263		235,505
Other		369,390		325,307
		8,700,654		8,473,907
Minority interests				
Preferred stock of subsidiaries not subject to mandatory redemption		34,293		34,405
Stockholders equity				
Preferred stock, no par value, authorized 10,000,000 shares; issued: none				
		1,018,966		1,010,090

Common stock, no par value, authorized 100,000,000 shares; issued and outstanding: 80,983,326 shares and 80,687,350 shares				
Retained earnings		235,394		208,998
Accumulated other comprehensive loss, net of income tax benefits				
Net unrealized losses on securities	$ (36,476)		$ (7,036)	
Minimum pension liability	(1,254)	(37,730)	(1,107)	(8,143)
		1,216,630		1,210,945
		$ 9,951,577		$ 9,719,257

See accompanying Notes to Consolidated Financial Statements.

Table of Contents

Consolidated Statements of Changes in Stockholders Equity

Hawaiian Electric Industries, Inc. and Subsidiaries

(in thousands, except per share amounts)	Common stock Shares	Common stock Amount	Retained earnings	Accumulated other comprehensive income (loss)	Total
Balance, December 31, 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
Comprehensive income:					
Net income			126,689		126,689
Net unrealized losses on securities:					
				(29,335)	(29,335)

Net unrealized losses arising during the period, net of tax benefits of $21,933					
Less: reclassification adjustment for net realized gains included in net income, net of taxes of $70				(105)	(105)
Minimum pension liability adjustment, net of tax benefits of $95				(147)	(147)
Comprehensive income (loss)			126,689	(29,587)	97,102
Issuance of common stock:					
Stock Option and Incentive Plan and other plans	296	6,095			6,095
Expenses and other, net		2,781			2,781
Common stock dividends ($1.24 per share)			(100,293)		(100,293)
Balance, December 31, 2005	80,983	$ 1,018,966	$ 235,394	$ (37,730)	$ 1,216,630

As of December 31, 2005, Hawaiian Electric Industries, Inc. (HEI) had reserved a total of 14,915,552 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.

96

Table of Contents

Consolidated Statements of Cash Flows

Hawaiian Electric Industries, Inc. and Subsidiaries

Years ended December 31	2005	2004	2003
(in thousands)			
Cash flows from operating activities			
Net income	$ 126,689	$ 109,652	$ 114,178
Adjustments to reconcile net income to net cash provided by operating activities			
Depreciation of property, plant and equipment	133,892	125,560	120,633
Other amortization	8,269	15,965	29,766
Provision (reversal of allowance) for loan losses	(3,100)	(8,400)	3,075
Gain on sale of income notes		(5,607)	
Deferred income taxes	43	12,349	2,838
Allowance for equity funds used during construction	(5,105)	(5,794)	(4,267)
Changes in assets and liabilities, net of effects from the disposal of businesses			
Increase in accounts receivable and unbilled revenues, net	(40,940)	(20,823)	(11,389)
Increase in fuel oil stock	(26,880)	(14,958)	(7,963)
Increase in federal tax deposit	(30,000)		
Increase in prepaid pension benefit cost	(2,661)	(24,539)	(24,681)
Increase in accounts payable	36,282	17,913	1,750
Increase in taxes accrued	37,631	46,675	22,045
Changes in other assets and liabilities	(15,682)	(3,841)	(4,653)
Net cash provided by operating activities	218,438	244,152	241,332
Cash flows from investing activities			
Available-for-sale investment and mortgage-related securities purchased	(486,432)	(1,105,133)	(2,155,980)
Principal repayments on available-for-sale investment and mortgage-related securities	727,901	803,517	1,860,383
Proceeds from sale of available-for-sale mortgage-related securities	28,039	45,207	243,406
Net increase in loans held for investment	(304,212)	(113,991)	(130,205)
Net proceeds from sale of investments	33,809	9,981	
Proceeds from sale of real estate acquired in settlement of loans	624	1,617	7,728
Capital expenditures	(223,675)	(214,654)	(162,891)
Contributions in aid of construction	21,083	8,522	12,963
Distributions from unconsolidated subsidiaries		24,379	
Other	909	180	(624)
Net cash used in investing activities	(201,954)	(540,375)	(325,220)
Cash flows from financing activities			
Net increase in deposit liabilities	261,247	269,922	225,478
Net increase in short-term borrowings with original maturities of three months or less	65,147	76,611	
Net increase in retail repurchase agreements	18,519	25,050	13,085
Proceeds from securities sold under agreements to repurchase	873,256	753,608	1,965,575
Repayments of securities sold under agreements to repurchase	(1,017,645)	(799,250)	(1,809,945)
Proceeds from advances from Federal Home Loan Bank	195,000	129,200	373,500
Principal payments on advances from Federal Home Loan Bank	(247,731)	(158,022)	(532,699)
Proceeds from issuance of long-term debt	59,462	103,097	167,935
Repayment of long-term debt	(84,000)	(224,166)	(210,000)
Preferred securities distributions of trust subsidiaries			(16,035)

Net proceeds from issuance of common stock	3,689	110,017	29,824
Common stock dividends	(100,238)	(93,864)	(75,119)
Other	(5,015)	(4,768)	(8,887)
Net cash provided by financing activities	21,691	187,435	122,712
Cash flows from discontinued operations (revised see Note 11)			
Cash flows used in operating activities	(2,857)	(3,571)	(3,361)
Cash flows provided by investing activities		6,000	
Net cash provided by (used in) discontinued operations	(2,857)	2,429	(3,361)
Net increase (decrease) in cash and equivalents and federal funds sold	35,318	(106,359)	35,463
Cash and equivalents and federal funds sold, January 1	173,629	279,988	244,525
Cash and equivalents and federal funds sold, December 31	$ 208,947	$ 173,629	$ 279,988

See accompanying Notes to Consolidated Financial Statements.

Notes to Consolidated Financial Statements

1 Summary of significant accounting policies

General

HEI is a holding company with direct and indirect subsidiaries engaged in electric utility, banking and other businesses, primarily in the State of Hawaii. HEI s common stock is traded on the New York Stock Exchange.

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

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

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

Consolidation of VIEs. In December 2003, the FASB issued Interpretation No. (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.

As of December 31, 2005, Hawaiian Electric Company, Inc. (HECO) and its subsidiaries had six purchase power agreements (PPAs) for a total of 540 MW of firm capacity, and other PPAs with smaller independent power producers (IPPs) and Schedule Q providers that supplied as-available energy. Approximately 91% of the 540 MW of firm capacity is under PPAs, entered into before December 31, 2003, with AES Hawaii, Inc. (AES Hawaii), Kalaeloa Partners, L.P. (Kalaeloa), Hamakua Energy Partners, L.P. (HEP) and HPower. Purchases from all IPPs for 2005 totaled $458 million, with purchases from AES Hawaii, Kalaeloa, HEP and HPower totaling $137 million, $169 million, $63 million and $33 million, respectively. The primary business activities of these IPPs are the generation and sale of power to HECO and its subsidiaries (and municipal waste disposal in the case of HPower). Current financial information about the size, including total assets and revenues, for many of these IPPs is not publicly available. Under FIN 46R, an enterprise with an interest in a VIE or potential VIE created before December 31, 2003 (and not thereafter materially modified) is not required to apply FIN 46R to that entity if the enterprise is unable to obtain, after making an exhaustive effort, the necessary information.

HECO and its subsidiaries have reviewed their 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 (HPower) as defined under FIN 46R, and thus excluded from the scope of FIN 46R. Other IPPs, including the three largest, declined to provide the information necessary for HECO and its subsidiaries to determine the applicability of FIN 46R, and HECO and its subsidiaries were unable to apply FIN 46R to these IPPs. In January 2005, HECO and its subsidiaries again sent letters to the IPPs that were not excluded from the scope of FIN 46R, requesting the information required to determine the applicability of FIN 46R to the respective IPP. All of these IPPs again declined to provide the necessary information. Kalaeloa has since provided its information (see below).

Table of Contents

As required under FIN 46R, HECO and its subsidiaries have continued their efforts to obtain from the IPPs the information necessary to make the determinations required under FIN 46R. If the requested information is ultimately received, a possible outcome of future analysis 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.

In October 2004, Kalaeloa and HECO executed two amendments to their PPA, under which Kalaeloa would make available additional firm capacity to HECO. The amendments became effective when the costs of the additional capacity and purchased power were included in HECO s rates as a result of an Interim D&O issued in HECO s current rate case. The additional firm capacity to be provided by Kalaeloa is 28 MW. Kalaeloa provided HECO the information HECO needed to complete its determination of whether Kalaeloa is a variable interest entity, and, whether HECO is the primary beneficiary. While it has been determined that Kalaeloa is a variable interest entity, HECO has concluded that it is not the primary beneficiary of that entity and accordingly Kalaeloa need not be consolidated in HECO s consolidated financial statements. See Note 5 for additional information regarding the application of FIN 46R to Kalaeloa.

In October 2004, Hawaii Electric Light Company, Inc. (HELCO) and Apollo Energy Corporation (Apollo) executed a restated and amended PPA which enables Apollo to repower its 7 MW facility, and install additional capacity, for a total windfarm allowed capacity of 20 MW. Due to problems with its wind turbine supplier, however, Apollo is claiming an event of force majeure under the PPA and the project may be delayed. In December 2004, MECO executed a new PPA with Kaheawa Wind Power, LLC (KWP), which is installing a 30 MW windfarm on Maui. The revised PPA with Apollo and new PPA with KWP were approved by the Public Utilities Commission of the State of Hawaii (PUC) in March 2005, and became effective in April 2005. The PPAs require Apollo and KWP to provide information necessary to (1) determine if HELCO and Maui Electric Company, Limited (MECO) must consolidate Apollo and KWP, respectively, under FIN 46R, (2) consolidate Apollo and/or KWP, if necessary under FIN 46R, and (3) comply with Section 404 of Sarbanes-Oxley Act of 2002 (SOX). Management is in the process of obtaining the information necessary to complete its determination of whether Apollo or KWP are VIEs and, if so, whether HELCO or MECO, respectively, is the primary beneficiary. Based on information currently available, management believes the impact on consolidated HECO s financial statements of the consolidation of Apollo and/or KWP, if necessary, would not be material. However, depending on the magnitude of the improvements contemplated in the PPAs, the impact of a required consolidation of Apollo and KWP could be material in the future. If required to consolidate the financial statements of Apollo and/or KWP in the future and such consolidation had a material effect, HECO would retrospectively apply FIN 46R in accordance with SFAS No. 154, Accounting Changes and Error Corrections.

See Note 5 for additional information regarding the application of FIN 46R.

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 temporary losses excluded from earnings and reported on a net basis in accumulated other comprehensive income (AOCI).

For securities that are not trading securities, declines in value determined to be other-than-temporary are included in earnings and result in a new cost basis for the investment. 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 forecasted 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.

Equity method. Investments in up to 50%-owned affiliates over which the Company has the ability to exercise significant influence over the operating and financing policies and investments in unconsolidated subsidiaries (e.g. HECO Capital Trust III) are accounted for under the equity method, whereby the investment is carried at cost, plus (or minus) the Company s equity in undistributed earnings (or losses) 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. Costs for betterments that make property, plant or equipment more useful, more efficient, of greater durability or of greater capacity are also capitalized. Upon the retirement or sale of electric utility plant, generally no gain or loss is recognized. The cost of the plant retired is charged to accumulated depreciation. Amounts collected from customers for cost of removal (expected to exceed salvage value in the future) are included in regulatory liabilities.

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

Depreciation. Depreciation is computed primarily using the straight-line method over the estimated lives of the assets being depreciated. Electric utility plant additions in the current year are depreciated beginning January 1 of the following year. Electric utility plant has lives ranging from 20 to 45 years for production plant, from 25 to 60 years for transmission and distribution plant and from 7 to 45 years for general plant. The electric utilities composite annual depreciation rate, which includes a component for cost of removal, was 3.9% in 2005, 2004 and 2003.

Retirement benefits. Pension and other postretirement benefit costs/(returns) are charged/(credited) primarily to expense and electric utility plant. The PUC requires the electric utilities to fund their pension and postretirement benefit costs. The Company s policy is to fund qualified pension plan 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.

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.

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 compensation are added to the denominator.

As of December 31, 2005, stock appreciation rights (SARs) on 879,000 shares of common stock were not included in the computation of diluted EPS because the SARs exercise prices were greater than the closing market price of HEI s common stock as of December 31, 2005 and, thus, the SARs were antidilutive. As of December 31, 2004 and 2003, all options and rights to purchase common stock and restricted stock were included in the computation of diluted EPS.

Stock compensation. For 2005, 2004 and 2003, the Company applied the fair value based method of accounting prescribed by SFAS No. 123, Accounting for Stock-Based Compensation, to account for its stock compensation. Since January 1, 2006, the Company applied the fair value based method of accounting prescribed by SFAS No. 123 (Revised 2004) to account for its stock compensation (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

Other-than-temporary impairment and its application to certain investments. In March 2004, 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 would have applied prospectively to all current and future investments within the scope of EITF Issue No. 03-1 in reporting periods beginning after June 15, 2004. However, in September 2004, the FASB issued FASB Staff Position (FSP) EITF 03-

Table of Contents

1-1 to delay the effective date of the recognition and measurement guidance. At its June 29, 2005 meeting, the FASB decided not to provide additional guidance on the meaning of other-than-temporary impairment, but directed its staff to issue proposed FSP EITF 03-1-a as final (retitled as FSP FAS 115-1 and FAS 124-1). The guidance in FSP FAS 115-1 and FAS 124-1 addresses the determination of when an investment is considered impaired, whether that impairment is other than temporary, and the measurement of an impairment loss. The FSP also includes accounting considerations subsequent to the recognition of an other-than-temporary impairment and requires certain disclosures about unrealized losses that have not been recognized as other-than-temporary impairments. The guidance in this FSP amends FASB Statement No. 115, Accounting for Certain Investments in Debt and Equity Securities, and FASB Statement No. 124, Accounting for Certain Investments Held by Not-for-Profit Organizations, and adds a footnote to APB Opinion No. 18, The Equity Method of Accounting for Investments in Common Stock. The guidance in this FSP nullifies certain requirements of EITF Issue No. 03-1 and supersedes EITF Abstracts, Topic D-44, Recognition of Other-Than-Temporary Impairment upon the Planned Sale of a Security Whose Cost Exceeds Fair Value. The guidance in this FSP is required to be applied to reporting periods beginning after December 15, 2005. Because the impact of adopting the provisions of FSP FAS 115-1 will be dependent on future events and circumstances, management cannot predict such impact.

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, which was effective for the first interim or annual period beginning after June 15, 2004. 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 accumulated postretirement benefit obligation for the Company s plans as of December 31, 2005 has been reduced by an estimated $3 million for the subsidy related to benefits attributed to past service. The net periodic postretirement benefit cost for 2006 has been reduced by an estimated $0.5 million for the subsidy.

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. In March 2005, the SEC issued Staff Accounting Bulletin (SAB) No. 107, which provides accounting, disclosure, valuation and other guidance related to share-based payment arrangements. The Company adopted the provisions of SFAS No. 123 (revised 2004) and the guidance in SAB No. 107 on January 1, 2006 and the net income impact of adoption was immaterial. Since the Company adopted the recognition provisions of SFAS No. 123 as of January 1, 2002, the only expense recognition change the Company made upon adoption of SFAS No. 123 (revised 2004) was how it accounts for forfeitures. Historically, forfeitures have not been significant.

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.

Table of Contents

Management is currently reviewing various aspects of the American Jobs Creation Act of 2004 (the 2004 Act), including proposed regulations relating to the 2004 Act recently issued by the Internal Revenue Service. There are at least two provisions with potential implications for HECO and its subsidiaries:

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.

These provisions had no impact on HECO s consolidated net income for 2005 and based on current estimates, management expects that the provisions will not have a significant impact on HECO s consolidated net income in the future, pending further guidance from the Internal Revenue Service.

Asset retirement obligations. In March 2005, the FASB issued FIN 47, Accounting for Conditional Asset Retirement Obligations, which requires recognition of a liability for the fair value of a legal obligation to perform asset-retirement activities that are conditional on a future event if the amount can be reasonably estimated. The Company adopted the provisions of FIN 47 on December 31, 2005 and recorded an asset retirement obligation of $0.3 million for estimated remediation activities for certain transformers that contain polychlorinated biphenyl contaminated oil. The pro forma amounts of the asset retirement obligation, measured using information, assumptions, and interest rates as of December 31, 2005, would have been $0.3 million as of December 31, 2004 and 2003.

The electric utilities own assets for which the fair value of the asset retirement obligation cannot be reasonably determined because the asset-retirement activities associated with the legal obligation are contingent on future events which, at this time, cannot be reasonably determined. These assets include certain parts of a power plant and a fuel-oil pipeline which may be required to be dismantled upon retirement of another power plant. The electric utilities currently intend to operate these assets for the foreseeable future and because of the indeterminate retirement dates, are unable to reasonably estimate the fair value of any legal obligations. The asset retirement obligation for these assets will be recorded once the future events can be reasonably determined.

Accounting changes and error corrections. In June 2005, the FASB issued SFAS No. 154, Accounting Changes and Error Corrections. This new standard replaces APB Opinion No. 20, Accounting Changes, and SFAS No. 3, Reporting Accounting Changes in Interim Financial Statements. Among other changes, SFAS No. 154 requires that a voluntary change in accounting principle be applied retrospectively so that all prior period financial statements presented are based on the new accounting principle, unless it is impracticable to do so. SFAS No. 154 also provides that (1) a change in method of depreciating or amortizing a long-lived nonfinancial asset be accounted for as a change in estimate (prospectively) that was effected by a change in accounting principle, and (2) correction of errors in previously issued financial statements should be termed a restatement. SFAS No. 154 is effective for accounting changes and error corrections made in fiscal years beginning after December 15, 2005. Because the impact of adopting the provisions of SFAS No. 154 will be dependent on future events and circumstances, management cannot predict such impact.

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 2005 presentation. For example, assets and liabilities as of December 31, 2004 have been restated for the reclassification of regulatory assets from Regulatory liabilities, net to Regulatory assets.

Table of Contents

Electric utility

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

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

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

Electric utility revenues. Electric utility revenues are based on rates authorized by the PUC and include revenues applicable to energy consumed in the accounting period but not yet billed to the customers. Revenues related to the sale of energy are generally recorded when service is rendered or energy is delivered to customers. However, the determination of the energy sales to individual customers for billing purposes is based on the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each month, amounts of energy delivered to customers since the date of the last meter reading are estimated and the corresponding unbilled revenue is estimated. This unbilled revenue is estimated each month based on the meter readings in the beginning of the following month, monthly generation volumes, estimated customer usage by account, line losses and applicable customer rates based on historical values and current rate schedules. As of December 31, 2005, customer accounts receivable include unbilled energy revenues of $91 million on a base of annual revenue of $1.8 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 2004 PUC decisions approving the electric utilities fuel supply contracts, the PUC affirmed the electric utilities right to include in their respective energy cost adjustment clauses the stated costs incurred pursuant to their respective new fuel supply contracts, to the extent that these costs are not included in their respective base rates, and restated its intention to examine the need for continued use of energy cost adjustment clauses in 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. Payments to the taxing authorities by HECO and its subsidiaries are based on the prior years revenues. For 2005, 2004 and 2003, HECO and its subsidiaries included approximately $159 million, $136 million and $123 million, respectively, of revenue taxes in operating revenues and in taxes, other than income taxes expense.

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

Table of Contents

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 8.5%, 8.6% and 8.7% in 2005, 2004 and 2003, respectively, and reflected quarterly compounding.

Bank

Loans receivable. American Savings Bank, F.S.B. and subsidiaries (ASB) state loans receivable at amortized cost less the allowance for loan losses, loan origination fees (net of direct loan origination costs), commitment fees and purchase premiums and discounts. Interest on loans is credited to income as it is earned. 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 included in ASB s noninterest income.

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

For commercial and commercial real estate loans, a risk rating system is used. Loans are rated based on the degree of risk at origination and periodically thereafter, as appropriate. ASB s credit review department performs an evaluation of these loan portfolios to ensure compliance with the internal risk rating system and timeliness of rating changes. A loan is deemed impaired when it is probable that ASB will be unable to collect all amounts due according to the contractual terms of the loan agreement. The measurement of impairment may be based on (i) the present value of the expected future cash flows of the impaired loan discounted at the loan s original effective interest rate, (ii) the observable market price of the impaired loan, or (iii) the fair value of the collateral. For all loans secured by real estate, ASB measures impairment by utilizing the fair value of the collateral; for other loans, discounted cash flows are used to measure impairment. Losses from impairment are charged to the provision for loan losses and included in the allowance for loan losses.

Table of Contents

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

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

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

Real estate acquired in settlement of loans. ASB records real estate acquired in settlement of loans at the lower of cost or fair value less estimated selling expenses. ASB obtains appraisals based on recent comparable sales to assist management in estimating the fair value of real estate acquired in settlement of loans. Subsequent declines in value are charged to expense through a valuation allowance. Costs related to holding real estate are charged to operations as incurred.

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, is 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 is estimated by an unrelated third party using a valuation method based on a market approach, which takes into consideration market values of comparable companies, which are publicly traded, and recent transactions of companies in the industry.

Amortized intangible assets.

	2005		2004	
December 31 **(in thousands)**	**Gross carrying amount**	**Accumulated amortization**	**Gross carrying amount**	**Accumulated amortization**
Core deposit intangibles	$ 20,276	$ 16,932	$ 20,276	$ 15,201
Mortgage servicing rights	11,662	8,650	11,740	7,998
	$ 31,938	$ 25,582	$ 32,016	$ 23,199

Changes in the valuation allowance for MSRs were as follows:

(in thousands)	2005	2004	2003
Valuation allowance, January 1	$ 701	$ 2,316	$ 2,215
Provision (reversal of allowance)	(359)	4	101
Other than temporary impairment	(135)	(1,619)	
Valuation allowance, December 31	$ 207	$ 701	$ 2,316

In 2005, 2004 and 2003, aggregate amortization expenses were $2.4 million, $3.2 million and $4.0 million, respectively.

The estimated aggregate amortization expense for ASB s core deposit intangibles and MSRs for 2006, 2007, 2008, 2009 and 2010 is $2.2 million, $2.0 million, $0.4 million, $0.3 million and $0.3 million, respectively.

Table of Contents

Core deposit intangibles are amortized each year based on the greater of the actual attrition rate of such deposit base or the applicable rate on the 10-year amortization table. 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 2005, 2004 and 2003, MSRs acquired through the sale or securitization of loans held for sale totaled $0.1 million, $0.4 million, and $1.2 million, respectively. Amortization expense for ASB s MSRs amounted to $0.7 million, $1.5 million, and $2.3 million for 2005, 2004 and 2003, respectively, and are recorded 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, HELCO and MECO, are electric public utilities in the business of generating, purchasing, transmitting, distributing and selling electric energy on all major islands in Hawaii other than Kauai, and are regulated by the PUC. HECO also owns non-regulated subsidiaries: Renewable Hawaii, Inc. (RHI), which will invest in renewable energy projects, 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. 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.

Table of Contents

(in thousands)	Electric Utility	Bank	Other	Total
2005				
Revenues from external customers	$ 1,806,198	$ 387,910	$ 21,456	$ 2,215,564
Intersegment revenues (eliminations)	186		(186)	
Revenues	1,806,384	387,910	21,270	2,215,564
Depreciation and amortization	131,350	10,065	746	142,161
Interest expense	49,408	121,426	25,901	196,735
Profit (loss)*	117,425	104,852	(20,933)	201,344
Income taxes (benefit)	44,623	39,969	(10,692)	73,900
Income (loss) from continuing operations	72,802	64,883	(10,241)	127,444
Capital expenditures	217,609	5,731	335	223,675
Assets (at December 31, 2005**)	3,081,460	6,835,335	34,782	9,951,577
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**)	2,879,615	6,766,505	73,137	9,719,257
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**)	2,687,798	6,515,208	104,694	9,307,700

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

** Includes net assets of discontinued operations.

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

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

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

Table of Contents

3 Electric utility subsidiary

Selected financial information

Hawaiian Electric Company, Inc. and Subsidiaries

Consolidated Statements of Income Data

Years ended December 31	2005	2004	2003
(in thousands)			
Revenues			
Operating revenues	$ 1,801,710	$ 1,546,875	$ 1,393,038
Other nonregulated	4,674	3,796	3,647
	1,806,384	1,550,671	1,396,685
Expenses			
Fuel oil	639,650	483,423	388,560
Purchased power	458,120	398,836	368,076
Other operation	172,962	157,198	155,531
Maintenance	82,242	77,313	64,621
Depreciation	122,870	114,920	110,560
Taxes, other than income taxes	167,295	143,834	130,677
Other nonregulated	1,542	1,244	2,095
	1,644,681	1,376,768	1,220,120
Operating income from regulated and nonregulated activities	161,703	173,903	176,565
Allowance for equity funds used during construction	5,105	5,794	4,267
Interest and other charges	(50,323)	(50,503)	(52,931)
Allowance for borrowed funds used during construction	2,020	2,542	1,914
Income before income taxes and preferred stock dividends of HECO	118,505	131,736	129,815
Income taxes	44,623	49,479	49,824
Income before preferred stock dividends of HECO	73,882	82,257	79,991
Preferred stock dividends of HECO	1,080	1,080	1,080
Net income for common stock	$ 72,802	$ 81,177	$ 78,911

Consolidated Balance Sheet Data

December 31	2005	2004
(in thousands)		
Assets		
Utility plant, at cost		
Property, plant and equipment	$ 3,782,565	$ 3,606,908
Less accumulated depreciation	(1,456,537)	(1,361,703)
Construction in progress	147,756	102,949
Net utility plant	2,473,784	2,348,154
Regulatory assets	110,718	108,630
Other	496,958	422,831
	$ 3,081,460	$ 2,879,615
Capitalization and liabilities		
Common stock equity	$ 1,039,259	$ 1,017,104
Cumulative preferred stock not subject to mandatory redemption, authorized 5,000,000 shares, $20 par value (1,114,657 shares outstanding), and 7,000,000 shares, $100 par value (120,000 shares outstanding); dividend rates of 4.25-7.625%	34,293	34,293
Long-term debt, net	765,993	752,735
Total capitalization	1,839,545	1,804,132
Short-term borrowings from nonaffiliates and affiliate	136,165	88,568
Deferred income taxes	208,374	189,193
Regulatory liabilities	219,204	197,089
Contributions in aid of construction	256,263	235,505
Other	421,909	365,128
	$ 3,081,460	$ 2,879,615

Table of Contents

Regulatory assets and liabilities. In accordance with SFAS No. 71, HECO and its subsidiaries financial statements reflect assets, liabilities, revenues and expenses based on current cost-based rate-making regulations. Their continued accounting under SFAS No. 71 generally requires that rates are established by an independent, third-party regulator; rates are designed to recover the costs of providing service; and it is reasonable to assume that rates can be charged to and collected from customers. Management believes HECO and its subsidiaries operations currently satisfy the SFAS No. 71 criteria. If events or circumstances should change so that those criteria are no longer satisfied, the electric utilities expect that the regulatory assets would be charged to income and the regulatory liabilities would be credited to income or refunded to ratepayers. In the event of unforeseen regulatory actions or other circumstances, however, management believes that a material adverse effect on the Company s results of operations and financial position may result if regulatory assets have to be charged to expense without an offsetting credit for regulatory liabilities or if regulatory liabilities are required to be refunded to ratepayers.

Regulatory liabilities represent amounts included in rates and collected from ratepayers for costs expected to be incurred in the future. For example, the regulatory liability for cost of removal in excess of salvage value represents amounts that have been collected from ratepayers for costs that are expected to be incurred in the future to retire utility plant. 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, 2005, if different. Regulatory liabilities were as follows:

December 31	2005	2004
(in thousands)		
Cost of removal in excess of salvage value (1 to 60 years)	$ 217,493	$ 197,089
Other (5 years; 2 to 5 years)	1,711	
	$ 219,204	$ 197,089

Regulatory assets were as follows:

December 31	2005	2004
(in thousands)		
Income taxes, net (1 to 36 years)	$ 70,743	$ 68,780
Postretirement benefits other than pensions (18 years; 7 years)	12,528	14,318
Unamortized expense and premiums on retired debt and equity issuances (11 to 30 years; 1 to 23 years)	16,081	15,509
Integrated resource planning costs, net (1 year)	2,395	1,554
Vacation earned, but not yet taken (1 year)	5,669	5,011
Other (1 to 20 years)	3,302	3,458
	$ 110,718	$ 108,630

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% ($176 million), 10% ($148 million) and 10% ($135 million) of their operating revenues from the sale of electricity to various federal government agencies in 2005, 2004 and 2003, 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 as of January 1, 2006, the estimated cost of minimum purchases under the fuel supply contracts is $542 million each year for 2006 and 2007, $543 million for 2008, $542 million each year for 2009 and 2010 and a total of $2.2 billion for the period 2011 through 2014. The actual cost of purchases in 2006 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 $662 million, $490 million and $390 million of fuel under contractual agreements in 2005, 2004 and 2003, respectively.

Table of Contents

Power purchase agreements (PPAs). As of December 31, 2005, HECO and its subsidiaries had six firm capacity PPAs for a total of 540 MW of firm capacity. Of the 540 MW of firm capacity under PPAs, approximately 91% is under PPAs with AES Hawaii, Inc. (PPA executed in March 1988), Kalaeloa Partners, L.P. (October 1988), Hamakua Energy Partners, L.P. (October 1997) and HPower (March 1986). The primary business activities of these six IPPs are the generation and sale of power to the electric utilities (and municipal waste disposal in the case of HPower). Purchases from these six IPPs and all other IPPs totaled $458 million, $399 million and $368 million for 2005, 2004 and 2003, 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 in 2006, $121 million in 2007, $119 million in 2008, $116 million in 2009, $119 million in 2010 and a total of $1.3 billion in the period from 2011 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, or participate in the operation of, any of the facilities that provide power under the agreements. Title to the facilities does not pass to HECO or its subsidiaries upon expiration of the agreements, and the agreements do not contain bargain purchase options for the facilities.

Interim increases. As of December 31, 2005, HECO and its subsidiaries had recognized $32 million of revenues with respect to interim orders regarding certain integrated resource planning costs and an Oahu general rate increase, 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. It planned to install at its Keahole power plant two 20 megawatt (MW) combustion turbines (CT-4 and CT-5), followed by an 18 MW heat recovery steam generator (ST-7), at which time these units would be converted to a 56 MW (net) dual train combined-cycle unit. In January 1994, the PUC approved expenditures for CT-4. In 1995, the PUC allowed HELCO to pursue construction of and commit expenditures for CT-5 and ST-7, but noted that such costs are not to be included in rate base until the project is installed and is used and useful for utility purposes.

Status. Installation of CT-4 and CT-5 was significantly delayed as a result of land use and environmental permitting delays and related administrative proceedings and lawsuits. However, in 2003, the parties opposing the plant expansion project (other than Waimana Enterprises, Inc. (Waimana), which did not participate in the settlement discussions and opposes the settlement) entered into a settlement agreement with HELCO and several Hawaii regulatory agencies, intended in part to permit HELCO to complete CT-4 and CT-5 (Settlement Agreement). Subsequently, CT-4 and CT-5 were installed and put into limited commercial operation in May and June 2004, respectively. The BLNR s construction deadline of July 31, 2005 has been met. Noise mitigation equipment has been installed on CT-4 and CT-5 and the need for additional noise mitigation work for CT-5 (not requiring any further construction) is being examined to ensure compliance with the night-time noise standard applicable to the plant. Currently, HELCO can operate the generating units at Keahole as required to meet its system needs.

Currently, four appeals to the Hawaii Supreme Court by Waimana have been briefed and are awaiting decision. These are appeals to judgments of the Third Circuit Court involving (i) vacating of a November 2002 Final Judgment which had halted construction; (ii) the Board of Land and Natural Resources (BLNR) 2003 construction period extension; (iii) the BLNR s approval of a revocable permit allowing HELCO to use brackish well water as the primary source of water for operating the Keahole plant; and (iv) appeals (now consolidated) by Waimana and another party of judgments upholding the BLNR s approval of the long-term lease allowing HELCO to use brackish well water. In the third appeal, additional briefs were filed on July 15, 2005 on the question of whether the appeal is moot given the granting by the BLNR of a long-term water lease allowing HELCO to use brackish water. Full implementation of the

Settlement Agreement is conditioned on obtaining final dispositions of all litigation pending at the time of the Settlement Agreement. If the remaining dispositions are obtained, as HELCO believes they will be, then HELCO must undertake a number of actions under the Settlement Agreement, including expediting efforts to obtain the permits and approvals necessary for installation of ST-7 with selective catalytic reduction emissions control equipment, assisting the Department of Hawaiian Home Lands in installing solar water heating in its housing projects, supporting the Keahole Defense Coalition s participation in certain PUC cases, and cooperating with neighbors and community groups (including a Hot Line service). Some of these actions have already commenced.

In November 2003, HELCO filed a boundary amendment petition (to reclassify the Keahole plant site from conservation land use to urban land use) with the State Land Use Commission, which was approved in October 2005. HELCO s plans for ST-7 are progressing, but construction cannot start until HELCO obtains County rezoning to a General Industrial classification and obtains the necessary permits. The application for rezoning was filed with the County in November 2005. In January 2006, the County Planning Commission recommended approval of the rezoning to the County Council. Further action by the County Council is pending.

Costs incurred; management s evaluation. As of December 31, 2005, HELCO s capitalized costs incurred in its efforts to put CT-4 and CT-5 into service and to support existing units (excluding costs for pre-air permit facilities) amounted to approximately $110 million, including $43 million for equipment and material purchases, $47 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 accruing AFUDC. The $110 million of costs was reclassified from construction in progress to plant and equipment in 2004 and 2005 and depreciated beginning January 1 of the year following the reclassification.

Management believes that the prospects are good that the remaining Settlement Agreement conditions will be satisfied and that any further necessary permits will be obtained and that the appeals will be favorably resolved. However, HELCO s electric rates will not change specifically as a result of including CT-4 and CT-5 in plant and equipment until HELCO files a rate increase application and the PUC grants HELCO rate relief. In December 2005, HELCO notified the PUC that it intends to file a request for an electric rate increase in spring 2006 in part to recover CT-4 and CT-5 costs. While management believes that no adjustment to costs incurred to put CT-4 and CT-5 into service is required as of December 31, 2005, 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 these costs.

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

HECO continues to believe that the proposed reliability project (the East Oahu Transmission Project) is needed. In December 2003, HECO filed an application with the PUC requesting approval to commit funds (currently estimated at $57 million; see costs incurred below) for a revised EOTP using a 46 kV system. In March 2004, the PUC granted intervenor status to an environmental organization and three elected officials (collectively treated as one party), and a more limited participant status to four community organizations. The environmental review process has been completed and the PUC issued a Finding of No Significant Impact in April 2005. Subject to PUC approval, HECO plans to construct the revised project, none of which is in conservation district lands, in two phases, currently projected for completion in 2007 and 2009.

As of December 31, 2005, the accumulated costs recorded for the EOTP amounted to $26 million, including $12 million of planning and permitting costs incurred prior to 2003, when HECO was denied the approval necessary for the partial underground/partial overhead 138 kV line, $3 million of planning and permitting costs incurred after 2002, and $11 million for AFUDC. In the written testimony filed in June 2005, the Consumer Advocate s consultant contended that HECO should always have planned for a project using only the 46 kV system and recommended that HECO be required to expense the $12 million incurred before 2003, and the related AFUDC of $5 million. In rebuttal testimony filed in August 2005, HECO contested the consultant s recommendation, emphasizing that the originally proposed 138 kV line would have been a more comprehensive and robust solution to the transmission concerns the project addressed. The PUC held an evidentiary hearing on HECO s application in November 2005. Just prior to the evidentiary hearing, the PUC approved that part of a stipulation between HECO and the Consumer Advocate that this proceeding should determine whether HECO should be given approval to expend funds for the EOTP provided that no part of the EOTP costs may be recovered from ratepayers unless and until the PUC grants HECO recovery in a rate case (which is consistent with other projects), and that the issue as to whether the pre-2003 planning and permitting costs, and related AFUDC, should be included in the project costs is reserved to, and may be raised in, the next HECO rate case (or other proceeding). Management believes no adjustment to project costs is required as of December 31, 2005. 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.

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 First Circuit Court of Hawaii alleging that the State of Hawaii and HECO s other customers had been overcharged for electricity by over $1 billion since September 1992 due to alleged excessive prices in the PUC-approved amended PPA between HECO and AES Hawaii. The PUC proceedings in which the amended PPA was approved addressed a number of issues, including whether the terms and conditions of the PPA were reasonable.

As a result of rulings by the First Circuit Court in 2003, all claims for relief and causes of action in the amended complaint were dismissed. In October 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. On July 16, 2004, the Supreme Court retained jurisdiction of the appeal (rather than assign the appeal to the Intermediate Court of Appeals) and a decision is pending. In the opinion of management, the ultimate disposition of this matter will not have a material adverse effect on the Company s or HECO s consolidated financial position, results of operations or liquidity.

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

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

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

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

Since 2001, subsurface investigation and assessment have been conducted and several preliminary oil removal tasks have been performed at the Iwilei Unit in accordance with notices of interest issued by the EPA and DOH. Currently, the Participating Parties are preparing Remediation Alternatives Analyses, which will identify and recommend remedial approaches. HECO routinely maintains its facilities and has investigated its operations in the Iwilei area and ascertained that they are not releasing petroleum.

In 2001, management developed a preliminary estimate of HECO s share of costs for continuing investigative work, remedial activities and monitoring at the Iwilei Unit of approximately $1.1 million (which was expensed in 2001 and of which $0.6 million has been incurred through February 28, 2005). 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 among the PRPs 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.

Regional Haze Rule amendments. In June 2005, the EPA finalized amendments to the July 1999 Regional Haze Rule that require emission controls known as best available retrofit technology (BART) for industrial facilities emitting air pollutants that reduce visibility in National Parks by causing or contributing to regional haze. States must develop BART implementation plans and schedules in accordance with the amended regional haze rule by December 2007. After Hawaii adopts its plan, HECO, MECO and HELCO will evaluate the impacts, if any, on them. If any of the utilities units are ultimately required to install post-combustion control technologies to meet BART emission limits, the capital and operations and maintenance costs could be significant.

Clean Water Act. Section 316(b) of the federal Clean Water Act requires that the EPA ensure that existing power plant cooling water intake structures reflect the best technology available for minimizing adverse environmental impacts. Effective September 9, 2004, the EPA issued a new rule, which establishes location and technology-based design, construction and capacity standards for existing cooling water intake structures. These standards will apply to HECO s Kahe, Waiau and Honolulu generating stations unless the utility can demonstrate that at each facility implementation of these standards will result in very high costs or little environmental benefit. HECO has until March 2008 to make this showing or demonstrate compliance. HECO has retained a consultant to develop a cost effective compliance strategy and a preliminary assessment of technologies and operational measures. HECO is developing a monitoring program and plans to perform a cost-benefit analysis to demonstrate that HECO s existing intake systems have minimal environmental impacts, which demonstration would exempt HECO from the standards. Concurrently, HECO will evaluate alternative compliance mechanisms allowed by the rule, some of which could entail significant capital expenditures to implement.

Collective bargaining agreements. Approximately 58% of the electric utilities employees are members of the International Brotherhood of Electrical Workers, AFL-CIO, Local 1260, Unit 8, which is the only union representing employees of the Company. The current 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, May 1, 2005, November 1, 2005 and May 1, 2006; and 3% on November 1, 2006).

Limited insurance. HECO and its subsidiaries purchase insurance coverages to protect themselves against loss of or damage to their properties and against claims made by third-parties and employees. However, the protection provided by such insurance is limited in significant respects and, in some instances, there is no coverage. HECO, HELCO and MECO s overhead and underground transmission and distribution systems (with the exception of substation buildings and contents) have a replacement value roughly estimated at $3 billion and are uninsured. Similarly, HECO, HELCO and MECO have no business interruption insurance. If a hurricane or other uninsured catastrophic natural disaster should occur, and if the PUC were not to allow the utilities to recover from ratepayers restoration costs and revenues lost from business interruption, their results of operations and financial condition could be materially adversely impacted. Also, certain insurance has substantial deductibles , limits on the maximum amounts that may be recovered and exclusions or limitations of coverage for claims related to certain perils. If a series of losses occurred, such as from a series of lawsuits in the ordinary course of business, each of which were subject to the deductible amount, or if the maximum limit of the available insurance were substantially exceeded, HECO, HELCO and MECO could incur losses in amounts that would have a material adverse effect on its results of operations and financial condition.

Table of Contents

4 Bank subsidiary

Selected financial information

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

Consolidated Statements of Income Data

Years ended December 31	2005	2004	2003
(in thousands)			
Interest and dividend income			
Interest and fees on loans	$ 205,084	$ 184,773	$ 198,948
Interest on mortgage-related securities	121,847	116,471	107,496
Interest and dividends on investment securities	4,077	5,876	6,384
	331,008	307,120	312,828
Interest expense			
Interest on deposit liabilities	52,064	47,184	53,808
Interest on Federal Home Loan Bank advances	44,699	43,301	48,280
Interest on securities sold under agreements to repurchase	24,663	22,302	21,236
	121,426	112,787	123,324
Net interest income	**209,582**	**194,333**	**189,504**
Provision (reversal of allowance) for loan losses	(3,100)	(8,400)	3,075
Net interest income after provision (reversal of allowance) for loan losses	**212,682**	**202,733**	**186,429**
Noninterest income			
Fees from other financial services	25,790	23,560	22,817
Fee income on deposit liabilities	16,989	17,820	16,971
Fee income on other financial products	9,058	10,184	9,920
Gain (loss) on sale of securities	175	(70)	4,085
Other income	4,890	5,670	4,699
	56,902	57,164	58,492
Noninterest expense			
Compensation and employee benefits	69,082	65,052	65,805
Occupancy	17,055	16,996	16,579
Equipment	13,722	13,756	13,967
Services	15,466	12,863	12,529
Data processing	10,598	11,794	10,668
Office supplies, printing and postage	4,440	4,699	4,850

Marketing	3,816	3,987	3,973
Communication	3,475	2,879	4,072
Other expense	27,029	22,897	19,723
	164,683	154,923	152,166
Income before minority interests and income taxes	**104,901**	**104,974**	**92,755**
Minority interests	45	97	124
Income taxes	39,969	58,404	30,959
Income before preferred stock dividends	**64,887**	**46,473**	**61,672**
Preferred stock dividends	4	5,411	5,411
Net income for common stock	**$ 64,883**	**$ 41,062**	**$ 56,261**

Table of Contents

Consolidated Balance Sheet Data

December 31	**2005**	**2004**
(in thousands)		
Assets		
Cash and equivalents	$ 150,130	$ 120,295
Federal funds sold	57,434	41,491
Available-for-sale investment and mortgage-related securities	2,629,351	2,953,372
Investment in stock of Federal Home Loan Bank of Seattle	97,764	97,365
Loans receivable, net	3,566,834	3,249,191
Other	244,443	213,528
Goodwill and other intangibles	89,379	91,263
	$ 6,835,335	$ 6,766,505
Liabilities and stockholders equity		
Deposit liabilities noninterest-bearing	$ 624,497	$ 558,958