IN MOTION

2007 Annual Report and Form 10-K

IN MOTION

Dear Shareholder

ALLETE is working its way through one of the busiest periods in our 100+ year corporate history. Major air emissions control projects at two of our Minnesota generating stations are underway. Renewable energy projects are taking shape. Retail stores, offices and residences are under construction on land ALLETE Properties has brought to market in Florida.

With several major mining and processing projects awaiting approval in our northern Minnesota electric service territory, strong energy demand, and a supply of entitled land in desirable Florida locations, ALLETE's future appears bright. Meanwhile, ALLETE's strategic investment in the American Transmission Company continues to grow.

We intend to be a leader in the movement toward renewable energy and cleaner power plants. In our latest resource plan, we stated that Minnesota Power can meet its customers' electric energy needs for the next decade while achieving real reductions in the emission of greenhouse gases. To be out in front on cutting carbon emissions is the right thing to do environmentally. We believe it's also the wisest course from a long-term financial perspective.

We're primed to set in motion the first wind turbines ever to generate commercial power in our northern Minnesota electric service territory. Fittingly, this Taconite Ridge Energy Center lies right in the heart of ALLETE's service territory, on land in Mountain Iron leased from our largest customer, U.S. Steel. Minnesota Power serves not only large mining operations, but also major customers in the papermaking, wood products and pipeline industries. Renewable energy potential is plentiful in our region, not only because of the hydropower we've harnessed for a century and the wind resource we're now developing, but because wood waste from papermaking and logging can provide biomass fuel to generate power. We're also well positioned to purchase clean hydropower from Canadian sources.

ALLETE Properties owns a valuable portfolio of assets in Florida. Essentially all of the ALLETE Properties inventory is already zoned for multiple uses and served by roads and utilities. We believe that construction of retail and residential projects now underway on property we've sold at Town Center and Palm Coast Park creates a momentum for future land sales on adjacent parcels. While real estate is in a down cycle nationally, current market conditions may create opportunities to add to our inventory. Even though it's a question of time when the cycle swings upward, we expect real estate to provide important earnings contributions for years to come.

Creating value for shareholders is uppermost in the minds of ALLETE's board and its management. Our decision to raise the company's common stock dividend by five percent earlier this year underscores our belief that future earnings growth will sustain a strong dividend.

Once again, thanks for your continued support of our company. Your investment is instrumental in moving ALLETE forward.

Sincerely,

Donald Shippar
Chairman, President and Chief Executive Officer

United States
Securities and Exchange Commission
Washington, D.C. 20549

Form 10-K

(Mark One)

☑ Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended **December 31, 2007**

☐ Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from ______________ to ______________

Commission File No. **1-3548**

ALLETE, Inc.

(Exact name of registrant as specified in its charter)

Minnesota	**41-0418150**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)

30 West Superior Street, Duluth, Minnesota 55802-2093
(Address of principal executive offices, including zip code)

(218) 279-5000
(Registrant's telephone number, including area code)

Securities Registered Pursuant to Section 12(b) of the Act:

Title of Each Class	Name of Each Stock Exchange on Which Registered
Common Stock, without par value	New York Stock Exchange

Securities Registered Pursuant to Section 12(g) of the Act:

None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.
Yes ☑ No ☐

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.
Yes ☐ No ☑

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

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer or a smaller reporting company (as defined in Rule 12b-2 of the Act).
Large Accelerated Filer ☑ Accelerated Filer ☐ Non-Accelerated Filer ☐ Smaller Reporting Company ☐

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act).
Yes ☐ No ☑

The aggregate market value of voting stock held by nonaffiliates on June 29, 2007, was $1,437,610,992.

As of February 1, 2008, there were 30,829,791 shares of ALLETE Common Stock, without par value, outstanding.

Documents Incorporated By Reference

Portions of the Proxy Statement for the 2008 Annual Meeting of Shareholders are incorporated by reference in Part III.

Index

Definitions

The following abbreviations or acronyms are used in the text. References in this report to "we," "us" and "our" are to ALLETE, Inc. and its subsidiaries, collectively.

Abbreviation or Acronym	Term
AICPA	American Institute of Certified Public Accountants
ALLETE	ALLETE, Inc.
ALLETE Properties	ALLETE Properties, LLC and its subsidiaries
AFUDC	Allowance for Funds Used During Construction - the cost of both the debt and equity funds used to finance utility plant additions during construction periods
AREA	Arrowhead Regional Emission Abatement
ATC	American Transmission Company LLC
Blandin Paper	UPM, Blandin Paper Mill
BNI Coal	BNI Coal, Ltd.
Boswell	Boswell Energy Center
Company	ALLETE, Inc. and its subsidiaries
Constellation Energy Commodities	Constellation Energy Commodities Group, Inc.
DOC	Minnesota Department of Commerce
DRI	Development of Regional Impact
EITF	Emerging Issues Task Force
Enventis Telecom	Enventis Telecom, Inc.
EPA	Environmental Protection Agency
ESA	Electric Service Agreement
ESOP	Employee Stock Ownership Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Florida Landmark	Florida Landmark Communities, Inc.
Florida Water	Florida Water Services Corporation
Form 8-K	ALLETE Current Report on Form 8-K
Form 10-K	ALLETE Annual Report on Form 10-K
Form 10-Q	ALLETE Quarterly Report on Form 10-Q
FPL Energy	FPL Energy, LLC
FPSC	Florida Public Service Commission
FSP	Financial Accounting Standards Board Staff Position
GAAP	Accounting Principles Generally Accepted in the United States
Heating Degree Days	Measure of the extent to which the average daily temperature is below 65 degrees Fahrenheit, increasing demand for heating
Invest Direct	ALLETE's Direct Stock Purchase and Dividend Reinvestment Plan
IPO	Initial Public Offering
kV	Kilovolt(s)
Laskin	Laskin Energy Center
Manitoba Hydro	Manitoba Hydro Board
MBtu	Million British thermal units
Mesabi Nugget	Mesabi Nugget Delaware, LLC
Minnesota Power	An operating division of ALLETE, Inc.
Minnkota Power	Minnkota Power Cooperative, Inc.
MISO	Midwest Independent Transmission System Operator, Inc.
Moody's	Moody's Investors Service, Inc.
MPCA	Minnesota Pollution Control Agency
MPUC	Minnesota Public Utilities Commission

Definitions (Continued)

Abbreviation or Acronym	Term
MW / MWh	Megawatt(s) / Megawatthour(s)
Non-residential	Retail commercial, non-retail commercial, office, industrial, warehouse, storage and institutional
NO_X	Nitrogen Oxide
Northwest Airlines	Northwest Airlines, Inc.
Note ___	Note ___ to the consolidated financial statements in this Form 10-K
NPDES	National Pollutant Discharge Elimination System
NYSE	New York Stock Exchange
OAG	Office of the Attorney General
Oliver Wind I	Oliver Wind I Energy Center
Oliver Wind II	Oliver Wind II Energy Center
Palm Coast Park	Palm Coast Park development project in Florida
Palm Coast Park District	Palm Coast Park Community Development District
PolyMet Mining	PolyMet Mining, Inc.
PSCW	Public Service Commission of Wisconsin
PUHCA 1935	Public Utility Holding Company Act of 1935
PUHCA 2005	Public Utility Holding Company Act of 2005
Rainy River Energy	Rainy River Energy Corporation
SEC	Securities and Exchange Commission
SFAS	Statement of Financial Accounting Standards No.
SO_2	Sulfur Dioxide
Square Butte	Square Butte Electric Cooperative
Standard & Poor's	Standard & Poor's Ratings Services, a division of The McGraw-Hill Companies, Inc.
SWL&P	Superior Water, Light and Power Company
Taconite Harbor	Taconite Harbor Energy Center
Town Center	Town Center at Palm Coast development project in Florida
Town Center District	Town Center at Palm Coast Community Development District
WDNR	Wisconsin Department of Natural Resources

Safe Harbor Statement
Under the Private Securities Litigation Reform Act of 1995

In connection with the safe harbor provisions of the Private Securities Litigation Reform Act of 1995, we are hereby filing cautionary statements identifying important factors that could cause our actual results to differ materially from those projected in forward-looking statements (as such term is defined in the Private Securities Litigation Reform Act of 1995) made by or on behalf of ALLETE in the Annual Report on Form 10-K, in presentations, in response to questions or otherwise. Any statements that express, or involve discussions as to expectations, beliefs, plans, objectives, assumptions, or future events or performance (often, but not always, through the use of words or phrases such as "anticipates," "believes," "estimates," "expects," "intends," "plans," "projects," "will likely result," "will continue," "could," "may," "potential," "target," "outlook" or similar expressions) are not statements of historical facts and may be forward-looking.

Forward-looking statements involve estimates, assumptions, risks and uncertainties, which are beyond our control and may cause actual results or outcomes to differ materially from those that may be projected. These statements are qualified in their entirety by reference to, and are accompanied by, the following important factors, in addition to any assumptions and other factors referred to specifically:

- our ability to successfully implement our strategic objectives;
- our ability to manage expansion and integrate acquisitions;
- prevailing governmental policies, regulatory actions, and legislation including those of the United States Congress, state legislatures, the FERC, the MPUC, the PSCW, and various local and county regulators, and city administrators, allowed rates of return, financings, industry and rate structure, acquisition and disposal of assets and facilities, real estate development, operation and construction of plant facilities, recovery of purchased power, capital investments and other expenses, present or prospective wholesale and retail competition (including but not limited to transmission costs), zoning and permitting of land held for resale and environmental matters;
- the potential impacts of climate change on our Regulated Utility operations;
- effects of restructuring initiatives in the electric industry;
- economic and geographic factors, including political and economic risks;
- changes in and compliance with laws and policies;
- weather conditions;
- natural disasters and pandemic diseases;
- war and acts of terrorism;
- wholesale power market conditions;
- population growth rates and demographic patterns;
- effects of competition, including competition for retail and wholesale customers;
- changes in the real estate market;
- pricing and transportation of commodities;
- changes in tax rates or policies or in rates of inflation;
- unanticipated project delays or changes in project costs;
- availability and management of construction materials and skilled construction labor for capital projects;
- unanticipated changes in operating expenses, capital and land development expenditures;
- global and domestic economic conditions;
- our ability to access capital markets and bank financing;
- changes in interest rates and the performance of the financial markets;
- our ability to replace a mature workforce and retain qualified, skilled and experienced personnel; and
- the outcome of legal and administrative proceedings (whether civil or criminal) and settlements that affect the business and profitability of ALLETE.

Additional disclosures regarding factors that could cause our results and performance to differ from results or performance anticipated by this report are discussed in Item 1A under the heading "Risk Factors" beginning on page 22 of this Form 10-K. Any forward-looking statement speaks only as of the date on which such statement is made, and we undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which that statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of these factors, nor can it assess the impact of each of these factors on the businesses of ALLETE or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. Readers are urged to carefully review and consider the various disclosures made by us in this Form 10-K and in our other reports filed with the SEC that attempt to advise interested parties of the factors that may affect our business.

Part I

Item 1. Business

ALLETE is a diversified company that has provided fundamental products and services since 1906. These include our former operations in the water, paper, telecommunications and automotive industries and the core **Energy** and **Real Estate** businesses we operate today.

Energy is comprised of Regulated Utility, Nonregulated Energy Operations and Investment in ATC.

- **Regulated Utility** includes retail and wholesale rate regulated electric, natural gas and water services in northeastern Minnesota and northwestern Wisconsin under the jurisdiction of state and federal regulatory authorities.
- **Nonregulated Energy Operations** includes our coal mining activities in North Dakota, approximately 50 MW of nonregulated generation and Minnesota land sales.
- **Investment in ATC** includes our equity ownership interest in ATC.

Real Estate includes our Florida real estate operations.

Other includes our investments in emerging technologies, and earnings on cash and short-term investments.

ALLETE is incorporated under the laws of Minnesota. Our corporate headquarters are in Duluth, Minnesota. Statistical information is presented as of December 31, 2007, unless otherwise indicated. All subsidiaries are wholly owned unless otherwise specifically indicated. References in this report to "we," "us" and "our" are to ALLETE and its subsidiaries, collectively.

Year Ended December 31	**2007**	**2006**	**2005**
Consolidated Operating Revenue – Millions	$841.7	$767.1	$737.4
Percentage of Consolidated Operating Revenue			
Regulated Utility	86	83	78
Nonregulated Energy Operations	8	9	16
Real Estate	6	8	6
	100%	100%	100%

For a detailed discussion of results of operations and trends, see Item 7 Management's Discussion and Analysis of Financial Condition and Results of Operations. For business segment information, see Notes 1 and 2.

Energy – Regulated Utility

Electric Sales / Customers

Minnesota Power provides regulated utility electric service in northeastern Minnesota to 141,000 retail customers and wholesale electric service to 16 municipalities. SWL&P provides regulated electric service, natural gas and water service in northwestern Wisconsin to 15,000 electric customers, 12,000 natural gas customers and 10,000 water customers. Our regulated utility operations include retail and wholesale activities under the jurisdiction of state and federal regulatory authorities. (see Item 1 - Regulatory Matters.) In addition to serving residential, commercial and municipal electric needs, a high proportion of our electric sales are to large industrial customers.

Regulated Utility Electric Sales

Year Ended December 31	**2007**	**%**	**2006**	**%**	**2005**	**%**
Millions of Kilowatthours						
Retail and Municipals						
Residential	1,141	9	1,100	9	1,102	10
Commercial	1,373	11	1,335	10	1,327	11
Industrial	7,054	55	7,206	56	7,130	61
Municipals and Other	1,092	8	990	8	956	8
	10,660	**83**	**10,631**	**83**	**10,515**	**90**
Other Power Suppliers *(a)*	2,157	17	2,153	17	1,142	10
	12,817	**100**	**12,784**	**100**	**11,657**	**100**

(a) Effective January 1, 2006, Taconite Harbor was redirected from Nonregulated Energy Operations to Regulated Utility.

Energy-Regulated Utility (Continued)

Industrial Customers

In 2007, our industrial customers represented 55 percent of total regulated utility kilowatthour sales. Our industrial customers are primarily in the taconite, paper, pulp, wood products and pipeline industries.

Industrial Customer Electric Sales Year Ended December 31	2007	%	2006	%	2005	%
Millions of Kilowatthours						
Taconite Producers	4,408	62	4,517	63	4,558	64
Paper, Pulp and Wood Products	1,613	23	1,689	23	1,623	23
Pipelines	562	8	550	8	480	7
Other Industrial	471	7	450	6	469	6
	7,054	**100**	**7,206**	**100**	**7,130**	**100**

Approximately 60 percent of the ore consumed by integrated steel facilities in the United States originates from six taconite customers of Minnesota Power. Taconite, an iron-bearing rock of relatively low iron content that is abundantly available in Minnesota, is an important domestic source of raw material for the steel industry. Taconite processing plants use large quantities of electric power to grind the iron-bearing rock, and agglomerate and pelletize the iron particles into taconite pellets. Strong worldwide steel demand, driven largely by extensive infrastructure development in China, has resulted in very robust world iron ore demand and steel pricing. This globalization of demand has positively impacted Minnesota taconite producers. With the exception of short-term production curtailments at two taconite plants, our taconite customers operated at maximum production levels in 2007. Annual taconite production in Minnesota was 39 million tons in 2007 (40 million tons in 2006 and 41 million tons in 2005) and it is estimated that it will be 41.5 million tons in 2008. An 800,000 ton per year expansion at Cleveland Cliffs' Northshore taconite facility is expected to be completed in April 2008, contributing to the expected increased production. It is expected that throughout 2008, Minnesota taconite producers will remain in a strong competitive position due to the strength of the world steel industry and their efficiency of production.

In addition to serving the taconite industry, Minnesota Power also serves a number of customers in the paper, pulp and wood products industry. In total, we serve four major paper and pulp mills directly and one paper mill indirectly by providing wholesale service to the retail provider of the mill. Minnesota Power also serves four wood products manufacturers. In 2007, approximately 90 percent of our revenue from this industry sector came from the paper and pulp producers, and 10 percent came from the wood products customers.

Minnesota Power's paper and pulp customers ran at, or very near, full capacity in 2007 despite the fact that the industry continued to face high fiber, chemical and energy costs as well as competition from exports in certain grades of paper products. Minnesota Power's customers benefited from the temporary or permanent idling of capacity both in North America at mills other than those served by Minnesota Power and the idling of capacity in Europe, as well as from the strength of the Canadian dollar and the Euro which has reduced imports both from Canada and Europe. Our wood products customers ran at reduced capacity levels, and two facilities were indefinitely idled due to the decreased number of new housing starts, a resultant declining demand and pricing for their products. One of the idled facilities was down for all of 2007 while another was idled during the last quarter of 2007.

The pipeline industry is the third key industrial segment served by Minnesota Power with services provided to two crude oil pipelines and one refinery. These customers have a common reliance on the importation of Canadian crude oil. After near capacity operation in 2006 and 2007, both pipeline operators are executing expansion plans to transport newly developed Western Canadian crude oil reserves (Alberta Oil Sands) to United States markets. Access to traditional Midwest markets is being expanded to Southern markets as the Canadian supply is displacing domestic production and deliveries imported from the Gulf Coast.

Energy-Regulated Utility (Continued)

Large Power Customer Contracts. Minnesota Power has large power customer contracts with 12 customers (Large Power Customers), 11 of which require 10 MW or more of generating capacity and one that requires at least 8 MW of generating capacity. Large Power Customers consist of five taconite producers, four paper and pulp mills, two pipeline companies and one manufacturer.

Large Power Customer contracts require Minnesota Power to have a certain amount of generating capacity available. (See Minimum Revenue and Demand Under Contract table below.) In turn, each Large Power Customer is required to pay a minimum monthly demand charge that covers the fixed costs associated with having this capacity available to serve the customer, including a return on common equity. Most contracts allow customers to establish the level of megawatts subject to a demand charge on a biannual (power pool season) or four-month basis and require that a portion of their megawatt needs be committed on a take-or-pay basis for at least a portion of the agreement. In addition to the demand charge, each Large Power Customer is billed an energy charge for each kilowatthour used that recovers the variable costs incurred in generating electricity. Six of the Large Power Customers have interruptible service for a portion of their needs, which provides a discounted demand rate and energy priced at Minnesota Power's incremental cost after serving all firm power obligations. Minnesota Power also provides incremental production service for customer demand levels above the contractual take-or-pay levels. There is no demand charge for this service and energy is priced at an increment above Minnesota Power's cost. Incremental production service is interruptible.

All contracts with Large Power Customers continue past the contract termination date unless the required advance notice of cancellation has been given. The advance notice of cancellation varies from one to four years. Such contracts minimize the impact on earnings that otherwise would result from significant reductions in kilowatthour sales to such customers. Large Power Customers are required to take all of their purchased electric service requirements from Minnesota Power for the duration of their contracts. The rates and corresponding revenue associated with capacity and energy provided under these contracts are subject to change through the same regulatory process governing all retail electric rates. (See Regulatory Matters – Electric Rates.)

Minnesota Power, as permitted by the MPUC, requires its taconite-producing Large Power Customers to pay weekly for electric usage based on monthly energy usage estimates. The customers receive estimated bills based on Minnesota Power's prediction of the customer's energy usage, forecasted energy prices and fuel clause adjustment estimates. Minnesota Power's five taconite-producing Large Power Customers have generally predictable energy usage on a week-to-week basis, which makes the variance between the estimated usage and actual usage small. Taconite-producing Large Power Customers subject to weekly billings receive interest on the money paid to Minnesota Power within the billing cycle.

Minimum Revenue and Demand Under Contract As of February 1, 2008	**Minimum Annual Demand Revenue** *(a,b)*	**Monthly Megawatts**
2008	$64.1 million	401
2009	$27.5 million	154
2010	$25.5 million	148
2011	$25.3 million	148
2012	$15.6 million	88

(a) Based on past experience, we believe revenue from our Large Power Customers will be substantially in excess of the minimum contract amounts. For example, in our 2006 Form 10-K we stated that 2007 minimum annual revenue demand from these Large Power Customers would be $62.5 million. Actual 2007 demand revenue from these Large Power Customers was $118.7 million.

(b) Although several contracts have a feature that allows demand to go to zero after a two-year advance notice of a permanent closure, this minimum revenue summary does not reflect this occurrence happening in the forecasted period because we believe it is unlikely.

Energy–Regulated Utility (Continued)

Contract Status for Minnesota Power Large Power Customers
As of February 1, 2008

Customer	Industry	Location	Ownership	Earliest Termination Date
Hibbing Taconite Co. *(a)*	Taconite	Hibbing, MN	62.3% Mittal Steel USA Inc. 23% Cleveland-Cliffs Inc 14.7% United States Steel (USS)	February 29, 2012
ArcelorMittal USA – Minorca Mine	Taconite	Virginia, MN	ArcelorMittal USA Inc.	December 31, 2013
United States Steel Corporation (USS) Minntac	Taconite	Mt. Iron, MN	USS	October 31, 2014
USS Keewatin Taconite	Taconite	Keewatin, MN	USS	October 31, 2014
United Taconite LLC *(a)*	Taconite	Eveleth, MN	70% Cleveland-Cliffs Inc 30% Laiwu Steel Group	February 29, 2012
UPM, Blandin Paper Mill *(a)*	Paper	Grand Rapids, MN	UPM-Kymmene Corporation	February 29, 2012
Boise White Paper, LLC *(b)*	Paper	International Falls, MN	Madison Dearborn Partnership	February 28, 2009
Sappi Cloquet LLC *(a)*	Paper	Cloquet, MN	Sappi Limited	February 29, 2012
NewPage Corporation – Duluth Mills	Paper and Pulp	Duluth, MN	NewPage Corporation	August 31, 2013
USG Interiors, Inc. *(b)*	Manufacturer	Cloquet, MN	USG Corporation	February 28, 2009
Enbridge Energy Company, Limited Partnership *(b)*	Pipeline	Deer River, MN Floodwood, MN	Enbridge Energy Company, Limited Partnership	February 28, 2009
Minnesota Pipeline Company *(b)*	Pipeline	Staples, MN Little Falls, MN Park Rapids, MN	60% Koch Pipeline Co. L.P. 40% Marathon Ashland Petroleum LLC	February 28, 2009

(a) *The contract will terminate four years from the date of written notice from either Minnesota Power or the customer. No notice of contract cancellation has been given by either party. Thus, the earliest date of cancellation is February 29, 2012.*
(b) *The contract will terminate one year from the date of written notice from either Minnesota Power or the customer. No notice of contract cancellation has been given by either party. Thus, the earliest date of cancellation is February 28, 2009.*

Energy–Regulated Utility (Continued)

Power Supply

In order to meet our customer's electric requirements, we utilize a mix of Company generation and purchased power. The Company's generation is primarily coal fired, but also includes approximately 115 MWs of hydro generation from ten hydro stations in Minnesota. Purchased power is made up of long–term power purchase agreements and market purchases. The following table reflects the Company's generating capabilities and total electrical requirements as of December 31, 2007. Minnesota Power had an annual net peak load of 1,614 MW on July 30, 2007.

Regulated Utility Power Supply	Unit No.	Year Installed	Net Winter Capability	For the Year Ended December 31, 2007 Electric Requirements	
			MW	MWh	%
Coal-Fired					
Boswell Energy Center	1	1958	69		
in Cohasset, MN	2	1960	69		
	3	1973	350		
	4	1980	429		
			917	6,005,520	45.7%
Laskin Energy Center	1	1953	55		
in Hoyt Lakes, MN	2	1953	54		
			109	591,499	4.5
Taconite Harbor Energy Center	1, 2 & 3	1957, 1957			
in Taconite Harbor, MN		1967	220	1,491,457	11.4
Total Coal			1,246	8,088,476	61.6
Purchased Steam					
Hibbard Energy Center in Duluth, MN	3 & 4	1949, 1951	47	53,354	0.4
Hydro					
Group consisting of ten stations in MN	Various		115	428,153	3.3
Total Company Generation			1,408	8,569,983	65.3
Long Term Purchased Power					
Square Butte burns lignite coal near Center, ND			273	1,533,186	11.7
Wind – Oliver County, ND *(a)*			20	203,675	1.5
Total Long Term Purchased Power			293	1,736,861	13.2
Other Purchased Power – Net *(b)*			–	2,819,715	21.5
Total Purchased Power			293	4,556,576	34.7
Total			1,701	13,126,559	100.0%

(a) The nameplate capacity of Oliver Wind I Energy Center is 50-MWs and 48-MWs for the Oliver Wind II Energy Center. The capacity reflected in the table is actual accredited capacity of the facility. Accredited capacity is the amount of net generating capability associated with the facility for which capacity credit may be obtained under applicable Mid-Continent Area Power Pool (MAPP) rules.

(b) Includes short term market purchases in the MISO market and from other power suppliers.

Fuel. Minnesota Power purchases low-sulfur, sub-bituminous coal from the Powder River Basin coal region located in Montana and Wyoming. Coal consumption in 2007 for electric generation at Minnesota Power's coal-fired generating stations was approximately 4.9 million tons. As of December 31, 2007, Minnesota Power had a coal inventory of about 922,000 tons. Of Minnesota Power's primary coal supply agreements, one agreement extends through 2011, one extends through 2009, and one has an initial term expiring at the end of 2008. Under these agreements, Minnesota Power has the tonnage flexibility to procure 70 percent to 100 percent of its total coal requirements. In 2008, Minnesota Power expects to obtain coal under these coal supply agreements and in the spot market. This diversity in coal supply options allows Minnesota Power to manage market price and supply risk and to take advantage of favorable spot market prices. Minnesota Power continues to explore future coal supply options. We believe that adequate supplies of low-sulfur, sub-bituminous coal will continue to be available.

In 2001, Minnesota Power and Burlington Northern Santa Fe Railway Company (BNSF) entered into a long-term agreement under which BNSF transports all of Minnesota Power's coal by unit train from the Powder River Basin directly to Minnesota Power's generating facilities or to a designated interconnection point. Minnesota Power also has agreements with an affiliate of the Canadian National Railway and Midwest Energy Resources Company to transport coal from the BNSF interconnection point to certain Minnesota Power facilities.

Energy–Regulated Utility (Continued)
Power Supply (Continued)

On January 24, 2008, we received a letter from BNSF alleging the Company defaulted on a material obligation under the Company's Coal Transportation Agreement (CTA). In the notice, BNSF claimed Minnesota Power underpaid approximately $1.6 million for coal transportation services in 2006 and that failure to pay such amount plus interest within 60 days may result in BNSF's termination of the CTA. We believe we do not owe the amount claimed, and that BNSF's claims are wholly without merit. We intend to vigorously defend our position in this dispute.

Coal Delivered to Minnesota Power **Year Ended December 31**	**2007**	**2006**	**2005**
Average Price per Ton	$21.78	$20.19	$19.76
Average Price per MBtu	$1.20	$1.10	$1.08

The Square Butte generating unit operated by Minnkota Power burns North Dakota lignite coal supplied by BNI Coal in accordance with the terms of a contract that extends through 2026. Square Butte's cost of lignite burned in 2007 was approximately $1.09 per MBtu. The lignite acreage that has been dedicated to Square Butte by BNI Coal is located on lands essentially all of which are under private control and presently leased by BNI Coal. This lignite supply is sufficient to provide fuel for the anticipated useful life of the generating unit.

Long Term Purchased Power. Minnesota Power has contracts to purchase capacity and energy from various entities. The largest contract is with Square Butte. Under an agreement with Square Butte expiring at the end of 2026, Minnesota Power is currently entitled to approximately 55 percent (50 percent in 2009 and thereafter) of the output of a 455-MW coal-fired generating unit located near Center, North Dakota. (See Note 8.)

In December 2006, we began purchasing the output from a 50-MW wind facility, Oliver Wind I, located in North Dakota, under a 25-year power purchase agreement with an affiliate of FPL Energy.

In May 2007, the MPUC approved a second 25-year wind power purchase agreement to purchase an additional 48 MW of wind energy from Oliver Wind II, an expansion of Oliver Wind I located in North Dakota. The MPUC also allowed immediate cost recovery for associated transmission upgrades. In November 2007, Oliver Wind II became operational and we began purchasing the output from the 48-MW wind facility.

On May 11, 2007, the MPUC approved a 50-MW power purchase agreement between Minnesota Power and Manitoba Hydro from May 2009 through April 2015.

Transmission and Distribution

We have electric transmission and distribution lines of 500 kV (8 miles), 230 kV (605 miles), 161 kV (43 miles), 138 kV (129 miles), 115 kV (1,203 miles) and less than 115 kV (6,347 miles). We own and operate 170 substations with a total capacity of 9,586 megavoltamperes. Some of our transmission and distribution lines interconnect with other utilities.

Properties

We own office and service buildings, an energy control center, repair shops, and lease offices and storerooms in various localities. Substantially all of our electric plant is subject to mortgages, which collateralize the outstanding first mortgage bonds of Minnesota Power and SWL&P. Generally, we hold fee interest in our real properties subject only to the lien of the mortgages. Most of our electric lines are located on land not owned in fee, but are covered by appropriate easement rights or by necessary permits from governmental authorities. Wisconsin Public Power, Inc. (WPPI) owns 20 percent of Boswell Unit 4. WPPI has the right to use our transmission line facilities to transport its share of Boswell generation. (See Note 4.)

Energy–Regulated Utility (Continued)

Regulatory Matters

We are subject to the jurisdiction of various regulatory authorities. The MPUC has regulatory authority over Minnesota Power's service area in Minnesota, retail rates, retail services, issuance of securities and other matters. The FERC has jurisdiction over the licensing of hydroelectric projects, the establishment of rates and charges for the sale of electricity for resale and transmission of electricity in interstate commerce and certain accounting and record-keeping practices. The PSCW has regulatory authority over SWL&P's retail sales of electricity, natural gas and water by SWL&P. The MPUC, FERC and PSCW had regulatory authority over 58 percent, 10 percent and 8 percent, respectively, of our 2007 consolidated operating revenue.

Electric Rates. Minnesota Power has historically designed its electric service rates based on cost of service studies under which allocations are made to the various classes of customers. Nearly all retail sales include billing adjustment clauses, which adjust electric service rates for changes in the cost of fuel and purchased energy, recovery of current and deferred conservation improvement program expenditures and recovery of certain environmental and renewable expenditures.

Information published by the Edison Electric Institute ("Typical Bills and Average Rates Report – Summer 2007" and "Rankings – July 1, 2007") ranked Minnesota Power as having the ninth lowest average retail rates out of 177 investor-owned utilities in the United States. We had the lowest rates in Minnesota and in the region consisting of Iowa, Kansas, Minnesota, Missouri, North Dakota, South Dakota and Wisconsin.

Minnesota Power requires that all large industrial and commercial customers under contract specify the date when power is first required. Thereafter, the customer is generally billed monthly for at least the minimum power for which they contracted. These conditions are part of all contracts covering power to be supplied to new large industrial and commercial customers and to current customers as their contracts expire or are amended. All rates and other contract terms are subject to approval by appropriate regulatory authorities.

Federal Energy Regulatory Commission. The FERC has jurisdiction over our wholesale electric service and operations. Minnesota Power's hydroelectric facilities, which are located in Minnesota, are also licensed by the FERC.

In August 2005, the Energy Policy Act of 2005 (EPAct 2005) was signed into law, which repealed PUHCA 1935 and enacted PUHCA 2005. PUHCA 2005 gives FERC certain authority over books and records of public utility holding companies and their affiliates. It also addresses FERC review and authorization of the allocation of costs for non-power goods, or administrative or management services when requested by a holding company system or state commission. In addition, EPAct 2005 directs the FERC to issue certain rules addressing electricity reliability, investment in energy infrastructure, fuel diversity for electric generation, promotion of energy efficiency and wise energy use. The FERC is currently in the process of implementing EPAct 2005. These include (among others):

- rulemaking for long-term transmission rights;
- dockets pertaining to the development and certification of electric reliability organizations, including delegated authority to regional entities for proposing and enforcing reliability standards;
- rules specifying the form of applications for federal construction permits to be issued in the exercise of federal backstop siting authority for transmission projects;
- rulemaking requiring unregulated transmitting utilities to provide open access to their transmission systems;
- various rulemakings regarding the consideration of merger applications under the revised Federal Power Act Section 203;
- a U.S. Department of Energy study/report on the benefits of economic dispatch and a report on recommendations of regional joint boards that considered economic dispatch;
- rulemaking to facilitate transmission market transparency; and
- the energy market manipulation rulemaking.

We continue to monitor FERC activity in these and other proceedings.

On December 28, 2007, we submitted a filing with the FERC seeking to increase electric rates for our wholesale customers. On February 8, 2008, the FERC approved our wholesale rate filing. Our wholesale customers consist of 16 municipalities in Minnesota and two private utilities in Wisconsin, including SWL&P. The FERC authorized an average 10 percent increase for wholesale municipal customers, a 12.5 percent increase for SWL&P, and an overall return on equity of 11.25 percent. The rate increase will go into effect on March 1, 2008, and on an annualized basis, the filing will generate approximately $7.5 million in additional revenue.

Municipal and Wholesale Customers. Minnesota Power has contracts with 16 Minnesota municipalities receiving wholesale electric service. One contract expires April 2008 (31,000 MWh purchased in 2007), while the other 15 are for service through at least January 2011. In 2007, these municipal customers purchased 893,000 MWh from Minnesota Power. Minnesota Power also has a contract for wholesale service with Dahlberg Light & Power Company (Dahlberg) in Wisconsin. Dahlberg purchased 115,000 MWh in 2007.

Energy–Regulated Utility (Continued)
Federal Energy Regulatory Commission (Continued)

Midwest Independent Transmission System Operator, Inc. (MISO). Minnesota Power and SWL&P are members of MISO. Minnesota Power and SWL&P retain ownership of their respective transmission assets and control area functions, but their transmission network is under the regional operational control of MISO, and they take and provide transmission service under MISO open access transmission tariff. MISO continues its efforts to standardize rates, terms and conditions of transmission service over its broad region, encompassing all or parts of 15 states and one Canadian province, and over 100,000 MW of generating capacity.

Mid-Continent Area Power Pool (MAPP). Minnesota Power also participates in MAPP, a power pool operating in parts of eight states in the Upper Midwest and in two Canadian provinces. MAPP functions include a regional transmission committee and a generation reserve-sharing pool. Minnesota Power is also a member of the Midwest Reliability Organization that was established as a regional reliability council within the North American Electric Reliability Council on January 1, 2005.

Minnesota Public Utilities Commission. Minnesota Power’s retail rates are based on a 1994 MPUC retail rate order that allows for an 11.6 percent return on common equity dedicated to utility plant. Minnesota Power may file a request to increase rates for its retail utility operations in mid-2008. Retail rates are being adjusted without a rate proceeding to reflect recovery of costs related to the AREA Plan, the Boswell 3 Environmental Improvement Plan (see AREA and Boswell Unit 3 Emission Reduction Plans), transmission investments and renewable investments.

Integrated Resource Plan. On October 31, 2007, Minnesota Power filed its Integrated Resource Plan (IRP), a comprehensive estimate of future capacity needs within the Minnesota Power service territory. Minnesota Power believes it can meet the estimated future customer demand for the next decade while achieving real reductions in the emission of greenhouse gases (primarily carbon dioxide).

Minnesota Power plans to meet expected loads through approximately 2020 by adding a significant amount of renewable generation and some supporting peaking generation. We do not plan to add new coal generation or enter into long-term power purchase agreements from coal-based generation resources without a greenhouse gas solution. We plan to add 300 to 500 megawatts of carbon-minimizing renewable energy to our generation mix. Besides the additional generation from renewable sources, Minnesota Power anticipates future supply will come from a combination of sources, including:

- "As-needed" peaking and intermediate generation facilities;
- Expiration of wholesale contracts presently in place;
- Short-term market purchases;
- Improved efficiency of existing generation and power delivery assets; and
- Expanded conservation and demand-side management initiatives.

We do not anticipate the need for new base load system generation within the Minnesota Power service territory through approximately 2020, and we project a one percent average annual growth in electric usage from our existing customers over that time frame.

Large Power Contracts. In 2006, a contract for approximately 70 MW was executed with PolyMet Mining, a new customer planning to start a copper, nickel and precious metals (non-ferrous) mining operation in late 2008. If PolyMet Mining receives all necessary environmental permits and achieves start-up, the contract will be fully implemented and would run through at least 2018. In April 2007, the MPUC approved our contract with PolyMet Mining.

In June 2007, a contract was executed with Mesabi Nugget, a company currently constructing an iron nugget facility near Hoyt Lakes, Minnesota. Iron nuggets, which typically consist of more than 94 percent iron (compared to taconite pellets at 63-65 percent iron), are ideal in meeting the requirements of electric-arc furnaces producing steel. On February 7, 2008, the MPUC held a hearing on the contract and adopted a motion approving the contract, subject to the issuance of a written order. Mesabi Nugget has received all necessary permits to begin construction and operations in 2008 and would be a 15 MW customer with the potential for further load growth. The Mesabi Nugget contract would run through at least 2017.

A new contract with Blandin Paper was approved by the MPUC on February 4, 2008. The new contract carries forward the same contract term, cancellation provision and take-or-pay provisions of the prior contract and only changed the demand nomination feature.

In February 2008, United States Steel announced its intent to restart a pellet line at its Keewatin Taconite processing facility. This pellet line, which has been idled since 1980, would be restarted and updated as part of a $300 million investment. It is anticipated that this will bring approximately 3.6 million tons of additional pellet making capability to Northeastern Minnesota by 2011, pending successful approval of environmental permitting.

Energy–Regulated Utility (Continued)
Minnesota Public Utilities Commission (Continued)

AREA and Boswell Unit 3 Emission Reduction Plans. In May 2006, the MPUC approved our filing for current cost recovery of expenditures to reduce emissions to meet pending federal requirements at Taconite Harbor and Laskin under the AREA Plan. The AREA Plan approval allows Minnesota Power to recover Minnesota jurisdictional costs for SO_2, NO_X and mercury emission reductions made at these facilities without a rate proceeding. Current cost recovery from retail customers which include a return on investment and recovery of incremental expense. The AREA Plan is expected to significantly reduce emissions from Taconite Harbor and Laskin, while maintaining a reliable and reasonably-priced energy supply to meet the needs of our customers. We believe that control and abatement technologies applicable to these plants have matured to the point where further significant air emission reductions can be attained in a relatively cost-effective manner. Cost recovery filings are required to be made 90 days prior to the anticipated in-service date for the equipment at each unit, with rate recovery beginning the month following the in-service date.

Minnesota Power has completed installation of new equipment at Laskin and current cost recovery of AREA Plan costs has begun. The first of three Taconite Harbor unit installations was completed and placed back in-service in June 2007, with current cost recovery began in July 2007. We anticipate cost recovery on the other Taconite Harbor units once work is completed and the units have been placed back in service, which is expected in late 2008. As of December 31, 2007, we have spent $36 million of the anticipated $60 million in AREA Plan expenditures.

In May 2006, Minnesota Power announced plans to make emission reduction investments at our Boswell Unit 3 generating unit. Plans include reductions of particulate, SO_2, NO_X and mercury emissions to meet pending federal and state requirements. In late March 2007, the Boswell Unit 3 project received the necessary construction permits. On October 26, 2007, the MPUC issued a written order approving Minnesota Power's petition for current cost recovery for the Boswell Unit 3 emission reduction plan with some minor modifications and additional reporting requirements. MPUC approval authorized a cash return on construction work in progress during the construction phase in lieu of AFUDC-Equity and allows for a return on investment and current cost recovery of incremental expenses once the unit is placed into service in late 2009. On December 26, 2007, the MPUC approved Boswell Unit 3's rate adjustment for 2008. As of December 31, 2007, we have spent $89 million of the anticipated $200 million in Boswell Unit 3 emission reduction plan expenditures.

Conservation Improvement Program (CIP). Minnesota requires electric utilities to spend a minimum of 1.5 percent of gross operating revenues from service provided in the state on energy CIP's each year. These investments are recovered from retail customers through a billing adjustment and amounts included in retail base rates. The MPUC allows utilities to accumulate, in a deferred account for future cost recovery, all CIP expenditures, as well as a carrying charge on the deferred account balance. The Next Generation Energy Act of 2007 introduced, in addition to minimum spending requirements, an energy-saving goal of 1.5 percent of gross annual retail electric energy sales by 2010. In May 2007, an abbreviated filing was submitted and subsequently approved by the MPUC, allowing the continuation of Minnesota Power's 2006-2007 CIP biennial and related goals for one additional year, through 2008. For future program years, Minnesota Power will build upon current successful CIP's in an effort to meet the newly established 1.5 percent energy-saving goal. Minnesota Power's CIP investment goal was $3.2 million for 2007 ($3.2 million for 2006 and 2005), with actual spending of $3.9 million in 2007 ($3.8 million in 2006; $3.6 million in 2005).

Public Service Commission of Wisconsin. SWL&P's current retail rates are based on a December 2006 PSCW retail rate order that became effective January 1, 2007, and allows for an 11.1 percent return on common equity. Current rates reflect a 2.8 percent average increase in retail utility rates for SWL&P customers (a 2.8 percent increase in electric rates, a 1.4 percent increase in natural gas rates and an 8.6 percent increase in water rates). SWL&P originally requested an average increase in retail utility rates of 5.2 percent in its 2006 application. The approved rates were lower than originally requested due to the subsequent removal of costs for a new water tower and electric substation from the original request. Both of these projects are now estimated to be in service in late 2008 because of delays in obtaining all the necessary construction approvals. SWL&P anticipates filing for another rate increase request in 2008 that would go into effect in 2009. Previously, SWL&P's retail rates were based on a 2005 PSCW retail order that allowed for an 11.7 percent return on common equity.

Minnesota Legislation

Renewable Energy. In February 2007, Minnesota enacted a law requiring Minnesota Power to generate or procure 25 percent of our energy through renewable energy sources by 2025. The legislation also requires Minnesota Power to meet interim milestones of 12 percent by 2012, 17 percent by 2016, and 20 percent by 2020. The legislation allows the MPUC to modify or delay a standard obligation if implementation will cause significant ratepayer cost or technical reliability issues. If a utility is not in compliance with a standard, the MPUC may order the utility to construct facilities, purchase renewable energy or purchase renewable energy credits. Minnesota Power was developing and making renewable supply additions as part of its generation planning strategy prior to this legislation and this activity continues. Minnesota Power believes it will meet the requirements of this legislation.

Energy–Regulated Utility (Continued)
Minnesota Legislation (Continued)

Greenhouse Gas Reduction. In 2007, Minnesota passed legislation establishing non-binding targets for carbon dioxide reductions. This legislation establishes a goal of reducing statewide greenhouse gas (GHG) emissions across all sectors reducing those emissions to a level at least 15 percent below 2005 levels by 2015, at least 30 percent below 2005 levels by 2025, and at least 80 percent below 2005 levels by 2050. Minnesota is also participating in the Midwestern Greenhouse Gas Accord, a regional effort to develop a multi-state approach to GHG emission reductions.

We cannot predict the nature or timing of any additional GHG legislation or regulation. Although we are unable to predict the compliance costs we might incur, the costs could have a material impact on our financial results.

Competition

We believe the overall impact of the EPAct 2005 on the electric utility industry has been positive and are continuing to evaluate the effects on our business as this legislation is being implemented. This federal legislation is designed to bring more certainty to energy markets in which ALLETE participates, as well as to provide investment incentives for energy efficiency, energy infrastructure (such as electric transmission lines) and energy production. The FERC has the responsibility of implementing numerous new standards as a result of the promulgation of the EPAct 2005. To date the FERC's regulatory efforts under the EPAct 2005 appear to be generally positive for the utility industry. The PUHCA 1935 repeal may also allow an acceleration of merger activity, as well as spawn moves by state regulators to adopt PUHCA-like regulations, although both events are speculative and difficult to predict. We cannot predict the timing or substance of any future legislation or regulation.

Franchises

Minnesota Power holds franchises to construct and maintain an electric distribution and transmission system in 91 cities and towns located within its electric service territory. SWL&P holds similar franchises for electric, natural gas and/or water systems in 15 cities and towns within its service territory. The remaining cities and towns served do not require a franchise to operate within their boundaries. Our exclusive service territories are established by state regulatory agencies.

Energy – Nonregulated Energy Operations

ALLETE's nonregulated energy operations include our coal mining activities in North Dakota, approximately 50 MW of nonregulated generation and Minnesota land sales.

BNI Coal operates a lignite mine in North Dakota. BNI Coal is a low-cost supplier of lignite in North Dakota, producing about 4 million tons annually. Two electric generating cooperatives, Minnkota Power and Square Butte, presently consume virtually all of BNI Coal's production of lignite under cost-plus a fixed-fee coal supply agreements extending through 2026. (See Item 1 - Fuel and Note 8.) The mining process disturbs and reclaims approximately 210 acres per year. Laws require that the reclaimed land be at least as productive as it was prior to mining. The average cost to reclaim one acre of land is about $15,000, however, it could be as high as $30,000. Reclamation costs are included in the cost of coal passed through to customers. With lignite reserves of an estimated 600 million tons, BNI Coal has ample capacity to expand production.

Nonregulated generation consists of approximately 50 MW of generation. In 2007, we sold 0.2 million MWh of nonregulated generation (0.2 million in 2006; 1.5 million in 2005). Effective January 1, 2006, Taconite Harbor was redirected from our Nonregulated Energy Operations segment to our Regulated Utility segment in accordance with an update to the Company's 2004 Resource Plan, as approved by the MPUC.

Nonregulated Power Supply	Unit No.	Year Installed	Year Acquired	Net Capability
				MW
Steam				
Wood-Fired *(a)*				
Cloquet Energy Center in Cloquet, MN	5	2001	2001	22
Rapids Energy Center *(b)* in Grand Rapids, MN	6 & 7	1969, 1980	2000	29
Hydro				
Conventional Run-of-River				
Rapids Energy Center *(b)* in Grand Rapids, MN	4 & 5	1917	2000	1

(a) Supplemented by coal.
(b) The net generation is primarily dedicated to the needs of one customer.

Energy – Nonregulated Energy Operations (Continued)

Taconite Harbor. Taconite Harbor facility has operated as a rate-based asset within the Minnesota retail jurisdiction since January 1, 2006. Prior to January 1, 2006, the Taconite Harbor facility was operated as nonregulated generation facility. (See Energy – Regulated Utility – Minnesota Public Utilities Commission.)

Rainy River Energy has been engaged in the acquisition and development of nonregulated generation and wholesale power marketing. (See Note 10.)

Rainy River Energy Corporation - Wisconsin continues to study the feasibility of the construction of a natural gas-fired electric generating facility in northwestern Wisconsin.

Minnesota Land. We have about 15,000 acres of land in northern Minnesota, available for sale. We acquired the land in 2001 when we purchased Taconite Harbor from LTV Steel Mining Co.

Energy – Investment in ATC

At December 31, 2007, we had an approximate 8 percent ownership interest in ATC. ATC is a Wisconsin-based public utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota and Illinois. ATC provides transmission service under rates regulated by the FERC that are set in accordance with the FERC's policy of establishing the independent operation and ownership of, and investment in, transmission facilities. (See Note 6.) Our Wisconsin subsidiary, Rainy River Energy Corporation - Wisconsin, has invested $60 million in ATC.

Real Estate

ALLETE Properties is our real estate business that has operated in Florida since 1991. ALLETE Properties acquires real estate portfolios and large land tracts at bulk prices, adds value through entitlements and/or infrastructure improvements, and resells the property over time to developers, end-users and investors. ALLETE Properties is focused on acquiring vacant land in Florida and other parts of the southeast United States. Management at ALLETE Properties uses their business relationships, understanding of real estate markets and expertise in the land development and sales processes to provide revenue and earnings growth opportunities to ALLETE.

ALLETE Properties is headquartered in Fort Myers, Florida, the location of its southwest Florida regional office. We also have a regional office in Palm Coast, Florida, which oversees northeast Florida operations.

Southwest Florida operations consist of land sales and a third-party brokerage business, with limited land development activities. Inventory includes residential and non-residential land located in Lehigh Acres and Cape Coral. The inventory represents the remaining properties acquired in 1991 from the Resolution Trust Corporation and in 1999 from Avatar Properties, Inc. The operation also generates rental income from a 186,000 square foot retail shopping center located in Winter Haven, Florida. The center is anchored by Macy's and Belk's department stores, along with Staples.

Northeast Florida operations focus on land sales and development activities. Development activities involve mainly zoning, permitting, platting and master infrastructure construction. Development costs are financed through a combination of community development district bonds, bank loans and internally-generated funds. Our three major development projects include Town Center at Palm Coast, Palm Coast Park and Ormond Crossings.

Town Center. Town Center, which is located in the city of Palm Coast, is a mixed-use development with a neo-traditional downtown core area. Surrounded by major arterial roads, including Interstate 95, Town Center is adjacent to the Florida Hospital-Flagler, the Flagler County Airport and the Flagler Palm Coast High School. Sites have also been set aside for a new city hall, a community center, an arts and entertainment center, and other public uses. At build-out, Town Center is expected to include approximately 3,200 residential units including lodging rooms and assisted living units, and 3.8 million square feet of various types of non-residential space. Market conditions will determine how quickly Town Center builds out.

Construction of the major infrastructure improvements at Town Center was substantially complete at the end of 2006. Improvements include 3.6 miles of roads, a master storm water management system, underground utilities, street lights, sidewalks, bike paths, and extensive landscaping. To date, our marketing program has targeted a blend of office, retail commercial, residential, mixed-use and institutional project developers. In April 2007, Palm Coast Center, LLC and Target Corporation closed on a 52 acre commercial site and immediately began construction of a 424,000 square foot retail power center. An 85,000 square foot retail center anchored by a Publix grocery store opened in 2007.

Real Estate (Continued)

Pending land sales under contract for properties at Town Center totaled $18.9 million at December 31, 2007. We have the opportunity to receive participation revenue as part of one of these sales contracts.

In March 2005, the Town Center District issued $26.4 million of tax-exempt, 6% Capital Improvement Revenue Bonds, Series 2005, which are payable through property tax assessments on the land owners over 31 years (by May 1, 2036). The bonds were primarily used to pay for the construction of a portion of the major infrastructure improvements at Town Center. (See Note 8.)

Palm Coast Park. Palm Coast Park, which is located in the city of Palm Coast, is a 4,700-acre mixed-use development bisected by a six-mile segment of U.S. Highway 1 about one mile from an existing Interstate 95 interchange and bounded on the west by a Florida East Coast Railroad line. Major infrastructure construction at Palm Coast Park was substantially complete by the end of 2007. At build-out, Palm Coast Park is expected to include approximately 4,000 residential units, 3.2 million square feet of various types of non-residential space and certain public facilities. Market conditions will determine how quickly Palm Coast Park builds out. Land sales at Palm Coast Park commenced in August 2006, and in June 2007, LRCF Palm Coast, LLC (a subsidiary of Lowe Enterprises) closed on the first phase of its Sawmill Creek project.

Pending land sales under contract for properties at Palm Coast Park totaled $31.9 million at December 31, 2007. We have the opportunity to receive participation revenue as part of these sales contracts.

In May 2006, the Palm Coast Park District issued $31.8 million of tax-exempt, 5.7% Special Assessment Bonds, Series 2006, which are payable through property tax assessments on the land owners over 31 years (by May 1, 2037). The bonds were primarily used to pay for the construction of the major infrastructure improvements at Palm Coast Park and to mitigate traffic and environmental impacts. (See Note 8.)

ALLETE Properties is funding certain platting and permitting costs; however, the majority of ongoing and future development costs may be funded by Palm Coast Park District bond proceeds. We anticipate that the Palm Coast Park District will need to issue additional bonds to pay for the development of retail commercial, office and industrial lots.

Ormond Crossings. Ormond Crossings is an approximately 6,000-acre mixed-use development that is located in both the city of Ormond Beach in Volusia County and unincorporated Flagler County. The site is bisected by Interstate 95 and a Florida East Coast Railroad line and is adjacent to the city of Ormond Beach airport. Ormond Crossings has three miles of frontage on the east and west sides of Interstate 95 and will have two main entrances each within a mile from an existing U.S. Highway 1 and Interstate 95 interchange.

Planning, engineering design and permitting of the master infrastructure are ongoing. Density of the residential and non-residential components of the project will be determined based on market and traffic mitigation cost considerations. We estimate the first two phases of Ormond Crossings will include 2,500–3,200 residential units and 2.5–3.5 million square feet of various types of non-residential space.

Ormond Crossings will also include an approximately 2,000 acre regionally significant wetlands mitigation bank that is expected to be fully permitted by the St. Johns River Water Management District and the U.S. Army Corps of Engineers by mid-2009. Wetland mitigation credits will be used at Ormond Crossings and will be available for sale to other developers. Market conditions will determine how quickly Ormond Crossings builds out.

Other Land. In addition to the major development projects, land inventories in Florida include approximately 1,600 acres of other property. Several smaller development projects are under way to plat these properties, add infrastructure, modify and enhance existing entitlements.

Property sale prices may vary depending on location; physical characteristics; parcel size; whether parcels are sold as raw land, partially developed land or individually developed lots; degree and status of entitlement; and whether the land is ultimately purchased for residential or non-residential development. Certain contracts allow us to receive participation revenue from land sales to third parties if various formula-based criteria are achieved.

Seller Financing

ALLETE Properties sometimes provides seller financing. At December 31, 2007, outstanding finance receivables were $15.3 million, with maturities up to 5 years. These finance receivables accrue interest at market-based rates and are collateralized by the financed properties.

Real Estate (Continued)

Regulation

A substantial portion of our development properties in Florida are subject to federal, state and local regulations, and restrictions that may impose significant costs or limitations on our ability to develop the properties. Much of our property is vacant land and some is located in areas where development may affect the natural habitats of various protected wildlife species or in sensitive environmental areas such as wetlands.

Development of real property in Florida entails an extensive approval process involving overlapping regulatory jurisdictions. Real estate projects must generally comply with the provisions of the Local Government Comprehensive Planning and Land Development Regulation Act (Growth Management Act), which requires counties and cities to adopt comprehensive plans guiding and controlling future real property development in their respective jurisdictions. In addition, development projects that exceed certain specified regulatory thresholds require approval of a comprehensive DRI application. The DRI review process includes an evaluation of a project's impact on the environment, infrastructure and government services, and requires the involvement of numerous state and local environmental, zoning and community development agencies. Compliance with the Growth Management Act and the DRI process is usually lengthy and costly.

Competition

The real estate industry is very competitive. Our properties are located in Florida. We are focused on acquiring additional vacant land in Florida and other parts of the southeast United States. This region continues to attract competitive real estate operations at many different levels in the land development pipeline. Competitors include local and out-of-state institutional investors, real estate investment trusts and real estate operators, among others. These competitors, both public and private, compete with us in seeking real estate for acquisition, resources for development and sales to prospective buyers. Consequently, competitive market conditions may influence the timing and profitability of our real estate transactions.

Other

Our Other segment consists of investments in emerging technologies related to the electric utility industry, and earnings on cash and short-term investments.

Emerging Technology Portfolio. As part of our emerging technology portfolio, we have several minority investments in venture capital funds and direct investments in privately-held, start-up companies. Since 1985, we have invested in start-up companies, developing technologies that may be utilized by the electric utility industry. We are committed to invest up to an additional $1.0 million in 2008 and do not have plans to make any additional investments. The investments were first made through emerging technology funds (Funds) initiated by other electric utilities and us. Due to the distribution of investments from matured venture capital funds, we also have direct investments in privately-held companies. Companies in the Funds' portfolios may complete IPOs, and the Funds may, in some instances, distribute publicly tradable shares to us. Some restrictions on sales may apply, including, but not limited to, underwriter lock-up periods that typically extend for 180 days following an IPO. (See Note 6.)

Discontinued Operations. In the past three years, we also had business operations in the water and telecommunications industries. (See Note 13.)

Sale of Water Services Businesses. In early 2005, we completed the exit from our Water Services businesses with the sale of our wastewater assets in Georgia.

Sale of Enventis Telecom. In December 2005, we sold all the stock of our telecommunications subsidiary, Enventis Telecom for $35.5 million. The transaction resulted in an after-tax loss of $3.6 million, which was reported in our 2005 loss from discontinued operations. Net cash proceeds realized from the sale were approximately $29 million after transaction costs, repayment of debt and payment of income taxes.

Environmental Matters

Our businesses are subject to regulation of environmental matters by various federal, state and local authorities. We consider our businesses to be in substantial compliance with currently applicable environmental regulations and believe all necessary permits to conduct such operations have been obtained. Due to future stricter environmental requirements through legislation and/or rulemaking, we anticipate that potential expenditures for environmental matters will be material and will require significant capital investments. (See Item 7 – Capital Requirements.) We are unable to predict if and when any such stricter environmental requirements will be imposed and the impact they will have on the Company. We review environmental matters on a quarterly basis. Accruals for environmental matters are recorded when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated, based on current law and existing technologies. These accruals are adjusted periodically as assessment and remediation efforts progress or as additional technical or legal information becomes available. Accruals for environmental liabilities are included in the balance sheet at undiscounted amounts and exclude claims for recoveries from insurance or other third parties. Costs related to environmental contamination treatment and cleanup are charged to expense unless recoverable in rates from customers.

Environmental Matters (Continued)

Air. *Clean Air Act.* Minnesota Power's generating facilities mainly burn low-sulfur western sub-bituminous coal. Square Butte, located in North Dakota, burns lignite coal. All of these facilities are equipped with pollution control equipment such as scrubbers, bag houses or electrostatic precipitators. Permitted emission requirements are currently being met. The federal Clean Air Act Amendments of 1990 (Clean Air Act) established the acid rain program which created emission allowances for SO_2 and system wide averaging NO_X limits. Each allowance is currently an authorization to emit one ton of SO_2, and each utility must have sufficient allowances to cover its annual emissions. Minnesota Power has adequate SO_2 allowances for its operations and is in compliance with applicable NO_X limits. Square Butte is meeting its SO_2 emission allowance requirements through increased use of its existing scrubber.

EPA Clean Air Interstate Rule. In March 2005, the EPA announced the final Clean Air Interstate Rule (CAIR) that reduces and permanently caps emissions of SO_2, NO_X and particulates in the eastern United States. The CAIR includes Minnesota as one of the 28 states it considers as "significantly contributing" to air quality standards non-attainment in other downwind states. The CAIR has been challenged in the court system, which may delay implementation or modify provisions in the rules. Minnesota Power is participating in the legal challenge to the CAIR. However, if the CAIR does go into effect, Minnesota Power expects to be required to:

(1) make emissions reductions (See AREA and Boswell Unit 3 Emission Reduction Plans for discussion of current emission reduction initiatives);
(2) purchase SO_2 and NO_X allowances through the EPA's cap-and-trade system (See CAIR Phase I NO_X Allowance Purchases below); and/or
(3) use a combination of both (1) and (2).

CAIR will be implemented over two phases. Phase I begins in 2009 and Phase II in 2015. The EPA will allocate an emissions budget to each CAIR-affected state for SO_2 and NO_X that will result in significant emission reductions. The emissions budgets are reduced from Phase I to Phase II. States can choose to implement the EPA's proposed model program or develop their own subject to EPA approval. The MPCA has indicated that it plans to adopt the EPA's Federal Implementation Plan. Minnesota Power is implementing a balanced environmental plan making significant capital investments with the AREA and Boswell Unit 3 emission reduction retrofits in efforts to comply with CAIR Phase I and purchasing emission allowances as necessary. In spite of these efforts, Minnesota Power expects to be in a short position relative to NO_X allowances beginning in 2009, and is anticipating purchasing NO_X allowances as needed during Phase I of CAIR.

EPA Clean Air Mercury Rule. In March 2005, the EPA also announced the final Clean Air Mercury Rule (CAMR) that would have reduced and permanently capped emissions of electric utility mercury emissions in the continental United States. On February 8, 2008 the United States Court of Appeals for the District of Columbia Circuit overturned the CAMR and remanded the rulemaking to the EPA for reconsideration. The Court's decision is subject to appeal. It is uncertain how the EPA will respond; and therefore it is also uncertain whether mercury emission reductions expected as a result of implementing AREA Plan expenditures at Taconite Harbor, and implementation of the 2006 Minnesota Mercury Emission Reduction Law which applies to Boswell Units 3 and 4, will meet the EPA's reformed mercury regulations. (See Minnesota Mercury Emission Law.) Cost estimates for complying with future mercury regulations under the Clean Air Act are therefore premature at this time.

Minnesota Mercury Emission Law. This legislation requires Minnesota Power to file mercury emission reduction plans for its Boswell Units 3 and 4. The Boswell Unit 3 emission reduction plan was filed with the MPCA in October 2006. Minnesota Power is required to install mercury emission reduction technology and equipment by December 31, 2010. (See AREA and Boswell Unit 3 Emission Reduction Plans in Item 1 Energy – Regulated Utility.) The next step will be to file a mercury emissions reduction plan for Boswell Unit 4 by July 1, 2011, with implementation no later than December 31, 2014.

Water. The Federal Water Pollution Control Act requires NPDES permits to be obtained from the EPA (or, when delegated, from individual state pollution control agencies) for any wastewater discharged into navigable waters. We have obtained all necessary NPDES permits, including NPDES storm water permits for applicable facilities, to conduct our operations. We are in material compliance with these permits.

Solid and Hazardous Waste. The Resource Conservation and Recovery Act of 1976 regulates the management and disposal of solid wastes and hazardous wastes. We are required to notify the EPA of hazardous waste activity and, consequently, routinely submit the necessary reports to the EPA. The Toxic Substances Control Act regulates the management and disposal of materials containing polychlorinated biphenyl (PCB). In response to the EPA Region V's request for utilities to participate in the Great Lakes Initiative by voluntarily removing remaining PCB inventories, Minnesota Power replaced its PCB capacitor banks by 2005. PCB-contaminated oil in substation equipment was replaced by June 2007. We are in material compliance with these rules.

Environmental Matters (Continued)

SWL&P Manufactured Gas Plant. In May 2001, SWL&P received notice from the WDNR that the City of Superior had found soil contamination on property adjoining a former Manufactured Gas Plant (MGP) site owned and operated by SWL&P from 1889 to 1904. A report submitted in 2003 identified some MGP-like chemicals that were found in the soil near the former plant site. The final Phase II report was issued on June 7, 2007, confirming our understanding of the issues involved. The final Phase II Report and Risk Assessment were sent to the WDNR for review on June 18, 2007. A remediation plan was developed during the last quarter of 2007 and will be submitted to the WDNR during the first quarter of 2008. Although it is not possible to fully quantify the potential clean-up cost until the WDNR's review is completed, a $0.5 million liability was recorded in December 2003 to address the known areas of contamination. The Company has recorded a corresponding dollar amount as a regulatory asset to offset this liability. The PSCW approved the collection through rates of $0.3 million of site investigation costs that had been incurred through 2005. ALLETE maintains pollution liability insurance coverage that includes coverage for SWL&P. A claim has been filed with respect to this matter. The insurance carrier has issued a reservation of rights letter and the Company continues to work with the insurer to determine the availability of insurance coverage.

Employees

At December 31, 2007, ALLETE had approximately 1,500 employees, of which 1,400 were full-time.

Minnesota Power and SWL&P have an aggregate 622 employees who are members of the International Brotherhood of Electrical Workers (IBEW) Local 31. The labor agreement with IBEW Local 31 expires on January 31, 2009.

BNI Coal has 97 employees who are members of the IBEW Local 1593. BNI Coal and IBEW Local 1593 have a labor agreement which expires on March 31, 2008. BNI expects to have a new labor agreement in place on, or before, the expiration of the existing contract.

Availability of Information

ALLETE makes its SEC filings, including its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any amendments to those reports, available free of charge on ALLETE's Website www.allete.com, as soon as reasonably practicable after they are electronically filed with or furnished to the SEC.

Executive Officers of the Registrant

Executive Officers	**Initial Effective Date**
Donald J. Shippar, Age 58	
Chairman, President and Chief Executive Officer	January 1, 2006
President and Chief Executive Officer	January 21, 2004
Executive Vice President – ALLETE and President – Minnesota Power	May 13, 2003
President and Chief Operating Officer – Minnesota Power	January 1, 2002
Deborah A. Amberg, Age 42	
Senior Vice President, General Counsel and Secretary	January 1, 2006
Vice President, General Counsel and Secretary	March 8, 2004
Steven Q. DeVinck, Age 48	
Controller	July 12, 2006
Laura A. Holquist, Age 46	
President – ALLETE Properties, LLC	September 6, 2001
Mark A. Schober, Age 52	
Senior Vice President and Chief Financial Officer	July 1, 2006
Senior Vice President and Controller	February 1, 2004
Vice President and Controller	April 18, 2001
Donald W. Stellmaker, Age 50	
Treasurer	July 24, 2004
Claudia Scott Welty, Age 55	
Senior Vice President and Chief Administrative Officer	February 1, 2004

All of the executive officers have been employed by us for more than five years in executive or management positions. Prior to election to the positions shown above, the following executives held other positions with the Company during the past five years.

Ms. Amberg was a Senior Attorney.

Mr. DeVinck was Director of Nonutility Business Development, and Assistant Controller.

Mr. Stellmaker was Director of Financial Planning.

Ms. Welty was Vice President Strategy and Technology Development.

There are no family relationships between any of the executive officers. All officers and directors are elected or appointed annually.

The present term of office of the executive officers listed above extends to the first meeting of our Board of Directors after the next annual meeting of shareholders. Both meetings are scheduled for May 13, 2008.

Item 1A. Risk Factors

Readers are cautioned that forward-looking statements, including those contained in this Form 10-K, should be read in conjunction with our disclosures under the heading: “Safe Harbor Statement Under the Private Securities Litigation Reform Act of 1995” located on page 5 of this Form 10-K and the factors described below. The risks and uncertainties described in this Form 10-K are not the only ones facing our Company. Additional risks and uncertainties that we are not presently aware of, or that we currently consider immaterial, may also affect our business operations. Our business, financial condition or results of operations could suffer if the concerns set forth below are realized.

Our Regulated Utility results of operations could be negatively impacted if our Large Power Customers experience an economic down cycle or fail to compete effectively in the global economy.

Our 12 Large Power Customers accounted for approximately 34 percent of our 2007 consolidated operating revenue (one of these customers accounted for 12 percent of consolidated revenue). These customers are involved in cyclical industries that by their nature are adversely impacted by economic downturns and are subject to strong competition in the global marketplace. An economic downturn or failure to compete effectively in the global economy could have a material adverse effect on their operations and, consequently, could negatively impact our results of operations.

Our Regulated Utility is subject to extensive governmental regulations that may have a negative impact on our business and results of operations.

We are subject to prevailing governmental policies and regulatory actions, including those of the United States Congress, state legislatures, the FERC, the MPUC and the PSCW. These governmental regulations relate to allowed rates of return, financings, industry and rate structure, acquisition and disposal of assets and facilities, operation and construction of plant facilities, recovery of purchased power and capital investments, and present or prospective wholesale and retail competition (including but not limited to transmission costs). These governmental regulations significantly influence our operating environment and may affect our ability to recover costs from our customers. We are required to have numerous permits, approvals and certificates from the agencies that regulate our business. We believe the necessary permits, approvals and certificates have been obtained for existing operations and that our business is conducted in accordance with applicable laws; however, we are unable to predict the impact on our operating results from the future regulatory activities of any of these agencies. Changes in regulations or the imposition of additional regulations could have an adverse impact on our results of operations.

Our ability to obtain rate adjustments to maintain current rates of return depends upon regulatory action under applicable statues and regulations, and we cannot assure that rate adjustments will be obtained or current authorized rates of return on capital will be earned. Minnesota Power and SWL&P from time to time file rate cases with federal and state regulatory authorities. In future rate cases, if Minnesota Power and SWL&P do not receive an adequate amount of rate relief, rates are reduced, increased rates are not approved on a timely basis or costs are otherwise unable to be recovered through rates, we may experience an adverse impact on our financial condition, results of operations and cash flows. We are unable to predict the impact on our business and operations results from future regulatory activities of any of these agencies.

Our Regulated Utility could be significantly impacted by initiatives designed to reduce the impact of greenhouse gas (GHG) emissions such as carbon dioxide from our generating facilities.

Proposals for voluntary initiatives and mandatory controls are being discussed within Minnesota, among a group of midwestern states that includes Minnesota, in the United States Congress and worldwide to reduce GHGs such as carbon dioxide, a by-product of burning fossil fuels. We currently use coal as the primary fuel in 94 percent of the energy produced by our generating facilities.

We cannot be certain whether new laws or regulations will be adopted to reduce GHGs and what affect any such laws or regulations would have on us. If any new laws or regulations are implemented, they could have a material effect on our results of operations, particularly if implementation costs are not fully recoverable from customers.

Our Regulated Utility has established a goal to reduce overall GHG emissions associated with electric generation and delivery. We plan to expand our renewable energy production, expand customer conservation and process efficiency improvements, select low GHG emitting resources to meet new generation needs, and expand the use of renewable generation resources through dispatching those units based on their environmental performance.

We are participating in research and study initiatives to mitigate the potential impact carbon emissions regulation to our business. There is no assurance that our current reduction efforts will mitigate the impact of any new regulations.

The cost of environmental emission allowances could have a negative financial impact on our Regulated Utility Operations.

Minnesota Power is subject to numerous environmental laws and regulations which require us to purchase environmental emissions allowances which could increase our cost of operations and expose us to emission price fluctuations. We are unable to predict emission allowance pricing or regulatory recovery of these costs. We will be pursuing a current cost recovery mechanism with the MPUC and FERC.

Our Regulated Utility and Nonregulated Energy Operations pose certain environmental risks which could adversely affect our results of operations and financial condition.

We are subject to extensive environmental laws and regulations affecting many aspects of our present and future operations, including air quality, water quality, waste management, reclamation and other environmental considerations. These laws and regulations can result in increased capital, operating and other costs, as a result of compliance, remediation, containment and monitoring obligations, particularly with regard to laws relating to power plant emissions. These laws and regulations generally require us to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Both public officials and private individuals may seek to enforce applicable environmental laws and regulations. We cannot predict the financial or operational outcome of any related litigation that may arise.

There are no assurances that existing environmental regulations will not be revised or that new regulations seeking to protect the environment will not be adopted or become applicable to us. Revised or additional regulations, which result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from customers, could have a material effect on our results of operations.

We cannot predict with certainty the amount or timing of all future expenditures related to environmental matters because of the difficulty of estimating such costs. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all potentially responsible parties.

The operation and maintenance of our generating facilities in our Regulated Utility and Nonregulated Energy Operations involve risks that could significantly increase the cost of doing business.

The operation of generating facilities involves many risks, including start-up risks, breakdown or failure of facilities, the dependence on a specific fuel source, or the impact of unusual or adverse weather conditions or other natural events, as well as the risk of performance below expected levels of output or efficiency, the occurrence of any of which could result in lost revenue, increased expenses or both. A significant portion of Minnesota Power's facilities were constructed many years ago. In particular, older generating equipment, even if maintained in accordance with good engineering practices, may require significant capital expenditures to keep operating at peak efficiency. This equipment is also likely to require periodic upgrading and improvements due to changing environmental standards and technological advances. (See Item I – Environmental Matters.) Minnesota Power could be subject to costs associated with any unexpected failure to produce power, including failure caused by breakdown or forced outage, as well as repairing damage to facilities due to storms, natural disasters, wars, terrorist acts and other catastrophic events. Further, our ability to successfully and timely complete capital improvements to existing facilities or other capital projects is contingent upon many variables and subject to substantial risks. Should any such efforts be unsuccessful, we could be subject to additional costs and/or the write-off of our investment in the project or improvement.

Our Regulated Utility and Nonregulated Energy Operations must have adequate and reliable transmission and distribution facilities to deliver electricity to its customers.

Minnesota Power depends on transmission and distribution facilities owned by other utilities, and transmission facilities primarily operated by MISO, as well as its own such facilities, to deliver the electricity we produce and sell to our customers, and to other energy suppliers. If transmission capacity is inadequate, our ability to sell and deliver electricity may be hindered, we may have to forego sales or we may have to buy more expensive wholesale electricity that is available in the capacity-constrained area. The cost to acquire or provide service may exceed the cost to serve other customers, resulting in lower gross margins. In addition, any infrastructure failure that interrupts or impairs delivery of electricity to our customers could negatively impact the satisfaction of our customers with our service.

Risk Factors (Continued)

In our Regulated Utility and Nonregulated Energy Operations the price of electricity and fuel may be volatile.

Volatility in market prices for electricity and fuel may result from:

- severe or unexpected weather conditions;
- seasonality;
- changes in electricity usage;
- transmission or transportation constraints, inoperability or inefficiencies;
- availability of competitively priced alternative energy sources;
- changes in supply and demand for energy;
- changes in power production capacity;
- outages at Minnesota Power's generating facilities or those of our competitors;
- changes in production and storage levels of natural gas, lignite, coal, crude oil and refined products;
- natural disasters, wars, sabotage, terrorist acts or other catastrophic events; and
- federal, state, local and foreign energy, environmental, or other regulation and legislation.

Since fluctuations in fuel expense related to our regulated utility operations are passed on to customers through our fuel clause, risk of volatility in market prices for fuel and electricity mainly impacts our nonregulated operations at this time.

We are dependent on good labor relations.

We believe our relations to be good with our approximately 1,500 employees. Failure to successfully renegotiate labor agreements could adversely affect the services we provide and our results of operations. Approximately 600 of our employees are members of either the International Brotherhood of Electrical Workers Local 31 or Local 1593. The labor agreement with Local 31 at Minnesota Power and SWL&P expires on January 31, 2009, and the labor agreement with Local 1593 at BNI Coal expires on March 31, 2008.

A downturn in economic conditions could adversely affect our real estate business.

The ability of our real estate business to generate revenue is directly related to the Florida real estate market, the national and local economy in general and changes in interest rates. While conditions in the Florida real estate market may fluctuate over time, continued demand for land is dependent on long-term prospects for strong, in-migration population expansion.

We are exposed to risks associated with real estate development.

Our real estate development activities entail risks that include construction delays or cost overruns, which may increase project development costs. In addition, the effects of the rebuilding efforts due to destructive weather, including hurricanes, could cause increased prices for construction materials and create labor shortages which could increase our development costs.

Our real estate development activities require significant expenditures. We obtain funds for our expenditures through cash flow from operations and financings, including the financings of the community development districts in which our development projects are located. We cannot be certain that the funds available from these sources will be sufficient to fund our required or desired expenditures for development. If we are unable to obtain sufficient funds, we may have to defer or otherwise limit our development activities.

Risk Factors (Continued)

Our real estate business is subject to extensive regulation through Florida laws regulating planning and land development which makes it difficult and expensive for us to conduct our operations.

Development of real property in Florida entails an extensive approval process involving overlapping regulatory jurisdictions. Real estate projects must generally comply with the provisions of the Local Government Comprehensive Planning and Land Development Regulation Act (Growth Management Act). In addition, development projects that exceed certain specified regulatory thresholds require approval of a comprehensive DRI application.

The Growth Management Act requires counties and cities to adopt comprehensive plans guiding and controlling future real property development in their respective jurisdictions. After a local government adopts its comprehensive plan, all development orders and development permits must be consistent with the plan. Each plan must address such topics as future land use, capital improvements, traffic circulation, sanitation, sewage, potable water, drainage and solid waste disposal.

The Growth Management Act, in some instances, can significantly affect the ability of developers to obtain local government approval in Florida. In many areas, infrastructure funding has not kept pace with growth. As a result, substandard facilities and services can delay or prevent the issuance of permits. Consequently, the Growth Management Act could adversely affect the cost and our ability to develop future real estate projects.

The DRI review process includes an evaluation of a project's impact on the environment, infrastructure and government services, and requires the involvement of numerous state and local environmental, zoning and community development agencies. The DRI approval process is usually lengthy and costly, and conditions, standards or requirements may be imposed on a developer with respect to a particular project, which may materially increase the cost of the project.

Changes in the Growth Management Act or DRI review process or the enactment of new laws regarding the development of real property could adversely affect our ability to develop future real estate projects.

Competition could adversely affect our real estate business.

Over the past few years, we have experienced an increase in competition for suitable land in the southeast United States real estate market. The availability of undeveloped land for purchase that meets our internal criteria depends on a number of factors outside our control, including land availability in general, competition with other developers and land buyers for desirable property, inflation in land prices, zoning, allowable development density and other regulatory requirements. Our long-term ability to acquire land suitable for development at reasonable prices in locations where we feel there is a viable market is crucial in maintaining our business success.

If we are not able to retain our executive officers and key employees, we may not be able to implement our business strategy and our business could suffer.

The success of our business heavily depends on the leadership of our executive officers, all of whom are employees-at-will and none of whom are subject to any agreements not to compete. If we lose the service of one or more of our executive officers or key employees, or if one or more of them decides to join a competitor or otherwise compete directly or indirectly with us, we may not be able to successfully manage our business or achieve our business objectives. We may have difficulty in retaining and attracting customers, developing new services, negotiating favorable agreements with customers and providing acceptable levels of customer service.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Properties are included in the discussion of our businesses in Item 1 and are incorporated by reference herein.

Item 3. Legal Proceedings

Material legal and regulatory proceedings are included in the discussion of our businesses in Item 1 and are incorporated by reference herein.

We are involved in litigation arising in the normal course of business. Also in the normal course of business, we are involved in tax, regulatory and other governmental audits, inspections, investigations and other proceedings that involve state and federal taxes, safety, compliance with regulations, rate base and cost of service issues, among other things. We do not expect the outcome of these matters to have a material effect on our financial position, results of operations or cash flows.

Item 4. Submission of Matters to a Vote of Security Holders

No matters were submitted to a vote of security holders during the fourth quarter of 2007.

Part II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Our common stock is listed on the NYSE under the symbol ALE. We have paid dividends without interruption on our common stock since 1948. A quarterly dividend of $0.43 per share on our common stock will be paid on March 1, 2008, to the holders of record on February 15, 2008.

The following table shows dividends declared per share, and the high and low prices for our common stock for the periods indicated as reported by the NYSE:

	2007			2006		
	Price Range		Dividends	Price Range		Dividends
Quarter	High	Low	Declared	High	Low	Declared
First	$49.69	$44.93	$0.4100	$47.81	$42.99	$0.3625
Second	51.30	45.39	0.4100	48.55	44.34	0.3625
Third	50.05	38.60	0.4100	49.30	43.26	0.3625
Fourth	46.48	38.17	0.4100	47.84	42.55	0.3625
Annual Total			$1.640			$1.450
Dividend Payout Ratio			53%			53%

At February 1, 2008, there were approximately 31,000 common stock shareholders of record.

Common Stock Repurchases. We did not repurchase any ALLETE common stock during the fourth quarter of 2007.

Item 6. Selected Financial Data

Financial results by segment for the periods presented were impacted by the integration of our Taconite Harbor facility into the Regulated Utility segment effective January 1, 2006. We have operated the Taconite Harbor facility as a rate-based asset within the Minnesota retail jurisdiction since January 1, 2006. Prior to January 1, 2006, we operated our Taconite Harbor facility as nonregulated generation (non-rate base generation sold at market-based rates primarily to the wholesale market). Historical financial results of Taconite Harbor for periods prior to the 2006 redirection are included in our Nonregulated Energy Operations segment.

Operating results of our Water Services businesses and our telecommunications business are included in discontinued operations, and accordingly, amounts have been restated for all periods presented. (See Note 13.) Common share and per share amounts have also been adjusted for all periods to reflect our September 20, 2004, one-for-three common stock reverse split.

	2007	2006	2005	2004	2003
Operating Revenue	$841.7	$767.1	$737.4	$704.1	$659.6
Operating Expenses	708.0	626.4	692.3 *(d)*	603.2	561.9
Income from Continuing Operations Before Change in Accounting Principle	87.6	77.3	17.6 *(d)*	38.5	29.2
Income (Loss) from Discontinued Operations – Net of Tax	–	(0.9)	(4.3)	73.7	207.2
Change in Accounting Principle – Net of Tax	–	–	–	(7.8) *(b)*	–
Net Income	87.6	76.4	13.3	104.4	236.4
Common Stock Dividends	44.3	40.7	34.4	79.7	93.2
Earnings Retained in (Distributed from) Business	$43.3	$35.7	$(21.1)	$24.7	$143.2
Shares Outstanding – Millions					
Year-End	30.8	30.4	30.1	29.7	29.1
Average *(c)*					
Basic	28.3	27.8	27.3	28.3	27.6
Diluted	28.4	27.9	27.4	28.4	27.8
Diluted Earnings (Loss) Per Share					
Continuing Operations	$3.08	$2.77	$0.64 *(d)*	$1.35 *(e)*	$1.05
Discontinued Operations	–	(0.03)	(0.16)	2.59	7.47 *(f)*
Change in Accounting Principle	–	–	–	(0.27)	–
	$3.08	$2.74	$0.48	$3.67	$8.52
Total Assets	$1,644.2	$1,533.4 *(a)*	$1,398.8	$1,431.4	$3,101.3
Long-Term Debt	410.9	359.8	387.8	389.4	513.9
Return on Common Equity	12.4%	12.1%	2.2% *(d)*	8.3%	17.7%
Common Equity Ratio	63.7%	63.1%	60.7%	61.7%	64.4%
Dividends Declared per Common Share	$1.6400	$1.4500	$1.2450	$2.8425	$3.3900
Dividend Payout Ratio	53%	53%	259% *(d)*	77%	40%
Book Value Per Share at Year-End	$24.11	$21.90	$20.03	$21.23	$50.18
Capital Expenditures by Segment					
Regulated Utility Operations	$220.6	$107.5	$46.5	$41.7	$42.2
Non Regulated Utility	3.3	1.9	12.1	15.7	26.5
Real Estate *(h)*	–	–	–	–	–
Other	–	–	–	0.4	–
Discontinued Operations	–	–	4.5	21.4	67.6
Total Capital Expenditures	$223.9	$109.4	$63.1	$79.2	$136.3
Current Cost Recovery *(g)*	$145	$27	–	–	–

(a) Included $86.1 million of assets and $107.6 million of liabilities reflecting the adoption of SFAS 158 "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans." (See Notes 2 and 16.)

(b) Reflected the cumulative effect on prior years (to December 2003) of changing to the equity method of accounting for investments in limited liability companies included in our emerging technology portfolio. (See Note 6.)

(c) Excludes unallocated ESOP shares.

(d) Impacted by a $50.4 million, or $1.84 per share, charge related to the assignment of the Kendall County power purchase agreement (See Note 10.), a $2.5 million, or $0.09 per share, deferred tax benefit due to comprehensive state tax planning initiatives, and a $3.7 million, or $0.13 per share, current tax benefit due to a positive resolution of income tax audit issues.

(e) Included a $10.9 million, or $0.38 per share, after-tax debt prepayment cost incurred as part of ALLETE's financial restructuring in preparation for the spin-off of the Automotive Services business and an $11.5 million, or $0.41 per share, gain on the sale of ADESA shares related to the Company's ESOP (see Note 16).

(f) Included a $71.6 million, or $2.59 per share, gain on the sale of the Water Services businesses.

(g) Estimated current capital expenditures recoverable outside of a rate case.

(h) Excludes capitalized improvements on our development projects, which are included in inventory. (See Note 6.)

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion should be read in conjunction with our consolidated financial statements and notes to those statements and the other financial information appearing elsewhere in this report. In addition to historical information, the following discussion and other parts of this report contain forward-looking information that involves risks and uncertainties. Readers are cautioned that forward-looking statements should be read in conjunction with our disclosures in this Form 10-K under the headings: "Safe Harbor Statement Under the Private Securities Litigation Reform Act of 1995" located on page 5 and "Risk Factors" located in Item 1A. The risks and uncertainties described in this Form 10-K are not the only ones facing our Company. Additional risks and uncertainties that we are not presently aware of, or that we currently consider immaterial, may also affect our business operations. Our business, financial condition or results of operations could suffer if the concerns set forth in this Form 10-K are realized.

Overview

ALLETE is a diversified company that has provided fundamental products and services since 1906. These include our former operations in the water, paper, telecommunications and automotive industries and the core **Energy** and **Real Estate** businesses we operate today.

Energy is comprised of Regulated Utility, Nonregulated Energy Operations and Investment in ATC.

- **Regulated Utility** includes retail and wholesale rate regulated electric, natural gas and water services in northeastern Minnesota and northwestern Wisconsin under the jurisdiction of state and federal regulatory authorities.
- **Nonregulated Energy Operations** includes our coal mining activities in North Dakota, approximately 50 MW of nonregulated generation and Minnesota land sales.
- **Investment in ATC** includes our equity ownership interest in ATC.

Real Estate includes our Florida real estate operations.

Other includes our investments in emerging technologies, and earnings on cash and short-term investments.

We are committed to earning a financial return that rewards our shareholders, allows for reinvestment in our businesses, and sustains our growth. We strive to grow earnings and dividends that will result in a total shareholder return that is superior to that of similar companies. Our goal is to earn a financial return that will allow us to provide dividend increases while at the same time fund our growth initiatives.

2007 Financial Overview

(See Note 1. Business Segments for financial results by segment.)

Net income for 2007 was $87.6 million, or $3.08 per diluted share ($76.4 million, or $2.74 per diluted share for 2006; $13.3 million, or $0.48 per diluted share for 2005). Net income for 2007 was up $11.2 million from 2006 reflecting:

Regulated Utility contributed income of $54.9 million in 2007 ($46.8 million in 2006; $45.7 million in 2005). The increase in earnings for 2007 reflects:

- increased electric sales to residential, commercial and municipal customers;
- continued strong demand from our industrial customers;
- rate increases, effective January 1, 2007, at SWL&P;
- commencement of current cost recovery on AREA project environmental capital expenditures;
- higher AFUDC related to increased capital expenditures;
- increased operations and maintenance expense, relating to outages and salary and wage increases; and
- a lower effective tax rate.

Nonregulated Energy Operations reported income of $3.5 million in 2007 ($3.7 million in 2006; a loss of $48.5 million in 2005), reflecting a $1.2 million after tax gain on land sold that was part of our purchase of Taconite Harbor and higher lease lot revenue due to newly developed lots. The increases were partially offset by lower income from BNI Coal, reflecting lower coal sales in 2007.

Investment in ATC contributed income of $7.5 million in 2007 ($1.9 million in 2006). Our initial investment in ATC began in May 2006. We reached our approximate 8 percent ownership in February 2007.

Real Estate contributed income of $17.7 million in 2007 ($22.8 million in 2006; $17.5 million in 2005). Income was lower in 2007 than in 2006 due to a weaker real estate market in 2007.

Other reflected net income of $4.0 million in 2007 ($2.1 million in 2006; $2.9 million in 2005). The increase in 2007 included a state tax audit settlement for $1.5 million and the release from a loan guarantee for Northwest Airlines of $0.6 million after tax.

Overview (Continued)

Financial results for continuing operations in 2005 were significantly impacted by a $77.9 million ($50.4 million after tax, or $1.84 per share) charge due to the assignment of the Kendall County power purchase agreement to Constellation Energy Commodities (Kendall County Charge). (See Note 10.)

Financial results by segment from 2005 and 2006 presented and discussed in this Form 10-K were impacted by the integration of our Taconite Harbor facility into the Regulated Utility segment effective January 1, 2006. We have operated the Taconite Harbor facility as a rate-based asset within the Minnesota retail jurisdiction since January 1, 2006. Prior to January 1, 2006, we operated our Taconite Harbor facility as nonregulated generation. Historical financial results of Taconite Harbor for periods prior to the 2006 redirection are included in our Nonregulated Energy Operations segment.

Kilowatthours Sold	2007	2006	2005
Millions			
Regulated Utility			
Retail and Municipals			
Residential	1,141	1,100	1,102
Commercial	1,373	1,335	1,327
Industrial	7,054	7,206	7,130
Municipals	1,008	911	877
Other	84	79	79
Total Retail and Municipals	10,660	10,631	10,515
Other Power Suppliers	2,157	2,153	1,142
Total Regulated Utility	12,817	12,784	11,657
Nonregulated Energy Operations	249	240	1,521
Total Kilowatthours Sold	13,066	13,024	13,178

Real Estate	2007		2006		2005	
Revenue and Sales Activity *(a)*	**Quantity**	**Amount**	**Quantity**	**Amount**	**Quantity**	**Amount**
Dollars in Millions						
Revenue from Land Sales						
Town Center Sales						
Non-residential Sq. Ft.	540,059	$15.0	401,971	$10.8	643,000	$15.2
Residential Units	130	1.6	773	12.9	–	–
Palm Coast Park						
Non-residential Sq. Ft.	40,000	2.0	–	–	–	–
Residential Unit	606	13.2	200	3.0	–	–
Other Land Sales						
Acres *(b)*	483	10.6	732	24.4	1,102	38.1
Lots	–	–	–	–	7	0.4
Contract Sales Price *(c)*		42.4		51.1		53.7
Revenue Recognized from						
Previously Deferred Sales		3.1		9.7		–
Deferred Revenue		(1.2)		(3.8)		(10.0)
Adjustments *(d)*		–		(0.9)		(1.7)
Revenue from Land Sales		44.3		56.1		42.0
Other Revenue		6.2		6.5		5.5
		$50.5		$62.6		$47.5

(a) Quantity amounts are approximate until final build-out.
(b) Acreage amounts are shown on a gross basis, including wetlands and minority interest.
(c) Reflected total contract sales price on closed land transactions. Land sales are recorded using a percentage-of-completion method. (See Critical Accounting Estimates and Note 2.)
(d) Contributed development dollars, which are credited to cost of real estate sold.

2007 Compared to 2006

(See Note 1. Business Segments for financial results by segment.)

Regulated Utility

Operating revenue increased $84.6 million, or 13.2 percent, from 2006, primarily due to increased fuel clause recoveries, increased kilowatthour sales to residential, commercial and municipal customers, increased power marketing prices, and rate increases at SWL&P.

Fuel clause recoveries increased $63.3 million in 2007 as a result of increased purchased power expenses (see Fuel and Purchased Power Expense discussion below).

Revenue recovered through current cost recovery related to AREA Plan expenditures represented $3.2 million in 2007 ($0.1 million in 2006).

Revenue from sales to other power suppliers increased $3.6 million, or 3.8 percent, from 2006, primarily due to a 3.6 percent increase in the price per kilowatthour.

New rates at SWL&P, which became effective January 1, 2007, reflect a 2.8 percent increase in electric rates, a 1.4 percent increase in gas rates and an 8.6 percent increase in water rates. These rate increases resulted in a $1.7 million increase in operating revenue.

Revenue from electric sales to taconite customers accounted for 24 percent of consolidated operating revenue in each 2007 and 2006. Revenue from electric sales to paper and pulp mills accounted for 9 percent of consolidated operating revenue in each of 2007 and 2006. Revenue from electric sales to pipelines accounted for 7 percent of consolidated operating revenue in 2007 (6 percent in 2006).

Overall, kilowatthour sales were flat in 2007. Combined residential, commercial and municipal kilowatthour sales increased 181.0 million, or 5.3 percent, from 2006, while industrial kilowatthour sales decreased by 152.1 million, or 2.1 percent. The increase in residential, commercial and municipal kilowatthour sales was primarily because of two existing municipal customers converting to full-energy requirements and a 9.2 percent increase in Heating Degree Days (primarily in February). The reduction in industrial kilowatthour sales was primarily due to an idle production line and production delays at one of our taconite customers. In September 2007, the affected taconite customer resumed production on the idle line. Minor fluctuations in industrial kilowatthour sales generally do not have a large impact on revenue due to a fixed demand component of revenue that is less sensitive to changes in kilowatthours sales.

Operating expenses increased $76.9 million, or 14.1 percent, from 2006.

Fuel and Purchased Power Expense increased $65.9 million, or 23.4 percent, from 2006 primarily due to a $61.4 million increase in purchased power reflecting a 45.1 percent increase in market purchases and an 11.0 percent increase in market prices. The increase in purchased power was primarily due to the following outages at our generating facilities:

- scheduled outage at Boswell Unit 3;
- scheduled outages at Laskin Unit 1 and Taconite Harbor Unit 2 relating to AREA Plan environmental upgrades; and
- unscheduled outages at Boswell Unit 4.

Boswell Unit 4 completed generator repairs and returned to service in May 2007. Substantially all of the costs of the replacement coils were covered under the original manufacturer's warranty.

Lower Square Butte entitlement (See Note 8) and output contributed to higher purchased power expense. Square Butte generation was lower in the fourth quarter of 2007 reflecting a major scheduled outage.

Replacement purchased power costs are recovered through the fuel adjustment clause in Minnesota.

Operating and Maintenance Expense increased $11.4 million, or 5.2 percent, from 2006, due to a $9.0 million increase in plant maintenance primarily due to planned and unscheduled outages and salary and wage increases.

Depreciation Expense decreased $0.4 million from 2006, primarily due to the life extension of Boswell Unit 3, mostly offset by higher depreciable asset balances.

Interest Expense increased $0.8 million, or 4.0 percent, from 2006, primarily due to higher debt balances reflecting increased construction activity. The increase was partially offset by the capitalization of more AFUDC-Debt.

Other income increased $3.2 million from 2006, primarily due to higher earnings from the capitalization of AFUDC-Equity reflecting increased construction activity.

2007 Compared to 2006 (Continued)

Nonregulated Energy Operations

Operating revenue increased $2.0 million, or 3.1 percent, from 2006, primarily due to higher coal revenue realized under a cost-plus contract. This increase reflects a 12.2 percent increase in the delivered price per ton due to higher coal production expenses (see Operating expenses below), partially offset by lower sales volume.

Operating expenses increased $4.3 million, or 7.0 percent, from 2006, reflecting higher coal production expense and higher property taxes. The increase in property taxes is primarily due to higher assessed market values on our Minnesota land, while the increase in coal operating expenses is due to higher fuel costs, tire and dragline repairs.

Interest Expense decreased $1.3 million from 2006, reflecting lower interest on income tax accruals.

Other income increased $1.7 million from 2006, reflecting higher gains on Minnesota land sales and higher lease lot revenue due to leasing newly developed lots.

Investment in ATC

Equity Earnings increased $9.6 million in 2007, resulting from our pro-rata share of ATC's earnings as discussed in Note 3. Our initial investment in ATC began in May 2006. We reached our approximate 8 percent ownership in February 2007.

Real Estate

Operating revenue decreased $12.1 million, or 19.3 percent, from 2006, due to a weaker real estate market in 2007, and less recognition of deferred revenue, accounted for under the percentage-of-completion method, as major infrastructure reached substantial completion at Town Center in 2006 and at Palm Coast Park in 2007. Revenue from land sales in 2007 was $44.3 million, which included $3.1 million in previously deferred revenue. In 2006, revenue from land sales was $56.1 million which included $9.7 million in previously deferred revenue. At December 31, 2007, revenue of $3.7 million ($5.6 million at December 31, 2006) was deferred and will be recognized on a percentage-of-completion basis.

Sales at Town Center consisted of 540,059 non-residential square feet (401,971 square feet in 2006), and 130 residential units (773 units in 2006). Palm Coast Park sales included 40,000 non-residential square feet (none in 2006) and 606 residential units (200 units in 2006). In 2007, 483 acres of other land were sold (732 acres in 2006).

Operating expenses increased $0.6 million, or 3.1 percent from 2006, reflecting community development district property tax assessments previously capitalized at Town Center during major infrastructure construction partially offset by lower cost of sales due to the decrease in land sales.

Interest expense increased $0.5 million from 2006. Interest capitalization was reduced in 2007 as the major infrastructure construction at Town Center was substantially completed at the end of 2006.

Minority Interest participation was down due to lower earnings.

Other

Interest expense decreased $2.8 million from 2006, primarily due to more interest charged to the regulated utility in 2007 as a result of increased capital expenditures and interest on additional taxes owed on the gain on sale of our Florida Water assets in 2006.

Other income decreased $1.4 million from 2006, reflecting lower investment income as a result of lower average balances in 2007, partially offset by the release from a loan guarantee for Northwest Airlines of $1.0 million.

Income Taxes

For the year ended December 31, 2007, the effective tax rate on income from continuing operations before minority interest was 34.8 percent (36.1 percent for December 31, 2006). The decrease in the effective rate compared to last year was primarily due to a tax benefit realized as a result of a state income tax audit settlement ($1.5 million), higher AFUDC-Equity, and a larger domestic manufacturing deduction taken in 2007 compared to 2006. The effective rate of 34.8 percent for the year ended December 31, 2007, deviated from the statutory rate (approximately 40 percent) due to the state income tax audit settlement, deductions for Medicare health subsidies and domestic manufacturing production, AFUDC-Equity and investment tax credits.

2006 Compared to 2005

Regulated Utility

Operating revenue was up $63.6 million, or 11 percent, from 2005, reflecting increased kilowatthour sales and increased fuel clause recoveries. Electric sales increased 1,127 million kilowatthours, or 10 percent, mostly due to the addition of Taconite Harbor wholesale power obligations to the Regulated Utility segment effective January 1, 2006. In 2006, the majority of Taconite Harbor sales are reflected in sales to other power suppliers. Sales to other power suppliers were 2,153 million kilowatthours and $94.3 million (1,142 million kilowatthours and $52.8 million in 2005). Absent the inclusion of pre-existing Taconite Harbor wholesale energy sales obligations, sales to other power suppliers were down reflecting less excess energy available for sale due to more planned outages at Company generating facilities in 2006 than 2005. Electric sales to retail and municipal customers increased 116 million kilowatthours, or 1 percent, and $23.5 million, mainly due to strong demand from industrial customers. Fuel clause recoveries were higher in 2006 as a result of increased fuel and purchased power expenses in 2006. Natural gas revenue was down $2.8 million from 2005 reflecting decreased usage due to warmer weather in 2006.

Operating expenses were up $57.8 million, or 12 percent, from 2005.

Fuel and Purchased Power Expense. Fuel and purchased power expense was up $38.0 million from 2005, reflecting the inclusion of Taconite Harbor operations beginning in 2006 ($22.8 million) and increased purchased power expense due to higher prices paid for purchased power, less Company hydro generation available as a result of below normal precipitation levels, and planned maintenance at Company generating facilities in 2006.

Other Operating Expenses. Other operating expenses were up $19.8 million from 2005. Employee compensation was up $7.3 million primarily due to the inclusion of Taconite Harbor, annual wage increases and the inclusion of union employees in our results sharing compensation awards program. Depreciation expense increased $4.8 million primarily due to the inclusion of Taconite Harbor and a full year of depreciation of projects capitalized in 2005. Plant maintenance expense increased $4.7 million reflecting the inclusion of Taconite Harbor maintenance in 2006 ($4.0 million), increased planned maintenance expense at Boswell Unit 4 ($1.6 million) and increased equipment fuel expenses ($0.9 million) partially offset by a decrease in maintenance expense at Boswell Unit 3 ($1.8 million). In 2005, planned maintenance was performed at Boswell Unit 3 while the unit was down due to a cooling tower failure. Pension expense increased $2.2 million primarily due to a reduction in the discount rate (5.50 percent in 2006; 5.75 percent in 2005). Insurance expense was up $1.0 million due to increased premiums. Vegetation management expense was up $0.7 million due to more completed in 2006. Property taxes were up $0.7 million due to higher mill rates in 2006. Purchased natural gas expense was down $2.7 million due to decreased natural gas sales.

Interest expense was up $2.8 million, or 16 percent, from 2005, reflecting the inclusion of Taconite Harbor in 2006 partially offset by lower effective interest rates (5.92 percent in 2006; 6.07 percent in 2005).

Nonregulated Energy Operations

Operating revenue was down $48.9 million, or 43 percent, from 2005 due to the absence of revenue from Taconite Harbor ($55.1 million in 2005) and Kendall County ($3.1 million in 2005). Effective January 1, 2006, Taconite Harbor is reported as part of Regulated Utility. Kendall County operations ceased to be included with our operations effective April 1, 2005, when the Company assigned the power purchase agreement to Constellation Energy Commodities. Coal revenue, realized under cost plus a fixed fee agreements, was up $3.7 million from 2005 reflecting a 16 percent increase in the delivery price per ton due to higher reimbursable coal production expenses (see Operating expenses below). In 2006, tons of coal sold were down 7 percent from 2005 in part due to an outage at Minnkota Power's Unit 1 in 2006.

Operating expenses were down $125.2 million, or 67 percent, from 2005 reflecting the absence of a $77.9 million charge related to the assignment of the Kendall County power purchase agreement to Constellation Energy Commodities on April 1, 2005, expenses related to Taconite Harbor ($49.3 million in 2005) and other expenses related to Kendall County ($6.3 million in 2005) that were incurred prior to April 1, 2005. Expenses related to coal operations were up $3.4 million reflecting increased equipment lease costs ($1.3 million), higher fuel expenses ($0.6 million) and increased parts and supplies ($0.9 million).

Interest expense was down $3.3 million, or 50 percent, primarily due to the absence of Taconite Harbor in 2006.

Other income (expense) reflected $0.5 million more income in 2006 due to increased Minnesota land sales.

Investment in ATC

Other income (expense) reflected $3.0 million of income in 2006 from our equity investment in ATC, resulting from our share of ATC's earnings.

2006 Compared to 2005 (Continued)

Real Estate

Operating revenue was up $15.1 million, or 32 percent, from 2005, due to the recognition of revenue from prior land sales at our Town Center development project, which are accounted for under the percentage-of-completion method. Revenue from land sales was $56.1 million in 2006 which included $9.7 million of previously deferred revenue. In 2005, revenue from land sales was $42.0 million. Sales at Town Center represented 773 residential units and the rights to build up to 401,971 square feet of non-residential space in 2006 (643,000 non-residential square feet in 2005). Sales at Palm Coast Park represented 200 residential units in 2006. In 2006, 732 acres of other land were sold (1,102 acres and 7 lots in 2005). The first land sales for Town Center were recorded in June 2005 and the first land sales at Palm Coast Park were recorded in August 2006. At December 31, 2006, revenue of $5.6 million ($11.5 million at December 31, 2005) was deferred and will be recognized on a percentage-of-completion basis as development obligations are completed.

Operating expenses were up $2.9 million, or 17 percent, from 2005 reflecting a $1.6 million increase in the cost of real estate sold ($10.2 million in 2006; $8.6 million in 2005) due to the recognition of the cost of real estate sold at our Town Center development project which were previously deferred under the percentage-of-completion method. Selling expenses increased $0.6 million due to higher broker commission in 2006 and recognition of prior year's selling expenses at our Town Center development project which were previously deferred under the percentage-of-completion method. Property tax expense was $0.2 million higher in 2006 due to increased assessment values and higher rates. At December 31, 2006, cost of real estate sold totaling $1.3 million ($2.2 million at December 31, 2005) and selling expenses of $0.2 million ($0.3 million at December 31, 2005), primarily related to Town Center land sales, were deferred until development obligations are completed.

Other

Operating expenses were down $1.4 million, or 29 percent, from 2005, reflecting lower general and administrative expenses in 2006.

Interest expense was up $1.6 million, or 70 percent, from 2005, reflecting interest on additional taxes owed on the gain on the sale of our Florida Water assets and state tax audits, and higher variable rates in 2006.

Other income (expense) reflected $9.9 million more income in 2006 due to a $4.4 million increase in earnings on cash and short-term investments due to higher rates and higher average balances in 2006, the absence of $5.1 million of impairments related to certain investments in our emerging technology portfolio recorded in 2005 and the absence of a $1.0 million charge recognized in 2005 for the probable payment under our guarantee of Northwest Airlines debt.

Discontinued Operations

Discontinued operations includes our Water Services businesses that we sold over a three-year period from 2003 to 2005 and our telecommunications business, which we sold in December 2005. There were no losses recognized in discontinued operations in 2007 (a $0.9 million loss in 2006; $4.3 million loss in 2005).

In 2006, discontinued operations reflected a $0.9 million loss resulting from additional legal and administrative expenses related to exiting the Water Services businesses (a $2.5 million loss in 2005). In 2005, administrative and other expenses were incurred to support Florida Water transfer proceedings. A $1.0 million rate-base settlement charge related to the sale of 63 of Florida Water systems to Aqua Utilities Florida, Inc. was also recorded in 2005. Our wastewater assets in Georgia were sold in February 2005.

Financial results for our telecommunications business reflected a loss of $1.8 million in 2005. In 2005, we recorded a $3.6 million loss on the sale of this business.

Income Taxes

For the year ended December 31, 2006, the effective tax rate from continuing operations before minority interest was 36.1 percent (2.5 percent benefit for the year ended December 31, 2005). The increase in the effective rate compared to 2005 was primarily due to the lower income from continuing operations in 2005 as a result of the Kendall County Charge, and one-time tax benefits realized in 2005 for adjustments to our deferred tax assets and liabilities as a result of comprehensive state tax planning initiatives, and positive resolution of audit issues. The effective rate of 36.1 percent for the year ended December 31, 2006, was less than the combined state and federal statutory rate because of investment tax credits, deductions for Medicare health subsidies, depletion and the expected use of state capital loss carryforwards.

Critical Accounting Estimates

The preparation of financial statements and related disclosures in conformity with GAAP requires management to make various estimates and assumptions that affect amounts reported in the consolidated financial statements. These estimates and assumptions may be revised, which may have a material effect on the consolidated financial statements. Actual results may differ from these estimates and assumptions. These policies are discussed with the Audit Committee of our Board of Directors on a regular basis. The following represent the policies we believe are most critical to our business and the understanding of our results of operations.

Real Estate Revenue and Expense Recognition. We account for sales of real estate in accordance with SFAS 66, "Accounting for Sales of Real Estate." Revenue from residential and non-residential properties is recorded at the time of closing using the full profit recognition method, provided that cash collections are at least 20 percent of the contract price and the other requirements of SFAS 66 are met. However, if we are obligated to perform significant development activities subsequent to the date of the sale, we recognize revenue using the percentage-of-completion method. This method of accounting requires that we recognize gross profit based upon the relationship of development costs incurred to the total estimated development costs of the parcels. During each reporting period, we must estimate the total costs to be incurred until project completion, including development overhead and interest capitalization costs. These total cost estimates will impact the recognition of profit on sales. The costs are allocated to each lot or parcel based on the relative sales value method. These estimates affect the amount of costs relieved as each lot is sold and incorrect estimates may result in a misstatement of the cost of real estate sold. Additionally, we must estimate the selling price of each individual lot or parcel that is included in inventory for inclusion in the inventory cost model. If the estimated selling prices of the lots are inaccurate, a material difference in the timing of recording cost of real estate sold for the lots sold could occur.

We record land held for sale at the lower of cost or fair value, which is determined by the evaluation of individual land parcels. Real estate costs include the cost of land acquired, subsequent development costs and costs of improvements, capitalized development period interest, real estate taxes and payroll costs of certain employees devoted directly to the development effort. Based on the relative sales value of the parcels within each development project, we capitalize the real estate costs incurred to the cost of real estate parcels in accordance with SFAS 67, "Accounting for Costs and Initial Rental Operations of Real Estate Projects." When real estate is sold, we include the actual costs incurred and the estimate of future completion costs allocated to the parcel(s) sold, based upon the relative sales value method in the cost of real estate sold. We include land held for sale in Investments on our consolidated balance sheet (See Note 6). In certain cases, we pay fees or construct improvements to mitigate offsite traffic impacts. In return, we receive traffic impact fee credits as a result of some of these expenditures. We recognize revenue from the sale of traffic impact fee credits when payment is received. Certain contracts allow us to receive participation revenue from land sales to third parties if various formula-based criteria are achieved. We recognize participation revenue when there is a contractual obligation to receive this revenue.

Pension and Postretirement Health and Life Actuarial Assumptions. We account for our pension and postretirement benefit obligations in accordance with the provisions of SFAS 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans," SFAS 87, "Employers' Accounting for Pensions," and SFAS 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions." These standards require the use of assumptions in determining our obligations and annual cost of our pension and postretirement benefits. An important actuarial assumption for pension and other postretirement benefit plans is the expected long-term rate of return on plan assets. In establishing this assumption, we consider the diversification and allocation of plan assets, the actual long-term historical performance for the type of securities invested in, the actual long-term historical performance of plan assets and the impact of current economic conditions, if any, on long-term historical returns. Our pension asset allocation is approximately 61 percent equity, 25 percent debt, 9 percent private equity, 2 percent real estate and 3 percent other securities. Equity securities consist of a mix of market capitalization sizes and both domestic and international securities. We currently use an expected long-term rate of return of 9 percent in our actuarial determination of our pension and other postretirement expense. We annually review our expected long-term rate of return assumption and will adjust it to respond to any changing market conditions. A one-quarter percent decrease in the expected long-term rate of return would increase the annual expense for pension and other postretirement benefits by approximately $1.5 million, pre-tax; conversely, a one-quarter percent increase in the expected long-term rate of return would decrease the annual expense by approximately $1.5 million, pre-tax.

For plan valuation purposes, we currently use a discount rate of 6.25 percent. The discount rate is determined considering high-quality long-term corporate bond rates at the valuation date. The discount rate is compared to the Citigroup Pension Discount Curve adjusted for ALLETE's specific cash flows. We believe the adjusted discount curve used in this comparison does not materially differ in duration and cash flows for our pension obligation. The Audit Committee of the Board of Directors annually reviews and approves the rate of return and discount rate estimates used for pension valuation and accounting purposes. (See Note 15.)

Critical Accounting Estimates (Continued)

Regulatory Accounting. Our regulated utility operations are subject to the provisions of SFAS 71, "Accounting for the Effects of Certain Types of Regulation". SFAS 71 requires us to reflect the effect of regulatory decisions in our financial statements. Regulatory assets or liabilities arise as a result of a difference between GAAP. and the accounting principles imposed by the regulatory agencies. Regulatory assets represent incurred costs that have been deferred as they are probable for recovery in customer rates. Regulatory liabilities represent obligations to make refunds to customers and amounts collected in rates for which the related costs have not yet been incurred.

We recognize regulatory assets and liabilities in accordance with applicable state and federal regulatory rulings. The recoverability of regulatory assets is periodically assessed by considering factors such as, but not limited to, changes in regulatory rules and rate orders issued by applicable regulatory agencies. The assumptions and judgments used by regulatory authorities may have an impact on the recovery of costs, the rate of return on invested capital, and the timing and amount of assets to be recovered by rates. A change in these assumptions may result in a material impact on our results of operations. (See Note 5.)

Valuation of Investments. As part of our emerging technology portfolio, we have several minority investments in venture capital funds and direct investments in privately-held, start-up companies. We account for our investment in venture capital funds under the equity method and account for our direct investments in privately-held companies under the cost method because of our ownership percentage. These investments are included in Investments on our consolidated balance sheet. Our policy is to review these investments for impairment on a quarterly basis by assessing such factors as continued commercial viability of products, cash flow and earnings. Any impairment would reduce the carrying value of the investment and be recognized as a loss. In 2007, we recorded an impairment loss on these investments of $0.5 million pretax (none in 2006). (See Note 6.)

Taxation. We are required to make judgments regarding the potential tax effects of various financial transactions and our ongoing operations to estimate our obligations to taxing authorities. These tax obligations include income, real estate and use taxes. Judgments related to income taxes require the recognition in our financial statements of the largest tax benefit of a tax position that is "more-likely-than-not" to be sustained on audit. Tax positions that do not meet the "more-likely-than-not" criteria are reflected as a tax liability. These judgments include reserves for potential adverse outcomes regarding tax positions that we have taken. We must also assess our ability to generate capital gains to realize tax benefits associated with capital losses expected to be generated in future periods. Capital losses may be deducted only to the extent of capital gains realized during the year of the loss or during the three prior or five succeeding years for federal purposes, and fifteen succeeding years for Minnesota purposes. As of December 31, 2007, we have, where appropriate, recorded a valuation allowance against our deferred tax assets associated with realized capital losses and impairments to reduce the deferred tax assets to the amount we estimate is more likely than not to be realized in accordance with FIN 48, "Accounting for Uncertainty in Income Taxes – an Interpretation of FASB Statement No. 109". While we believe the resulting tax reserve balances as of December 31, 2007, reflect the most likely outcome of these tax matters in accordance with SFAS 109, "Accounting for Income Taxes," the ultimate amount of capital losses resulting in tax benefits could differ from the net amount of deferred tax assets at December 31, 2007.

Outlook

ALLETE is committed to earning a financial return that rewards our shareholders, allows for reinvestment in our businesses and sustains growth. New opportunities have arisen which we believe will allow us to achieve our long term earnings growth goals through our existing businesses. Our Regulated Utility expects to make significant investments to comply with renewable and environmental requirements, maintain its existing low-cost generation fleet and strengthen and enhance the regional transmission grid. In addition, we expect kilowatt-hour sales growth from existing and potential new customers. Earnings from our ATC investment are expected to grow as we anticipate making additional investments to fund our pro-rata share of ATC's capital expansion program. We expect net income from Real Estate to be approximately 10 percent to 20 percent of total ALLETE consolidated net income over the next several years.

We will focus our business development activities on growth opportunities in, or complementary to, our core businesses. We believe that current weak market conditions will present an opportunity to add to our portfolio of properties for sale at our Real Estate operations. We anticipate that we will have ready access to sufficient funds for capital investments and acquisitions.

Earnings Guidance. In 2008, we expect ALLETE's diluted earnings per share from continuing operations to be in the range of $2.70 to $2.90. This guidance reflects:

Regulated Utility

- New FERC-approved wholesale rates effective March 1, 2008;
- Minnesota Power's intention to file a retail rate case with the MPUC in mid-2008, with interim rates in effect 60 days later;
- Minnesota Power's expectation that electricity sales to industrial customers will continue at the current high levels during 2008;
- increased revenue from current cost recovery riders related to the Company's investments in environmental and renewable energy initiatives;
- increased operation and maintenance expenses, including labor and benefit costs;
- increased financing costs associated with the 2008 capital expenditure program;
- anticipation of approximately $316 million in capital expenditures in 2008, about half of which will be invested in environmental and renewable energy initiatives;

Investment in ATC

- the expectation of ALLETE investing an additional $5 to $7 million in ATC in 2008;

Real Estate

- a continuation of the difficult market conditions; and
- an expectation that net income in 2008 will be less than in 2007.

Energy. As part of our strategy, we will leverage the strengths of our Regulated Utility business to improve our strategic and financial outlook and seek growth opportunities in close proximity to existing operations in the Midwest. We believe electric industry deregulation is unlikely in Minnesota and Wisconsin in the next five years.

Minnesota Power expects significant rate base growth over the next several years as it makes capital expenditures to comply with renewable energy requirements and environmental mandates. In addition, significant investment will be made in our existing low-cost generation fleet to provide for continued future operations as we continue to believe ownership of low-cost generation is a competitive advantage. Minnesota Power will also look for transmission opportunities which strengthen and enhance the regional transmission grid and take advantage of our geographic location between sources of renewable energy and growing energy markets. Our capital investments will be recovered through a combination of current cost recovery riders and anticipated increased base electric rates. We also expect an average annual kilowatt-hour growth of approximately one percent from our existing customers, as well as up to 400 MW of additional growth from several potential new industrial customers planning projects in our service territory.

Our energy strategy is to be a leader in the movement toward renewable energy and cleaner power plants. We believe we can meet our customers' electric energy needs for the next decade while achieving real reductions in total carbon emissions. We intend to aggressively pursue renewable energy resources and expect to comply with Minnesota's 25 percent renewable energy mandate prior to the 2025 deadline.

Outlook (Continued)
Energy (Continued)

Integrated Resource Plan. On October 31, 2007, Minnesota Power filed its Integrated Resource Plan (IRP), a comprehensive estimate of future capacity needs within the Minnesota Power service territory. Minnesota Power believes it can meet the estimated future customer demand for the next decade while achieving real reductions in the emission of GHGs (primarily carbon dioxide).

Minnesota Power plans to meet expected loads through approximately 2020 by adding a significant amount of renewable generation and some supporting peaking generation. We do not plan to add new coal generation or enter into long-term power purchase agreements from coal-based generation resources without a GHG solution. We plan to add 300 to 500 megawatts of carbon-minimizing renewable energy to our generation mix. Besides the additional generation from renewable sources, Minnesota Power anticipates future supply will come from a combination of sources, including:

- "As-needed" peaking and intermediate generation facilities;
- Expiration of wholesale contracts presently in place;
- Short-term market purchases;
- Improved efficiency of existing generation and power delivery assets; and
- Expanded conservation and demand-side management initiatives.

We do not anticipate the need for new base load system generation within the Minnesota Power service territory through approximately 2020, and we project a one percent average annual growth in electric usage from our existing customers over that time frame.

Mesaba Energy Project. On August 30, 2007, the MPUC issued an order denying Excelsior Energy Inc.'s request for a power purchase agreement with Xcel Energy to sell power from the Mesaba Energy Project (Mesaba Project). We participated in the MPUC proceeding to demonstrate the unnecessary costs the Mesaba Project would cause for our ratepayers and the negative energy policy impacts of a forced resource addition. The MPUC's August 30, 2007, order states that the MPUC will explore in IRPs and resource acquisition proceedings whether all Minnesota utilities should participate in the Mesaba Project. Beyond the fact that we forecast no need for base load energy supply additions until late in the next decade, we object to the Mesaba Project because it does not include a GHG solution.

Climate Change. A key component of our energy strategy is a goal to reduce overall GHG emissions. While there continues to be debate about the causes and extent of global warming, certain scientific evidence suggests that emissions from fossil fuel generation facilities are a contributing factor. Minnesota Power has a long history of environmental stewardship.

We believe that future regulations may restrict the emissions of GHGs from our generation facilities. Several proposals on the Federal level to "cap" the amount of GHG emissions have been made. Other proposals consider establishing emissions allowances or taxes as economic incentives to address the GHG emission issue.

In 2007, Minnesota passed legislation establishing non-binding targets for GHG reductions. This legislation establishes a goal of reducing statewide GHG emissions across all sectors producing those emissions to a level at least 15 percent below 2005 levels by 2015, at least 30 percent below 2005 levels by 2025, and at least 80 percent below 2005 levels by 2050. Minnesota is also participating in the Midwestern Greenhouse Gas Accord, a regional effort to develop a multi-state approach to GHG emission reductions. We are proactively taking steps to strategically engage the GHG emission issue and the impact of climate change regulation on our business.

Minnesota Power is addressing this challenge by taking the following steps that also ensure reliable and environmentally compliant generation resources to meet our customer's requirements.

- We will consider only carbon minimizing resources to supply power to our customers. We will not consider a new coal resource without a carbon emission solution.
- We will aggressively pursue Minnesota's Renewable Energy Standard by adding significant renewable resources to our portfolio of generation facilities and power supply agreements.
- We will continue to improve the efficiency of coal-based generation facilities.
- We plan to implement aggressive demand side conservation efforts.
- We will continue to support research of technologies to reduce carbon emissions from generation facilities and support carbon sequestration efforts.
- We plan to achieve overall carbon emission reductions while maintaining competitively priced electric service to our customers.

Renewable Generation Sources. The areas in which we operate have strong wind, water and biomass resources, and provide us with opportunities to develop a number of renewable forms of generation. Our electric service area in Northeastern Minnesota is well situated for delivery of renewable energy that is generated here and in adjoining regions. We intend to secure the most cost competitive and geographically advantageous renewable energy resources available. We believe that the demand for these resources is likely to grow, and the costs of the resources to generate renewable energy will continue to escalate. While we intend to maintain our disciplined approach to developing generation assets, we also believe that by acting sooner rather than later we can deliver lower cost power to our customers and maintain or improve our cost competitiveness among regional utilities. We will continue to work cooperatively with our customers, our regulators and the communities we serve to develop generation options that reflect the needs of our customers as well as the environment. We believe that our location and our proactive leadership in developing renewable generation provide us with a competitive advantage.

We have already begun executing this strategy. For more than a century, we have been Minnesota's leading producer of renewable hydroelectric energy. By the second quarter of this year, we will have doubled our renewable generation capacity with wind additions in North Dakota and Minnesota. We will also continue to support research and development activity in carbon capture and storage technologies that will enable our industry to better manage GHG emissions associated with existing and future coal based generating assets.

Renewable Energy. In February 2007, Minnesota enacted a law requiring Minnesota Power to generate or procure 25 percent of our energy through renewable energy sources by 2025. The legislation also requires Minnesota Power to meet interim milestones of 12 percent by 2012, 17 percent by 2016, and 20 percent by 2020. The legislation allows the MPUC to modify or delay a standard obligation if implementation will cause significant ratepayer cost or technical reliability issues. If a utility is not in compliance with a standard, the MPUC may order the utility to construct facilities, purchase renewable energy or purchase renewable energy credits. Minnesota Power was developing and making renewable supply additions as part of its generation planning strategy prior to this legislation and this activity continues. Minnesota Power believes it will meet the requirements of this legislation.

In December 2006, we began purchasing the output from a 50-MW wind facility, Oliver Wind I, located in North Dakota, under a 25-year power purchase agreement with an affiliate of FPL Energy.

In May 2007, the MPUC approved a second 25-year wind power purchase agreement to purchase an additional 48-MW of wind energy from Oliver Wind II, an expansion of Oliver Wind I located in North Dakota. The MPUC also allowed current cost recovery for associated transmission upgrades. In November 2007, Oliver Wind II became operational and we began purchasing the output from the wind facility.

In May 2007, the MPUC approved a 20-year Community-Based Energy Development Project power purchase agreement. The 2.5-MW Wing River Wind project, with Wing River Wind, LLC, became operational July 2007.

In September 2007, the MPUC approved our site permit application and we began construction of the $50 million, 25-MW Taconite Ridge Wind I Facility, located in northeastern Minnesota. Minnesota Power filed a petition for current cost recovery on the Taconite Ridge Wind I Facility with the MPUC in August 2007. In October 2007, the DOC recommended approval of Minnesota Power's current cost recovery filing. The MPUC hearing regarding Minnesota Power's current cost recovery filing is currently waiting scheduling. The Taconite Ridge Wind I Facility is expected to become operational in mid-2008.

We continue to investigate additional renewable energy resources including biomass, hydroelectric and wind generation that will help us meet the Minnesota 25 percent renewable energy standard. In particular, we are conducting a feasibility study for construction of a 25-MW biomass generating unit at Laskin, as well as looking at opportunities to expand biomass energy production at existing facilities. Additionally, we are pursuing a potential 10-MW expansion of our Fond du Lac hydroelectric station. We will make specific renewable project filings for regulatory approval as needed.

Outlook (Continued)
Energy (Continued)

In January 2008, Minnesota Power and Manitoba Hydro executed a term sheet for the purchase of surplus energy beginning in 2008 and an anticipated 250-MW capacity purchase to begin in about 2020. Minnesota Power anticipates the initial purchase of surplus energy will be about 100 MWs during high hydro production periods in the spring and fall. The 250-MW long-term purchase will require construction of hydroelectric facilities in Manitoba and major new transmission facilities between Canada and the United States. Minnesota Power and Manitoba Hydro have one year to complete negotiations and sign a definitive agreement. Each purchase is expected to require MPUC approval.

CapX 2020. Minnesota Power is a participant in the CapX 2020 project which represents an effort to ensure the electricity reliability of Minnesota and the surrounding region for the future. CapX 2020 started with the state's largest transmission owners, including electric cooperatives, municipals and investor-owned utilities, assessing the transmission system and projected growth in customer demand for electricity through 2020. Studies show that the region's transmission system will require major upgrades and expansion to accommodate increased electricity demand as well as support renewable energy expansion through 2020.

The CapX 2020 participants filed a Certificate of Need for three 345 kV lines and associated system interconnections with the MPUC in August 2007. Following a public process, the MPUC is expected to decide on the need for these 345 kV lines by early 2009. If the MPUC certifies need, it will then determine routes for the new lines in subsequent proceedings. Portions of the 345 kV lines will also require approvals by federal officials and by regulators in North Dakota, South Dakota and Wisconsin. A fourth line, a 230 kV line in north central Minnesota, is also among the CapX 2020 projects. A request for a Certificate of Need/Site Permit for this line is expected to be filed by mid-2008, with the MPUC decision on need and routing expected approximately one year later.

Minnesota Power may invest capital in two of the lines, a 250-mile 345 kV line between Fargo, North Dakota and Monticello, Minnesota, and a 70-mile 230 kV line between Bemidji and Grand Rapids, Minnesota. Our investment in these two lines would entail an estimated $60 million and $90 million, respectively. Upon receipt of the required Certificates of Need, we intend to file with the MPUC for current cost recovery of the expenditures related to our investment in the lines under a Minnesota Power transmission cost recovery tariff rider mechanism authorized by Minnesota legislation. For the utilities involved, the first four projects represent a combined investment of approximately $1.4 to $1.7 billion. Construction of the lines is targeted to begin in 2009 or 2010 and last approximately three to four years, but depends on the timing and outcome of regulatory need and routing decisions.

AREA and Boswell Unit 3 Emission Reduction Plans. In May 2006, the MPUC approved our filing for current cost recovery of expenditures to reduce emissions to meet pending federal requirements at Taconite Harbor and Laskin under the AREA Plan. The AREA Plan approval allows Minnesota Power to recover Minnesota jurisdictional costs for SO_2, NO_X and mercury emission reductions made at these facilities without a rate proceeding. Current cost recovery from retail customers will include a return on investment and recovery of incremental expense. The AREA Plan is expected to significantly reduce emissions from Taconite Harbor and Laskin, while maintaining a reliable and reasonably-priced energy supply to meet the needs of our customers. We believe that control and abatement technologies applicable to these plants have matured to the point where further significant air emission reductions can be attained in a relatively cost-effective manner. Current cost recovery filings are required to be made 90 days prior to the anticipated in-service date for the equipment at each unit, with rate recovery beginning the month following the in-service date.

Minnesota Power has completed installation of new equipment at Laskin and current cost recovery of AREA Plan costs has begun. The first of three Taconite Harbor unit installations was completed and placed back in-service in June 2007, with current cost-recovery began in July 2007. We anticipate cost recovery on the other Taconite Harbor units once work is completed and the units have been placed back in-service, which is expected in late 2008. As of December 31, 2007, we have spent $36 million of the anticipated $60 million in AREA Plan expenditures.

In May 2006, we announced plans to make emission reduction investments at our Boswell Unit 3 generating unit. Plans include reductions of particulate, SO_2, NO_X and mercury emissions to meet pending federal and state requirements. In late March 2007, the Boswell Unit 3 project received the necessary construction permits. On October 26, 2007, the MPUC issued a written order approving Minnesota Power’s petition for current cost recovery for the Boswell Unit 3 emission reduction plan with some minor modifications and additional reporting requirements. MPUC approval authorized a cash return on construction work in progress during the construction phase in lieu of AFUDC-Equity and allows for a return on investment and current cost recovery of incremental operations and maintenance expenses once the unit is placed into service in late 2009. On December 26, 2007, the MPUC approved Boswell Unit 3’s rate adjustment for 2008. As of December 31, 2007, we have spent $89 million of the anticipated $200 million in Boswell Unit 3 emission reduction plan expenditures.

Outlook (Continued)
Energy (Continued)

Rate Cases. We have and will continue to significantly increase our rate base. On December 28, 2007, we submitted a filing with the FERC seeking to increase electric rates for our wholesale customers. On February 8, 2008, the FERC approved our wholesale rate. Our wholesale customers consist of 16 municipalities in Minnesota and two private utilities in Wisconsin, including SWL&P. The FERC authorized an average 10 percent increase for wholesale municipal customers, a 12.5 percent increase for SWL&P, and an overall return on equity of 11.25 percent. The rate increase will go into effect on March 1, 2008, and on an annualized basis, the filing will generate approximately $7.5 million in additional revenue. We also anticipate filing a retail rate case with the MPUC in mid-2008. SWL&P also anticipates filing a retail rate case with the PSCW in 2008.

Industrial Customers. Electric power is a key component in the mining, paper production and pipeline industries. Approximately 50 percent of our Regulated Utility kilowatthour sales are made to our Large Power Customers in the taconite, paper and pulp, and pipeline industries.

Based on our research of the taconite industry, Minnesota taconite production for 2008 is anticipated to be about 41.5 million tons (production was 39 million tons in 2007; 40 million tons in 2006 and 41 million tons in 2005).

The pulp and paper customers are projected to run near capacity in 2008. Capacity closures in North America and Europe, along with the strength of the Euro and Canadian dollar, should benefit Minnesota Power's customers.

Our pipeline customers continued to operate at or above historic pumping levels during 2007 and forecast operating at record pumping levels in 2008. As Western Canadian oil sands reserves continue to develop and expand, pipeline operators served by the Company are executing expansion plans to transport additional crude oil supply to United States markets. We believe we are strategically positioned to serve these expanding pipeline facilities as Canadian supply continues to grow and displace domestic and imported Gulf Coast production.

Several natural resource-based companies have been making significant progress developing new projects in northeastern Minnesota. These potential projects are in the ferrous and non-ferrous mining, paper, oil and steel related industries. They include the Polymet Mining, Mesabi Nugget and Minnesota Steel Industry projects, as well as the Keewatin Taconite expansion. If some or all of these projects are completed, Minnesota Power could serve between 100 MW and 400 MW of new load.

In 2006, a contract for approximately 70 MW was executed with PolyMet Mining, a new customer planning to start a copper, nickel and precious metals (non-ferrous) mining operation in late 2008. If PolyMet Mining receives all necessary environmental permits and achieves start-up, the contract will be fully implemented and would run through at least 2018. In April 2007, the MPUC approved our contract with PolyMet Mining.

In June 2007, a contract was executed with Mesabi Nugget, a company currently constructing an iron nugget facility near Hoyt Lakes, Minnesota. Iron nuggets, which typically consist of more than 94 percent iron (compared to taconite pellets at 63-65 percent iron), are ideal in meeting the requirements of electric-arc furnaces producing steel. On February 7, 2008, the MPUC held a hearing on the contract and adopted a motion approving the contract, subject to the issuance of a written order. Mesabi Nugget has received all necessary permits to begin construction and operations in 2008 and would be a 15-MW customer with the potential for further load growth. The Mesabi Nugget contract would run through at least 2017.

In February 2008, United States Steel announced its intent to restart a pellet line at its Keewatin Taconite processing facility. This pellet line, which has been idled since 1980, would be restarted and updated as part of a $300 million investment. It is anticipated to bring about 3.6 million tons of additional pellet making capability to Northeastern Minnesota by 2011, pending successful approval of environmental permitting.

A new contract with Blandin Paper was approved by the MPUC on February 4, 2008. The new contract carries forward the same contract term, cancellation provision and take-or-pay provisions of the prior contract and only changed the demand nomination feature.

Outlook (Continued)
Energy. (Continued)

Minnesota Fuel Clause. In June 2003, the MPUC initiated an investigation into the continuing usefulness of the fuel clause as a regulatory tool for electric utilities. Our initial comments on the proposed scope and procedure of the investigation were filed in July 2003. In November 2003, the MPUC approved the initial scope and procedure of the investigation. Subsequent comments were filed during 2004. The fuel clause docket then became dormant while the MISO Day 2 docket, which held many fuel clause considerations, became active. In March 2007, the MPUC solicited comments on whether the original fuel clause investigation should continue and, if so, what issues should be pursued. We filed comments in April 2007, suggesting that if the investigation continued, it should focus on remaining key elements of the fuel clause, beyond the purchased power transactions examined in the MISO Day 2 proceeding, such as fuel purchases and outages. Additionally, we suggested that more specialized fuel clause issues be addressed in separate dockets on an as needed basis. The DOC filed a letter requesting that the parties to the docket update the record in this proceeding by the end of September 2007. Minnesota Power complied by filing additional comments, updating our previous filings in the fuel clause investigation docket to account for changes occurring since the investigation began in July 2003. Reply comments were filed in October 2007. The fuel clause investigation docket is awaiting further action by the MPUC.

Fuel Clause Recovery of MISO Day 2 Costs. We filed a petition with the MPUC in February 2005 to amend our fuel clause to accommodate costs and revenue related to the day-ahead and real-time markets through which we engage in wholesale energy transactions in MISO (MISO Day 2). In December 2006, the MPUC issued an order allowing us and the other utilities involved in the MISO Day 2 proceeding to continue recovering MISO Day 2 charges through the Minnesota retail fuel clause except for MISO Day 2 administrative charges. On January 8, 2007, this order was challenged by the Minnesota OAG, through a request for reconsideration. The request was opposed by Minnesota Power and the other utilities, as well as MISO. The reconsideration request was denied by the MPUC. Upon denial of the reconsideration request, the OAG appealed the MPUC Order in a filing with the Minnesota Court of Appeals. Oral argument in the case will be held on February 27, 2008, and a decision would be expected approximately 90 days thereafter. The Company is unable to predict the outcome of this matter.

The December 2006 MPUC order, subject to appeal, granted deferred accounting treatment for three MISO Day 2 charge types that were determined to be administrative charges. Under the order, Minnesota Power refunded, through customer bills, approximately $2 million of administrative charges previously collected through the fuel clause between April 1, 2005, and December 31, 2006, and recorded these administrative charges as a regulatory asset. We were permitted to continue accumulating MISO Day 2 administrative charges after December 31, 2006, as a regulatory asset until we file our next rate case, at which time recovery for such charges will be determined. The balance of this regulatory asset was $3.7 million on December 31, 2007, and we consider regulatory recovery to be probable. This order removed the subject to refund requirement of the two interim orders, and included extensive fuel clause reporting requirements impacting our monthly and annual fuel clause filings with the MPUC. There was no impact on earnings as a result of this ruling. As a result of the MPUC's December 2006 order allowing recovery of nearly all MISO Day 2 charges through the fuel clause, we rescinded our December 2005 Letter of Intent to Withdraw from MISO in December 2006.

Investment in ATC. Our Wisconsin subsidiary, Rainy River Energy Corporation – Wisconsin, has invested $60 million in ATC. As of December 31, 2007, our equity investment balance in ATC was $65.7 million, representing approximately an 8 percent ownership interest. (See Note 6.) We will have the opportunity to make additional investments in ATC through general capital calls based upon our pro-rata investment level in ATC. We expect to invest an additional $5 to $7 million in 2008.

Real Estate. Conditions in the Florida real estate market were very difficult in 2007. Market demand worsened throughout the year, consistent with conditions experienced throughout most of the rest of the country. While we are unable to predict when the Florida real estate market will improve, we believe the long-term growth indicators for Florida real estate remain strong.

Substantially all of our properties have key entitlements in place. With minimal leverage, low on-going carrying costs and a low inventory book basis, we expect that our Real Estate business will continue to be profitable, and an important contributor to ALLETE's on-going earnings stream. We expect net income from Real Estate to be approximately 10 percent to 20 percent of total ALLETE consolidated net income over the next several years. We believe the northeastern Florida market area where a large portion of our real estate inventory is located will continue to experience above average long-term population growth, and our inventory of mixed-use land in those areas will remain attractive to buyers.

ALLETE Properties plans to maximize the value of the property it currently owns through entitlement, infrastructure improvements and orderly sales of properties. In addition to managing its current real estate inventory, ALLETE Properties is focused on identifying, acquiring, entitling and developing infrastructure on vacant land in Florida and other parts of the southeast United States.

Outlook (Continued)
Real Estate (Continued)

Progress continues on our three major planned development projects in Florida—Town Center, a new downtown for Palm Coast; Palm Coast Park, located in northwest Palm Coast; and Ormond Crossings, located in Ormond Beach along Interstate 95. (See Item 1 – Business - Real Estate.) Other ongoing land sales and rental income at the retail shopping center in Winter Haven provide us with additional revenue.

Summary of Development Projects For the Year Ended December 31, 2007	**Ownership**	**Total Acres *(a)***	**Residential Units *(b)***	**Non-residential Sq. Ft. *(b, c)***
Town Center	80%			
At December 31, 2006		1,356	2,222	2,705,310
Property Sold		(99)	(130)	(540,059)
Change in Estimate *(a)*		(266)	197	62,949
		991	2,289	2,228,200
Palm Coast Park	100%			
At December 31, 2006		4,337	3,760	3,156,800
Property Sold		(888)	(606)	(40,000)
Change in Estimate *(a)*		(13)	–	–
		3,436	3,154	3,116,800
Ormond Crossings	100%			
At December 31, 2006		5,960	*(d)*	*(d)*
Change in Estimate *(a)*		8		
		5,968		
		10,395	5,443	5,345,000

(a) Acreage amounts are approximate and shown on a gross basis, including wetlands and minority interest.
(b) Estimated and includes minority interest. Density at build out may differ from these estimates.
(c) Depending on the project, non-residential includes retail commercial, non-retail commercial, office, industrial, warehouse, storage and institutional.
(d) A development order approved by the City of Ormond Beach includes up to 3,700 residential units and 5 million square feet of non-residential space. We estimate the first two phases of Ormond Crossings will include 2,500-3,200 residential units and 2.5-3.5 million square feet of various types of non-residential space. Density of the residential and non-residential components of the project will be determined based upon market and traffic mitigation cost considerations. Approximately 2,000 acres will be devoted to a regionally significant wetlands mitigation bank.

Summary of Other Land Inventories For the Year Ended December 31, 2007	**Ownership**	**Total**	**Mixed Use**	**Residential**	**Non-residential**	**Agricultural**
Acres *(a)*						
Palm Coast Holdings	80%					
At December 31, 2006		2,136	1,404	346	247	139
Property Sold		(111)	(78)	–	(14)	(19)
Change in Estimate *(a)*		(1,160)	(964)	(239)	96	(53)
		865	362	107	329	67
Lehigh	80%					
At December 31, 2006		223	–	140	74	9
Change in Estimate *(a)*		6	–	–	–	6
		229	–	140	74	15
Cape Coral	100%					
At December 31, 2006		30	–	1	29	–
Property Sold		(8)	–	–	(8)	–
		22	–	1	21	–
Other *(b)*	100%					
At December 31, 2006		934	–	–	–	934
Property Sold		(364)	–	–	–	(364)
Change in Estimate *(a)*		(113)	–	–	–	(113)
		457	–	–	–	457
		1,573	362	248	424	539

(a) Acreage amounts are approximate and shown on a gross basis, including wetlands and minority interest.
(b) Includes land located in Palm Coast, Florida not included in development projects.

Outlook (Continued)
Real Estate (Continued)

*Town Cente*r. Major construction continues at Town Center. In April 2007, Palm Coast Center, LLC and Target Corporation closed on a 52 acre commercial site and immediately began construction on a 424,000 square foot retail power center. An 85,000 square foot Publix grocery store anchored retail center opened in 2007, and an 84,000 square foot medical center is under construction along with a Hilton Garden Inn and a residential condominium project. Several other projects are in the permitting stage including a charter school, independent living facility, movie theater, office buildings and banks.

At build-out, Town Center is expected to include approximately 3,200 residential units including lodging rooms and assisted living units, and 3.8 million square feet of various types of non-residential space. Market conditions will determine how quickly Town Center builds out.

Palm Coast Park. Major infrastructure construction at Palm Coast Park was substantially complete by the end of 2007. At build-out, Palm Coast Park is expected to include approximately 4,000 residential units, 3.2 million square feet of various types of non-residential space and certain public facilities. Market conditions will determine how quickly Palm Coast Park builds out.

Ormond Crossings. Planning, engineering design and permitting of the master infrastructure are ongoing. Density of the residential and non-residential components of the project will be determined based upon market and traffic mitigation cost considerations. We estimate the first two phases of Ormond Crossing will include 2,500-3,200 residential units and 2.5–3.5 million square feet of various types of non-residential space.

Ormond Crossings will also include an approximately 2,000 acre regionally significant wetlands mitigation bank that is expected to be fully permitted by the St. Johns River Water Management District and the U.S. Army Corps of Engineers by mid-2009. Wetland mitigation credits will be used at Ormond Crossings and will be available for sale to other developers. Market conditions will determine how quickly Ormond Crossings builds out.

We have a diversified mix of residential and non-residential property under contract and available for sale. At December 31, 2007, total pending land sales under contract were $55.2 million ($113.8 million at December 31, 2006) and are anticipated to close at various times through 2012. Prices on these contracts range from $20 to $42 per non-residential square foot, $15,000 to $27,200 per residential unit and $11,200 to $660,000 per acre for all other properties. Prices per acre are stated on a gross acreage basis and are dependent on the type and location of the properties sold. The majority of the other properties under contract are zoned non-residential or mixed use. Certain contracts allow us to receive participation revenue from land sales to third parties if various formula-based criteria are achieved.

Real Estate Pending Contracts ***(a, b)*** **At December 31, 2007**	**Quantity** ***(c)***	**Contract Sales Price**
Dollars in Millions		
Town Center		
Non-residential Sq. Ft.	304,000	$9.6
Residential Units	490	9.3
Palm Coast Park		
Non-residential Sq. Ft.	–	–
Residential Units	1,263	31.9
Other Land		
Acres	123	4.4
Total Pending Land Sales Under Contract		$55.2

(a) For the year ended December 31, 2007, we had contract cancellations totaling $22.1 million.
(b) Pending contracts are contracts for which the due diligence period has ended, and the contract deposit is non-refundable subject to performance by the seller.
(c) Acreage amounts are approximate and shown on a gross basis, including wetlands and minority interest. Non-residential square feet and residential units are estimated and include minority interest. The actual property densities at build-out may differ from these estimates.

Decreases in pending land sales under contract during 2007 are primarily due to closing two large sales during the second quarter of 2007 and contract cancellations totaling $22.1 million. In April 2007, Palm Coast Center, LLC and Target Corporation closed on a tract at Town Center for $12.6 million and in June 2007, LRCF Palm Coast, LLC (Lowe Enterprises) closed on the first phase of its Sawmill Creek project at Palm Coast Park for $13.1 million pursuant to revised contract terms.

Outlook (Continued)
Real Estate. (Continued)

If a purchaser defaults on a sales contract, the legal remedy is limited to terminating the contract and retaining the purchaser's deposit. The property is then available for resale. In many cases, contract purchasers incur significant costs during due diligence, planning, designing and marketing the property before the contract closes, therefore they have substantially more at risk than the deposit.

As of December 31, 2007, we had $2.7 million of deferred profit on sales of real estate, before taxes and minority interest, on our balance sheet. All of the deferred profit relates to Town Center and is expected to be recognized in 2008 as the remaining development obligations are completed.

Other. We have the potential to recognize gains or losses on the sale of investments in our emerging technology portfolio. We plan to sell investments in our emerging technology portfolio as shares are distributed to us. Some restrictions on sales may apply, including, but not limited to, underwriter lock-up periods that typically extend for 180 days following an initial public offering. We have committed to make up to $1.0 million in additional investments in certain emerging technology holdings. We do not have plans to make any additional investments beyond this commitment.

Income Taxes. ALLETE's aggregate federal and multi-state statutory tax rate is expected to be approximately 40 percent for 2008. On an ongoing basis, ALLETE has certain tax credits and other tax adjustments that will reduce the statutory rate to the expected effective tax rate. These tax credits and adjustments historically have included items such as investment tax credits, AFUDC-Equity, domestic manufacturer's deduction, depletion, Medicare prescription reimbursement, as well as other items. The annual effective rate can also be impacted by such items as changes in income from operations before minority interest and income taxes, state and federal tax law changes that become effective during the year, business combinations and configuration changes, tax planning initiatives and resolution of prior years' tax matters. We expect our effective tax rate to be approximately 35 percent for 2008.

Liquidity and Capital Resources

Cash Flow Activities

We believe our financial condition is strong, as evidenced by a debt to total capital ratio of 36 percent at December 31, 2007. Our cash and cash equivalents and short-term investments were $46.4 million at December 31, 2007.

Operating Activities. Cash flow from operating activities was $123.1 million for 2007 ($142.5 million for 2006; $53.5 million for 2005). Cash flow from operating activities was lower in 2007 than 2006 primarily due to a decrease in cash flow from operating assets and liabilities. Colder weather in December 2007 resulted in an increase in customer receivables of $14.7 million. Cash used for prepayments and other is higher in 2007 due to an $11.5 million change in deferred fuel costs yet to be recovered through future billings. The increase in deferred fuel costs are a result of higher purchased power expenses due to generation outages relating to the AREA Plan environmental retrofits, lower hydro generation, lower Square Butte entitlement and Square Butte's major scheduled outage. Other current liabilities decreased primarily due to a reduction in accrued taxes of $8.9 million. The decrease in cash flow from operating activities was partially offset by increased earnings from continuing operations of $11.2 million and a decrease in cash used for discontinued operations of $13.5 million.

Cash flow from operating activities was higher in 2006 than 2005, primarily due to the $77.9 million Kendall County Charge in 2005 and related $24.3 million federal tax refund received in 2006. Cash also increased $4.4 million in 2006 due to the collection of customer receivables which were up as a result of colder weather in December 2005. Other differences between 2006 and 2005 include an additional $9 million cash used for inventories in 2006 and the payment of approximately $13 million of 2005 accrued liabilities. Additional inventories primarily reflect coal purchases in anticipation of maintenance on coal handling equipment.

Investing Activities. Cash flow used for investing activities was $154.1 million for 2007 (cash flow used for investing activities of $154.7 million for 2006; cash flow from investing activities of $3.9 million for 2005). Activity within our short-term investment portfolio reflected increased net sales of short-term investments of $81.4 million compared to $12.4 million in 2006. The net proceeds from the sale of short-term investments were used to fund increased additions to property, plant and equipment. Additions to property, plant and equipment were higher in 2007 than 2006 by $111.7 million primarily due to increased spending on major environmental construction projects. Cash invested in ATC decreased from $51.4 million in 2006 to $8.7 million in 2007.

Cash used for investing activities was higher in 2006 than 2005, primarily due to $51.4 million invested in ATC and a $43.7 million increase in expenditures for property, plant and equipment due to major environmental construction projects. Activity within our short-term investment portfolio reflected net sales of short-term investments of $12.4 million compared to $32.3 million in 2005.

Liquidity and Capital Resources (Continued)
Cash Flow Activities (Continued)

Financing Activities. Cash flow from financing activities was $9.5 million for 2007 (cash used for financing activities was $32.6 million for 2006; cash used for financing activities was $13.9 million for 2005). The increase in cash flows from financing activities resulted from additional long-term debt issued in 2007, which included $50.0 million of Senior unsecured notes and $6.0 million in tax exempt bonds at SWL&P. The increase in new long-term debt was offset partially by the retirement of $20.0 in first mortgage bonds and $2.5 million in variable demand revenue refunding bonds. In 2007, $66.5 million in long-term debt was refinanced at lower rates.

Cash used for financing activities was higher in 2006 than 2005 primarily due to an additional $7.2 million in dividends paid as a result of more shares outstanding, a higher dividend rate and fewer shares of common stock issued under our long-term incentive compensation plan. In 2006, we refinanced $77.8 million of long-term debt at lower rates.

In 2006, our Town Center development project was financed with tax-exempt bonds issued by the Town Center District and a revolving development loan. In March 2005, the Town Center District issued $26.4 million of tax-exempt, 6% Capital Improvement Revenue Bonds, Series 2005, which are payable through property tax assessments on the land owners over 31 years (by May 1, 2036). The bond proceeds (less capitalized interest, a debt service reserve fund and cost of issuance) were used to pay for the construction of a portion of the major infrastructure improvements at Town Center. The bonds are payable from and collateralized by the revenue derived from assessments imposed, levied and collected by the Town Center District. The assessments represent an allocation of the costs of the improvements, including bond financing costs, to the lands within the Town Center District benefiting from the improvements. The assessments were billed to Town Center landowners effective November 2006. To the extent that we still own land at the time of the assessment, we will incur the cost of our portion of these assessments, based upon our ownership of benefited property. At December 31, 2007, we owned approximately 69 percent of the assessable land in the Town Center District (73 percent at December 31, 2006). As we sell property, the obligation to pay special assessments passes to the new landowners. Under current accounting rules, these bonds are not reflected as debt on our consolidated balance sheet.

Our Palm Coast Park development project in Florida is being financed with tax-exempt bonds issued by the Palm Coast Park District. In May 2006, Palm Coast Park District issued $31.8 million of tax-exempt, 5.7% Special Assessment Bonds, Series 2006 which are payable through property tax assessments on the land owners over 31 years (by May 1, 2037). The bond proceeds (less capitalized interest, a debt service reserve fund and cost of issuance) were used to fund the construction of the major infrastructure improvements at Palm Coast Park, and to mitigate traffic and environmental impacts. The bonds are payable from and collateralized by the revenue derived from assessments imposed, levied and collected by the Palm Coast Park District. The assessments represent an allocation of the costs of the improvements, including bond financing costs, to the lands within the Palm Coast Park District benefiting from the improvements. The assessments will be billed to Palm Coast Park landowners effective November 2007. To the extent that we still own land at the time of the assessment, we will incur the cost of our portion of these assessments, based upon our ownership of benefited property. At December 31, 2007, we owned 86 percent of the assessable land in the Palm Coast Park District (97 percent at December 31, 2006). As we sell property, the obligation to pay special assessments passes to the new landowners. Under current accounting rules, these bonds are not reflected as debt on our consolidated balance sheet.

Working Capital. Additional working capital, if and when needed, generally is provided by the sale of commercial paper. We have 0.2 million original issue shares of our common stock available for issuance through *Invest Direct*, our direct stock purchase and dividend reinvestment plan. We have bank lines of credit aggregating $170.0 million, the majority of which expire in January 2012. In January 2006, we renewed, increased and extended a committed, syndicated, unsecured revolving credit facility with LaSalle Bank National Association, as Agent, for $150 million (Line) with a maturity date of January 11, 2011. The Line was subsequently extended for an additional year in December 2006 and currently matures on January 11, 2012. At our request and subject to certain conditions, the Line may be increased to $200 million and extended for two additional 12-month periods. We may prepay amounts outstanding under the Line in whole or in part at our discretion. Additionally, we may irrevocably terminate or reduce the size of the Line prior to maturity. The Line may be used for general corporate purposes, working capital and to provide liquidity in support of our commercial paper program. The amount and timing of future sales of our securities will depend upon market conditions and our specific needs. We may sell securities to meet capital requirements, to provide for the retirement or early redemption of issues of long-term debt, to reduce short-term debt and for other corporate purposes.

Liquidity and Capital Resources (Continued)

Securities

On December 10, 2007, ALLETE filed a registration statement with the SEC, pursuant to Rule 415 under the Securities Act of 1933, relating to the possible issuance from time to time of ALLETE common stock or first mortgage bonds. The amount of securities issuable by ALLETE is established from time to time by its board of directors. We may sell all or a portion of the above-described registered securities if warranted by market conditions and our capital requirements. Any offer and sale of the above-mentioned securities will be made only by means of a prospectus meeting the requirements of the Securities Act of 1933 and the rules and regulations there under.

On February 1, 2007, we issued $60 million in principal amount of First Mortgage Bonds (Bonds), 5.99% Series due February 1, 2027, in the private placement market. We have the option to prepay all or a portion of the Bonds at our discretion, subject to a make-whole provision. Proceeds were used to retire $60 million in principal amount of First Mortgage Bonds, 7% Series on February 15, 2007.

On June 8, 2007, we issued $50 million of senior unsecured notes (Notes) in the private placement market. The Notes bear an interest rate of 5.99 percent and will mature on June 1, 2017. We have the option to prepay all or a portion of the Notes at our discretion, subject to a make-whole provision. We used the proceeds from the sale of the Notes to fund utility capital projects and for general corporate purposes.

On behalf of SWL&P, the City of Superior, Wisconsin, issued $6.4 million in principal amount of Collateralized Utility Revenue Refunding Bonds (Series A Bonds) and $6.1 million of Collateralized Utility Revenue Bonds (Series B Bonds) on October 3, 2007. The Series A Bonds bear an interest rate of 5.375% and will mature on November 1, 2021. The proceeds, together with other funds, were used to redeem $6.5 million of existing 6.125% bonds. The Series B Bonds bear an interest rate of 5.75% and will mature on November 1, 2037. The proceeds will be used to fund qualifying electric and gas projects.

On January 11, 2008, we accepted an offer from certain institutional buyers in the private placement market to purchase $60 million of First Mortgage Bonds (Bonds). The Bonds were issued on February 1, 2008, carry an interest rate of 4.86% and will mature on April 1, 2013. We have the option to prepay all or a portion of the Bonds at our discretion, subject to a make-whole provision. We intend to use the proceeds from the sale of the Bonds to fund utility capital expenditures and for general corporate purposes.

Financial Covenants

Our long-term debt arrangements contain customary covenants. In addition, our lines of credit and letters of credit supporting certain long-term debt arrangements contain financial covenants. The most restrictive covenant requires ALLETE to maintain a quarterly ratio of its Funded Debt to Total Capital of less than or equal to 0.65 to 1.00. Failure to meet this covenant could give rise to an event of default, if not corrected after notice from the lender, in which event ALLETE may need to pursue alternative sources of funding. Some of ALLETE's debt arrangements contain "cross-default" provisions that would result in an event of default if there is a failure under other financing arrangements to meet payment terms or to observe other covenants that would result in an acceleration of payments due. As of December 31, 2007, ALLETE was in compliance with its financial covenants.

Off-Balance Sheet Arrangements

Off-balance sheet arrangements are discussed in Note 8.

Contractual Obligations and Commercial Commitments

Our long-term debt obligations, including long-term debt due within one year, represent the principal amount of bonds, notes and loans which are recorded on our consolidated balance sheet, plus interest. The table below assumes the interest rate in effect at December 31, 2007, remains constant through the remaining term. (See Note 7.)

Unconditional purchase obligations represent our Square Butte power purchase agreements, minimum purchase commitments under coal and rail contracts, additional investment commitments in emerging technology funds and purchase obligations for capital expenditures related to the Taconite Ridge Wind Facility, AREA and Boswell Unit 3 environmental upgrade projects. (See Note 8.)

Under our power purchase agreement with Square Butte that extends through 2026, we are obligated to pay our pro rata share of Square Butte's costs based on our entitlement to the output of Square Butte's 455-MW coal-fired generating unit near Center, North Dakota. Our payment obligation is suspended if Square Butte fails to deliver any power, whether produced or purchased, for a period of one year. Square Butte's fixed costs consist primarily of debt service. The following table reflects our share of future debt service based on our output entitlement of approximately 55 percent in 2008 and 50 percent thereafter. (See Note 8.)

Liquidity and Capital Resources (Continued)
Contractual Obligations and Commercial Commitments (Continued)

We have two wind power purchase agreements with an affiliate of FPL Energy to purchase the output from two wind facilities, Oliver Wind I and II located near Center, North Dakota. We began purchasing the output from Oliver Wind I, a 50-MW facility, in December 2006 and the output from Oliver Wind II, a 48-MW facility in November 2007. Each agreement is for 25 years and provides for the purchase of all output from the facilities. There are no fixed capacity charges, and we only pay for energy as it is delivered to us.

	Payments Due by Period				
Contractual Obligations As of December 31, 2007	**Total**	**Less than 1 Year**	**1 to 3 Years**	**4 to 5 Years**	**After 5 Years**
Millions					
Long-Term Debt *(a)*	$760.2	$33.7	$79.6	$47.7	$599.2
Operating Lease Obligations	86.4	8.1	23.0	12.4	42.9
FIN 48 – Uncertain Tax Positions	4.5	2.0	2.5	–	–
Unconditional Purchase Obligations	407.7	114.2	64.7	28.8	200.0
	$1,258.8	$158.0	$169.8	$88.9	$842.1

(a) Includes interest and assumes variable interest rates in effect at December 31, 2007, remains constant through remaining term.

We expect to contribute approximately $11 million to our defined benefit pension plans and $6 million to our postretirement health and life plans in 2008. We are unable to predict contribution levels to our defined benefit pension or postretirement health and life plans after 2008.

Credit Ratings

Our securities have been rated by Standard & Poor's and by Moody's. Rating agencies use both quantitative and qualitative measures in determining a company's credit rating. These measures include business risk, liquidity risk, competitive position, capital mix, financial condition, predictability of cash flows, management strength and future direction. Some of the quantitative measures can be analyzed through a few key financial ratios, while the qualitative ones are more subjective. The disclosure of these credit ratings is not a recommendation to buy, sell or hold our securities. Ratings are subject to revision or withdrawal at any time by the assigning rating organization. Each rating should be evaluated independently of any other rating.

Credit Ratings	**Standard & Poor's**	**Moody's**
Issuer Credit Rating	BBB+	Baa2
Commercial Paper	A-2	P-2
Senior Secured		
First Mortgage Bonds	A–	Baa1
Pollution Control Bonds	A–	Baa1
Unsecured Debt		
Collier County Industrial Development Revenue Bonds – Fixed Rate	BBB	–

Payout Ratio

In 2007, we paid out 53 percent (53 percent in 2006; 259 percent in 2005) of our per share earnings in dividends. The payout ratio in 2005 was impacted by a $1.84 per diluted share charge resulting from our assignment of the Kendall County power purchase agreement to Constellation Energy Commodities in April 2005. (See Note 10.)

On January 24, 2008, our Board of Directors increased the dividend on ALLETE common stock by 5 percent, declaring a dividend of $0.43 per share payable on March 1, 2008, to shareholders of record at the close of business on February 15, 2008.

Capital Requirements

Continuing Operations. ALLETE's projected capital expenditures for the years 2008 through 2012 are presented in the table below. In addition to non-regulated energy and real estate estimated capital expenditures (other), the table includes the estimated amount of capital expenditures related to the regulated utility for which we anticipate receiving current cost recovery. Actual capital expenditures may vary from the estimates due to changes in forecasted plant maintenance, regulatory decisions or approvals, future environmental requirements and base load growth. A significant portion of the environmental capital expenditures and current cost recovery reflected in 2008 include expenditures for the Boswell Unit 3 emission reduction and AREA Plan projects. (See Item 1 - AREA and Boswell Unit 3 Emission Reduction Plans.)

Capital Expenditures *(a)*	**2008**	**2009**	**2010**	**2011**	**2012**	**Total**
Regulated Utility Operations						
Base and Other	$121	$136	$173	$158	$151	$739
Current Cost Recovery *(b)*						
Environmental	130	68	12	–	23	233
Renewable	54	158	97	108	64	481
Transmission	11	17	15	20	15	78
Total Current Cost Recovery	195	243	124	128	102	792
Regulated Utility Capital Expenditures	316	379	297	286	253	1,531
Other *(c)*	7	1	5	4	4	21
Total Capital Expenditures	$323	$380	$302	$290	$257	$1,552

(a) Actual and expected results will vary with time, regulatory requirements and company direction.
(b) Estimated current capital expenditures recoverable outside of a rate case.
(c) Excludes capitalized improvements on our real estate development projects, which are included in inventory. (See Note 6.)

We intend to finance about one-half of this capital expenditure program from internally generated funds, about one-third with incremental debt and the remainder with additional equity.

Discontinued Operations. There were no capital additions for discontinued operations in 2007 (none in 2006; $4.5 million in 2005).

Environmental and Other Matters

As previously mentioned in our Critical Accounting Estimates section, our businesses are subject to regulation of environmental matters by various federal, state and local authorities. Due to future restrictive environmental requirements through legislation and/or rulemaking, we anticipate that potential expenditures for environmental matters will be material and will require significant capital investments. We are unable to predict the outcome of the issues discussed in Note 8. (See Item 1 – Environmental Matters.)

Market Risk

Securities Investments

Available-for-Sale Securities. At December 31, 2007, our available-for-sale securities portfolio consisted of securities in a grantor trust established to fund certain employee benefits included in Investments, and various auction rate bonds and variable rate demand notes included as Short-Term Investments. (See Note 6.)

Emerging Technology Portfolio. As part of our emerging technology portfolio, we have several minority investments in venture capital funds and direct investments in privately-held, start-up companies. (See Note 6.)

Capital Requirements (Continued)
Interest Rate Risk

We are exposed to risks resulting from changes in interest rates as a result of our issuance of variable rate debt. We manage our interest rate risk by varying the issuance and maturity dates of our fixed rate debt, limiting the amount of variable rate debt, and continually monitoring the effects of market changes in interest rates. The table below presents the long-term debt obligations and the corresponding weighted average interest rate at December 31, 2007.

	Principal Cash Flow by Expected Maturity Date							
Interest Rate Sensitive Financial Instruments	**2008**	**2009**	**2010**	**2011**	**2012**	**Thereafter**	**Total**	**Fair Value**
Dollars in Millions								
Long-Term Debt								
Fixed Rate	$7.5	$2.5	$1.4	$1.4	$1.4	$330.9	$345.1	$333.2
Average Interest Rate – %	7.1	5.6	6.3	6.3	6.3	5.5	5.6	
Variable Rate	$4.3	$8.2	$3.6	–	$1.7	$59.8	$77.6	$77.7
Average Interest Rate – % *(a)*	7.3	3.5	3.5	–	3.9	3.5	3.7	

(a) Assumes rate in effect at December 31, 2007, remains constant through remaining term.

The interest rate on variable rate long-term debt is reset on a periodic basis reflecting current market conditions. Based on the variable rate debt outstanding at December 31, 2007, and assuming no other changes to our financial structure, an increase or decrease of 100 basis points in interest rates would impact the amount of pretax interest expense by $0.8 million. This amount was determined by considering the impact of a hypothetical 100 basis point change to the average variable interest rate on the variable rate debt held as of December 31, 2007.

Commodity Price Risk

Our regulated utility operations in Minnesota and Wisconsin incur costs for fuel (primarily coal), power and natural gas purchased for resale in our regulated service territories, and related transportation. Our regulated utilities' exposure to price risk for these commodities is significantly mitigated by the current ratemaking process and regulatory environment, which generally allows a fuel clause surcharge if costs are in excess of those in our last rate filing. Conversely, costs below those in our last rate filing result in a rate credit. We seek to prudently manage our customers' exposure to price risk by entering into contracts of various durations and terms for the purchase of coal and power (in Minnesota), power and natural gas (in Wisconsin), and related transportation costs.

Power Marketing

Our power marketing activities consist of (1) purchasing energy in the wholesale market for resale in our regulated service territories when retail energy requirements exceed generation output, and (2) selling excess available generation and purchased power.

From time to time, our utility operations may have excess generation that is temporarily not required by retail and municipal customers in our regulated service territory. We actively sell this generation to the wholesale market to optimize the value of our generating facilities. This generation is generally sold in the MISO market at market prices.

Approximately 200 MW of generation from our Taconite Harbor facility in northern Minnesota has been sold through various long-term capacity and energy contracts. Long-term, we have entered into two capacity and energy sales contracts totaling 175-MW (201-MW including a 15 percent reserve), which were effective May 1, 2005, and expire on April 30, 2010. Both contracts contain fixed monthly capacity charges and fixed minimum energy charges. One contract provides for an annual escalator to the energy charge based on increases in our cost of coal, subject to a small minimum annual escalation. The other contract provides that the energy charge will be the greater of a fixed minimum charge or an amount based on the variable production cost of a combined-cycle, natural gas unit. Our exposure in the event of a full or partial outage at our Taconite Harbor facility is significantly limited under both contracts. When the buyer is notified at least two months prior to an outage, there is no exposure. Outages with less than two months' notice are subject to an annual duration limitation typical of this type of contract. We also have a 50-MW capacity and energy sales contract that extends through April 2008, with formula pricing based on variable production cost of a combustion-turbine, natural gas unit.

New Accounting Standards

New accounting standards are discussed in Note 2.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

See Item 7 Management's Discussion and Analysis of Results of Operations and Financial Condition – Market Risk for information related to quantitative and qualitative disclosure about market risk.

Item 8. Financial Statements and Supplementary Data

See our consolidated financial statements as of December 31, 2007 and 2006, and for each of the three years in the period ended December 31, 2007, and supplementary data, also included, which are indexed in Item 15(a).

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

Not applicable.

Item 9A. Controls and Procedures

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of the design and operation of ALLETE's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934 ("Exchange Act")). Based upon those evaluations, our principal executive officer and principal financial officer have concluded that such disclosure controls and procedures are effective to provide assurance that information required to be disclosed in ALLETE's reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms and such information is accumulated and communicated to our management, including our principal executive and principal financial officer, to allow timely decisions regarding required disclosure.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. There has been no change in our internal control over financial reporting that occurred during our most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting. Based on our evaluation under the framework in Internal Control—Integrated Framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2007.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2007, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Item 9B. Other Information

Severance Pay Plan

On February 13, 2008, the Board of Directors approved the ALLETE and Affiliated Companies Change in Control Severance Plan, (the Plan) which provides certain key employees with severance benefits in connection with a change in control of ALLETE. The purpose of the Plan is to enable and encourage the continued dedication and objectivity of members of the Company's management. The Plan will allow the affected individuals to focus their attention on obtaining the best possible transaction and to make an independent evaluation of all possible transactions without being diverted by concerns regarding the impact various transactions may have on the security of their jobs and benefits. A change in control generally includes: (i) acquisition by any person, entity or group acting together of more than 50 percent of the total fair market value or total voting power of the Company's common stock, (ii) acquisition in any twelve month period of 40 percent or more of the Company's assets by any person, entity or group acting together, (iii) acquisition in any twelve month period by any person, entity or group acting together of 30 percent or more of the securities entitled to vote in the election of Directors, or (iv) a majority of members of the Board of Directors is replaced during any twelve month period. All of our named executive officers and four of our senior managers were selected by the Executive Compensation Committee of the Board of Directors to participate in the Plan.

A participant in the Plan is entitled to receive specified benefits in the event of certain involuntary terminations of employment (including terminations by the employee following specified changes in duties, benefits, etc., that are treated as involuntary terminations) occurring during the period that begins six months before and ends two years after a change in control. Under the Plan, Mr. Shippar, Mr. Schober, Ms. Welty, and Ms. Amberg would be entitled to receive a benefit of 2.5 times their annual compensation. Annual compensation includes base salary, and an amount representing a "target" award under the Annual Incentive Plan and the Results Sharing program, and certain retirement and welfare benefit make up costs. Ms. Holquist and four other members of senior management would receive 1.5 times their annual compensation. Participants are also entitled to receive outplacement benefits up to a value of $25,000. Payments to participants are to be paid in a lump sum generally within 30 days of termination. As a condition of receiving said payment, participants will be required to sign a waiver of potential claims against the Company, and agree to restrictions on recruiting employees, competing with the Company, and confidentiality. If the total payments to any individual would trigger an excise tax under the Internal Revenue Code Section 4999, payments will be reduced to an amount that would result in no portion of such payment being subject to the excise tax, unless the payment would have to be reduced to an amount less than 85 percent of the amount the participant would otherwise have received, absent the imposition of the excise tax. If payments to a participant would need to be reduced to an amount that is less than 85 percent of the amount the participant would otherwise have received, total payments would not be reduced and the participant would instead receive an additional gross-up payment that would provide the participant with the same net after-tax payment the participant would have received if the excise tax had not applied to any of the payments.

The summary description of the Plan set forth above does not purport to be complete and is qualified in its entirety by the ALLETE and Affiliated Companies Change in Control Severance Plan which is filed as Exhibit 10(q).

The ALLETE and Affiliated Companies Supplemental Executive Retirement Plan (SERP) was also amended on February 13, 2008 to provide that in the event of certain involuntary terminations of employment (including terminations by the employee following specified changes in duties, benefits, etc., that are treated as involuntary terminations) occurring during the period that begins six months before and ends two years after a change in control, as such term is defined in the SERP, a participant in SERP will receive vested amounts in the participant's deferral account and retirement benefits, if any, in a single lump sum.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

Unless otherwise stated, the information required for this Item is incorporated by reference herein from our Proxy Statement for the 2008 Annual Meeting of Shareholders (2008 Proxy Statement) under the following headings:

- **Directors.** The information regarding directors will be included in the "Election of Directors" section;
- **Audit Committee Financial Expert.** The information regarding the Audit Committee financial expert will be included in the "Audit Committee Report" section;
- **Audit Committee Members.** The identity of the Audit Committee members is included in the "Audit Committee Report" section;
- **Executive Officers.** The information regarding executive officers is included in Part I of this Form 10-K; and
- **Section 16(a) Compliance.** The information regarding Section 16(a) compliance will be included in the "Section 16(a) Beneficial Ownership Reporting Compliance" section.

Our 2008 Proxy Statement will be filed with the SEC within 120 days after the end of our 2007 fiscal year.

Code of Ethics. We have adopted a written Code of Ethics that applies to all of our employees, including our chief executive officer, chief financial officer and controller. A copy of our Code of Ethics is available on our Website at www.allete.com and print copies are available without charge upon request to ALLETE, Inc., Attention: Secretary, 30 West Superior St. Duluth, Minnesota 55802. Any amendment to the Code of Ethics or any waiver of the Code of Ethics will be disclosed on our Website at www.allete.com promptly following the date of such amendment or waiver.

Corporate Governance. The following documents are available on our Website at www.allete.com and print copies are available upon request:

- Corporate Governance Guidelines;
- Audit Committee Charter;
- Executive Compensation Committee Charter; and
- Corporate Governance and Nominating Committee Charter.

Any amendment to these documents will be disclosed on our Website at www.allete.com promptly following the date of such amendment.

Item 11. Executive Compensation

The information required for this Item is incorporated by reference herein from the "Compensation of Executive Officers," the "Compensation Discussion and Analysis", the "Executive Compensation Committee Report" and the "Director Compensation – 2007" sections in our 2008 Proxy Statement.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

The information required for this Item is incorporated by reference herein from the "Security Ownership of Certain Beneficial Owners," the "Security Ownership of Management" and the "Equity Compensation Plan Information" sections in our 2008 Proxy Statement.

Item 13. Certain Relationships and Related Transactions, and Director Independence

The information required for this Item is incorporated by reference herein from the "Corporate Governance" section in our 2008 Proxy Statement.

We have adopted a Related Person Transaction Policy which is available on our Website at www.allete.com. Print copies are available, free of charge, upon request. Any amendment to this policy will be disclosed on our Website at www.allete.com promptly following the date of such amendment.

Item 14. Principal Accountant Fees and Services

The information required by this Item is incorporated by reference herein from the "Audit Committee Report" section in our 2008 Proxy Statement.

Part IV

Item 15. Exhibits and Financial Statement Schedules

(a) Certain Documents Filed as Part of this Form 10-K.

(1) Financial Statements

(2) Financial Statement Schedules

All other schedules have been omitted either because the information is not required to be reported by ALLETE or because the information is included in the consolidated financial statements or the notes.

(3) Exhibits including those incorporated by reference.

Exhibit Number

*3(a)1 - Articles of Incorporation, amended and restated as of May 8, 2001 (filed as Exhibit 3(b) to the March 31, 2001, Form 10-Q, File No. 1-3548).

*3(a)2 - Amendment to Articles of Incorporation, effective 12:00 p.m. Eastern Time on September 20, 2004 (filed as Exhibit 3 to the September 21, 2004, Form 8-K, File No. 1-3548).

*3(a)3 - Amendment to Certificate of Assumed Name, filed with the Minnesota Secretary of State on May 8, 2001 (filed as Exhibit 3(a) to the March 31, 2001, Form 10-Q, File No. 1-3548).

*3(b) - Bylaws, as amended effective August 24, 2004 (filed as Exhibit 3 to the August 25, 2004, Form 8-K, File No. 1-3548).

*4(a)1 - Mortgage and Deed of Trust, dated as of September 1, 1945, between Minnesota Power & Light Company (now ALLETE) and The Bank of New York (formerly Irving Trust Company) and Douglas J. MacInnes (successor to Richard H. West), Trustees (filed as Exhibit 7(c), File No. 2-5865).

*4(a)2 - Supplemental Indentures to ALLETE's Mortgage and Deed of Trust:

Number	Dated as of	Reference File	Exhibit
First	March 1, 1949	2-7826	7(b)
Second	July 1, 1951	2-9036	7(c)
Third	March 1, 1957	2-13075	2(c)
Fourth	January 1, 1968	2-27794	2(c)
Fifth	April 1, 1971	2-39537	2(c)
Sixth	August 1, 1975	2-54116	2(c)
Seventh	September 1, 1976	2-57014	2(c)
Eighth	September 1, 1977	2-59690	2(c)
Ninth	April 1, 1978	2-60866	2(c)
Tenth	August 1, 1978	2-62852	2(d)2
Eleventh	December 1, 1982	2-56649	4(a)3
Twelfth	April 1, 1987	33-30224	4(a)3
Thirteenth	March 1, 1992	33-47438	4(b)
Fourteenth	June 1, 1992	33-55240	4(b)
Fifteenth	July 1, 1992	33-55240	4(c)
Sixteenth	July 1, 1992	33-55240	4(d)
Seventeenth	February 1, 1993	33-50143	4(b)
Eighteenth	July 1, 1993	33-50143	4(c)
Nineteenth	February 1, 1997	1-3548 (1996 Form 10-K)	4(a)3
Twentieth	November 1, 1997	1-3548 (1997 Form 10-K)	4(a)3
Twenty-first	October 1, 2000	333-54330	4(c)3
Twenty-second	July 1, 2003	1-3548 (June 30, 2003 Form 10-Q)	4
Twenty-third	August 1, 2004	1-3548 (Sept. 30, 2004 Form 10-Q)	4(a)
Twenty-fourth	March 1, 2005	1-3548 (March 31, 2005 Form 10-Q)	4
Twenty-fifth	December 1, 2005	1-3548 (March 31, 2006 Form 10-Q)	4
Twenty-sixth	October 1, 2006	1-3548 (2006 Form 10-K)	4

Exhibit Number

4(a)3	-	Twenty-Seventh Supplemental Indenture, dated as of February 1, 2008, between ALLETE and The Bank of New York and Douglas J. MacInnes, as Trustees.
*4(b)1	-	Indenture of Trust, dated as of August 1, 2004, between the City of Cohasset, Minnesota and U.S. Bank National Association, as Trustee relating to $111 Million Collateralized Pollution Control Refunding Revenue Bonds (filed as Exhibit 4(b) to the September 30, 2004, Form 10-Q, File No. 1-3548).
*4(b)2	-	Loan Agreement, dated as of August 1, 2004, between the City of Cohasset, Minnesota and ALLETE relating to $111 Million Collateralized Pollution Control Refunding Revenue Bonds (filed as Exhibit 4(c) to the September 30, 2004, Form 10-Q, File No. 1-3548).
*4(c)1	-	Mortgage and Deed of Trust, dated as of March 1, 1943, between Superior Water, Light and Power Company and Chemical Bank & Trust Company and Howard B. Smith, as Trustees, both succeeded by U.S. Bank Trust N.A., as Trustee (filed as Exhibit 7(c), File No. 2-8668).
*4(c)2	-	Supplemental Indentures to Superior Water, Light and Power Company's Mortgage and Deed of Trust:

Number	Dated as of	Reference File	Exhibit
First	March 1, 1951	2-59690	2(d)(1)
Second	March 1, 1962	2-27794	2(d)1
Third	July 1, 1976	2-57478	2(e)1
Fourth	March 1, 1985	2-78641	4(b)
Fifth	December 1, 1992	1-3548 (1992 Form 10-K)	4(b)1
Sixth	March 24, 1994	1-3548 (1996 Form 10-K)	4(b)1
Seventh	November 1, 1994	1-3548 (1996 Form 10-K)	4(b)2
Eighth	January 1, 1997	1-3548 (1996 Form 10-K)	4(b)3

4(c)3	-	Ninth Supplemental Indenture, dated as of October 1, 2007, between Superior Water, Light and Power Company and U.S. Bank National Association, as Trustees.
4(c)4	-	Tenth Supplemental Indenture, dated as of October 1, 2007, between Superior Water, Light and Power Company and U.S. Bank National Association, as Trustees.
*4(d)	-	Amended and Restated Rights Agreement, dated as of July 12, 2006, between ALLETE and the Corporate Secretary of ALLETE, as Rights Agent (filed as Exhibit 4 to the July 14, 2006, Form 8-K, File No. 1-3548).
*10(a)	-	Power Purchase and Sale Agreement, dated as of May 29, 1998, between Minnesota Power, Inc. (now ALLETE) and Square Butte Electric Cooperative (filed as Exhibit 10 to the June 30, 1998, Form 10-Q, File No. 1-3548).
*10(c)	-	Master Agreement (without Appendices and Exhibits), dated December 28, 2004, by and between Rainy River Energy Corporation and Constellation Energy Commodities Group, Inc. (filed as Exhibit 10(c) to the 2004 Form 10-K, File No. 1-3548).
*10(d)1	-	Fourth Amended and Restated Committed Facility Letter (without Exhibits), dated January 11, 2006, by and among ALLETE and LaSalle Bank National Association, as Agent (filed as Exhibit 10 to the January 17, 2006, Form 8-K, File No. 1-3548).
*10(d)2	-	First Amendment to Fourth Amended and Restated Committed Facility Letter dated June 19, 2006, by and among ALLETE and LaSalle Bank National Association, as Agent (filed as Exhibit 10(a) to the June 30, 2006, Form 10-Q, File No. 1-3548).
10(d)3	-	Second Amendment to Fourth Amended and Restated Committed Facility Letter dated December 14, 2006, by and among ALLETE and LaSalle Bank National Association, as Agent.
*10(e)1	-	Financing Agreement between Collier County Industrial Development Authority and ALLETE dated as of July 1, 2006 (filed as Exhibit 10(b)1 to the June 30, 2006, Form 10-Q, File No. 1-3548).
*10(e)2	-	Letter of Credit Agreement, dated as of July 5, 2006, among ALLETE, the Participating Banks and Wells Fargo Bank, National Association, as Administrative Agent and Issuing Bank (filed as Exhibit 10(b)2 to the June 30, 2006, Form 10-Q, File No. 1-3548).
*10(g)	-	Agreement (without Exhibit) dated December 16, 2005, among ALLETE, Wisconsin Public Service Corporation and WPS Investments, LLC (filed as Exhibit 10 to the December 21, 2005 Form 8-K, File No. 1-3548).
+*10(h)1	-	Minnesota Power (now ALLETE) Executive Annual Incentive Plan, as amended, effective January 1, 1999 with amendments through January 2003 (filed as Exhibit 10 to the September 30, 2003, Form 10-Q, File No. 1-3548).
+*10(h)2	-	November 2003 Amendment to the ALLETE Executive Annual Incentive Plan (filed as Exhibit 10(t)2 to the 2003 Form 10-K, File No. 1-3548).
+*10(h)3	-	July 2004 Amendment to the ALLETE Executive Annual Incentive Plan (filed as Exhibit 10(a) to the June 30, 2004, Form 10-Q, File No. 1-3548).

Exhibit Number

+10(h)4	-	January 2007 Amendment to the ALLETE Executive Annual Incentive Plan.
+*10(h)5	-	Form of ALLETE Executive Annual Incentive Plan 2006 Award – President of ALLETE Properties (filed as Exhibit 10(b) to the January 30, 2006, Form 8-K, File No. 1-3548).
+*10(h)6	-	Form of ALLETE Executive Annual Incentive Plan 2006 Award (filed as Exhibit 10 to the February 17, 2006, Form 8-K, File No. 1-3548).
+10(h)7	-	Form of ALLETE Executive Annual Incentive Plan Awards Effective 2007.
+*10(i)1	-	ALLETE and Affiliated Companies Supplemental Executive Retirement Plan, as amended and restated, effective January 1, 2004 (filed as Exhibit 10(u) to the 2003 Form 10-K, File No. 1-3548).
+*10(i)2	-	January 2005 Amendment to the ALLETE and Affiliated Companies Supplemental Executive Retirement Plan (filed as Exhibit 10(b) to the March 31, 2005, Form 10-Q, File No. 1-3548).
+*10(i)3	-	August 2006 Amendments to the ALLETE and Affiliated Companies Supplemental Executive Retirement Plan (filed as Exhibit 10(a) to the September 30, 2006, Form 10-Q, File No. 1-3548).
+10(i)4	-	December 2006 Amendments to the ALLETE and Affiliated Companies Supplemental Executive Retirement Plan.
+*10(j)1	-	Minnesota Power and Affiliated Companies Executive Investment Plan I, as amended and restated, effective November 1, 1988 (filed as Exhibit 10(c) to the 1988 Form 10-K, File No. 1-3548).
+*10(j)2	-	Amendments through December 2003 to the Minnesota Power and Affiliated Companies Executive Investment Plan I (filed as Exhibit 10(v)2 to the 2003 Form 10-K, File No. 1-3548).
+*10(j)3	-	July 2004 Amendment to the Minnesota Power and Affiliated Companies Executive Investment Plan I (filed as Exhibit 10(b) to the June 30, 2004, Form 10-Q, File No. 1-3548).
+*10(j)4	-	August 2006 Amendment to the Minnesota Power and Affiliated Companies Executive Investment Plan I (filed as Exhibit 10(b) to the September 30, 2006, Form 10-Q, File No. 1-3548).
+*10(k)1	-	Minnesota Power and Affiliated Companies Executive Investment Plan II, as amended and restated, effective November 1, 1988 (filed as Exhibit 10(d) to the 1988 Form 10-K, File No. 1-3548).
+*10(k)2	-	Amendments through December 2003 to the Minnesota Power and Affiliated Companies Executive Investment Plan II (filed as Exhibit 10(w)2 to the 2003 Form 10-K, File No. 1-3548).
+*10(k)3	-	July 2004 Amendment to the Minnesota Power and Affiliated Companies Executive Investment Plan II (filed as Exhibit 10(c) to the June 30, 2004, Form 10-Q, File No. 1-3548).
+*10(k)4	-	August 2006 Amendment to the Minnesota Power and Affiliated Companies Executive Investment Plan II (filed as Exhibit 10(c) to the September 30, 2006, Form 10-Q, File No. 1-3548).
+*10(l)	-	Deferred Compensation Trust Agreement, as amended and restated, effective January 1, 1989 (filed as Exhibit 10(f) to the 1988 Form 10-K, File No. 1-3548).
+*10(m)1	-	ALLETE Executive Long-Term Incentive Compensation Plan as amended and restated effective January 1, 2006 (filed as Exhibit 10 to the May 16, 2005, Form 8-K, File No. 1-3548).
+*10(m)2	-	Form of ALLETE Executive Long-Term Incentive Compensation Plan 2006 Nonqualified Stock Option Grant (filed as Exhibit 10(a)1 to the January 30, 2006, Form 8-K, File No. 1-3548).
+*10(m)3	-	Form of ALLETE Executive Long-Term Incentive Compensation Plan 2006 Performance Share Grant (filed as Exhibit 10(a)2 to the January 30, 2006, Form 8-K, File No. 1-3548).
+*10(m)4	-	Form of ALLETE Executive Long-Term Incentive Compensation Plan 2006 Long-Term Cash Incentive Award – President of ALLETE Properties (filed as Exhibit 10(a)3 to the January 30, 2006, Form 8-K, File No. 1-3548).
+*10(m)5	-	Form of ALLETE Executive Long-Term Incentive Compensation Plan 2006 Stock Grant – President of ALLETE Properties (filed as Exhibit 10(a)4 to the January 30, 2006, Form 8-K, File No. 1-3548).
+10(m)6	-	Form of ALLETE Executive Long-Term Incentive Compensation Plan Nonqualified Stock Option Grant Effective 2007.
+10(m)7	-	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2007.
+10(m)8	-	Form of ALLETE Executive Long-Term Incentive Compensation Plan Long-Term Cash Incentive Award Effective 2007.
+10(m)9	-	Form of ALLETE Executive Long-Term Incentive Compensation Plan Stock Grant Effective 2007.
+10(m)10	-	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2008.
+*10(n)1	-	Minnesota Power (now ALLETE) Director Stock Plan, effective January 1, 1995 (filed as Exhibit 10 to the March 31, 1995 Form 10-Q, File No. 1-3548).

Exhibit Number

+*10(n)2	-	Amendments through December 2003 to the Minnesota Power (now ALLETE) Director Stock Plan (filed as Exhibit 10(z)2 to the 2003 Form 10-K, File No. 1-3548).
+*10(n)3	-	July 2004 Amendment to the ALLETE Director Stock Plan (filed as Exhibit 10(e) to the June 30, 2004, Form 10-Q, File No. 1-3548).
+10(n)4	-	January 2007 Amendment to the ALLETE Director Stock Plan.
+*10(n)5	-	ALLETE Director Compensation Summary Effective May 1, 2005 (filed as Exhibit 10 to the June 30, 2005, Form 10-Q, File No. 1-3548).
+10(n)6	-	ALLETE Non-Management Director Compensation Summary Effective February 15, 2007.
+*10(o)1	-	Minnesota Power (now ALLETE) Director Compensation Deferral Plan Amended and Restated, effective January 1, 1990 (filed as Exhibit 10(ac) to the 2002 Form 10-K, File No. 1-3548).
+*10(o)2	-	October 2003 Amendment to the Minnesota Power (now ALLETE) Director Compensation Deferral Plan (filed as Exhibit 10(aa)2 to the 2003 Form 10-K, File No. 1-3548).
+*10(o)3	-	January 2005 Amendment to the ALLETE Director Compensation Deferral Plan (filed as Exhibit 10(c) to the March 31, 2005, Form 10-Q, File No. 1-3548).
+*10(o)4	-	August 2006 Amendment to the ALLETE Director Compensation Deferral Plan (filed as Exhibit 10(d) to the September 30, 2006, Form 10-Q, File No. 1-3548).
+*10(p)	-	ALLETE Director Compensation Trust Agreement, effective October 11, 2004 (filed as Exhibit 10(a) to the September 30, 2004, Form 10-Q, File No. 1-3548).
+10(q)	-	ALLETE Change of Control Severance Pay Plan Effective February 13, 2008.
12	-	Computation of Ratios of Earnings to Fixed Charges.
21	-	Subsidiaries of the Registrant.
23(a)	-	Consent of Independent Registered Public Accounting Firm.
23(b)	-	Consent of General Counsel.
31(a)	-	Rule 13a-14(a)/15d-14(a) Certification by the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(b)	-	Rule 13a-14(a)/15d-14(a) Certification by the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32	-	Section 1350 Certification of Annual Report by the Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99	-	ALLETE News Release dated February 15, 2008, announcing earnings for the year ended December 31, 2007. **(This exhibit has been furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, nor shall it be deemed incorporated by reference in any filing under the Securities Act of 1933, except as shall be expressly set forth by specific reference in such filing.)**

SWL&P is a party to other long-term debt instruments, $6,370,000 of City of Superior, Wisconsin, Collateralized Utility Revenue Refunding Bonds Series 2007A and $6,130,000 of City of Superior, Wisconsin, Collateralized Utility Revenue Bonds Series 2007B, that, pursuant to Regulation S-K, Item 601(b)(4)(iii), are not filed as exhibits since the total amount of debt authorized under each of these omitted instruments does not exceed 10 percent of our total consolidated assets. We will furnish copies of these instruments to the SEC upon its request.

We are a party to another long-term debt instrument, $38,995,000 of City of Cohasset, Minnesota, Variable Rate Demand Revenue Refunding Bonds (ALLETE, formerly Minnesota Power & Light Company, Project) Series 1997A, Series 1997B, Series 1997C and Series 1997D that, pursuant to Regulation S-K, Item 601(b)(4)(iii), is not filed as an exhibit since the total amount of debt authorized under this omitted instrument does not exceed 10 percent of our total consolidated assets. We will furnish copies of this instrument to the SEC upon its request.

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* *Incorporated herein by reference as indicated.*

\+ *Management contract or compensatory plan or arrangement required to be filed as an exhibit to this report pursuant to Item 15(c) of Form 10-K.*

Signatures

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

ALLETE, Inc.

Dated: February 15, 2008

By /s/ Donald J. Shippar
Donald J. Shippar
Chairman, President and Chief Executive Officer

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

Signature	Title	Date
/s/ Donald J. Shippar Donald J. Shippar	Chairman, President, Chief Executive Officer and Director (Principal Executive Officer)	February 15, 2008
/s/ Mark A. Schober Mark A. Schober	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 15, 2008
/s/ Steven Q. DeVinck Steven Q. DeVinck	Controller (Principal Accounting Officer)	February 15, 2008
/s/ Kathleen A. Brekken Kathleen A. Brekken	Director	February 15, 2008
/s/ Heidi J. Eddins Heidi J. Eddins	Director	February 15, 2008
/s/ Sidney W. Emery, Jr Sidney W. Emery, Jr	Director	February 15, 2008
/s/ James J. Hoolihan James J. Hoolihan	Director	February 15, 2008
/s/ Madeleine W. Ludlow Madeleine W. Ludlow	Director	February 15, 2008
/s/ George L. Mayer George L. Mayer	Director	February 15, 2008
/s/ Douglas C. Neve Douglas C. Neve	Director	February 15, 2008
/s/ Roger D. Peirce Roger D. Peirce	Director	February 15, 2008
/s/ Jack I. Rajala Jack I. Rajala	Director	February 15, 2008
/s/ Bruce W. Stender Bruce W. Stender	Director	February 15, 2008

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of ALLETE, Inc.

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of ALLETE, Inc. and its subsidiaries (the Company) at December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on criteria established in *Internal Control – Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 12 to the consolidated financial statements, in 2007, the Company adopted the provisions of FIN 48, "Accounting for Uncertainty in Income Taxes – an Interpretation of FASB Statement No. 109." As discussed in Note 15 to the consolidated financial statements, in 2006 the Company adopted SFAS 158, "Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans." As discussed in Note 16 to the consolidated financial statements, in 2006 the Company changed the manner in which it accounts for share-based compensation.

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

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

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Minneapolis, Minnesota
February 11, 2008

Consolidated Financial Statements

ALLETE Consolidated Balance Sheet

December 31 Millions	2007	2006
Assets		
Current Assets		
Cash and Cash Equivalents	$23.3	$44.8
Short-Term Investments	23.1	104.5
Accounts Receivable (Less Allowance of $1.0 and $1.1)	79.5	70.9
Inventories	49.5	43.4
Prepayments and Other	39.1	23.8
Deferred Income Taxes	–	0.3
Total Current Assets	214.5	287.7
Property, Plant and Equipment – Net	1,104.5	921.6
Investments	213.8	189.1
Other Assets	111.4	135.0
Total Assets	$1,644.2	$1,533.4
Liabilities and Shareholders' Equity		
Liabilities		
Current Liabilities		
Accounts Payable	$72.7	$53.5
Accrued Taxes	14.8	23.3
Accrued Interest	7.8	8.6
Long-Term Debt Due Within One Year	11.8	29.7
Deferred Profit on Sales of Real Estate	2.7	4.1
Other	27.3	24.3
Total Current Liabilities	137.1	143.5
Long-Term Debt	410.9	359.8
Deferred Income Taxes	144.2	130.8
Other Liabilities	200.1	226.1
Minority Interest	9.3	7.4
Total Liabilities	901.6	867.6
Commitments and Contingencies		
Shareholders' Equity		
Common Stock Without Par Value, 43.3 Shares Authorized 30.8 and 30.4 Shares Outstanding	461.2	438.7
Unearned ESOP Shares	(64.5)	(71.9)
Accumulated Other Comprehensive Loss	(4.5)	(8.8)
Retained Earnings	350.4	307.8
Total Shareholders' Equity	742.6	665.8
Total Liabilities and Shareholders' Equity	$1,644.2	$1,533.4

The accompanying notes are an integral part of these statements.

ALLETE Consolidated Statement of Income

For the Year Ended December 31	2007	2006	2005
Millions Except Per Share Amounts			
Operating Revenue	$841.7	$767.1	$737.4
Operating Expenses			
Fuel and Purchased Power	347.6	281.7	273.1
Operating and Maintenance	311.9	296.0	293.5
Kendall County Charge	–	–	77.9
Depreciation	48.5	48.7	47.8
Total Operating Expenses	708.0	626.4	692.3
Operating Income from Continuing Operations	133.7	140.7	45.1
Other Income (Expense)			
Interest Expense	(24.6)	(27.4)	(26.4)
Equity Earnings in ATC	12.6	3.0	–
Other	15.5	11.9	1.1
Total Other Income (Expense)	3.5	(12.5)	(25.3)
Income from Continuing Operations Before Minority Interest and Income Taxes	137.2	128.2	19.8
Income Tax Expense (Benefit)	47.7	46.3	(0.5)
Minority Interest	1.9	4.6	2.7
Income from Continuing Operations	87.6	77.3	17.6
Loss from Discontinued Operations – Net of Tax	–	(0.9)	(4.3)
Net Income	$87.6	$76.4	$13.3
Average Shares of Common Stock			
Basic	28.3	27.8	27.3
Diluted	28.4	27.9	27.4
Basic Earnings (Loss) Per Share of Common Stock			
Continuing Operations	$3.09	$2.78	$0.65
Discontinued Operations	–	(0.03)	(0.16)
	$3.09	$2.75	$0.49
Diluted Earnings (Loss) Per Share of Common Stock			
Continuing Operations	$3.08	$2.77	$0.64
Discontinued Operations	–	(0.03)	(0.16)
	$3.08	$2.74	$0.48
Dividends Per Share of Common Stock	$1.640	$1.450	$1.245

The accompanying notes are an integral part of these statements.

ALLETE Consolidated Statement of Cash Flows

For the Year Ended December 31 Millions	2007	2006	2005
Operating Activities			
Net Income	$87.6	$76.4	$13.3
Loss from Discontinued Operations	–	0.9	4.3
AFUDC - Equity	(3.8)	–	–
Income from Equity Investments, Net of Dividends	(2.7)	(1.8)	–
Gain on Sale of Assets	(2.2)	–	–
Loss on Impairment of Investments	0.3	–	5.1
Depreciation	48.5	48.7	47.8
Deferred Income Taxes (Benefit)	14.0	27.8	(34.2)
Minority Interest	1.9	4.6	2.7
Stock Compensation Expense	2.0	1.8	1.5
Bad Debt Expense	1.0	0.7	1.1
Changes in Operating Assets and Liabilities			
Accounts Receivable	(6.6)	7.5	(1.4)
Inventories	(6.1)	(10.3)	(1.3)
Prepayments and Other	(11.7)	(2.3)	(2.5)
Accounts Payable	9.4	5.1	4.9
Other Current Liabilities	(10.0)	0.2	5.8
Other Assets	0.8	(4.3)	8.2
Other Liabilities	0.7	1.0	(4.1)
Net Operating Activities from (for) Discontinued Operations	–	(13.5)	2.3
Cash from Operating Activities	123.1	142.5	53.5
Investing Activities			
Proceeds from Sale of Available-For-Sale Securities	449.7	608.8	376.0
Payments for Purchase of Available-For-Sale Securities	(368.3)	(596.4)	(343.7)
Changes to Investments	(19.6)	(52.0)	(1.1)
Additions to Property, Plant and Equipment	(210.2)	(102.3)	(58.6)
Proceeds from Sale of Assets	1.5	–	–
Other	(7.2)	(15.0)	0.6
Net Investing Activities from Discontinued Operations	–	2.2	30.7
Cash from (for) Investing Activities	(154.1)	(154.7)	3.9
Financing Activities			
Issuance of Common Stock	20.6	15.8	21.0
Issuance of Long-Term Debt	123.9	77.8	35.0
Reductions of Long-Term Debt	(90.7)	(78.9)	(35.7)
Dividends on Common Stock and Distributions to Minority Shareholders	(44.3)	(43.9)	(36.7)
Net Increase (Decrease) in Book Overdrafts	–	(3.4)	3.4
Net Financing Activities for Discontinued Operations	–	–	(0.9)
Cash from (for) Financing Activities	9.5	(32.6)	(13.9)
Change in Cash and Cash Equivalents	(21.5)	(44.8)	43.5
Cash and Cash Equivalents at Beginning of Period	44.8	89.6	46.1
Cash and Cash Equivalents at End of Period	$23.3	$44.8	$89.6

The accompanying notes are an integral part of these statements.

ALLETE Consolidated Statement of Shareholders' Equity

Millions	Total Shareholders' Equity	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Unearned ESOP Shares	Common Stock
Balance at December 31, 2004	$630.5	$293.2	$(11.4)	$(51.4)	$400.1
Comprehensive Income					
Net Income	13.3	13.3			
Other Comprehensive Income – Net of Tax					
Unrealized Gains on Securities – Net	0.6		0.6		
Additional Pension Liability	(2.0)		(2.0)		
Total Comprehensive Income	11.9				
Common Stock Issued – Net	21.0				21.0
Dividends Declared	(34.4)	(34.4)			
Purchase of ALLETE Shares by ESOP	(30.3)			(30.3)	
ESOP Shares Earned	4.1			4.1	
Balance at December 31, 2005	602.8	272.1	(12.8)	(77.6)	421.1
Comprehensive Income					
Net Income	76.4	76.4			
Other Comprehensive Income – Net of Tax					
Unrealized Gains on Securities – Net	1.9		1.9		
Additional Pension Liability	6.4		6.4		
Total Comprehensive Income	84.7				
Adjustment to initially apply SFAS 158 – Net of Tax	(4.3)		(4.3)		
Common Stock Issued – Net	17.6				17.6
Dividends Declared	(40.7)	(40.7)			
ESOP Shares Earned	5.7			5.7	
Balance at December 31, 2006	665.8	307.8	(8.8)	(71.9)	438.7
Comprehensive Income					
Net Income	87.6	87.6			
Other Comprehensive Income – Net of Tax					
Unrealized Gains on Securities – Net	1.1		1.1		
Defined Benefit Pension and Other Postretirement Plans	3.2		3.2		
Total Comprehensive Income	91.9				
Adjustment to initially apply FIN 48	(0.7)	(0.7)			
Common Stock Issued – Net	22.5				22.5
Dividends Declared	(44.3)	(44.3)			
ESOP Shares Earned	7.4			7.4	
Balance at December 31, 2007	$742.6	$350.4	$(4.5)	$(64.5)	$461.2

The accompanying notes are an integral part of these statements.

Notes to Consolidated Financial Statements

Note 1. Business Segments

Presented below are the operating results and other financial information related to our reporting segments. For a description of our reporting segments, see Note 2.

Financial results by segment for the periods presented were impacted by the integration of our Taconite Harbor facility into the Regulated Utility segment, effective January 1, 2006. We have operated the Taconite Harbor facility as a rate-based asset within the Minnesota retail jurisdiction since January 1, 2006. Prior to January 1, 2006, we operated our Taconite Harbor facility as nonregulated generation (non-rate base generation sold at market-based rates primarily to the wholesale market). Historical financial results of Taconite Harbor for periods prior to the 2006 redirection are included in our Nonregulated Energy Operations segment.

		Energy				
	Consolidated	Regulated Utility	Nonregulated Energy Operations	Investment In ATC	Real Estate	Other
Millions						
2007						
Operating Revenue	$841.7	$723.8	$67.0	–	$50.5	$0.4
Fuel and Purchased Power	347.6	347.6	–	–	–	–
Operating and Maintenance	311.9	229.3	61.2	–	20.1	1.3
Depreciation Expense	48.5	43.8	4.5	–	0.1	0.1
Operating Income (Loss) from Continuing Operations	133.7	103.1	1.3	–	30.3	(1.0)
Interest Expense	(24.6)	(21.0)	(2.0)	–	(0.5)	(1.1)
Equity Earnings in ATC	12.6	–	–	$12.6	–	–
Other Income	15.5	4.1	3.9	–	1.4	6.1
Income from Continuing Operations Before Minority Interest and Income Taxes	137.2	86.2	3.2	12.6	31.2	4.0
Income Tax Expense (Benefit)	47.7	31.3	(0.3)	5.1	11.6	–
Minority Interest	1.9	–	–	–	1.9	–
Income from Continuing Operations	87.6	$54.9	$3.5	$7.5	$17.7	$4.0
Loss from Discontinued Operations – Net of Tax	–					
Net Income	$87.6					
Total Assets	$1,644.2	$1,330.9	$84.2	$65.7	$91.3	$72.1
Capital Additions	$223.9	$220.6	$3.3	–	–	–

Note 1. Business Segments (Continued)

Millions	Consolidated	Energy: Regulated Utility	Energy: Nonregulated Energy Operations	Energy: Investment in ATC	Real Estate	Other
2006						
Operating Revenue	$767.1	$639.2	$65.0	–	$62.6	$0.3
Fuel and Purchased Power	281.7	281.7	–	–	–	–
Operating and Maintenance	296.0	217.9	57.1	–	19.5	1.5
Depreciation Expense	48.7	44.2	4.3	–	0.1	0.1
Operating Income (Loss) from Continuing Operations	140.7	95.4	3.6	–	43.0	(1.3)
Interest Expense	(27.4)	(20.2)	(3.3)	–	–	(3.9)
Equity Earnings in ATC	3.0	–	–	$3.0	–	–
Other Income	11.9	0.9	2.2	–	1.3	7.5
Income from Continuing Operations Before Minority Interest and Income Taxes	128.2	76.1	2.5	3.0	44.3	2.3
Income Tax Expense (Benefit)	46.3	29.3	(1.2)	1.1	16.9	0.2
Minority Interest	4.6	–	–	–	4.6	–
Income from Continuing Operations	77.3	$46.8	$3.7	$1.9	$22.8	$2.1
Loss from Discontinued Operations – Net of Tax	(0.9)					
Net Income	$76.4					
Total Assets	$1,533.4	$1,143.3	$81.3	$53.7	$89.8	$165.3
Capital Additions	$109.4	$107.5	$1.9	–	–	–
2005						
Operating Revenue	$737.4	$575.6	$113.9	–	$47.5	$0.4
Fuel and Purchased Power	273.1	243.7	29.4	–	–	–
Operating and Maintenance	293.5	202.9	71.2	–	16.6	2.8
Kendall County Charge	77.9	–	77.9	–	–	–
Depreciation Expense	47.8	39.4	8.1	–	0.1	0.2
Operating Income (Loss) from Continuing Operations	45.1	89.6	(72.7)	–	30.8	(2.6)
Interest Expense	(26.4)	(17.4)	(6.6)	–	(0.1)	(2.3)
Other Income (Expense)	1.1	0.7	1.7	–	1.1	(2.4)
Income (Loss) from Continuing Operations Before Minority Interest and Income Taxes	19.8	72.9	(77.6)	–	31.8	(7.3)
Income Tax Expense (Benefit)	(0.5)	27.2	(29.1)	–	11.6	(10.2)
Minority Interest	2.7	–	–	–	2.7	–
Income (Loss) from Continuing Operations	17.6	$45.7	$(48.5)	–	$17.5	$2.9
Loss from Discontinued Operations – Net of Tax	(4.3)					
Net Income	$13.3					
Total Assets	$1,398.8 *(a)*	$909.5	$185.2	–	$73.7	$227.8
Capital Additions	$63.1 *(a)*	$46.5	$12.1	–	–	–

(a) Discontinued Operations represented $2.6 million of total assets in 2005 and $4.5 million of capital additions in 2005.

Note 2. Operations and Significant Accounting Policies

Financial Statement Preparation. References in this report to “we,” “us” and “our” are to ALLETE and its subsidiaries, collectively. We prepare our financial statements in conformity with accounting principles generally accepted in the United States of America. These principles require management to make informed judgments, best estimates and assumptions that affect the reported amounts of assets, liabilities, revenue and expenses. Actual results could differ from those estimates.

Principles of Consolidation. Our consolidated financial statements include the accounts of ALLETE and all of our majority-owned subsidiary companies. All material intercompany balances and transactions have been eliminated in consolidation.

Business Segments. Our Regulated Utility, Nonregulated Energy Operations, Real Estate, Investment in ATC and Other segments were determined in accordance with SFAS 131, “Disclosures about Segments of an Enterprise and Related Information.” Segmentation is based on the manner in which we operate, assess, and allocate resources to the business. We measure performance of our operations through budgeting and monitoring of contributions to consolidated net income by each business segment. Discontinued Operations includes our telecommunications business, which we sold in December 2005, and our Water Services businesses, the majority of which were sold in 2003 (See Note 13.)

Regulated Utility includes retail and wholesale rate-regulated electric, natural gas and water services in northeastern Minnesota and northwestern Wisconsin. Minnesota Power provides regulated utility electric service to 141,000 retail customers in northeastern Minnesota. SWL&P, a wholly-owned subsidiary, provides regulated utility electric, natural gas and water service in northwestern Wisconsin to 15,000 electric customers, 12,000 natural gas customers and 10,000 water customers. Approximately 39 percent of regulated utility electric revenue is from Large Power Customers (34 percent of consolidated revenue). Large Power Customers consist of five taconite producers, four paper and pulp mills, two pipeline companies and one manufacturer under all-requirements contracts with expiration dates extending from February 2009 through October 2014. Revenue of $100.6 million (12.0 percent of consolidated revenue) was received from one taconite producer in 2007 (11.6 percent in 2006; 11.3 percent in 2005). Regulated utility rates are under the jurisdiction of Minnesota and Wisconsin, and federal regulatory authorities. Billings are rendered on a cycle basis. Revenue is accrued for service provided but not billed. Regulated utility electric rates include adjustment clauses that: (1) bill or credit customers for fuel and purchased energy costs above or below the base levels in rate schedules; (2) bill retail customers for the recovery of conservation improvement program expenditures not collected in base rates; and (3) bill customers for the recovery of certain environmental expenditures. Fuel and purchased power expense is deferred to match the period in which the revenue for fuel and purchased power expense is collected from customers pursuant to the fuel adjustment clause.

Nonregulated Energy Operations includes our coal mining activities in North Dakota, approximately 50 MW of nonregulated generation and Minnesota land sales. BNI Coal, a wholly-owned subsidiary, mines and sells lignite coal to two North Dakota mine-mouth generating units, one of which is Square Butte. In 2007, Square Butte supplied approximately 60 percent (273 MW) of its output to Minnesota Power under a long-term contract. (See Note 8.) Coal sales are recognized when delivered at the cost of production plus a specified profit per ton of coal delivered.

In 2005, Nonregulated Energy Operations included nonregulated generation (non-rate base generation sold at market-based rates to the wholesale market) from our Taconite Harbor facility in northern Minnesota and generation secured through the Kendall County power purchase agreement. To help meet forecasted base load energy requirements effective January 1, 2006, Taconite Harbor was integrated into our Regulated Utility, as approved by the MPUC. The Kendall County power purchase agreement was assigned to Constellation Energy Commodities in April 2005. (See Note 10.)

Investment in ATC includes our approximate 8 percent equity ownership interest in ATC, a Wisconsin-based public utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota and Illinois. ATC provides transmission service under rates regulated by the FERC that are set in accordance with the FERC’s policy of establishing the independent operation and ownership of, and investment in, transmission facilities. (See Note 6.)

Real Estate includes our Florida real estate operations. Our real estate operations include several wholly-owned subsidiaries and an 80 percent ownership in Lehigh Acquisition Corporation, which are consolidated in ALLETE's financial statements. Our Florida real estate companies are principally engaged in real estate acquisitions, development and sales.

Full profit recognition is recorded on sales upon closing, provided cash collections are at least 20 percent of the contract price and the other requirements of SFAS 66, "Accounting for Sales of Real Estate," are met. In certain cases, where there are obligations to perform significant development activities after the date of sale, we recognize profit on a percentage-of-completion basis in accordance with SFAS 66. Pursuant to this method of accounting, gross profit is recognized based upon the relationship of development costs incurred as of that date to the total estimated development costs of the parcels, including related amenities or common costs of the entire project. Revenue and cost of real estate sold in excess of the amount recognized based on the percentage-of-completion method is deferred and recognized as revenue and cost of real estate sold during the period in which the related development costs are incurred. Deferred revenue and cost of real estate sold are recorded net as Deferred Profit on Sales of Real Estate on our consolidated balance sheet. Certain contracts allow us to receive participation revenue from land sales to third parties if various formula-based criteria are achieved.

In certain cases, we pay fees or construct improvements to mitigate offsite traffic impacts. In return, we receive traffic impact fee credits as a result of some of these expenditures. We recognize revenue from the sale of traffic impact fee credits when payment is received.

Land held for sale is recorded at the lower of cost or fair value determined by the evaluation of individual land parcels and is included in Investments on our consolidated balance sheet. Real estate costs include the cost of land acquired, subsequent development costs and costs of improvements, capitalized development period interest, real estate taxes and payroll costs of certain employees devoted directly to the development effort. These real estate costs incurred are capitalized to the cost of real estate parcels based upon the relative sales value of parcels within each development project in accordance with SFAS 67, "Accounting for Costs and Initial Rental Operations of Real Estate Projects." When real estate is sold, the cost of real estate sold includes the actual costs incurred and the estimate of future completion costs allocated to the real estate sold based upon the relative sales value method.

Whenever events or circumstances indicate that the carrying value of the real estate may not be recoverable, impairments would be recorded and the related assets would be adjusted to their estimated fair value, less costs to sell.

Other includes investments in emerging technologies, and earnings on cash and short-term investments. As part of our emerging technology portfolio, we have several minority investments in venture capital funds and direct investments in privately-held, start-up companies. We account for our investment in venture capital funds under the equity method and account for our direct investments in privately-held companies under the cost method because of our ownership percentage. Short-term investments consist of auction rate bonds and variable rate demand notes, and are classified as available-for-sale securities. All income generated from these short-term investments is recorded as interest income. (See Note 6.)

Property, Plant and Equipment. Property, plant and equipment are recorded at original cost and are reported on the balance sheet net of accumulated depreciation. Expenditures for additions and significant replacements and improvements are capitalized; maintenance and repair costs are expensed as incurred. Expenditures for major plant overhauls are also accounted for using this same policy. Gains or losses on nonregulated property, plant and equipment are recognized when they are retired or otherwise disposed. When regulated utility property, plant and equipment are retired or otherwise disposed, no gain or loss is recognized, pursuant to SFAS 71, "Accounting for the Effects of Certain Types of Regulations." Our Regulated Utility operations capitalize AFUDC, which includes both an interest and equity component. (See Note 3.)

Long-Lived Asset Impairments. We account for our long-lived assets at depreciated historical cost. A long-lived asset is tested for recoverability whenever events or changes in circumstances indicate that its carrying amount may not be recoverable. We conduct this assessment using SFAS 144, "Accounting for the Impairment and Disposal of Long-Lived Assets." Judgments and uncertainties affecting the application of accounting for asset impairment include economic conditions affecting market valuations, changes in our business strategy, and changes in our forecast of future operating cash flows and earnings. We would recognize an impairment loss only if the carrying amount of a long-lived asset is not recoverable from its undiscounted future cash flows. Management judgment is involved in both deciding if testing for recoverability is necessary and in estimating undiscounted future cash flows.

Note 2. Operations and Significant Accounting Policies (Continued)

Accounts Receivable. Accounts receivable are reported on the balance sheet net of an allowance for doubtful accounts. The allowance is based on our evaluation of the receivable portfolio under current conditions, overall portfolio quality, review of specific problems and such other factors that, in our judgment, deserve recognition in estimating losses.

Accounts Receivable December 31	2007	2006
Millions		
Trade Accounts Receivable		
Billed	$63.9	$58.5
Unbilled	16.6	13.5
Less: Allowance for Doubtful Accounts	1.0	1.1
Total Accounts Receivable – Net	$79.5	$70.9

Inventories. Inventories are stated at the lower of cost or market. Amounts removed from inventory are recorded on an average cost basis.

Inventories December 31	2007	2006
Millions		
Fuel	$22.1	$18.9
Materials and Supplies	27.4	24.5
Total Inventories	$49.5	$43.4

Unamortized Discount and Premium on Debt. Discount and premium on debt are deferred and amortized over the terms of the related debt instruments using the effective interest method.

Cash and Cash Equivalents. We consider all investments purchased with original maturities of three months or less to be cash equivalents.

Supplemental Statement of Cash Flow Information.

Consolidated Statement of Cash Flows Supplemental Disclosure For the Year Ended December 31	2007	2006	2005
Millions			
Cash Paid During the Period for			
Interest – Net of Amounts Capitalized	$26.3	$25.3	$24.6
Income Taxes	$34.2	$32.4 *(a)*	$27.1
Noncash Investing Activities			
Accounts Payable for Capital Additions to Property, Plant and Equipment	$9.8	$7.1	–
AFUDC - Equity	$3.8	–	–

(a) Net of a $24.3 million cash refund.

Available-for-Sale Securities. Available-for-sale securities are recorded at fair value with unrealized gains and losses included in accumulated other comprehensive income (loss), net of tax. Unrealized losses that are other than temporary are recognized in earnings. Our auction rate securities and variable rate demand notes, classified as available-for-sale securities, are recorded at cost because their cost approximates fair market value as they typically reset every 7 to 35 days. Despite the long-term nature of their stated contractual maturities, we have the ability to quickly liquidate these securities. We use the specific identification method as the basis for determining the cost of securities sold. Our policy is to review on a quarterly basis available-for-sale securities for other than temporary impairment by assessing such factors as the share price trends and the impact of overall market conditions.

Note 2. Operations and Significant Accounting Policies (Continued)

Accounting for Stock-Based Compensation. Effective January 1, 2006, we adopted the fair value recognition provisions of SFAS 123R, "Share-Based Payment," using the modified prospective transition method. Under this method, we recognize compensation expense for all share-based payments granted after January 1, 2006, and those granted prior to but not yet vested as of January 1, 2006. Under the fair value recognition provisions of SFAS 123R, we recognize stock-based compensation net of an estimated forfeiture rate and only recognize compensation expense for those shares expected to vest over the required service period of the award. Prior to our adoption of SFAS 123R, we accounted for share-based payments under Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" and related interpretations. (See Note 16.)

Prepayments and Other Current Assets **December 31**	**2007**	**2006**
Millions		
Deferred Fuel Adjustment Clause	$26.5	$15.1
Other	12.6	8.7
Total Prepayments and Other Current Assets	$39.1	$23.8

Other Assets **December 31**	**2007**	**2006**
Millions		
Deferred Regulatory Charges (See Note 5)		
Future Benefit Obligations Under Defined Benefit Pension and Other Postretirement Plans	$53.7	$86.1
Other Deferred Regulatory Charges	22.9	17.5
Total Deferred Regulatory Charges	76.6	103.6
Other	34.8	31.4
Total Other Assets	$111.4	$135.0

Other Liabilities **December 31**	**2007**	**2006**
Millions		
Future Benefit Obligation Under Defined Benefit Pension and Other Postretirement Plans	$71.6	$108.2
Deferred Regulatory Credits (See Note 5)	31.3	33.8
Asset Retirement Obligation (See Note 3)	36.5	27.2
Other	60.7	56.9
Total Other Liabilities	$200.1	$226.1

Environmental Liabilities. We review environmental matters on a quarterly basis. Accruals for environmental matters are recorded when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated, based on current law and existing technologies. These accruals are adjusted periodically as assessment and remediation efforts progress or as additional technical or legal information becomes available. Accruals for environmental liabilities are included in the balance sheet at undiscounted amounts and exclude claims for recoveries from insurance or other third parties. Costs related to environmental contamination treatment and cleanup are charged to operating expense unless recoverable in rates from customers. (See Note 8.)

Income Taxes. We file a consolidated federal income tax return. We account for income taxes using the liability method as prescribed by SFAS 109, "Accounting for Income Taxes." Under the liability method, deferred income tax assets and liabilities are established for all temporary differences in the book and tax basis of assets and liabilities, based upon enacted tax laws and rates applicable to the periods in which the taxes become payable. Due to the effects of regulation on Minnesota Power, certain adjustments made to deferred income taxes are, in turn, recorded as regulatory assets or liabilities. Investment tax credits have been recorded as deferred credits and are being amortized to income tax expense over the service lives of the related property. Effective January 1, 2007, we adopted the provisions of FIN 48, "Accounting for Uncertainty in Income Taxes – an Interpretation of FASB Statement No. 109." Under this provision we are required to recognize in our financial statements the largest tax benefit of a tax position that is "more-likely-than-not" to be sustained, on audit, based solely on the technical merits of the position as of the reporting date. Only tax positions that meet the "more-likely-than-not' threshold may be recognized, and the term "more-likely-than-not" means more than 50 percent. (See Note 12.)

Excise Taxes. We collect excise taxes from our customers levied by government entities. These taxes are stated separately on the billing to the customer and recorded as a liability to be remitted to the government entity. We account for the collection and payment of these taxes on the net basis.

Note 2. Operations and Significant Accounting Policies (Continued)

New Accounting Standards. *SFAS 157*. In September 2006, the FASB issued SFAS 157, "Fair Value Measurements," to increase consistency and comparability in fair value measurements by defining fair value, establishing a framework for measuring fair value in generally accepted accounting principles, and expanding disclosures about fair value measurements. SFAS 157 emphasizes that fair value is a market-based measurement, not an entity-specific measurement. It clarifies the extent to which fair value is used to measure recognized assets and liabilities, the inputs used to develop the measurements, and the effect of certain measurements on earnings for the period. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and is applied on a prospective basis. On February 6, 2008, the FASB announced it will issue a FASB Staff Position (FSP) to allow a one-year deferral of adoption of SFAS 157 for nonfinancial assets and nonfinancial liabilities that are recognized at fair value on a nonrecurring basis. The FSP will also amend SFAS 157 to exclude SFAS 13, "Accounting for Leases," and its related interpretive accounting pronouncements. The FSP is expected to be issued in the near future. We have determined that the adoption of SFAS 157 will not have a material impact on our consolidated financial position, results of operations or cash flows.

SFAS 159. In February 2007, the FASB issued SFAS 159, "The Fair Value Option for Financial Assets and Financial Liabilities," which is an elective, irrevocable election to measure eligible financial instruments and certain other assets and liabilities at fair value on an instrument-by-instrument basis. The election may only be applied at specified election dates and to instruments in their entirety rather than to portions of instruments. Upon initial election, the entity reports the difference between the instruments' carrying value and their fair value as a cumulative-effect adjustment to the opening balance of retained earnings. At each subsequent reporting date, an entity reports in earnings, unrealized gains and losses on items for which the fair value option has been elected. SFAS 159 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and is applied on a prospective basis. Early adoption of SFAS 159 is permitted provided the entity also elects to adopt the provisions of SFAS 157 as of the early adoption date selected for SFAS 159. We have elected not to adopt the provisions of SFAS 159 at this time.

SFAS 141R. In December 2007, the FASB issued SFAS 141(revised 2007), "Business Combinations," to increase the relevance, representational faithfulness, and comparability of the information a reporting entity provides in its financial reports about a business combination and its effects. SFAS 141R replaces SFAS 141, "Business Combinations" but, retains the fundamental requirements of SFAS 141 that the acquisition method of accounting be used and an acquirer be identified for all business combinations. SFAS 141R expands the definition of a business and of a business combination and establishes how the acquirer is to: (1) recognize and measure in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree; (2) recognize and measure the goodwill acquired in the business combination or a gain from a bargain purchase; and (3) determine what information to disclose to enable users of the financial statements to evaluate the nature and financial effects of the business combination. SFAS 141R is applicable to business combinations for which the acquisition date is on or after the beginning of the first annual reporting period beginning on or after December 15, 2008, and is to be applied prospectively. Early adoption is prohibited. SFAS 141R will impact ALLETE if we elect to enter into a business combination subsequent to December 31, 2008.

SFAS 160. In December 2007, the FASB issued SFAS 160, "Noncontrolling Interests in Consolidated Financial Statements – an amendment of ARB No. 51," to improve the relevance, comparability, and transparency of the financial information a reporting entity provides in its consolidated financial statements. SFAS 160 amends ARB 51 to establish accounting and reporting standards for noncontrolling interests in subsidiaries and to make certain consolidation procedures consistent with the requirements of SFAS 141R. It defines a noncontrolling interest in a subsidiary as an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. SFAS 160 changes the way the consolidated income statement is presented by requiring consolidated net income to include amounts attributable to the parent and the noncontrolling interest. SFAS 160 establishes a single method of accounting for changes in a parent's ownership interest in a subsidiary which do not result in deconsolidation. SFAS 160 also requires expanded disclosures that clearly identify and distinguish between the interests of the parent and the interests of the noncontrolling owners of a subsidiary. SFAS 160 is effective for financial statements issued for fiscal years beginning on or after December 15, 2008, and interim periods within those fiscal years. Early adoption is prohibited. SFAS 160 shall be applied prospectively, with the exception of the presentation and disclosure requirements which shall be applied retrospectively for all periods presented. We are currently evaluating the effect that the adoption of SFAS 160 will have on our consolidated financial position, results of operations and cash flows; however ALLETE Properties does have certain noncontrolling interests in consolidated subsidiaries. If SFAS 160 had been applied as of December 31, 2007, the $9.3 million reported as Minority Interest in the Liabilities section on our Consolidated Balance Sheet would have been reported as $9.3 million of Noncontrolling Interest in Subsidiaries in the Equity section of our Consolidated Balance Sheet.

Note 3. Property, Plant and Equipment

Property, Plant and Equipment December 31	2007	2006
Millions		
Regulated Utility	$1,683.0	$1,575.8
Construction Work in Progress	165.8	71.4
Accumulated Depreciation	(796.8)	(781.3)
Regulated Utility Plant – Net	1,052.0	865.9
Nonregulated Energy Operations	89.9	88.5
Construction Work in Progress	2.5	2.6
Accumulated Depreciation	(43.2)	(40.1)
Nonregulated Energy Operations Plant – Net	49.2	51.0
Other Plant – Net	3.3	4.7
Property, Plant and Equipment – Net	$1,104.5	$921.6

Depreciation is computed using the straight-line method over the estimated useful lives of the various classes of assets. The MPUC and the PSCW have approved depreciation rates for our Regulated Utility plant.

Estimated Useful Lives of Property, Plant and Equipment

Regulated Utility –	Generation	4 to 29 years	Nonregulated Energy Operations	4 to 40 years
	Transmission	40 to 60 years	Other Plant	5 to 25 years
	Distribution	30 to 70 years		

Asset Retirement Obligations. Pursuant to SFAS 143, "Accounting for Asset Retirement Obligations," we recognize, at fair value, obligations associated with the retirement of tangible, long-lived assets that result from the acquisition, construction or development and/or normal operation of the asset. The associated retirement costs are capitalized as part of the related long-lived asset and depreciated over the useful life of the asset. Asset retirement obligations relate primarily to the decommissioning of our utility steam generating facilities and land reclamation at BNI Coal, and are included in Other Liabilities on our consolidated balance sheet. Removal costs associated with certain distribution and transmission assets have not been recognized as these facilities have been determined to have indeterminate useful lives. Prior to the adoption of SFAS 143, utility decommissioning obligations were accrued through depreciation expense at depreciation rates approved by the MPUC. Conditional asset retirement obligations have been identified for treated wood poles and remaining polychlorinated biphenyl and asbestos-containing assets; however, removal costs have not been recognized because they are considered immaterial to our consolidated financial statements.

Asset Retirement Obligation	
Millions	
Obligation at December 31, 2005	$25.3
Accretion Expense	1.8
Additional Liabilities Incurred in 2006	0.1
Obligation at December 31, 2006	27.2
Accretion Expense	2.1
Additional Liabilities Incurred in 2007	7.2
Obligation at December 31, 2007	$36.5

Note 4. Jointly-Owned Electric Facility

We own 80 percent of the 536-MW Boswell Energy Center Unit 4 (Boswell Unit 4). While we operate the plant, certain decisions about the operations of Boswell Unit 4 are subject to the oversight of a committee on which we and Wisconsin Public Power, Inc., the owner of the other 20 percent of Boswell Unit 4, have equal representation and voting rights. Each of us must provide our own financing and is obligated to pay our ownership share of operating costs. Our share of direct operating expenses of Boswell Unit 4 is included in operating expense on our consolidated statement of income. Our 80 percent share of the original cost of Boswell Unit 4, which is included in property, plant and equipment at December 31, 2007, was $316 million ($314 million at December 31, 2006). The corresponding accumulated depreciation balance was $170 million at December 31, 2007 ($168 million at December 31, 2006).

Note 5. Regulatory Matters

Electric Rates. Entities within our Regulated Utility segment file for periodic rate revisions with the MPUC, the FERC or the PSCW. On February 8, 2008, the FERC approved our wholesale rate filing. Our wholesale customers consist of 16 municipalities in Minnesota and two private utilities in Wisconsin, including SWL&P. The FERC authorized an average 10 percent increase for wholesale municipal customers, a 12.5 percent increase for SWL&P, and an overall return on equity of 11.25 percent. The rate increase will go into effect on March 1, 2008, and on an annualized basis, the filing will generate approximately $7.5 million in additional revenue. Minnesota Power's retail rates are based on a 1994 MPUC retail rate order that allows for an 11.6 percent return on common equity dedicated to utility plant. SWL&P's current retail rates are based on a 2006 PSCW retail rate order, effective January 1, 2007. In 2007, 76 percent of our consolidated operating revenue was under regulatory authority (72 percent in 2006 and 2005). The MPUC had regulatory authority over approximately 58 percent of our consolidated operating revenue in 2007 (56 percent in 2006 and 2005).

Deferred Regulatory Charges and Credits. Our regulated utility operations are subject to the provisions of SFAS 71, "Accounting for the Effects of Certain Types of Regulation." We capitalize as deferred regulatory charges incurred costs which are probable of recovery in future utility rates. Deferred regulatory credits represent amounts expected to be credited to customers in rates. Deferred regulatory charges and credits are included in Other Assets and Other Liabilities on our consolidated balance sheet except for deferred fuel adjustment clause charges which are included in Prepayments and Other Current Assets (See Note 2). No deferred regulatory charges or credits are currently earning a return.

Deferred Regulatory Charges and Credits **December 31**	**2007**	**2006**
Millions		
Deferred Charges		
Income Taxes	$11.3	$11.6
Premium on Reacquired Debt	2.3	2.8
Future Benefit Obligations Under		
Defined Benefit Pension and Other Postretirement Plans (See Note 15)	53.7	86.1
Deferred MISO Costs	3.7	–
Asset Retirement Obligation	3.6	2.3
Other	2.0	0.8
	76.6	103.6
Deferred Credits – Income Taxes	31.3	33.8
Net Deferred Regulatory Assets	$45.3	$69.8

Note 6. Investments

Available-for-Sale Investments. We account for our available-for-sale portfolio in accordance with SFAS 115, "Accounting for Certain Investments in Debt and Equity Securities." Our available-for-sale securities portfolio consisted of securities in a grantor trust established to fund certain employee benefits included in Investments and various auction rate municipal bonds and variable rate municipal demand notes included as Short-Term Investments (see below). As a result of our periodic assessments, we did not record an impairment charge on our available for sale securities in the last three years.

Available-For-Sale Securities **Million** **s**				
		Gross Unrealized		
At December 31	**Cost**	**Gain**	**(Loss)**	**Fair Value**
2007	$45.3	$8.4	$(0.1)	$53.6
2006	$123.2	$7.0	$(0.1)	$130.1
2005	$135.2	$4.4	$(0.1)	$139.5

Year Ended December 31	**Sales Proceeds**	**Gross Realized Gain**	**Gross Realized (Loss)**	**Net Unrealized Gain (Loss) in Other Comprehensive Income**
2007	$81.4	–	–	$1.4
2006	$12.4	–	–	$2.5
2005	$32.3	–	–	$1.3

Note 6. Investments (Continued)

Short-Term Investments. At December 31, 2007, we held $23.1 million of short-term investments ($104.5 million at December 31, 2006) consisting of various auction rate municipal bonds and variable rate municipal demand notes. Substantially all of these securities consisted of guaranteed student loans, insured or reinsured by the federal government. The credit markets are currently experiencing significant uncertainty, and some of this uncertainty has impacted the markets where our auction rate securities would be offered. We are unable to estimate the impact, if any, which emerging credit market conditions may have on the liquidity of our auction rate securities. Any reduction in liquidity of our auction rate securities will not have a material impact on our overall liquidity needs. We believe the $23.1 million carrying value is not impaired, but we may have to reclassify the investment from short-term to long-term investments if future liquidity conditions mandate.

Investments. At December 31, 2007, our long-term investment portfolio included the real estate assets of ALLETE Properties, our investment in ATC, debt and equity securities consisting primarily of securities held to fund employee benefits, and our emerging technology portfolio.

Investments **December 31**	**2007**	**2006**
Millions		
Real Estate Assets	$91.3	$89.8
Debt and Equity Securities	48.9	36.4
Investment in ATC	65.7	53.7
Emerging Technology Portfolio	7.9	9.2
Total Investments	$213.8	$189.1

Real Estate Assets		**2007**	**2006**
Millions			
Land Held for Sale Beginning Balance		$58.0	$48.0
Additions during period:	Capitalized Improvements	12.8	18.8
	Purchases	–	1.4
Deductions during period:	Cost of Real Estate Sold	(8.2)	(10.2)
Land Held for Sale Ending Balance		62.6	58.0
Long-Term Finance Receivables		15.3	18.3
Other *(a)*		13.4	13.5
Total Real Estate Assets		$91.3	$89.8

(a) Consisted primarily of a shopping center.

Finance receivables, which are collateralized by property sold, accrue interest at market-based rates and are net of an allowance for doubtful accounts of $0.2 million at December 31, 2007 ($0.2 million at December 31, 2006). The majority are receivables having maturities up to 5 years. Minority interest associated with real estate operations was $9.3 million at December 31, 2007 ($7.4 million at December 31, 2006).

Investment in ATC. Our Wisconsin subsidiary, Rainy River Energy Corporation - Wisconsin, has invested $60 million in ATC, a Wisconsin-based public utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota and Illinois. ATC provides transmission service under rates regulated by the FERC that are set in accordance with the FERC's policy of establishing the independent operation and ownership of, and investment in, transmission facilities. We account for our investment in ATC under the equity method of accounting, pursuant to EITF 03-16, "Accounting for Investments in Limited Liability Companies." As of December 31, 2007, our equity investment balance in ATC was $65.7 million ($53.7 million at December 31, 2006), representing an approximate 8.0 percent ownership interest.

ALLETE's Interest in ATC **For the Year Ended December 31, 2007**	
Millions	
Equity Investment Balance at December 31, 2006	$53.7
2007 Cash Investments	8.7
Equity in ATC Earnings	12.6
Distributed ATC Earnings	(9.3)
Equity Investment Balance at December 31, 2007	$65.7

Note 6. Investments (Continued)

Emerging Technology Portfolio. As part of our emerging technology portfolio, we have several minority investments in venture capital funds and direct investments in privately-held, start-up companies. We account for our investment in venture capital funds under the equity method and account for our direct investments in privately-held companies under the cost method because of our ownership percentage. The total carrying value of our emerging technology portfolio was $7.9 million at December 31, 2007 ($9.2 million at December 31, 2006). Our policy is to review these investments quarterly for impairment by assessing such factors as continued commercial viability of products, cash flow and earnings. Any impairment would reduce the carrying value of the investment. Due to the distribution of investments from matured venture capital funds, our basis in direct investments in privately-held companies included in the emerging technology portfolio was $1.2 million at December 31, 2007 (zero at December 31, 2006). In 2007, we recorded $0.5 million ($0.3 million after tax) of impairments related to our venture capital funds whose future business prospects had significantly diminished. Developments at these companies indicated that future commercial viability was unlikely, as was new financing necessary to continue development. We did not record any impairments in 2006. In 2005, we recorded $5.1 million ($3.3 million after tax) of impairments related to our direct investments in certain privately-held, start-up companies.

Fair Value of Financial Instruments. With the exception of the items listed below, the estimated fair value of all financial instruments approximates the carrying amount. The fair value for the items below were based on quoted market prices for the same or similar instruments.

Financial Instruments December 31	**Carrying Amount**	**Fair Value**
Millions		
Long-Term Debt, Including Current Portion		
2007	$422.7	$410.9
2006	$389.5	$387.6

Concentration of Credit Risk. Financial instruments that subject us to concentrations of credit risk consist primarily of accounts receivable. Minnesota Power sells electricity to 12 Large Power Customers. Receivables from these customers totaled approximately $14 million at December 31, 2007 ($9 million at December 31, 2006). Minnesota Power does not obtain collateral to support utility receivables, but monitors the credit standing of major customers. In addition, our taconite-producing Large Power Customers are on a weekly billing cycle, which allows us to closely manage collection of amounts due.

Note 7. Short-Term and Long-Term Debt

Short-Term Debt. Total short-term debt outstanding at December 31, 2007, was $11.8 million ($29.7 million at December 31, 2006) and consisted of Long-Term Debt Due Within One Year.

As of December 31, 2007, we had bank lines of credit aggregating $170.0 million ($170.0 million at December 31, 2006), the majority of which expire in January 2012. These bank lines of credit made financing available through short-term bank loans and provided credit support for commercial paper. At December 31, 2007, $4.3 million ($2.9 million at December 31, 2006) was drawn on our lines of credit leaving a $165.7 million balance available for use ($167.1 million at December 31, 2006). The drawn amounts at December 31, 2007, related to an $8.5 million revolving development loan with CypressCoquina Bank that we entered into in March 2005. The revolving development loan has an interest rate equal to the prime rate, with an initial term of 36 months. The term of the loan may be extended 24 months if certain conditions are met. The loan is guaranteed by Lehigh Acquisition Corporation, an 80 percent owned subsidiary of ALLETE Properties. There was no commercial paper issued as of December 31, 2007 and 2006.

In January 2006, we renewed, increased and extended a committed, syndicated, unsecured revolving credit facility (Line) with LaSalle Bank National Association, as Agent, for $150 million. The Line was subsequently extended for an additional year in December 2006 and currently matures in January 2012. At our request and subject to certain conditions, the Line may be increased to $200 million and extended for two additional 12-month periods. The Line may be used for general corporate purposes and working capital, and to provide liquidity in support of our commercial paper program. We may prepay amounts outstanding under the Line in whole or in part at our discretion without premium or penalty. Additionally, we may irrevocably terminate or reduce the size of the Line prior to maturity without premium or penalty. No funds were drawn under this Line at December 31, 2007 and 2006.

Note 7. Short-Term and Long-Term Debt (Continued)

Long-Term Debt. The aggregate amount of long-term debt maturing during 2008 is $11.8 million ($10.7 million in 2009; $5.0 million in 2010; $1.4 million in 2011; $3.1 million in 2012; and $390.7 million thereafter). Substantially all of our electric plant is subject to the lien of the mortgages collateralizing various first mortgage bonds.

On February 1, 2007, we issued $60 million in principal amount of First Mortgage Bonds (Bonds), 5.99% Series due February 1, 2027, in the private placement market. The Company has the option to prepay all or a portion of the Bonds at its discretion, subject to a make-whole provision. Proceeds were used to retire $60 million in principal amount of First Mortgage Bonds, 7% Series on February 15, 2007.

On June 8, 2007, we issued $50 million of senior unsecured notes (Notes) in the private placement market. The Notes bear an interest rate of 5.99% and will mature on June 1, 2017. The Company has the option to prepay all or a portion of the Notes at its discretion, subject to a make-whole provision. The Company used the proceeds from the sale of the Notes to fund utility capital projects and for general corporate purposes.

On behalf of SWL&P, the City of Superior, Wisconsin, issued $6.4 million in principal amount of Collateralized Utility Revenue Refunding Bonds (Series A Bonds) and $6.1 million of Collateralized Utility Revenue Bonds (Series B Bonds) on October 3, 2007. The Series A Bonds bear an interest rate of 5.375% and will mature on November 1, 2021. The proceeds, together with other funds, were used to redeem $6.5 million of existing 6.125% bonds. The Series B Bonds bear an interest rate of 5.75% and will mature on November 1, 2037. The proceeds from the Series B Bonds will be used to fund qualifying electric and gas projects.

On February 1, 2008, we issued $60 million in principal amount of First Mortgage Bonds (Bonds), 4.86% Series due April 1, 2013, in the private placement market. We have the option to prepay all or a portion of the Bonds at our discretion, subject to a make-whole provision. We intend to use the proceeds from the sale of the Bonds to fund utility capital expenditures and for general corporate purposes.

Long-Term Debt **December 31**	**2007**	**2006**
Millions		
First Mortgage Bonds		
6.68% Series Due 2007	–	$20.0
7.00% Series Due 2007	–	60.0
5.28% Series Due 2020	$35.0	35.0
4.95% Pollution Control Series F Due 2022	111.0	111.0
5.99% Series Due 2027	60.0	–
5.69% Series Due 2036	50.0	50.0
Senior Unsecured Notes 5.99% Due 2017	50.0	–
Variable Demand Revenue Refunding Bonds Series 1997 A, B, and C Due 2009 – 2020	36.5	39.0
Industrial Development Revenue Bonds 6.5% Due 2025	6.0	6.0
Industrial Development Variable Rate Demand Refunding Revenue Bonds Series 2006 Due 2025	27.8	27.8
Other Long-Term Debt, 2.0% – 8.0% Due 2008 – 2037	46.4	40.7
Total Long-Term Debt	422.7	389.5
Less: Due Within One Year	11.8	29.7
Net Long-Term Debt	$410.9	$359.8

Financial Covenants. Our long-term debt arrangements contain customary covenants. In addition, our lines of credit and letters of credit supporting certain long-term debt arrangements contain financial covenants. The most restrictive covenant requires ALLETE to maintain a quarterly ratio of its funded debt to total capital of less than or equal to .65 to 1.00. Failure to meet this covenant could give rise to an event of default, if not corrected after notice from the lender, in which event ALLETE may need to pursue alternative sources of funding. Some of ALLETE's debt arrangements contain "cross-default" provisions that would result in an event of default if there is a failure under other financing arrangements to meet payment terms or to observe other covenants that would result in an acceleration of payments due.

Note 8. Commitments, Guarantees and Contingencies

Off-Balance Sheet Arrangements. *Square Butte Power Purchase Agreement.* Minnesota Power has a power purchase agreement with Square Butte that extends through 2026 (Agreement). It provides a long-term supply of low-cost energy to customers in our electric service territory and enables Minnesota Power to meet power pool reserve requirements. Square Butte, a North Dakota cooperative corporation, owns a 455-MW coal-fired generating unit (Unit) near Center, North Dakota. The Unit is adjacent to a generating unit owned by Minnkota Power, a North Dakota cooperative corporation whose Class A members are also members of Square Butte. Minnkota Power serves as the operator of the Unit and also purchases power from Square Butte.

Minnesota Power was entitled to approximately 71 percent of the Unit's output under the Agreement prior to 2006. Minnkota Power exercised its option to reduce Minnesota Power's entitlement by approximately 5 percent annually to 66 percent in 2006 and 60 percent in 2007. We received notices from Minnkota Power that they further reduced our output entitlement by approximately 5 percent annually to 55 percent on January 1, 2008, and 50 percent on January 1, 2009, and thereafter. Minnkota Power has no further option to reduce Minnesota Power's entitlement below 50 percent.

Minnesota Power is obligated to pay its pro rata share of Square Butte's costs based on Minnesota Power's entitlement to Unit output. Minnesota Power's payment obligation will be suspended if Square Butte fails to deliver any power, whether produced or purchased, for a period of one year. Square Butte's fixed costs consist primarily of debt service. At December 31, 2007, Square Butte had total debt outstanding of $323.0 million. Total annual debt service for Square Butte is expected to be approximately $29 million in each of the years 2008 through 2012. Variable operating costs include the price of coal purchased from BNI Coal, our subsidiary, under a long-term contract.

Minnesota Power's cost of power purchased from Square Butte during 2007 was $57.3 million ($57.9 million in 2006; $56.4 million in 2005). This reflects Minnesota Power's pro rata share of total Square Butte costs, based on the 60 percent output entitlement in 2007, the 66 percent output entitlement in 2006 and the 71 percent output entitlement in 2005. Included in this amount was Minnesota Power's pro rata share of interest expense of $11.0 million in 2007 ($12.6 million in 2006; $13.6 million in 2005). Minnesota Power's payments to Square Butte are approved as a purchased power expense for ratemaking purposes by both the MPUC and the FERC.

We have two wind power purchase agreements with an affiliate of FPL Energy to purchase the output from two wind facilities, Oliver Wind I and II located near Center, North Dakota. We began purchasing the output from Oliver Wind I, a 50-MW facility, in December 2006 and the output from Oliver Wind II, a 48-MW facility in November 2007. Each agreement is for 25 years and provides for the purchase of all output from the facilities. There are no fixed capacity charges, and we only pay for energy as it is delivered to us.

Leasing Agreements. BNI Coal is obligated to make lease payments for a dragline totaling $2.8 million annually for the lease term which expires in 2027. BNI Coal has the option at the end of the lease term to renew the lease at a fair market rental, to purchase the dragline at fair market value, or to surrender the dragline and pay a $3.0 million termination fee. We lease other properties and equipment under operating lease agreements with terms expiring through 2016. The aggregate amount of minimum lease payments for all operating leases is $8.1 million in 2008, $8.1 million in 2009, $7.7 million in 2010, $7.2 million in 2011, $6.6 million in 2012 and $48.7 million thereafter. Total rent and lease expense was $6.6 million in 2007 ($6.8 million in 2006; $6.2 million in 2005).

Coal, Rail and Shipping Contracts. We have three coal supply agreements with various expiration dates ranging from December 2008 to December 2011. We also have rail and shipping agreements for the transportation of all of our coal, with various expiration dates ranging from December 2008 to December 2011. Our minimum annual payment obligations under these coal, rail and shipping agreements are currently $44.8 million in 2008, $10.8 million in 2009, $5.3 million in 2010, $5.4 million in 2011 and no specific commitments beyond 2011. Our minimum annual payment obligations will increase when annual nominations are made for coal deliveries in future years.

On January 24, 2008, the Company received a letter from BNSF alleging Minnesota Power defaulted on a material obligation under the Company's Coal Transportation Agreement (CTA). In the notice, BNSF claimed Minnesota Power underpaid approximately $1.6 million for coal transportation services in 2006 and that failure to pay such amounts plus interest within 60 days may result in BNSF's termination of the CTA. Minnesota Power believes it does not owe the amount claimed, and that BNSF's claims are wholly without merit. Minnesota Power intends to vigorously defend its position in this dispute.

Fuel Clause Recovery of MISO Day 2 Costs. We filed a petition with the MPUC in February 2005 to amend our fuel clause to accommodate costs and revenue related to the day-ahead and real-time markets through which we engage in wholesale energy transactions in MISO (MISO Day 2). In December 2006, the MPUC issued an order allowing Minnesota Power and the other utilities involved in the MISO Day 2 proceeding to continue recovering MISO Day 2 charges through the Minnesota retail fuel clause except for MISO Day 2 administrative charges. On January 8, 2007, this order was challenged by the Minnesota OAG, through a request for reconsideration. The request was opposed by Minnesota Power and the other utilities, as well as MISO. The reconsideration request effectively was denied by the MPUC. Upon denial of the reconsideration request, the OAG appealed the MPUC Order in a filing with the Minnesota Court of Appeals. Oral argument in the case is scheduled to be held on February 27, 2008, and a decision would be expected approximately 90 days there after. We are unable to predict the outcome of this matter.

Note 8. Commitments, Guarantees and Contingencies (Continued)

Fuel Clause Recovery of MISO Day 2 Costs (Continued). The December 2006 MPUC order, subject to the rehearing request, granted deferred accounting treatment for three MISO Day 2 charge types that were determined to be administrative charges. Under the order, Minnesota Power refunded, through customer bills, approximately $2 million of administrative charges previously collected through the fuel clause between April 1, 2005, and December 31, 2006, and recorded these administrative charges as a regulatory asset. We were permitted to continue accumulating MISO Day 2 administrative charges after December 31, 2006, as a regulatory asset until we file our next rate case, at which time recovery for such charges will be determined. The balance of this regulatory asset was $3.7 million on December 31, 2007, and we consider regulatory recovery to be probable. This order removed the subject to refund requirement of the two interim orders, and included extensive fuel clause reporting requirements that review our monthly and annual fuel clause filings with the MPUC. There was no impact on earnings as a result of this ruling. As a result of the MPUC's December 2006 order allowing recovery of nearly all MISO Day 2 charges through the fuel clause, we rescinded our December 2005 Letter of Intent to Withdraw from MISO in December 2006.

Emerging Technology Portfolio. We have investments in emerging technologies through minority investments in venture capital funds structured as limited liability companies, and direct investments in privately-held, start-up companies. We have committed to make additional investments in certain emerging technology venture capital funds. The total future commitment was $1.0 million at December 31, 2007, and may be invested in 2008. We do not have plans to make any additional investments beyond this commitment.

Discontinued Operations. Two of our subsidiaries, which were involved in our discontinued water operations, have been named in a claim brought by Capital Resources and Properties, Inc, (CRP). CRP alleges that Georgia Water and ALLETE Water Services are obligated to pay $2 million dollars plus interest and attorney fees pursuant to a contract that was entered into in 2001. The contract provides for payments of certain amounts upon the satisfaction of specified contingencies, which CRP alleges were satisfied in 2005 or were waived, or are otherwise due and owing. We intend to vigorously assert our defenses to the claim, and cannot predict the outcome of this matter. A trial date is expected later this year.

Environmental Matters. Our businesses are subject to regulation of environmental matters by various federal, state and local authorities. Due to future stricter environmental requirements through legislation and/or rulemaking, we anticipate that potential expenditures for environmental matters will be material and will require significant capital investments. We review environmental matters on a quarterly basis. Accruals for environmental matters are recorded when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated, based on current law and existing technologies. These accruals are adjusted periodically as assessment and remediation efforts progress or as additional technical or legal information becomes available. Accruals for environmental liabilities are included in the balance sheet at undiscounted amounts and exclude claims for recoveries from insurance or other third parties. Costs related to environmental contamination treatment and cleanup are charged to expense unless recoverable in rates from customers.

SWL&P Manufactured Gas Plant. In May 2001, SWL&P received notice from the WDNR that the City of Superior had found soil contamination on property adjoining a former Manufactured Gas Plant (MGP) site owned and operated by SWL&P from 1889 to 1904. A report submitted in 2003 identified some MGP-like chemicals that were found in the soil near the former plant site. The final Phase II report was issued in June 2007, confirming our understanding of the issues involved. The final Phase II Report and Risk Assessment were sent to the WDNR for review in June 2007. A remediation plan was developed during the fourth quarter of 2007 and will be submitted to the WDNR during the first quarter of 2008. Although it is not possible to quantify the potential clean-up cost until the investigation is completed, a $0.5 million liability was recorded in December 2003 to address the known areas of contamination. The Company has recorded a corresponding dollar amount as a regulatory asset to offset this liability. The PSCW approved the collection through rates of $0.3 million of site investigation costs that had been incurred through 2005. ALLETE maintains pollution liability insurance coverage that includes coverage for SWL&P. A claim has been filed with respect to this matter. The insurance carrier has issued a reservation of rights letter and the Company continues to work with the insurer to determine the availability of insurance coverage.

EPA Clean Air Interstate Rule. In March 2005, the EPA announced the final Clean Air Interstate Rule (CAIR) that reduces and permanently caps emissions of SO_2, NO_X and particulates in the eastern United States. The CAIR includes Minnesota as one of the 28 states it considers as "significantly contributing" to air quality standards non-attainment in other states. The CAIR has been challenged in the court system, which may delay implementation or modify provisions in the rules. Minnesota Power is participating in the legal challenge to the CAIR. However, if the CAIR does go into effect, Minnesota Power expects to be required to:

(1) make emissions reductions;
(2) purchase mercury, SO_2 and NO_X allowances through the EPA's cap-and-trade system; and/or
(3) use a combination of both.

Note 8. Commitments, Guarantees and Contingencies (Continued)

EPA Clean Air Mercury Rule. In March 2005, the EPA also announced the final Clean Air Mercury Rule (CAMR) that would have reduced and permanently capped emissions of electric utility mercury emissions in the continental United States. On February 8, 2008 the United States Court of Appeals for the District of Columbia Circuit overturned the CAMR and remanded the rulemaking to the EPA for reconsideration. The Court's decision is subject to appeal. It is uncertain how the EPA will respond; and therefore it is also uncertain whether mercury emission reductions expected as a result of implementing AREA Plan expenditures at Taconite Harbor, and implementation of the 2006 Minnesota Mercury Emission Reduction Law which applies to Boswell Units 3 and 4, will meet the EPA's reformed mercury regulations. (See Minnesota Mercury Emission Law.) Cost estimates for complying with future mercury regulations under the Clean Air Act are therefore premature at this time.

Real Estate. As of December 31, 2007, ALLETE Properties, through its subsidiaries, had surety bonds outstanding of $35.9 million primarily related to performance and maintenance obligations to governmental entities to construct improvements in the company's various projects. The remaining work to be completed on these improvements is estimated to be approximately $6.4 million, and ALLETE Properties does not believe it is likely that any of these outstanding bonds will be drawn upon.

Community Development District Obligations. *Town Center.* In March 2005, the Town Center District issued $26.4 million of tax-exempt, 6% Capital Improvement Revenue Bonds, Series 2005, which are payable through property tax assessments on the land owners over 31 years (by May 1, 2036). The bond proceeds (less capitalized interest, a debt service reserve fund and cost of issuance) were used to pay for the construction of a portion of the major infrastructure improvements at Town Center. The bonds are payable from and secured by the revenue derived from assessments imposed, levied and collected by the Town Center District. The assessments represent an allocation of the costs of the improvements, including bond financing costs, to the lands within the Town Center District benefiting from the improvements. The assessments were billed to Town Center landowners effective in November 2006. To the extent that we still own land at the time of the assessment, in accordance with EITF 91-10, "Accounting for Special Assessments and Tax Increment Financing Entities," we will incur the cost of our portion of these assessments, based upon our ownership of benefited property. At December 31, 2007, we owned approximately 69 percent of the assessable land in the Town Center District (73 percent at December 31, 2006). As we sell property, the obligation to pay special assessments will pass to the new landowners. Under current accounting rules, these bonds are not reflected as debt on our consolidated balance sheet.

Palm Coast Park. In May 2006, the Palm Coast Park District issued $31.8 million of tax-exempt, 5.7% Special Assessment Bonds, Series 2006, which are payable through property tax assessments on the land owners over 31 years (by May 1, 2037). The bond proceeds (less capitalized interest, a debt service reserve fund and cost of issuance) were used to pay for the construction of the major infrastructure improvements at Palm Coast Park and to mitigate traffic and environmental impacts. The bonds are payable from and secured by the revenue derived from assessments imposed, levied and collected by the Palm Coast Park District. The assessments represent an allocation of the costs of the improvements, including bond financing costs, to the lands within the Palm Coast Park District benefiting from the improvements. The assessments will be billed to Palm Coast Park landowners effective in November 2007. To the extent that we still own land at the time of the assessment, in accordance with EITF 91-10, "Accounting for Special Assessments and Tax Increment Financing Entities," we will incur the cost of our portion of these assessments, based upon our ownership of benefited property. At December 31, 2007, we owned 86 percent of the assessable land in the Palm Coast Park District (97 percent at December 31, 2006). As we sell property, the obligation to pay special assessments will pass to the new landowners. Under current accounting rules, these bonds are not reflected as debt on our consolidated balance sheet.

Other. We are involved in litigation arising in the normal course of business. Also in the normal course of business, we are involved in tax, regulatory and other governmental audits, inspections, investigations and other proceedings that involve state and federal taxes, safety, compliance with regulations, rate base and cost of service issues, among other things. While the resolution of such matters could have a material effect on earnings and cash flows in the year of resolution, none of these matters are expected to materially change our present liquidity position, or have a material adverse effect on our financial condition.

Note 9. Common Stock and Earnings Per Share

Our Articles of Incorporation contains provisions that, under certain circumstances, would restrict the payment of common stock dividends. As of December 31, 2007, no retained earnings were restricted as a result of these provisions.

Summary of Common Stock		Shares	Equity
		Thousands	Millions
Balance at December 31, 2004		29,651	$400.1
2005	Employee Stock Purchase Plan	13	0.5
	Invest Direct *(a)*	238	10.5
	Options and Stock Awards	241	10.0
Balance at December 31, 2005		30,143	421.1
2006	Employee Stock Purchase Plan	12	0.5
	Invest Direct *(a)*	218	10.0
	Options and Stock Awards	63	7.1
Balance at December 31, 2006		30,436	438.7
2007	Employee Stock Purchase Plan	17	0.7
	Invest Direct *(a)*	331	15.1
	Options and Stock Awards	43	6.7
Balance at December 31, 2007		30,827	$461.2

(a) Invest Direct is ALLETE's direct stock purchase and dividend reinvestment plan.

Shareholder Rights Plan. In 1996, we adopted a rights plan that provides for a dividend distribution of one preferred share purchase right (Right) to be attached to each share of common stock. In July 2006, we amended the rights plan to extend the expiration of the Rights to July 11, 2009. The amendment also provides that the Company may not consolidate, merge, or sell a majority of its assets or earning power if doing so would be counter to the intended benefits of the Rights or would result in the distribution of Rights to the shareholders of the other parties to the transaction. Finally, the amendment provides for the creation of a committee of independent directors to annually review the terms and conditions of the amended rights plan (Rights Plan), as well as to consider whether termination or modification of the Rights Plan would be in the best interests of the shareholders and to make a recommendation based on such review to the Board of Directors.

The Rights, which are currently not exercisable or transferable apart from our common stock, entitle the holder to purchase one-and-a-half one-hundredths (three two-hundredths) of a share of ALLETE's Junior Serial Preferred Stock A, without par value. The purchase price, as defined in the Rights Plan, remains at $90. These Rights would become exercisable if a person or group acquires beneficial ownership of 15 percent or more of our common stock or announces a tender offer which would increase the person's or group's beneficial ownership interest to 15 percent or more of our common stock, subject to certain exceptions. If the 15 percent threshold is met, each Right entitles the holder (other than the acquiring person or group) to receive, upon payment of the purchase price, the number of shares of common stock (or, in certain circumstances, cash, property or other securities of ours) having a market value equal to twice the exercise price of the Right. If we are acquired in a merger or business combination, or more than 50 percent of our assets or earning power are sold, each exercisable Right entitles the holder to receive, upon payment of the purchase price, the number of shares of common stock of the acquiring or surviving company having a value equal to twice the exercise price of the Right. Certain stock acquisitions will also trigger a provision permitting the Board of Directors to exchange each Right for one share of our common stock.

The Rights are nonvoting and may be redeemed by us at a price of $0.005 per Right at any time they are not exercisable. One million shares of Junior Serial Preferred Stock A have been authorized and are reserved for issuance under the Rights Plan.

Note 9. Common Stock and Earnings Per Share (Continued)

Earnings Per Share. The difference between basic and diluted earnings per share arises from outstanding stock options and performance share awards granted under our Executive and Director Long-Term Incentive Compensation Plans. In accordance with SFAS 128, "Earnings Per Share," for 2007, 0.2 million options to purchase shares of common stock were excluded from the computation of diluted earnings per share because the option exercise prices were greater than the average market prices, and therefore, their effect would be anti-dilutive (no shares were excluded for 2006 and 2005).

Reconciliation of Basic and Diluted Earnings Per Share For the Year Ended December 31	Basic	Dilutive Securities	Diluted
Millions Except Per Share Amounts			
2007			
Income from Continuing Operations	$87.6	–	$87.6
Common Shares	28.3	0.1	28.4
Per Share from Continuing Operations	$3.09	–	$3.08
2006			
Income from Continuing Operations	$77.3	–	$77.3
Common Shares	27.8	0.1	27.9
Per Share from Continuing Operations	$2.78	–	$2.77
2005			
Income from Continuing Operations	$17.6	–	$17.6
Common Shares	27.3	0.1	27.4
Per Share from Continuing Operations	$0.65	–	$0.64

Note 10. Kendall County Charge

On April 1, 2005, Rainy River Energy, a wholly-owned subsidiary of ALLETE, assigned its power purchase agreement with LSP-Kendall Energy, LLC, the owner of an energy generation facility located in Kendall County, Illinois, to Constellation Energy Commodities. Rainy River Energy paid Constellation Energy Commodities $73 million in cash to assume the power purchase agreement that remains in effect through mid-September 2017. The federal tax benefits of the payment were realized through a $24.3 million capital loss carryback refund received in the third quarter of 2006. In addition, consent, advisory and closing costs of $4.9 million were incurred to complete the transaction. As a result of this transaction, ALLETE incurred a charge to operating expenses totaling $77.9 million ($50.4 million after tax, or $1.84 per diluted share) in the second quarter of 2005.

Note 11. Other Income (Expense)

For the Year Ended December 31	2007	2006	2005
Millions			
Loss on Emerging Technology Investments	$(1.3)	$(0.9)	$(6.1)
AFUDC - Equity	3.8	0.5	0.2
Debt Prepayment Premium and Unamortized Debt Issuance Costs	–	(0.6)	–
Investments and Other Income	13.0	12.9	7.0
Total Other Income	$15.5	$11.9	$1.1

In August 2006, we redeemed $29.1 million of outstanding Collier County Industrial Development Refunding Revenue Bonds 6.5% Series 1996 due 2025 with proceeds from the issuance of $27.8 million of Collier County Industrial Development Variable Rate Demand Refunding Revenue Bonds Series 2006 due 2025 and internally generated funds. As a result of an early redemption premium, we recognized an expense of $0.6 million in the third quarter of 2006.

Note 12. Income Tax Expense

Income Tax Expense Year Ended December 31	2007	2006	2005
Millions			
Current Tax Expense			
Federal	$26.5	$8.9 *(a)*	$27.2 *(b)*
State	7.2	9.6	6.5 *(b)*
Total Current Tax Expense	33.7	18.5	33.7
Deferred Tax Expense (Benefit)			
Federal	10.7	28.0 *(a)*	(26.4) *(b)*
State	4.7	2.0	(9.5)
Total Deferred Tax Expense (Benefit)	15.4	30.0	(35.9)
Change in Valuation Allowance	(0.3)	(1.1)	3.0
Investment Tax Credit Amortization	(1.1)	(1.1)	(1.3)
Income Tax Expense (Benefit) for Continuing Operations	47.7	46.3	(0.5)
Income Tax Expense (Benefit) for Discontinued Operations	–	(0.6)	3.4
Total Income Tax Expense	$47.7	$45.7	$2.9

(a) Included a current federal tax benefit of $24.3 million and a deferred federal tax expense of $24.3 million related to the refund from the Kendall County capital loss carryback. (See Note 10.)

(b) Included a current federal tax benefit of $1.3 million, current state tax benefit of $0.4 million and deferred federal tax benefit of $25.8 million related to the Kendall County charge. (See Note 10.)

Reconciliation of Taxes from Federal Statutory Rate to Total Income Tax Expense for Continuing Operations Year Ended December 31	2007	2006	2005
Millions			
Income from Continuing Operations Before Minority Interest and Income Taxes	$137.2	$128.2	$19.8
Statutory Federal Income Tax Rate	35%	35%	35%
Income Taxes Computed at 35% Statutory Federal Rate	$48.0	$44.9	$6.9
Increase (Decrease) in Tax Due to:			
Amortization of Deferred Investment Tax Credits	(1.1)	(1.1)	(1.3)
State Income Taxes – Net of Federal Income Tax Benefit	7.4	6.5	1.1
Depletion	(0.9)	(1.1)	(1.0)
Employee Benefits	0.4	0.1	(0.5)
Domestic Manufacturing Deduction	(1.1)	(0.6)	(0.4)
Regulatory Differences for Utility Plant	(2.2)	(0.9)	(0.6)
Positive Resolution of Audit Issues	(1.6)	–	(3.7)
Other	(1.2)	(1.5)	(1.0)
Total Income Tax Expense (Benefit) for Continuing Operations	$47.7	$46.3	$(0.5)

The effective tax rate on income from continuing operations before minority interest was a 34.8 percent expense for 2007; (36.1 percent expense for 2006; 2.5 percent benefit for 2005). The 2007 effective tax rate was impacted by state income tax audit settlements ($1.6 million), deductions for Medicare health subsidies (included in Employee Benefits, above), domestic manufacturing deduction, AFUDC-Equity (included in Regulatory Differences for Utility Plant, above), investment tax credits and depletion. The 2006 effective rate was impacted by investment tax credits, deductions for Medicare health subsidies, depletion and the expected use of state capital loss carryforwards, of which a $1.1 million benefit was included in the state tax provision.

Note 12. Income Tax Expense (Continued)

Deferred Tax Assets and Liabilities

December 31 Millions	2007	2006
Deferred Tax Assets		
Employee Benefits and Compensation *(a)*	$80.5	$95.5
Property Related	26.5	32.8
Investment Tax Credits	11.4	12.1
Other	13.4	17.9
Gross Deferred Tax Assets	131.8	158.3
Deferred Tax Asset Valuation Allowance	(3.3)	(3.6)
Total Deferred Tax Assets	$128.5	$154.7
Deferred Tax Liabilities		
Property Related	$201.7	$204.7
Regulatory Asset for Benefit Obligations	21.6	34.8
Unamortized Investment Tax Credits	16.1	17.2
Employee Benefits and Compensation	19.5	13.2
Fuel Clause Adjustment	10.7	6.0
Other	8.1	9.3
Total Deferred Tax Liabilities	$277.7	$285.2
Accumulated Deferred Income Taxes	$149.2	$130.5
Recorded as:		
Net Current Deferred Tax Liabilities (Assets)	$5.0	$(0.3)
Net Long-Term Deferred Tax Liabilities	144.2	130.8
Net Deferred Tax Liabilities	$149.2	$130.5

(a) Includes Unfunded Employee Benefits

Uncertain Tax Positions. Effective January 1, 2007, we adopted the provisions of FIN 48, "Accounting for Uncertainty in Income Taxes – an Interpretation of FASB Statement No. 109." As a result of the implementation of FIN 48, we recognized a $1.0 million increase in the liability for unrecognized tax benefits. The adoption of FIN 48 also resulted in a reduction in retained earnings of $0.7 million, a reduction of deferred tax liabilities of $0.8 million and an increase in accrued interest of $0.5 million. Subsequent to the implementation of FIN 48, ALLETE's gross unrecognized tax benefits were $10.4 million. Of this total, $6.8 million (net of federal tax benefit on state issues) represents the amount of unrecognized tax benefits that, if recognized, would favorably affect the effective income tax rate.

Uncertain Tax Positions
December 31, 2007

Millions	Gross Unrecognized Income Tax Benefits
Balance at January 1, 2007	$10.4
Additions for Tax Positions Related to the Current Year	0.8
Reductions for Tax Positions Related to the Current Year	–
Additions for Tax Positions Related to Prior Years	–
Reduction for Tax Positions Related to Prior Years	(2.4)
Settlements	(3.5)
Balance at December 31, 2007	$5.3
Less: Tax Attributable to Temporary Items and Federal Benefit on State Tax	(2.3)
Total Unrecognized Tax Benefits that, if Recognized, Would Impact the Effective Tax Rate as of December 31, 2007	$3.0

We recognize interest related to unrecognized tax benefits in interest expense and penalties in operating expenses in the Consolidated Statement of Income. As of January 1, 2007, the Company had $1.3 million of accrued interest and no accrued penalties related to unrecognized tax benefits included in the Consolidated Balance Sheet. As of December 31, 2007, the liability for the payment of interest is $0.9 million with no penalties. Due to the settlement of audits, $0.1 million of interest benefit and no penalties were recognized in the Consolidated Statement of Income for the year ended December 31, 2007.

We file income tax returns in the U.S. federal and various state jurisdictions. With few exceptions, ALLETE is no longer subject to federal examination for years before 2003 or state examinations for years before 2004.

We expect that the total amount of unrecognized tax benefits as of December 31, 2007, will change by less than $2.0 million in the next 12 months due to statute expirations.

Note 13. Discontinued Operations

Enventis Telecom. In December 2005, we sold all the stock of our telecommunications subsidiary, Enventis Telecom, to Hickory Tech Corporation of Mankato, Minnesota, for $35.5 million. The transaction resulted in an after-tax loss of $3.6 million, which was included in our 2005 loss from discontinued operations. Net cash proceeds realized from the sale were approximately $29 million after transaction costs, repayment of debt and payment of income taxes. In accordance with SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," we have reported our telecommunications business in discontinued operations for all periods presented.

Water Services. During 2003, we sold, under condemnation or imminent threat of condemnation, substantially all of our water assets in Florida for a total sales price of approximately $445 million. In 2004, we essentially concluded our strategy to exit our Water Services businesses with the sale of our North Carolina water assets and the sale of the remaining 72 water and wastewater systems in Florida. Aqua Utilities Florida, Inc. (Aqua Utilities) purchased our North Carolina water assets for $48 million and assumed approximately $28 million in debt. Aqua Utilities also purchased 63 of our water and wastewater systems in Florida for $14 million. Seminole County purchased the remaining 9 Florida systems for a total of $4 million. The FPSC approved the Seminole County transaction in September 2004. In December 2005, the FPSC ordered a $1.7 million reduction to plant investment, which the Company reserved for in 2005, and approved the transfer of the remaining 63 water and wastewater systems from Florida Water to Aqua Utilities. In March 2006, the Company paid Aqua Utilities the adjustment refund amount of $1.7 million.

In February 2005, we completed the exit from our Water Services businesses in Georgia with the sale of our wastewater assets for an immaterial gain. In 2005, we also incurred administrative and other expenses to support Florida Water transfer proceedings and recorded the $1.7 million rate-base settlement charge related to the sale by Florida Water of 63 systems to Aqua Utilities mentioned above.

Financial results for 2006 reflected additional legal and administrative expenses incurred by the Company to exit the Water Services businesses. There were no discontinued operations in 2007.

Discontinued Operations Summary Income Statement For the Year Ended December 31	**2006**	**2005**
Millions		
Operating Revenue		
Enventis Telecom	–	$50.7
Total Operating Revenue	–	$50.7
Pre-Tax Income from Operations		
Enventis Telecom	–	$3.0
	–	3.0
Income Tax Expense		
Enventis Telecom	–	1.2
	–	1.2
Total Income from Operations	–	1.8
Loss on Disposal		
Water Services	$(1.5)	(4.5)
Enventis Telecom	–	0.6
	(1.5)	(3.9)
Income Tax Expense (Benefit)		
Water Services	(0.6)	(2.0)
Enventis Telecom	–	4.2
	(0.6)	2.2
Net Loss on Disposal	(0.9)	(6.1)
Loss from Discontinued Operations	$(0.9)	$(4.3)

Note 14. Other Comprehensive Income (Loss)

Other Comprehensive Income (Loss) Year Ended December 31	Pre-Tax Amount	Tax Expense (Benefit)	Net-of-Tax Amount
Millions			
2007			
Unrealized Gain on Securities During the Year	$1.4	$0.3	$1.1
Defined Benefit Pension and Other Postretirement Plans	5.5	2.3	3.2
Other Comprehensive Income	$6.9	$2.6	$4.3
2006			
Unrealized Gain on Securities During the Year	$2.5	$0.6	$1.9
Additional Pension Liability	11.0	4.6	6.4
Other Comprehensive Income	$13.5	$5.2	$8.3
2005			
Unrealized Gain on Securities During the Year	$1.3	$0.7	$0.6
Additional Pension Liability	(3.4)	(1.4)	(2.0)
Other Comprehensive Loss	$(2.1)	$(0.7)	$(1.4)

Accumulated Other Comprehensive Income (Loss) December 31	2007	2006
Millions		
Unrealized Gain on Securities	$5.1	$4.0
Defined Benefit Pension and Other Postretirement Plans	(9.6)	(12.8)
Total Accumulated Other Comprehensive Loss	$(4.5)	$(8.8)

Note 15. Pension and Other Postretirement Benefit Plans

We have noncontributory defined benefit pension plans covering eligible employees. The plans provide defined benefits based on years of service and final average pay. We also have defined contribution pension plans covering substantially all employees; employer contributions are made through our employee stock ownership plan (see Note 16), except for BNI Coal, which made cash contributions of $0.4 million in 2007 ($0.7 million in 2006 and 2005). In 2007, we made no contributions to ALLETE's defined benefit plan ($8.3 million in 2006).

On August 9, 2006, ALLETE's Board of Directors approved amendments to the Minnesota Power and Affiliated Companies Retirement Plan A (Retirement Plan A) and the Minnesota Power and Affiliated Companies Retirement Savings and Stock Ownership Plan (RSOP). Retirement Plan A was amended to suspend further crediting service pursuant to the plan, effective as of September 30, 2006, and to close Retirement Plan A to new participants. Participants will continue to accrue benefits under the plan for future pay increases. In conjunction with this change, the Board of Directors took action to increase benefits employees will receive under the RSOP. The modification of Retirement Plan A required us to re-measure our pension expense as of August 9, 2006. As a result of the re-measurement, Retirement Plan A pension expense for 2006 was reduced by $0.2 million.

We have postretirement health care and life insurance plans covering eligible employees. The postretirement health plans are contributory with participant contributions adjusted annually. Postretirement health and life benefits are funded through a combination of Voluntary Employee Benefit Association trusts (VEBAs), established under section 501(c)(9) of the Internal Revenue Code, and an irrevocable grantor trust. Contributions deductible for income tax purposes are made directly to the VEBAs; nondeductible contributions are made to the irrevocable grantor trust. Amounts are transferred from the irrevocable grantor trust to the VEBAs when they become deductible for income tax purposes. In 2007, $5.9 million was transferred from the grantor trust to the VEBAs ($3.6 million in 2006; $11.4 million in 2005).

In September 2006, the FASB issued SFAS 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans" (SFAS 158). SFAS 158 requires that employers recognize on a prospective basis the funded status of their defined benefit pension and other postretirement plans on their consolidated balance sheet and recognize as a component of other comprehensive income, net of tax, the gains or losses and prior service costs or credits that arise during the period but that are not recognized as components of net periodic benefit cost. SFAS 158 also requires additional disclosures in the notes to financial statements. SFAS 158 was effective for fiscal years ending after December 15, 2006.

Note 15. Pension and Other Postretirement Benefit Plans (Continued)

We use a September 30 measurement date for the pension and postretirement health and life plans. Pursuant to SFAS 158, we are required to change our measurement date to December 31 during the year ending December 31, 2008. On January 1, 2008, ALLETE recorded three months of pension expense as a reduction to retained earnings in the amount of $1.6 million, net of tax, to reflect the impact of this measurement date change.

Approximately 82 percent of the defined benefit pension and 69 percent of the postretirement health and life benefit costs recognized annually by our regulated companies are recovered through rates filed with our regulatory jurisdictions. It is expected that these costs will continue to be recovered in future rates in accordance with the requirements of SFAS 71. As a result, these amounts that are required to otherwise be recognized in accumulated other comprehensive income under the provisions of SFAS 158 have been recognized as a long-term regulatory asset on our consolidated balance sheet. The remaining 18 percent of the defined benefit pension and 31 percent of the postretirement health and life benefit costs relate to costs associated with our nonregulated operations and, accordingly, have been recognized as a charge to accumulated other comprehensive income at December 31, 2007.

Pension Obligation and Funded Status **At September 30**	**2007**	**2006**
Millions		
Accumulated Benefit Obligation	$384.9	$376.1
Change in Benefit Obligation		
Obligation, Beginning of Year	$417.7	$412.4
Service Cost	5.3	9.1
Interest Cost	23.4	22.2
Actuarial Gain	(7.1)	(12.2)
Benefits Paid	(21.6)	(19.8)
Participant Contributions	2.7	6.0
Obligation, End of Year	$420.4	$417.7
Change in Plan Assets		
Fair Value, Beginning of Year	$364.7	$337.1
Actual Return on Assets	58.9	32.5
Employer Contribution	3.6	8.9
Benefits Paid	(21.6)	(19.8)
Other	–	6.0
Fair Value, End of Year	$405.6	$364.7
Funded Status, End of Year	$(14.8)	$(53.0)
Net Pension Amounts Recognized in Consolidated Balance Sheet Consist of:		
Noncurrent Assets	$29.3	–
Current Liabilities	$0.8	$0.8
Noncurrent Liabilities	$43.3	$52.3

Note 15. Pension and Other Postretirement Benefit Plans (Continued)

The pension costs reported on our consolidated balance sheet as regulatory long-term assets and accumulated other comprehensive income consist of the following:

Pension Costs **Year Ended December 31**	**2007**	**2006**
Millions		
Net Loss	$31.1	$69.9
Prior Service Cost	3.2	3.9
Transition Obligation	–	(0.1)
Total Pension Cost	$34.3	$73.7

Components of Net Periodic Pension Expense **Year Ended December 31**	**2007**	**2006**	**2005**
Millions			
Service Cost	$5.3	$9.1	$8.7
Interest Cost	23.4	22.2	21.3
Expected Return on Assets	(30.6)	(28.6)	(28.2)
Amortized Amounts			
Loss	3.4	4.6	3.1
Prior Service Cost	0.6	0.6	0.6
Transition Obligation	–	–	0.2
Net Pension Expense	$2.1	$7.9	$5.7

Other Changes in Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income **Year Ended December 31**	**2007**	**2006**
Millions		
Net Gain	$(35.4)	$(5.9)
Amortization		
Prior Service Cost	(0.6)	(0.6)
Prior Loss	(3.3)	(4.6)
Total Recognized in Other Comprehensive Income	$(39.3)	$(11.1)

Information for Pension Plans with an **Accumulated Benefit Obligation in Excess of Plan Assets** **At September 30**	**2007**	**2006**
Millions		
Projected Benefit Obligation	$170.6	$180.4
Accumulated Benefit Obligation	$188.3	$160.6
Fair Value of Plan Assets	$145.3	$130.9

Note 15. Pension and Other Postretirement Benefit Plans (Continued)

Postretirement Health and Life Obligation and Funded Status **At September 30**	**2007**	**2006**
Millions		
Change in Benefit Obligation		
Obligation, Beginning of Year	$138.9	$136.9
Service Cost	4.2	4.4
Interest Cost	7.9	7.4
Actuarial Loss (Gain)	7.5	(4.7)
Participation Contributions	1.4	1.4
Benefits Paid	(6.2)	(6.4)
Amendments	–	(0.1)
Obligation, End of Year	$153.7	$138.9
Change in Plan Assets		
Fair Value, Beginning of Year	$78.9	$60.9
Actual Return on Assets	9.6	5.8
Employer Contribution	6.8	17.2
Participation Contributions	1.4	1.4
Benefits Paid	(5.8)	(6.4)
Fair Value, End of Year	$90.9	$78.9
Funded Status, End of Year	($62.8)	$(60.0)
Net Pension Amounts Recognized in Consolidated Balance Sheet Consist of:		
Current Liabilities	$0.6	–
Noncurrent Liabilities	$62.2	$60.0

Under SFAS 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions," only assets in the VEBAs are treated as plan assets in the above table for the purpose of determining funded status. In addition to the postretirement health and life assets reported in the previous table, we had $22.8 million in an irrevocable grantor trust at December 31, 2007 ($25.6 million at December 31, 2006). We consolidate the irrevocable grantor trust and it is included in Investments on our consolidated balance sheet.

The postretirement health and life costs reported on our consolidated balance sheet as regulatory long-term assets and accumulated other comprehensive income consist of the following:

Postretirement Health and Life Costs **Year Ended December 31**	**2007**	**2006**
Millions		
Net Loss	$22.7	$19.2
Prior Service Cost	(0.1)	(0.1)
Transition Obligation	12.6	15.0
Total Postretirement Health and Life Costs	$35.2	$34.1

Components of Net Periodic Postretirement Health and Life Expense (Income) **Year Ended December 31**	**2007**	**2006**	**2005**
Millions			
Service Cost	$4.2	$4.4	$4.0
Interest Cost	7.8	7.4	6.7
Expected Return on Assets	(6.5)	(5.6)	(4.8)
Amortized Amounts			
Loss	1.0	1.7	0.7
Transition Obligation	2.4	2.4	2.4
Net Expense	$8.9	$10.3	$9.0

Note 15. Pension and Other Postretirement Benefit Plans (Continued)

Estimated Future Benefit Payments	Pension	Postretirement Health and Life
Millions		
2008	$22.5	$5.9
2009	$23.1	$6.7
2010	$24.0	$7.6
2011	$25.0	$8.4
2012	$25.9	$9.0
Years 2013 – 2017	$148.2	$54.8

The pension and postretirement health and life costs recorded in other long-term assets and accumulated other comprehensive income expected to be recognized as a component of net pension and postretirement benefit costs for the year ending December 31, 2008, are as follows:

	Pension	Postretirement Health and Life
Millions		
Net Loss	$1.5	$1.4
Prior Service Costs	$0.6	–
Transition Obligations	–	$2.5
Total Pension and Postretirement Health and Life Costs	$2.1	$3.9

Weighted-Average Assumptions Used to Determine Benefit Obligation At September 30	2007	2006
Discount Rate	6.25%	5.75%
Rate of Compensation Increase	4.3 – 4.6%	3.5 – 4.5%
Health Care Trend Rates		
Trend Rate	10%	10%
Ultimate Trend Rate	5%	5%
Year Ultimate Trend Rate Effective	2012	2011

Weighted-Average Assumptions Used to Determine Net Periodic Benefit Costs Year Ended December 31	2007	2006	2005
Discount Rate	5.75%	5.50%	5.75%
Expected Long-Term Return on Plan Assets			
Pension	9.0%	9.0%	9.0%
Postretirement Health and Life	5.0 – 9.0%	5.0 – 9.0%	5.0 – 9.0%
Rate of Compensation Increase	4.3 – 4.6%	3.5 – 4.5%	3.5 – 4.5%

In establishing the expected long-term return on plan assets, we consider the diversification and allocation of plan assets, the actual long-term historical performance for the type of securities invested in, the actual long-term historical performance of plan assets and the impact of current economic conditions, if any, on long-term historical returns.

Note 15. Pension and Other Postretirement Benefit Plans (Continued)

Currently for plan valuation purposes, the discount rate is determined considering high-quality long-term corporate bond rates at the valuation date. The discount rate is compared to the Citigroup Pension Discount Curve adjusted for ALLETE's specific cash flows.

Sensitivity of a One-Percentage-Point Change in Health Care Trend Rates	One Percent Increase	One Percent Decrease
Millions		
Effect on Total of Postretirement Health and Life Service and Interest Cost	$1.9	$(1.5)
Effect on Postretirement Health and Life Obligation	$18.4	$(15.1)

	Pension		Postretirement Health and Life *(a)*	
Plan Asset Allocations	**2007**	**2006**	**2007**	**2006**
Equity Securities	61.3%	65.1%	61.6%	68.9%
Debt Securities	25.1%	29.6%	27.9%	30.6%
Real Estate	1.6%	0.8%	–	–
Private Equity	9.4%	4.2%	5.5%	–
Cash	2.6%	0.3%	5.0%	0.5%
	100.0%	100.0%	100.0%	100.0%

(a) Includes VEBAs and irrevocable grantor trust.

Pension plan equity securities did not include ALLETE common stock at September 30, 2007 or 2006.

To achieve strong returns within managed risk, we diversify our asset portfolio to approximate the target allocations in the table below. Equity securities are diversified among domestic companies with large, mid and small market capitalizations, as well as investments in international companies. In addition, all debt securities must have a Standard & Poor's credit rating of A or higher.

Plan Asset Target Allocations	Pension	Postretirement Health and Life *(a)*
Equity Securities	60%	69%
Debt Securities	24	30
Real Estate	9	–
Private Equity	6	–
Cash	1	1
	100%	100%

(a) Includes VEBAs and irrevocable grantor trust.

In May 2004, the FASB issued FSP 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Act)," which provides accounting and disclosure guidance for employers that sponsor postretirement health care plans that provide prescription drug benefits. FSP 106-2 requires that the accumulated postretirement benefit obligation and postretirement benefit cost reflect the impact of the Act upon adoption. We provide postretirement health benefits that include prescription drug benefits and have concluded that our prescription drug benefits qualified us for the federal subsidy to be provided for under the Act. We adopted FSP 106-2 in the third quarter of 2004. The deduction for Medicare health subsidies reduced our after-tax postretirement medical expense by $2.3 million for 2007 ($2.4 million for 2006; $3.5 million in 2005).

In 2005, we determined that our postretirement health care plans met the requirements of the Centers for Medicare and Medicaid Services' (CMS) regulations, and enrolled with the CMS to begin recovering the subsidy. We received the first subsidy payment of $0.3 million in May 2007 for 2006 credits.

Note 16. Employee Stock and Incentive Plans

Employee Stock Ownership Plan. We sponsor a leveraged employee stock ownership plan (ESOP) within the RSOP. As of their date of hire, all employees of ALLETE, SWL&P and Minnesota Power Affiliate Resources are eligible to contribute to the plan. In 1990, the ESOP issued a $75 million note (term not to exceed 25 years at 10.25 percent) to us as consideration for 2.8 million shares (1.9 million shares adjusted for stock splits) of our newly issued common stock. The note was refinanced in 2006 at 6 percent. We make annual contributions to the ESOP equal to the ESOP's debt service less available dividends received by the ESOP. The majority of dividends received by the ESOP are used to pay debt service, with the balance distributed to participants. The ESOP shares were initially pledged as collateral for its debt. As the debt is repaid, shares are released from collateral and allocated to participants based on the proportion of debt service paid in the year. As shares are released from collateral, we report compensation expense equal to the current market price of the shares less dividends on allocated shares. Dividends on allocated ESOP shares are recorded as a reduction of retained earnings; available dividends on unallocated ESOP shares are recorded as a reduction of debt and accrued interest. ESOP compensation expense was $9.5 million in 2007 ($6.9 million in 2006; $5.5 million in 2005).

Pursuant to AICPA Statement of Position 93-6, "Employers' Accounting for Employee Stock Ownership Plans," unallocated ALLETE common stock currently held and purchased by the ESOP will be treated as unearned ESOP shares and not considered as outstanding for earnings per share computations. ESOP shares are included in earnings per share computations after they are allocated to participants.

Year Ended December 31	2007	2006	2005
Millions			
ESOP Shares			
Allocated	1.8	1.7	1.9
Unallocated	2.2	2.5	2.6
Total	4.0	4.2	4.5
Fair Value of Unallocated Shares	$87.1	$115.2	$115.0

Stock-Based Compensation. *Stock Incentive Plan.* Under our Executive Long-Term Incentive Compensation Plan (Executive Plan), share-based awards may be issued to key employees through a broad range of methods, including non-qualified and incentive stock options, performance shares, performance units, restricted stock, stock appreciation rights and other awards. There are 1.5 million shares of common stock reserved for issuance under the Executive Plan, with 0.9 million of these shares available for issuance as of December 31, 2007.

We had a Director Long-Term Stock Incentive Plan (Director Plan) which expired on January 1, 2006. No grants have been made since 2003 under the Director Plan. Approximately 7,758 options were outstanding under the Director Plan at December 31, 2007.

Note 16. Employee Stock and Incentive Plans (Continued)

We currently have the following types of share-based awards outstanding:

Non-Qualified Stock Options. The options allow for the purchase of shares of common stock at a price equal to the market value of our common stock at the date of grant. Options become exercisable beginning one year after the grant date, with one-third vesting each year over three years. Options may be exercised up to ten years following the date of grant. In the case of qualified retirement, death or disability, options vest immediately and the period over which the options can be exercised is three years. Employees have up to three months to exercise vested options upon voluntary termination or involuntary termination without cause. All options are cancelled upon termination for cause. All options vest immediately upon retirement, death, disability or a change of control, as defined in the award agreement. We determine the fair value of options using the Black-Scholes option-pricing model. The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on the straight-line basis over the options' vesting periods, or the accelerated vesting period if the employee is retirement eligible.

The following assumptions were used in determining the fair value of stock options granted during 2007, under the Black-Scholes option-pricing model:

	2007	2006
Risk-Free Interest Rate	4.8%	4.5%
Expected Life	5 Years	5 Years
Expected Volatility	20%	20%
Dividend Growth Rate	5%	5%

The risk-free interest rate for periods within the contractual life of the option is based on the U.S. Treasury yield curve in effect at the grant date. Expected volatility is estimated based on the historic volatility of our stock and the stock of our peer group companies. We utilize historical option exercise and employee pre-vesting termination data to estimate the option life. The dividend growth rate is based upon historical growth rates in our dividends.

Performance Shares. Under these awards, the number of shares earned is contingent upon attaining specific performance targets over a three-year performance period. In the case of qualified retirement, death or disability during a performance period, a pro-rata portion of the award will be earned at the conclusion of the performance period based on the performance goals achieved. In the case of termination of employment for any reason other than qualified retirement, death or disability, no award will be earned. If there is a change in control, a pro-rata portion of the award will be paid based on the greater of actual performance up to the date of the change in control or target performance. The fair value of these awards is equal to the grant date fair value which is estimated based upon the assumed share-based payment three years from the date of grant. Compensation cost is recognized over the three-year performance period based on our estimate of the number of shares which will be earned by the award recipients.

Employee Stock Purchase Plan (ESPP). Under our ESPP, eligible employees may purchase ALLETE common stock at a 5 percent discount from the market price. Because the discount is not greater than 5 percent, we are not required by SFAS 123R to apply fair value accounting to these awards.

RSOP. Shares held in our RSOP are excluded from SFAS 123R and are accounted for in accordance with the AICPA Statement of Position No. 93-6, "Employers' Accounting for Employee Stock Ownership Plans."

The following share-based compensation expense amounts were recognized in our consolidated statement of income for the periods presented since our adoption of SFAS 123R.

Share-Based Compensation Expense **For the Year Ended December 31**	**2007**	**2006**
Millions		
Stock Options	$0.8	$0.8
Performance Shares	1.0	1.0
Total Share-Based Compensation Expense	$1.8	$1.8
Income Tax Benefit	$0.7	$0.7

There were no capitalized stock-based compensation costs at December 31, 2007.

As of December 31, 2007, the total unrecognized compensation cost for performance share awards not yet recognized in our statements of income was $1.1 million. This amount is expected to be recognized over a weighted-average period of 1.7 years.

Note 16. Employee Stock and Incentive Plans (Continued)

The following table presents the pro forma effect of stock-based compensation had we applied the provisions of SFAS 123 for the year ended December 31, 2005.

Pro Forma Effect of SFAS 123 Accounting for Stock-Based Compensation	2005
Millions Except Per Share Amounts	
Net Income	
As Reported	$13.3
Less: Employee Stock Compensation Expense Determined Under SFAS 123 – Net of Tax	1.5
Plus: Employee Stock Compensation Expense Included in Net Income – Net of Tax	1.5
Pro Forma Net Income	$13.3
Basic Earnings Per Share	
As Reported	$0.49
Pro Forma	$0.49
Diluted Earnings Per Share	
As Reported	$0.48
Pro Forma	$0.48

In the previous table, the pro forma expense determined under SFAS 123 for employee stock options granted was calculated using the Black-Scholes option-pricing model with the following assumptions:

	2005
Risk-Free Interest Rate	3.7%
Expected Life	5 Years
Expected Volatility	20.0%
Dividend Growth Rate	5%

The following table presents information regarding our outstanding stock options for the year ended December 31, 2007.

	Number of Options	Weighted-Average Exercise Price	Aggregate Intrinsic Value	Weighted-Average Remaining Contractual Term
			Millions	
Outstanding at December 31, 2006	438,351	$37.35	$4.0	7.2 years
Granted	100,702	$48.65		
Exercised	(28,061)	$32.80		
Forfeited	–	–		
Outstanding at December 31, 2007	510,992	$39.83	$(0.1)	6.8 years
Exercisable at December 31, 2007	327,473	$36.43	$1.0	6.0 years
Fair Value of Options				
Granted During the Year	$8.15			

The weighted-average grant-date fair value of options was $6.92 for 2007 ($6.48 for 2006). The intrinsic value of a stock award is the amount by which the fair value of the underlying stock exceeds the exercise price of the award. The total intrinsic value of options exercised was $0.4 million during 2007 ($0.6 in 2006).

At December 31, 2007, options outstanding consisted of 0.1 million with exercise prices ranging from $18.85 to $29.79, 0.2 million with exercise prices ranging from $37.76 to $41.35 and 0.2 million with exercise prices ranging from $44.15 to $48.65. The options with exercise prices ranging from $18.85 to $29.79 have an average remaining contractual life of 3.8 years; all are exercisable at December 31, 2007, at a weighted average price of $26.70. The options with exercise prices ranging from $37.76 to $41.35 have an average remaining contractual life of 6.6 years; all are exercisable on December 31, 2007, at a weighted average price of $39.92. The options with exercise prices ranging from $44.15 to $48.65 have an average remaining contractual life of 8.5 years; less than 0.1 million are exercisable on December 31, 2007, at a weighted average price of $46.25.

In February 2007, we granted stock options to purchase 0.1 million shares of common stock (exercise price of $48.65 per share).

Note 16. Employee Stock and Incentive Plans (Continued)

Performance Shares. The following table presents information regarding our nonvested performance shares for the year ended December 31, 2007.

	Number of Shares	Weighted-Average Grant Date Fair Value
Nonvested at December 31, 2006	71,004	$45.39
Granted	23,974	$54.48
Awarded	(24,714)	$42.80
Forfeited	(3,299)	$49.70
Nonvested at December 31, 2007	66,965	$49.39

Less than 0.1 million performance share grants were awarded in February 2007 for performance periods ending in 2009. The ultimate issuance is contingent upon the attainment of certain future performance goals of ALLETE during the performance periods. The grant date fair value of the performance share awards was $1.1 million.

Less than 0.1 million performance share grants were awarded in February 2006 for the performance periods ending in 2007. The grant date fair value of the share awards was $1.0 million. Performance share grants related to the 2007 period will be issued in early 2008.

Note 17. Quarterly Financial Data (Unaudited)

Information for any one quarterly period is not necessarily indicative of the results which may be expected for the year.

Quarter Ended		Mar. 31	Jun. 30	Sept. 30	Dec. 31
Millions Except Earnings Per Share					
2007					
Operating Revenue		$205.3	$223.3	$200.8	$212.3
Operating Income from Continuing Operations		$41.3	$33.9	$24.7	$33.8
Income from Continuing Operations		$26.3	$22.6	$16.5	$22.2
Net Income		$26.3	$22.6	$16.5	$22.2
Earnings Per Share of Common Stock					
Basic	Continuing Operations	$0.93	$0.80	$0.58	$0.78
Diluted	Continuing Operations	$0.93	$0.80	$0.58	$0.77
2006					
Operating Revenue		$192.5	$178.3	$199.1	$197.2
Operating Income from Continuing Operations		$36.4	$26.3	$38.7	$39.3
Income from	Continuing Operations	$18.8	$13.6	$21.9	$23.0
Loss from	Discontinued Operations	–	(0.4)	(0.1)	(0.4)
Net Income		$18.8	$13.2	$21.8	$22.6
Earnings (Loss) Per Share of Common Stock					
Basic	Continuing Operations	$0.68	$0.50	$0.78	$0.82
	Discontinued Operations	–	(0.02)	–	(0.01)
		$0.68	$0.48	$0.78	$0.81
Diluted	Continuing Operations	$0.68	$0.49	$0.78	$0.82
	Discontinued Operations	–	(0.02)	–	(0.01)
		$0.68	$0.47	$0.78	$0.81

Schedule II

ALLETE
Valuation and Qualifying Accounts and Reserves

For the Year Ended December 31	Balance at Beginning of Year	Additions Charged to Income	Additions Other Changes	Deductions from Reserves *(a)*	Balance at End of Period
Millions					
Reserve Deducted from Related Assets					
Reserve For Uncollectible Accounts					
2007 Trade Accounts Receivable	$1.1	$1.0	–	$1.1	$1.0
Finance Receivables – Long-Term	0.2	–	–	–	0.2
2006 Trade Accounts Receivable	1.0	0.7	–	0.6	1.1
Finance Receivables – Long-Term	0.6	–	–	0.4	0.2
2005 Trade Accounts Receivable	1.0	1.1	–	1.1	1.0
Finance Receivables – Long-Term	0.7	–	–	0.1	0.6
Deferred Asset Valuation Allowance					
2007 Deferred Tax Assets	3.6	(0.3)	–	–	3.3
2006 Deferred Tax Assets	4.1	(1.1)	$0.6	–	3.6
2005 Deferred Tax Assets	1.1	3.8	–	0.8	4.1

(a) Includes uncollectible accounts written off.

Exhibit 12

ALLETE
Computation of Ratios of Earnings to Fixed Charges (Unaudited)

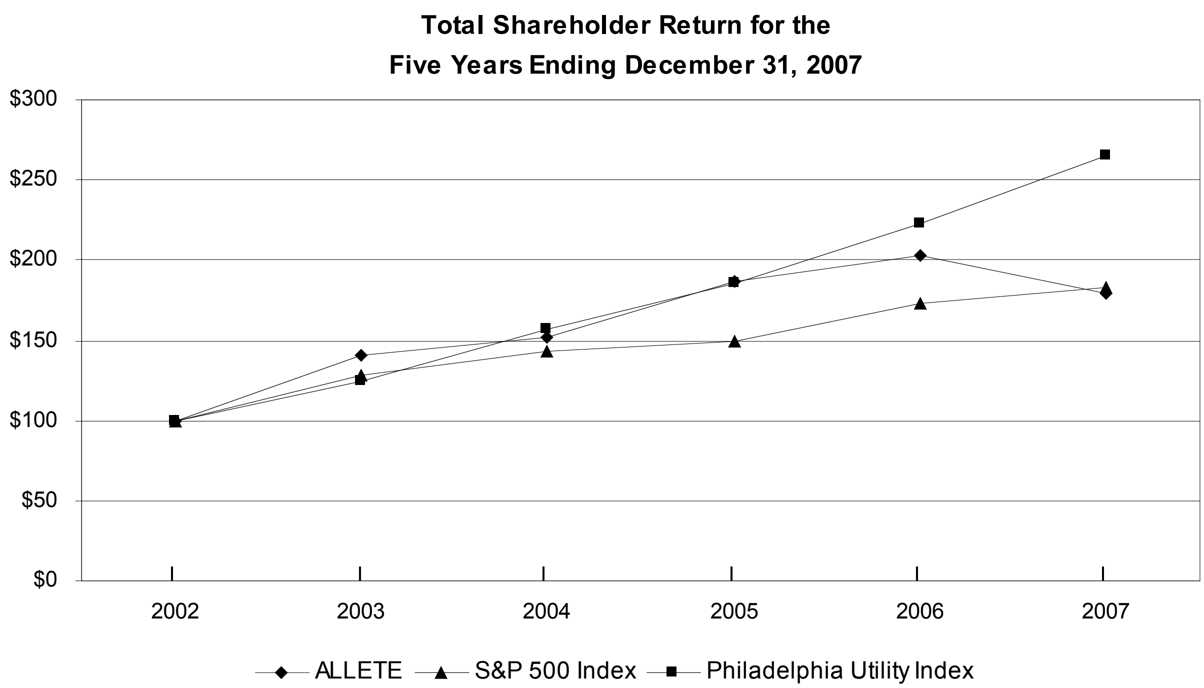
For the Year Ended December 31	2007	2006	2005	2004	2003
Millions Except Ratios					
Income from Continuing Operations Before Minority Interest and Income Taxes	$137.2	$128.2	$19.8	$57.0	$49.5
Less: Minority Interest *(a)*	–	–	–	2.1	2.6
Undistributed Income from Less than 50 percent Owned Equity Investment	3.3	2.3	–	–	2.9
	133.9	125.9	19.8	54.9	44.0
Fixed Charges					
Interest on Long-Term Debt	21.2	22.2	23.1	60.3	70.0
Capitalized Interest	2.0	0.6	0.3	0.7	1.2
Other Interest Charges *(b)*	3.5	5.3	3.5	8.7	4.3
Interest Component of All Rentals *(c)*	1.9	2.0	2.8	3.5	8.0
Total Fixed Charges	28.6	30.1	29.7	73.2	83.5
Earnings Before Income Taxes and Fixed Charges (Excluding Capitalized Interest)	$160.5	$155.4	$49.2	$127.4	$126.3
Ratio of Earnings to Fixed Charges	5.61	5.16	1.66	1.74	1.51

(a) Pre-tax income of subsidiaries that have not incurred fixed charges.
(b) Includes interest expense relating to the adoption of FIN 48 – "Accounting for Uncertainty in Income Taxes."
(c) Represents interest portion of rents estimated at 33 1/3 percent.

ALLETE Common Stock Performance

The following graph compares ALLETE's cumulative Total Shareholder Return on its common stock with the cumulative return of the S&P 500 Index and the Philadelphia Stock Exchange Utility Index (Philadelphia Utility Index). The S&P 500 Index is a capitalization-weighted index of 500 stocks designed to measure performance of the broad domestic economy through changes in the aggregate market value of 500 stocks representing all major industries. Because this composite index has a broad industry base, its performance may not closely track that of a composite index comprised solely of electric utilities. The Philadelphia Utility Index is a capitalization-weighted index of 20 utility companies involved in the production of electrical energy.

The calculations assume a $100 investment on December 31, 2002, and reinvestment of dividends. The calculations further assume that the shares of ADESA common stock received by ALLETE shareholders in connection with the September 20, 2004, spin-off of ADESA were immediately sold and the proceeds invested in additional ALLETE common stock.



	2002	2003	2004	2005	2006	2007
ALLETE	$100	$141	$151	$186	$203	$180
S&P 500 Index	$100	$129	$143	$150	$173	$183
Philadelphia Utility Index	$100	$125	$157	$186	$223	$265

Officers of ALLETE and its Principal Subsidiaries

For a current listing of the officers of ALLETE and its principal subsidiaries, visit our Website at www.allete.com.

Investor Governance

Shareholder Information and Assistance

For shareholder information and assistance, write or call Shareholder Services at our corporate headquarters.

ALLETE Shareholder Services
30 West Superior Street
Duluth, MN 55802-2093
Toll-free phone: 800-535-3056
Duluth area number: 218-723-3974
Fax: 218-720-2502
E-mail: shareholder@allete.com

Invest Direct

ALLETE offers Invest Direct—a multi-featured direct stock purchase and dividend reinvestment plan. For information, contact ALLETE Shareholder Services.

Analyst Inquiries

Security analysts seeking information about us may contact one of the following:

Timothy J. Thorp
Vice President – Investor Relations
Phone: 218-723-3953
Fax: 218-720-2507
E-mail: tthorp@allete.com

Vincent J. Meyer
Investor Relations Manager
Phone: 218-723-3952
Fax: 218-720-2507
E-mail: vmeyer@allete.com

Annual Meeting

Our Annual Meeting of Shareholders is held the second Tuesday in May. Shareholders are invited to attend the 2008 Annual Meeting, beginning at 10:30 a.m., May 13, at the Duluth Entertainment and Convention Center, 350 Harbor Drive, Duluth, MN.

Corporate Website

www.allete.com

Stock Exchange Listings

ALLETE common stock is listed on the New York Stock Exchange under the symbol ALE and our CUSIP number is 018522300. Price quotes on our common stock may be found in many newspapers under the New York Stock Exchange composite transaction listing or at various Internet sites.

Transfer Agents and Registrars for Common Stock

ALLETE, Duluth, MN
Wells Fargo Bank, N.A., South St. Paul, MN

Common Stock Dividend Payment Dates

March 1, June 1, September 1 and December 1

Annual Report

This Annual Report and Form 10-K, and the financial statements contained herein, are submitted for the general information of our shareholders and not in connection with the sale or offer for sale of, or solicitation of an offer to buy, any securities. A copy of this Annual Report and Form 10-K will be furnished without charge to any shareholder upon written request to the address listed above.

We have included as Exhibit 31(a) and 31(b) to our 2007 Form 10-K, filed with the Securities and Exchange Commission, certificates of the Chief Executive Officer and Chief Financial Officer of ALLETE certifying the quality of ALLETE’s public disclosure. We have also submitted to the New York Stock Exchange a certificate of the Chief Executive Officer of ALLETE certifying that he is not aware of any violation by ALLETE of New York Stock Exchange corporate governance listing standards.

The ALLETE Annual Report and Form 10-K was printed on premium coated paper manufactured by Sappi Fine Paper North America. Sappi’s Cloquet Mill is served with electricity by Minnesota Power. ALLETE is proud to use the high quality product of a valued customer in this report.

IN MOTION

ALLETE BOARD OF DIRECTORS

(standing, left to right)

GEORGE L. MAYER, 63, President of Manhattan Realty Group, Larchmont, New York.

MADELEINE W. LUDLOW, 53, Principal in Ludlow Ward Capital Partners, Cincinnati, Ohio.

DONALD J. SHIPPAR, 58, Chairman, President and CEO of ALLETE, Duluth, Minnesota.

ROGER D. PEIRCE, 70, retired Vice Chairman and CEO of Super Steel Products Corp., a manufacturer of fabricated metal products, Mequon, Wisconsin.

JACK J. RAJALA, 68, Chairman and CEO of Rajala Companies, lumber manufacturing and trading firms, Grand Rapids, Minnesota.

HEIDI J. EDDINS, 51, Executive Vice President, Secretary and General Counsel of Florida East Coast Railway, LLC, a transportation company, St. Augustine, Florida.

JAMES J. HOOLIHAN, 55, President and CEO of the Blandin Foundation and Chairman of Industrial Lubricant Co., a provider of industrial supplies and services to logging, railroad and mining companies, Grand Rapids, Minnesota.

(seated, left to right)

DOUGLAS C. NEVE, 52, Former Chief Financial Officer of Minneapolis-based Ceridian Corp., a multinational human resources company, Eden Prairie, Minnesota.

BRUCE W. STENDER, 66, Vice Chair of Labovitz Enterprises, which owns and manages commercial real estate, Duluth, Minnesota.

KATHLEEN BREKKEN, 58, retired President and CEO of Midwest of Cannon Falls, a designer, wholesaler and distributor of giftware, Cannon Falls, Minnesota.

SIDNEY W. EMERY JR., 61, Chairman of MTS Systems Corp., a global supplier of mechanical testing systems and industrial position sensors, Minneapolis, Minnesota.

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