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, 2009**

☐ 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 30, 2009, was $974,440,368.

As of February 1, 2010, there were 35,243,905 shares of ALLETE Common Stock, without par value, outstanding.

Documents Incorporated By Reference

Portions of the Proxy Statement for the 2010 Annual Meeting of Shareholders are incorporated by reference in Part III.

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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 debt and equity funds used to finance utility plant additions during construction periods
AREA	Arrowhead Regional Emission Abatement
ARS	Auction Rate Securities
ATC	American Transmission Company LLC
Basin	Basin Electric Power Cooperative
Bison I	Bison I Wind Project
BNI Coal	BNI Coal, Ltd.
BNSF	Burlington Northern Santa Fe Railway Company
Boswell	Boswell Energy Center
Boswell NO_X Reduction Plan	NO_X emission reductions from Boswell Units 1, 2, and 4
CO_2	Carbon Dioxide
Company	ALLETE, Inc. and its subsidiaries
DC	Direct Current
DRI	Development of Regional Impact
EITF	Emerging Issues Task Force
EPA	Environmental Protection Agency
ESOP	Employee Stock Ownership Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
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
FTR	Financial Transmission Rights
GAAP	Accounting Principles Generally Accepted in the United States
GHG	Greenhouse Gases
Heating Degree Days	Measure of the extent to which the average daily temperature is below 65 degrees Fahrenheit, increasing demand for heating
IBEW Local 31	International Brotherhood of Electrical Workers Local 31
Invest Direct	ALLETE's Direct Stock Purchase and Dividend Reinvestment Plan
kV	Kilovolt(s)
Laskin	Laskin Energy Center
Manitoba Hydro	Manitoba Hydro-Electric 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

Definitions (Continued)

MPUC	Minnesota Public Utilities Commission
MW / MWh	Megawatt(s) / Megawatt-hour(s)
NextEra Energy	NextEra Energy Resources, LLC
NDPSC	North Dakota Public Service Commission
Non-residential	Retail commercial, non-retail commercial, office, industrial, warehouse, storage and institutional
NO_X	Nitrogen Oxides
Note ___	Note ___ to the consolidated financial statements in this Form 10-K
NPDES	National Pollutant Discharge Elimination System
NYSE	New York Stock Exchange
OES	Minnesota Office of Energy Security
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 Corp.
PSCW	Public Service Commission of Wisconsin
PUHCA 2005	Public Utility Holding Company Act of 2005
Rainy River Energy	Rainy River Energy Corporation - Wisconsin
SEC	Securities and Exchange Commission
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
Taconite Ridge	Taconite Ridge 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

Statements in this report that are not statements of historical facts may be considered "forward-looking" and, accordingly, involve risks and uncertainties that could cause actual results to differ materially from those discussed. Although such forward-looking statements have been made in good faith and are based on reasonable assumptions, there is no assurance that the expected results will be achieved. Any statements that express, or involve discussions as to, future expectations, risks, beliefs, plans, objectives, assumptions, events, uncertainties, financial performance, or growth strategies (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 words of similar meaning) are not statements of historical facts and may be forward-looking.

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, or expectations suggested, in forward-looking statements made by or on behalf of ALLETE in this Annual Report on Form 10-K, in presentations, on our website, in response to questions or otherwise. 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 in connection with such forward-looking statements:

- our ability to successfully implement our strategic objectives;
- prevailing governmental policies, regulatory actions, and legislation including those of the United States Congress, state legislatures, the FERC, the MPUC, the PSCW, the NDPSC, and various local and county regulators, and city administrators, about 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;
- our ability to manage expansion and integrate acquisitions;
- the potential impacts of climate change and future regulation to restrict the emissions of GHG on our Regulated 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 regulations;
- 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;
- project delays or changes in project costs;
- availability and management of construction materials and skilled construction labor for capital projects;
- changes in operating expenses, capital and land development expenditures;
- global and domestic economic conditions affecting us or our customers;
- 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 23 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.

Item 1. Business

Regulated Operations includes our regulated utilities, Minnesota Power and SWL&P, as well as our investment in ATC, a Wisconsin-based utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota and Illinois. Minnesota Power provides regulated utility electric service in northeastern Minnesota to 144,000 retail customers and wholesale electric service to 16 municipalities. Minnesota Power also provides regulated utility electric service to 1 private utility in Wisconsin. SWL&P, a wholesale customer of Minnesota Power, provides regulated electric, 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. Business – Regulated Operations – Regulatory Matters.)

Investments and Other is comprised primarily of BNI Coal, our coal mining operations in North Dakota, and ALLETE Properties, our Florida real estate investment. This segment also includes a small amount of non-rate base generation, approximately 7,000 acres of land available-for-sale in Minnesota, and earnings on cash and investments.

ALLETE is incorporated under the laws of Minnesota. Our corporate headquarters are in Duluth, Minnesota. Statistical information is presented as of December 31, 2009, 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	2009	2008	2007
Consolidated Operating Revenue – Millions	$759.1	$801.0	$841.7
Percentage of Consolidated Operating Revenue			
Regulated Operations	90%	89%	86%
Investments and Other	10%	11%	14%
	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 Note 1. Operations and Significant Accounting Policies and Note 2. Business Segments.

REGULATED OPERATIONS

Electric Sales / Customers

Regulated Utility Electric Sales

Year Ended December 31	2009	%	2008	%	2007	%
Millions of Kilowatt-hours						
Retail and Municipals						
Residential	1,164	10	1,172	9	1,141	9
Commercial	1,420	12	1,454	12	1,456	11
Industrial	4,475	37	7,192	57	7,054	55
Municipals (FERC rate regulated)	992	8	1,002	8	1,009	8
Total Retail and Municipals	8,051	67	10,820	86	10,660	83
Other Power Suppliers	4,056	33	1,800	14	2,157	17
Total Regulated Utility Electric Sales	12,107	100	12,620	100	12,817	100

Seasonality

Due to the high concentration of industrial sales, Minnesota Power is not subject to significant seasonal fluctuations. The operations of our industrial customers, which make up a large portion of our sales portfolio, as shown in the table above, are not typically subject to significant seasonal variations.

Industrial Customers. In 2009, our industrial customers represented 37 percent of total regulated utility kilowatt-hour sales. Our industrial customers are primarily in the taconite, paper, pulp and wood products, and pipeline industries.

Industrial Customer Electric Sales

Year Ended December 31	**2009**	**%**	**2008**	**%**	**2007**	**%**
Millions of Kilowatt-hours						
Taconite Producers	2,124	47	4,579	64	4,408	62
Paper, Pulp and Wood Products	1,454	33	1,567	22	1,613	23
Pipelines	504	11	582	8	562	8
Other Industrial	393	9	464	6	471	7
	4,475	100	7,192	100	7,054	100

Approximately 60 percent of the ore consumed by integrated steel facilities in the United States originates from six taconite customers of Minnesota Power, which represented 2,124 million kilowatt-hours, or 47 percent, of our total industrial sales in 2009. Taconite, an iron-bearing rock of relatively low iron content, is abundantly available in northern Minnesota and 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.

Beginning in the fall of 2008, worldwide steel makers began to dramatically cut steel production in response to reduced demand driven largely by the global credit concerns. United States raw steel production ran at approximately 50 percent of capacity in 2009, reflecting poor demand in automobiles, durable goods, and structural and other steel products.

In late 2008, Minnesota taconite producers began to feel the impacts of decreased steel demand, and reduced taconite production levels occurred in 2009. Annual taconite production in Minnesota was approximately 18 million tons in 2009 (40 million tons in 2008 and 39 million tons in 2007). Consequently, 2009 kilowatt-hour sales to our taconite customers were lower by approximately 54 percent from 2008 levels, and we sold available power to Other Power Suppliers to partially mitigate the earnings impact of these lower taconite sales.

Raw steel production in the United States is projected to improve in 2010, and is estimated to run at approximately 60 percent of capacity. As a result, Minnesota Power expects an increase in taconite production in 2010 compared to 2009, although production will still be less than previous years' levels. We will continue to market available power to Other Power Suppliers in an effort to mitigate the earnings impact of these lower industrial sales. These sales are dependent upon the availability of generation and are sold at market-based prices into the MISO market on a daily basis or through bilateral agreements of various durations. We can make no assurances that our power marketing efforts will fully offset the reduced earnings resulting from lower demand nominations from our industrial customers.

In addition to serving the taconite industry, Minnesota Power also serves a number of customers in the paper, pulp and wood products industry, which represented 1,454 million kilowatt-hours, or 33 percent, of our total industrial sales in 2009. 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 several wood product manufacturers.

Minnesota Power's paper and pulp customers ran at, or very near, full capacity for the majority of 2009, despite the fact that the industry as a whole experienced the impacts of the global recession in reduced sales of nearly every paper grade. Federal tax credits provided a subsidy for paper producers which allowed them to remain competitive. Minnesota Power's paper and pulp customers benefited from the temporary or permanent idling of competitor plants both in North America and in Europe, as well as continued strength of the Canadian dollar and the Euro which has reduced imports both from Canada and Europe.

The pipeline industry is the third key industrial segment served by Minnesota Power with services provided to two crude oil pipelines and one refinery indirectly through SWL&P, which represented 504 million kilowatt-hours, or 11 percent, of our total industrial sales in 2009. These customers have a common reliance on the importation of Canadian crude oil. After near capacity operations in 2007, 2008, and 2009, both pipeline operators are executing expansion plans to transport 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.

Large Power Customer Contracts. Minnesota Power has 9 Large Power contracts with 10 Large Power Customers. All of these contracts serve requirements of 10 MWs or more of generating capacity. The customers consist of five taconite producing facilities (two of which are owned by one company and are served under a single contract), one iron nugget plant, and four paper and pulp mills.

Large Power Customer Contracts (Continued)

Large Power Customer contracts require Minnesota Power to have a certain amount of generating capacity available. 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 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 kilowatt-hour used that recovers the variable costs incurred in generating electricity. Four of the Large Power Customers have interruptible service which provides a discounted demand rate for the ability to interrupt the customers during system emergencies. 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 kilowatt-hour 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 Item 1. Business – Regulated Operations – 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.

Contract Status for Minnesota Power Large Power Customers
As of February 1, 2010

Customer *(a)*	Industry	Location	Ownership	Earliest Termination Date
Hibbing Taconite Co.	Taconite	Hibbing, MN	62.3% ArcelorMittal USA Inc. 23% Cliffs Natural Resources Inc. 14.7% United States Steel Corporation	December 31, 2015
ArcelorMittal USA – Minorca Mine *(b)*	Taconite	Virginia, MN	ArcelorMittal USA Inc.	February 28, 2014
United States Steel Corporation (USS – Minnesota Ore) *(b,c)*	Taconite	Mt. Iron, MN and Keewatin, MN	United States Steel Corporation	February 28, 2014
United Taconite LLC	Taconite	Eveleth, MN	Cliffs Natural Resources Inc.	December 31, 2015
Mesabi Nugget Delaware, LLC	Iron Nugget	Hoyt Lakes, MN	Steel Dynamics, Inc (80%) Kobe Steel USA (20%)	December 31, 2017
UPM, Blandin Paper Mill *(b)*	Paper	Grand Rapids, MN	UPM-Kymmene Corporation	February 28, 2014
Boise White Paper, LLC	Paper	International Falls, MN	Boise Paper Holdings, LLC	December 31, 2013
Sappi Cloquet LLC	Paper and Pulp	Cloquet, MN	Sappi Limited	February 28, 2014
NewPage Corporation – Duluth Mills *(b)*	Paper and Pulp	Duluth, MN	NewPage Corporation	February 28, 2014

(a) During 2009, three Large Power Customers moved to the Large Light and Power rate class.
(b) 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 28, 2014.
(c) United States Steel Corporation includes the Minntac Plant in Mountain Iron, MN and the Keewatin Taconite Plant in Keewatin, MN.

Residential and Commercial Customers. In 2009, our residential and commercial customers represented 22 percent of total regulated utility kilowatt-hour sales. Minnesota Power provides regulated utility electric service in northeastern Minnesota to approximately 144,000 residential and commercial customers. SWL&P provides regulated electric, natural gas and water service in northwestern Wisconsin to approximately 15,000 electric customers, 12,000 natural gas customers and 10,000 water customers.

Municipal Customers. In 2009, our municipal customers represented 8 percent of total regulated utility kilowatt-hour sales, which included 16 municipalities in Minnesota and 1 private utility in Wisconsin. SWL&P, a wholly-owned subsidiary of ALLETE, is also a customer of Minnesota Power. In 2008, Minnesota Power entered into new contracts with its municipal customers with the exception of one small customer (less than 2 MW) whose contract is now in the cancellation period. The new contracts transitioned each customer to formula based rates, allowing rates to be adjusted annually based on changes in costs, and expire in December 2013. In February 2009, the FERC approved our municipal contracts, including the formula-based rate provision.

Other Power Suppliers. The Company also enters into off-system sales with Other Power Suppliers. These sales are dependent upon the availability of generation and are sold at market-based prices into the MISO market on a daily basis or through bilateral agreements of various durations.

Approximately 200 MWs of capacity and energy from our Taconite Harbor facility in northern Minnesota has been sold through two sales contracts totaling 175 MWs (201 MWs 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 fuel, subject to a small minimum annual escalation. The other contract provides that the energy charge will be the greater of the fixed minimum charge or an annual 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 liability. Outages with less than two months notice are subject to an annual duration limitation typical of this type of contract.

On October 29, 2009, Minnesota Power entered into an agreement to sell 100 MWs of capacity and energy for the next ten years to Basin. The transaction is scheduled to begin in May 2010, following the expiration of the two wholesale power sales contracts on April 30, 2010. The capacity charge is based on a fixed monthly schedule with a minimum annual escalation provision. The energy charge is based on a fixed monthly schedule and provides for annual escalation based on our cost of fuel. The agreement allows us to recover a pro rata share of increased costs related to emissions that may occur during the last five years of the contract.

Power Supply

In order to meet our customers' electric requirements, we utilize a mix of Company generation and purchased power. The Company's generation is primarily coal-fired, but also includes approximately 112 MWs of hydro generation from ten hydro stations in Minnesota and 25 MWs of wind generation. 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, 2009. Minnesota Power had an annual net peak load of 1,414 MWs on January 15, 2009.

REGULATED OPERATIONS (Continued)
Power Supply (Continued)

Regulated Utility Power Supply	Unit No.	Year Installed	Net Winter Capability	Year Ended December 31, 2009 Electric Requirements	
			MW	MWh	%
Coal-Fired					
Boswell Energy Center	1	1958	68		
in Cohasset, MN	2	1960	67		
	3	1973	352		
	4	1980	429		
			916	5,390,131	42.8%
Laskin Energy Center	1	1953	55		
in Hoyt Lakes, MN	2	1953	51		
			106	510,505	4.1
Taconite Harbor Energy Center	1	1957	75		
in Schroeder, MN	2	1957	74		
	3	1967	76		
			225	1,058,263	8.4
Total Coal			1,247	6,958,899	55.3
Biomass/Coal/Natural Gas					
Hibbard Renewable Energy Center					
in Duluth, MN	3 & 4	1949, 1951	54	40,703	0.3
Cloquet Energy Center					
in Cloquet, MN	5	2001	22	19,340	0.2
Total Biomass/Coal/Natural Gas			76	60,043	0.5
Hydro					
Group consisting of ten stations in MN	Various		109	434,541	3.5
Wind					
Taconite Ridge					
in Mt. Iron, MN *(a)*	1-10	2008	4	56,255	0.4
Total Company Generation			1,436	7,509,738	59.7
Long-Term Purchased Power					
Square Butte burns lignite coal near Center, ND				1,695,254	13.5
Wind – Oliver County, ND				361,624	2.9
Hydro – Manitoba Hydro in Winnipeg, MB, Canada				433,543	3.4
Total Long-Term Purchased Power				2,490,421	19.8
Other Purchased Power *(b)*				2,579,408	20.5
Total Purchased Power				5,069,829	40.3
Total			1,436	12,579,567	100.0%

(a) The nameplate capacity of Taconite Ridge is 25 MWs. 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 using limited historical data. As more data is collected, actual accredited capacity may increase.
(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 2009 for electric generation at Minnesota Power's coal-fired generating stations was approximately 4.2 million tons. As of December 31, 2009, Minnesota Power had a coal inventory of about 810,000 tons. Minnesota Power's primary coal supply agreements have expiration dates through 2011. Under these agreements, Minnesota Power has the flexibility to procure 70 percent to 100 percent of its total coal requirements. In 2010, 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 its coal 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 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 designated interconnection points. Minnesota Power also has agreements with an affiliate of the Canadian National Railway and with Midwest Energy Resources Company to transport coal from BNSF interconnection points to certain Minnesota Power facilities.

Coal Delivered to Minnesota Power

Year Ended December 31	2009	2008	2007
Average Price per Ton	$24.99	$22.73	$21.78
Average Price per MBtu	$1.37	$1.25	$1.20

Long-Term Purchased Power. Minnesota Power has contracts to purchase capacity and energy from various entities. The largest contract is with Square Butte. Under the agreement with Square Butte, which expires at the end of 2026, Minnesota Power is currently entitled to approximately 50 percent of the output of a 455-MW coal-fired generating unit located near Center, North Dakota. (See Note 11. Commitments, Guarantees, and Contingencies.) The lignite 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. Square Butte's cost of lignite burned in 2009 was approximately $1.02 per MBtu.

We have two wind power purchase agreements with an affiliate of NextEra 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. We pay a contracted energy price and will receive any potential renewable energy or environmental air quality credits.

We also have a power purchase agreement with Manitoba Hydro that began in May 2009 and expires in April 2015. Under the agreement with Manitoba Hydro, Minnesota Power will purchase 50 MW of capacity and the energy associated with that capacity. Both the capacity price and the energy price are adjusted annually by the change in a governmental inflationary index.

Transmission and Distribution

We have electric transmission and distribution lines of 500 kV (8 miles), 250kV (465 miles), 230 kV (605 miles), 161 kV (43 miles), 138 kV (128 miles), 115 kV (1,220 miles) and less than 115 kV (6,206 miles). We own and operate 166 substations with a total capacity of 10,287 megavoltamperes. Some of our transmission and distribution lines interconnect with other utilities.

Investment in ATC

Rainy River Energy, our wholly owned subsidiary, owns approximately 8 percent of ATC, a Wisconsin-based 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. ATC rates are based on a 12.2 percent return on common equity dedicated to utility plant. We account for our investment in ATC under the equity method of accounting. As of December 31, 2009, our equity investment balance in ATC was $88.4 million ($76.9 million at December 31, 2008). (See Note 6. Investment in ATC.)

Properties

We own office and service buildings, an energy control center, repair shops, lease offices, and storerooms in various localities. All of our electric plants are 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. WPPI Energy owns 20 percent of Boswell Unit 4. WPPI Energy has the right to use our transmission line facilities to transport its share of Boswell generation. (See Note 4. Jointly-Owned Electric Facility.)

REGULATED OPERATIONS (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, certain accounting and record-keeping practices and ATC. The PSCW has regulatory authority over SWL&P's retail sales of electricity, natural gas, water, issuances of securities, and other matters. The NDPSC has jurisdiction over site and route permitting of generation and transmission facilities necessary for construction in North Dakota.

Electric Rates. Minnesota Power designs 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 2009* and *Rankings – July 1, 2009*) ranked Minnesota Power as having the eighth lowest average retail rates out of 175 utilities in the United States. According to this report, Minnesota Power had the lowest rates in Minnesota and third lowest 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.

Minnesota Public Utilities Commission. The MPUC has jurisdiction over Minnesota Power's service area in Minnesota, retail rates, retail services, issuance of securities and other matters.

2008 Rate Case. In May 2008, Minnesota Power filed a retail rate increase request with the MPUC seeking additional revenues of approximately $40 million annually; the request also sought an 11.15 percent return on equity, and a capital structure consisting of 54.8 percent equity and 45.2 percent debt. As a result of a May 2009 Order and an August 2009 Reconsideration Order, the MPUC granted Minnesota Power a revenue increase of approximately $20 million, including a return on equity of 10.74 percent and a capital structure consisting of 54.79 percent equity and 45.21 percent debt. Rates went into effect on November 1, 2009.

Interim rates, subject to refund, were in effect from August 1, 2008 through October 31, 2009. During 2009, Minnesota Power recorded a $21.7 million liability for refunds of interim rates, including interest, required to be made as a result of the May 2009 Order and the August 2009 Reconsideration Order. In 2009, $21.4 million was refunded, with a remaining $0.3 million balance to be refunded in early 2010; $7.6 million of the refunds required to be made were related to interim rates charged in 2008.

With the May 2009 Order, the MPUC also approved the stipulation and settlement agreement that affirmed the Company's continued recovery of fuel and purchased power costs under the former base cost of fuel that was in effect prior to the retail rate filing. The transition to the former base cost of fuel began with the implementation of final rates on November 1, 2009. Any revenue impact associated with this transition will be identified in a future filing related to the Company's fuel clause operation.

2010 Rate Case. Minnesota Power previously stated its intention to file for additional revenues to recover the costs of significant investments to ensure current and future system reliability, enhance environmental performance and bring new renewable energy to northeastern Minnesota. As a result, Minnesota Power filed a retail rate increase request with the MPUC on November 2, 2009, seeking a return on equity of 11.50 percent, a capital structure consisting of 54.29 percent equity and 45.71 percent debt, and on an annualized basis, an $81.0 million net increase in electric retail revenue.

Minnesota law allows the collection of interim rates while the MPUC processes the rate filing. On December 30, 2009, the MPUC issued an Order (the Order) authorizing $48.5 million of Minnesota Power's November 2, 2009, interim rate increase request of $73.0 million. The MPUC cited exigent circumstances in reducing Minnesota Power's interim rate request. Because the scope and depth of this reduction in interim rates was unprecedented, and because Minnesota law does not allow Minnesota Power to formally challenge the MPUC's action until a final decision in the case is rendered, on January 6, 2010, Minnesota Power sent a letter to the MPUC expressing its concerns about the Order and requested that the MPUC reconsider its decision on its own motion. Minnesota Power described its belief the MPUC's decision violates the law by prejudging the merits of the rate request prior to an evidentiary hearing and results in the confiscation of utility property. Further, the Company is concerned that the decision will have negative consequences on the environmental policy directions of the State of Minnesota by denying recovery for statutory mandates during the pendency of the rate proceeding. The MPUC has not acted in response to Minnesota Power's letter.

The rate case process requires public hearings and an evidentiary hearing before an administrative law judge, both of which are scheduled for the second quarter of 2010. A final decision on the rate request is expected in the fourth quarter. We cannot predict the final level of rates that may be approved by the MPUC, and we cannot predict whether a legal challenge to the MPUC's interim rate decision will be forthcoming or successful.

North Dakota Wind Project. On July 7, 2009, the MPUC approved our petition seeking current cost recovery of investments and expenditures related to Bison I and associated transmission upgrades. We anticipate filing a petition with the MPUC in the first quarter of 2010 to establish customer billing rates for the approved cost recovery. Bison I is the first portion of several hundred MWs of our North Dakota Wind Project, which upon completion will fulfill the 2025 renewable energy supply requirement for our retail load. Bison I will be comprised of 33 wind turbines with a total nameplate capacity of 76 MWs, located near Center, North Dakota, and be in service in late 2010 and 2011.

On September 29, 2009, the NDPSC authorized site construction for Bison I. On October 2, 2009, Minnesota Power filed a route permit application with the NDPSC for a 22 mile, 230 kV Bison I transmission line that will connect Bison I to the DC transmission line at the Square Butte Substation in Center, North Dakota. An order is expected in the first quarter 2010.

On December 31, 2009, we purchased an existing 250 kV DC transmission line from Square Butte for $69.7 million. The 465-mile transmission line runs from Center, North Dakota to Duluth, Minnesota. We expect to use this line to transport increasing amounts of wind energy from North Dakota while gradually phasing out coal-based electricity currently being delivered to our system over this transmission line from Square Butte's lignite coal-fired generating unit. We expect that the Square Butte generating unit will continue to be fully utilized and supplied with lignite coal by BNI Coal, as Minnkota Power is expected to take Square Butte generation not utilized by Minnesota Power. Acquisition of this transmission line was approved by an MPUC order dated December 21, 2009. In addition, the FERC issued an order on November 24, 2009, authorizing acquisition of the transmission facilities and conditionally accepting, upon compliance and other filings, the proposed tariff revisions, interconnection agreement and other related agreements.

Integrated Resource Plan. On October 5, 2009, Minnesota Power filed with the MPUC its 2010 Integrated Resource Plan, a comprehensive estimate of future capacity needs within Minnesota Power's service territory. Minnesota Power does not anticipate the need for new base load generation within the Minnesota Power service territory over the next 15 years, and plans to meet estimated future customer demand while achieving:

- Increased system flexibility to adapt to volatile business cycles and varied future industrial load scenarios;
- Reductions in the emission of GHGs (primarily carbon dioxide); and
- Compliance with mandated renewable energy standards.

To achieve these objectives over the coming years, we plan to reshape our generation portfolio by adding 300 to 500 megawatts of renewable energy to our generation mix, and exploring options to incorporate peaking or intermediate resources. Our 76 MW Bison I Wind Project in North Dakota is expected to be in service in late 2010 and 2011.

We project average annual long-term growth of approximately one percent in electric usage over the next 15 years. We will also focus on conservation and demand side management to meet the energy savings goals established in Minnesota legislation.

Emission Reduction Plans. We have made investments in pollution control equipment at our Boswell Unit 3 generating unit that reduces particulates, SO_2, NO_x and mercury emissions to meet future federal and state requirements. This equipment was placed in service in November 2009. During the construction phase, the MPUC authorized a cash return on construction work in progress in lieu of AFUDC, and this amount was collected through a current cost recovery rider. Our 2010 rate case proposes to move this project from a current cost recovery rider to base rates.

The environmental regulatory requirements for Taconite Harbor Unit 3 are pending approval of the Minnesota Regional Haze implementation by the EPA. We are evaluating compliance requirements for this Unit. Environmental retrofits at Laskin and Taconite Harbor Units 1 and 2 have been completed and are in-service.

Boswell NO_X Reduction Plan. In September 2008, we submitted to the MPCA and MPUC a $92 million environmental initiative proposing cost recovery for expenditures relating to NO_X emission reductions from Boswell Units 1, 2, and 4. The Boswell NO_X Reduction Plan is expected to significantly reduce NO_X emissions from these units. In conjunction with the NO_X reduction, we plan to make an efficiency improvement to our existing turbine/generator at Boswell Unit 4 adding approximately 60 MWs of total output. The Boswell 1, 2 and 4, selective non-catalytic reduction NO_X controls are currently in service, while the Boswell 4 low NO_X burners and turbine efficiency projects are anticipated to be in service in late 2010. Our 2010 rate case seeks recovery for this project in base rates.

Transmission. We have an approved cost recovery rider in-place for certain transmission expenditures, and our current billing factor was approved by the MPUC in June 2009. The billing factor allows us to charge our retail customers on a current basis for the costs of constructing certain transmission facilities plus a return on the capital invested. Our 2010 rate case proposes to move completed transmission projects from the current cost recovery rider to base rates.

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 CIPs 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. Minnesota's 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 June 2008, a biennial filing was submitted for 2009 through 2010, and subsequently approved by the OES. For future program years, Minnesota Power will build upon current successful CIPs in an effort to meet the newly established 1.5 percent energy-saving goal. Minnesota Power's CIP investment goal was $4.6 million for 2009 ($3.7 million for 2008; $3.2 million for 2007), with actual spending of $5.5 million in 2009 ($4.8 million in 2008; $3.9 million in 2007).

Federal Energy Regulatory Commission. 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, certain accounting and record-keeping practices and ATC.

Minnesota Power's non-affiliated municipal customers consist of 16 municipalities in Minnesota and 1 private utility in Wisconsin. SWL&P, a wholly-owned subsidiary of ALLETE, is also a customer of Minnesota Power. In 2008, Minnesota Power entered into new contracts with these municipal customers which transitioned customers to formula-based rates, allowing rates to be adjusted annually based on changes in cost. In February 2009, the FERC approved our municipal contracts which expire December 31, 2013. Under the formula-based rates provision, wholesale rates are set at the beginning of the year based on expected costs and provide for a true-up calculation for actual costs. Wholesale rate increases totaling approximately $6 million and $10 million annually were implemented on February 1, 2009 and January 1, 2010, respectively, with approximately $6 million of additional revenues under the true-up provision accrued in 2009, which will be billed in 2010.

In August 2005, the Energy Policy Act of 2005 (EPAct 2005) was signed into law, which 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.

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.

Public Service Commission of Wisconsin. The PSCW has regulatory authority over SWL&P's retail sales of electricity, natural gas, water, issuances of securities, and other matters.

SWL&P's current retail rates are based on a December 2008 PSCW retail rate order that became effective January 1, 2009, and allows for an 11.1 percent return on equity. The new rates reflected a 3.5 percent average increase in retail utility rates for SWL&P customers (a 13.4 percent increase in water rates, a 4.7 percent increase in electric rates, and a 0.6 percent decrease in natural gas rates). On an annualized basis, the rate increase will generate approximately $3 million in additional revenue.

North Dakota Public Service Commission. The NDPSC has jurisdiction over site and route permitting of generation and transmission facilities necessary for construction in North Dakota.

On September 29, 2009, the NDPSC authorized site construction for Bison I. On October 2, 2009, Minnesota Power filed a route permit application with the NDPSC for the 22 mile, 230 kV Bison I transmission line that will connect Bison I to the DC transmission line at the Square Butte Substation in Center, North Dakota. An order is expected in the first quarter 2010.

Regional Organizations

Midwest Independent Transmission System Operator, Inc. Minnesota Power and SWL&P are members of MISO, a regional transmission organization. While Minnesota Power and SWL&P retain ownership of their respective transmission assets and control area functions, their transmission network is under the regional operational control of MISO. Minnesota Power and SWL&P take and provide transmission service under the 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 MWs of generating capacity.

In January 2009, MISO launched the new Ancillary Services Market (ASM), aimed at establishing a market for energy and operating reserves. In May 2008, in preparation of the new market, Minnesota Power and the other investor-owned utilities in Minnesota prepared a joint filing seeking MPUC approval for the authority to account for costs and revenues that resulted from the institution of the ASM market. The MPUC conditionally approved Minnesota investor-owned utility participation in the MISO ASM market in an order dated March 17, 2009. Under this approval, recovery of ASM charges is subject to refund pending the MPUC's review of our February 5, 2010 filing which documents the cost effectiveness of ASM. The utilities must validate ASM cost recovery to date, as well as on-going recovery, through a review of the cost and benefits of ASM participation. The Company cannot predict the outcome of this proceeding.

Mid-Continent Area Power Pool (MAPP). Minnesota Power also participates in MAPP, a power pool operating in parts of nine states in the Upper Midwest and in two Canadian provinces. MAPP functions include a regional transmission committee that is charged with planning for the future transmission needs of the region as well as ensuring that all electric industry participants have equal access to the transmission system.

Minnesota Legislation

Renewable Energy. In February 2007, Minnesota enacted a law requiring 25 percent of Minnesota Power's total retail energy sales in Minnesota come from renewable energy sources by 2025. The law also requires Minnesota Power to meet interim milestones of 12 percent by 2012, 17 percent by 2016, and 20 percent by 2020. Minnesota Power has identified a plan to meet the renewable goals set by Minnesota and has included this in the most recent filing of the IRP with the MPUC. The law 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 the enactment of this law and this activity continues.

Greenhouse Gas Reduction. In 2007, Minnesota passed legislation establishing non-binding targets for carbon dioxide reductions. This legislation establishes a goal of reducing statewide GHG emissions across all sectors 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 Reduction 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

Retail energy sales in Minnesota and Wisconsin are made to customers in assigned service territories. As a result, most retail electric customers in Minnesota do not have the ability to choose their electric supplier. Large energy users outside of a municipality of 2 MW and above may be allowed to choose a supplier upon MPUC approval. Minnesota Power serves 10 Large Power facilities over 10 MW, none of which have engaged in a competitive rate process. Two customers within the past 15 years that are over 2 MW but less than 10 MW under our Large Light and Power tariff have participated in a competitive rate process with neighboring electric cooperatives but were ultimately retained by Minnesota Power. Retail electric and natural gas customers in Wisconsin do not have the ability to choose their energy supplier. In both states, however, electricity may compete with other forms of energy. Customers may also choose to generate their own electricity, or substitute other fuels for their manufacturing processes.

For the year ended December 31, 2009, 8 percent of the Company's energy sales were sales to municipal customers in Minnesota and a private utility in Wisconsin by contract under a formula-based rate approved by FERC. These customers have the right to seek an energy supply from any wholesale electric service provider upon contract expiration.

The FERC has continued with its efforts to promote a more competitive wholesale market through open-access transmission and other means. As a result, our sales to Other Power Suppliers and our purchases to supply our retail and wholesale load are in the competitive market.

Franchises

Minnesota Power holds franchises to construct and maintain an electric distribution and transmission system in 93 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 by us do not require a franchise to operate within their boundaries. Our exclusive service territories are established by state regulatory agencies.

INVESTMENTS AND OTHER

Investments and Other is comprised primarily of BNI Coal, our coal mining operations in North Dakota, and ALLETE Properties, our Florida real estate investment. This segment also includes a small amount of non-rate base generation, approximately 7,000 acres of land available-for-sale in Minnesota, and earnings on cash and investments.

BNI Coal

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, fixed fee coal supply agreements extending through 2026. (See Item 1. Business – Long-Term Purchased Power and Note 11. Commitments, Guarantees and Contingencies.) The mining process disturbs and reclaims between 200 and 250 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 approximately $35,000; however, depending on conditions, it could be significantly higher. 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.

ALLETE Properties

ALLETE Properties represents our Florida real estate investment. Our current strategy for the assets is to complete and maintain key entitlements and infrastructure improvements without requiring significant additional investment, and sell the portfolio over time or in bulk transactions. ALLETE intends to sell its Florida land assets at reasonable prices when opportunities arise, and reinvest the proceeds in its growth initiatives. ALLETE does not intend to acquire additional Florida real estate.

Our two major development projects are Town Center and Palm Coast Park. Ormond Crossings, a third major project that is currently in the planning stage, received land use approvals in December 2006. However, due to a change in Florida law that became effective in July 2009, those approvals are being revised. It is anticipated that the City of Ormond Beach, FL will approve a new Development Agreement for Ormond Crossings in the first quarter of 2010. The new agreement will facilitate development of the project as currently planned. Separately, Lake Swamp wetland mitigation bank was permitted on land that was previously part of 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. Construction of the major infrastructure improvements at Town Center was substantially complete at the end of 2008. At build-out, Town Center is expected to include approximately 3,000 residential units and 4.0 million square feet of various types of non-residential space. Sites have also been set aside for a new city hall, a community center, an art and entertainment center, and other public uses. Market conditions will determine how quickly Town Center builds out.

Palm Coast Park. Palm Coast Park, which is located in the City of Palm Coast, is a 4,700-acre mixed-use development. Construction of the major infrastructure improvements at Palm Coast Park was substantially complete at the end of 2007. At build-out, Palm Coast Park is expected to include approximately 4,000 residential units, 3.0 million square feet of various types of non-residential space and public facilities. Market conditions will determine how quickly Palm Coast Park builds out.

Ormond Crossings. Ormond Crossings, which is located in the City of Ormond Beach, is a 3,000-acre, mixed-use development. Planning, engineering design, and permitting of the master infrastructure are ongoing. At build out, Ormond Crossings is expected to include approximately 3,000 residential units, 5.0 million square feet of various types of non-residential space and public facilities. Market conditions will determine when Ormond Crossings will be built out. We do not expect any development activity at Ormond Crossings in 2010.

Lake Swamp. Lake Swamp wetland mitigation bank is a 1,900 acre regionally significant wetlands mitigation bank that was permitted by the St. Johns River Water Management District in 2008 and the U.S. Army Corps of Engineers in December 2009. Wetland mitigation credits will be used at Ormond Crossings and will also be available for sale to developers of other projects that are located in the bank's service area. Applications are currently being prepared to expand the bank by approximately 1,000 acres.

See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Outlook for more information on ALLETE Properties' land holdings.

INVESTMENTS AND OTHER (Continued)

Seller Financing. ALLETE Properties occasionally provides seller financing to certain qualified buyers. At December 31, 2009, outstanding finance receivables were $12.9 million, with maturities up to 3 years. These finance receivables accrue interest at market-based rates and are collateralized by the financed properties.

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.

Non-Rate Base Generation

As of December 31, 2009, non-rate base generation consists of 30 MWs of generation at Rapids Energy Center. For January through October non-rate base generation also included Cloquet Energy Center (23 MWs of generation), which was transferred to rate base as a result of our 2008 rate order. In 2009, we sold 0.2 million MWh of non-rate base generation (0.2 million in 2008 and 2007).

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

(a) Cloquet Energy Center is supplemented by natural gas; Rapids Energy Center is supplemented by coal.
(b) Transferred to Regulated Operations as a result of our 2008 rate order on November 1, 2009.
(c) The net generation is primarily dedicated to the needs of one customer.

Other

Minnesota Land. We have approximately 7,000 acres of land available-for-sale in Minnesota. We acquired the land in 2001 when we purchased the Taconite Harbor generating facilities.

Environmental Matters

Our businesses are subject to regulation of environmental matters by various federal, state and local authorities. Currently, a number of regulatory changes are under consideration by both the Congress and the EPA. Most notably, clean energy technologies and the regulation of GHGs have taken a lead in these discussions. Minnesota Power's fossil fueled facilities will likely to be subject to regulation under these climate change policies. Our intention is to reduce our exposure to possible future carbon and GHG legislation by reshaping our generation portfolio, over time, to reduce our reliance on coal.

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 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. (See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Capital Requirements.)

We review environmental matters for disclosure 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 become available. Accruals for environmental liabilities are included in the consolidated 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.* 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 average NO_X limits. 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. Minnesota Power's generating facilities are currently in compliance with applicable emission requirements.

New Source Review. On August 8, 2008, Minnesota Power received a Notice of Violation (NOV) from the United States EPA asserting violations of the New Source Review (NSR) requirements of the Clean Air Act at Boswell Units 1-4 and Laskin Unit 2. The NOV also asserts that the Boswell Unit 4 Title V permit was violated, and that seven projects undertaken at these coal-fired plants between the years 1981 and 2000 should have been reviewed under the NSR requirements. Minnesota Power believes the projects were in full compliance with the Clean Air Act, NSR requirements and applicable permits.

We are engaged in discussions with the EPA regarding resolution of these matters, but we are unable to predict the outcome of these discussions. Since 2006, Minnesota Power has significantly reduced, and continues to reduce, emissions at Boswell and Laskin. The resolution could result in civil penalties and the installation of control technology, some of which is already planned or completed for other regulatory requirements. Any costs of installing pollution control technology would likely be eligible for recovery in rates over time subject to MPUC and FERC approval in a rate proceeding. We are unable to predict the ultimate financial impact or the resolution of these matters at this time.

EPA Clean Air Interstate Rule. In March 2005, the EPA announced the Clean Air Interstate Rule (CAIR) that sought to reduce and permanently cap emissions of SO_2, NO_X, and particulates in the eastern United States. Minnesota was included as one of the 28 states considered as "significantly contributing" to air quality standards non-attainment in other downwind states. On July 11, 2008, the United States Court of Appeals for the District of Columbia Circuit (Court) vacated the CAIR and remanded the rulemaking to the EPA for reconsideration while also granting our petition that the EPA reconsider including Minnesota as a CAIR state. In September 2008, the EPA and others petitioned the Court for a rehearing or alternatively requested that the CAIR be remanded without a court order. In December 2008, the Court granted the request that the CAIR be remanded without a court order, effectively reinstating a January 1, 2009, compliance date for the CAIR, including Minnesota. However, in the May 12, 2009, Federal Register, the EPA issued a proposed rule that would amend the CAIR to stay its effectiveness with respect to Minnesota until completion of the EPA's determination of whether Minnesota should be included as a CAIR state. The formal administrative stay of CAIR for Minnesota was published in the November 3, 2009, Federal Register with an effective date of December 3, 2009. The EPA has indicated the CAIR Replacement Rule is expected in April 2010 with finalization in early 2011. At this time we do not have any indication whether Minnesota will be included in the Replacement Rule.

Minnesota Regional Haze. The federal regional haze rule requires states to submit state implementation plans (SIPs) to the EPA to address regional haze visibility impairment in 156 federally-protected parks and wilderness areas. Under the regional haze rule, certain large stationary sources, that were put in place between 1962 and 1977 with emissions contributing to visibility impairment are required to install emission controls, known as best available retrofit technology (BART). We have certain steam units, Boswell Unit 3 and Taconite Harbor Unit 3, which are subject to BART requirements.

Pursuant to the regional haze rule, Minnesota was required to develop its SIP by December 2007. As a mechanism for demonstrating progress towards meeting the long-term regional haze goal, in April 2007, the MPCA advanced a draft conceptual SIP which relied on the implementation of CAIR. However, a formal SIP was never filed due to the Court's review of CAIR as more fully described above under "EPA Clean Air Interstate Rule." Subsequently, the MPCA requested that companies with BART eligible units complete and submit a BART emissions control retrofit study, which was done on Taconite Harbor Unit 3 in November 2008. The retrofit work completed in 2009 at Boswell Unit 3 meets the BART requirement for that unit. On December 15, 2009, the MPCA approved the SIP for submittal to the EPA for review and approval. It is uncertain what controls will ultimately be required at Taconite Harbor Unit 3 in connection with the regional haze rule.

EPA National Emission Standards for Hazardous Air Pollutants. In March 2005, the EPA also announced the Clean Air Mercury Rule (CAMR) that would have reduced and permanently capped electric utility mercury emissions in the continental United States through a cap-and-trade program. In February 2008, the United States Court of Appeals for the District of Columbia Circuit vacated the CAMR and remanded the rulemaking to the EPA for reconsideration. In October 2008, the EPA petitioned the Supreme Court to review the Court's decision in the CAMR case. In January 2009, the EPA withdrew its petition, paving the way for possible regulation of mercury and other hazardous air pollutant emissions through Section 112 of the Clean Air Act, setting Maximum Achievable Control Technology standards for the utility sector. In December 2009, Minnesota Power and other utilities received an Information Collection Request from the EPA, requiring that emissions data be provided and stack testing be performed in order to develop an improved database with which to base future regulations. Cost estimates for complying with potential future mercury and other hazardous air pollutant regulations under the Clean Air Act cannot be estimated at this time.

Environmental Matters (Continued)

Minnesota Mercury Emission Reduction Act. This legislation requires Minnesota Power to file mercury emission reduction plans for Boswell Units 3 and 4, with a goal of 90 percent reduction in mercury emissions. The Boswell Unit 3 emission reduction plan was filed with the MPCA in October 2006. Mercury control equipment has been installed and was placed into service in November 2009. (See Item 1. Business – Regulated Operations – Minnesota Public Utilities Commission – Emission Reduction Plans.) A mercury emissions reduction plan for Boswell Unit 4 is required by July 1, 2011, with implementation no later than December 31, 2014. The legislation calls for an evaluation of a mercury control alternative which provides for environmental and public health benefits without imposing excessive costs on the utility's customers. Cost estimates for the Boswell Unit 4 emission reduction plan are not available at this time.

Ozone. The EPA is attempting to control, more stringently, emissions that result in ground level ozone. In January 2010, the EPA proposed to reduce the eight-hour ozone standard and to adopt a secondary standard for the protection of sensitive vegetation from ozone-related damage. The EPA projects stating rules to address attainment of these new, more stringent standards will not be required until December 2013.

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

- Expand our renewable energy supply.
- Improve the efficiency of our coal-based generation facilities, as well as other process efficiencies.
- Provide energy conservation initiatives with our customers and demand side efforts.
- Support research of technologies to reduce carbon emissions from generation facilities and support carbon sequestration efforts.
- Achieve overall carbon emission reductions.

The scientific community generally accepts that emissions of GHGs are linked to global climate change. Climate change creates physical and financial risk. These physical risks could include, but are not limited to, increased or decreased precipitation and water levels in lakes and rivers; increased temperatures; and the intensity and frequency of extreme weather events. These all have the potential to affect the Company's business and operations.

Federal Legislation. We believe that future regulations may restrict the emissions of GHGs from our generation facilities. Several proposals at the Federal level to "cap" the amount of GHG emissions have been made. On June 26, 2009, the U.S. House of Representatives passed H.R. 2454, the American Clean Energy and Security Act of 2009. H.R. 2454 is a comprehensive energy bill that also includes a cap-and-trade program. H.R. 2454 allocates a significant number of emission allowances to the electric utility sector to mitigate cost impacts on consumers. Based on the emission allowance allocations, we expect we would have to purchase additional allowances. We're unable to predict at this time the value of these allowances.

On September 30, 2009, the Senate introduced S. 1733, the Senate version of H.R. 2454. This legislation proposes a more stringent, near-term greenhouse emissions reduction target in 2020 of 20 percent below 2005 levels, as compared to the 17 percent reduction proposed by H.R. 2454.

Congress may consider proposals other than cap-and-trade programs to address GHG emissions. We are unable to predict the outcome of H.R. 2454, S. 1733, or other efforts that Congress may make with respect to GHG emissions, and the impact that any GHG emission regulations may have on the Company. 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.

Greenhouse Gas Reduction. In 2007, Minnesota passed legislation establishing non-binding targets for carbon dioxide reductions. This legislation establishes a goal of reducing statewide GHG emissions across all sectors 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.

Midwestern Greenhouse Gas Reduction Accord. Minnesota is also participating in the Midwestern Greenhouse Gas Reduction Accord (the Accord), a regional effort to develop a multi-state approach to GHG emission reductions. The Accord includes an agreement to develop a multi-sector cap-and-trade system to help meet the targets established by the group.

Greenhouse Gas Emissions Reporting. In May 2008, Minnesota passed legislation that required the MPCA to track emissions and make interim emissions reduction recommendations towards meeting the State's goal of reducing GHG by 80 percent by 2050. GHG emissions from 2008 were reported in 2009.

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.

Environmental Matters (Continued)
Climate Change (Continued)

International Climate Change Initiatives. The United States is not a party to the Kyoto Protocol, which is a protocol to the United Nations Framework Convention on Climate Change (UNFCCC) that requires developed countries to cap GHG emissions at certain levels during the 2008 to 2012 time period. In December 2009, leaders of developed and developing countries met in Copenhagen, Denmark, under the UNFCCC and issued the Copenhagen Accord. The Copenhagen Accord provides a mechanism for countries to make economy-wide GHG emission mitigation commitments for reducing emissions of GHG by 2020 and provide for developed countries to fund GHG emissions mitigation projects in developing countries. President Obama participated in the development of, and endorsed the Copenhagen Accord.

EPA Greenhouse Gas Reporting Rule. On September 22, 2009, the EPA issued the final rule mandating that certain GHG emission sources, including electric generating units, are required to report emission levels. The rule is intended to allow the EPA to collect accurate and timely data on GHG emissions that can be used to form future policy decisions. The rule was effective January 1, 2010, and all GHG emissions must be reported on an annual basis by March 31 of the following year. Currently, we have the equipment and data tools necessary to report our 2010 emissions to comply with this rule.

Title V Greenhouse Gas Tailoring Rule. On October 27, 2009, the EPA issued the proposed Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas Tailoring rule. This proposed regulation addresses the six primary greenhouse gases and new thresholds for when permits will be required for new and existing facilities which undergo major modifications. The rule would require large industrial facilities, including power plants, to obtain construction and operating permits that demonstrate Best Available Control Technologies (BACT) are being used at the facility to minimize GHG emissions. The EPA is expected to propose BACT standards for GHG emissions from stationary sources.

For our existing facilities, the proposed rule does not require amending our existing Title V operating permits to include BACT for GHGs. However, modifying or installing units with GHG emissions that trigger the PSD permitting requirements could require amending operating permits to incorporate BACT to control GHG emissions.

EPA Endangerment Findings. On December 15, 2009, the EPA published its findings that the emissions of six GHG, including CO_2, methane, and nitrous oxide, endanger human health or welfare. This finding may result in regulations that establish motor vehicle GHG emissions standards in 2010. There is also a possibility that the endangerment finding will enable expansion of the EPA regulation under the Clean Air Act to include GHGs emitted from stationary sources. A petition for review of the EPA's endangerment findings was filed by the Coalition for Responsible Regulation, et. al. with the United States District Court Circuit Court of Appeals on December 23, 2009.

Research and Study Initiatives. We participate in several research and study initiatives aimed at mitigating the potential impact of carbon emissions regulation on our business. Through this research, we cannot be certain that carbon emissions will be reduced or avoided through use of renewable energy sources or through implementing efficiency and conservation efforts. In developing strategies for our comprehensive approach to reducing our carbon emissions, we participate in and fund organizations and studies.

As an example, we commissioned a study with the University of Minnesota titled: *Assessment of Carbon Flows Associated with Forest Management and Biomass Procurement for the Laskin Biomass Facility*. This study was the first of its kind to comprehensively look at the carbon lifecycle as it relates to burning biomass for electrical generation in the region.

We participate in the Electric Power Research Institute's CoalFleet for Tomorrow program, which reviews advanced clean coal generation and carbon capture research and assessment. Similarly, we participate as a North Dakota Lignite Interest member of the Canadian Clean Power Coalition. It also reviews advanced clean coal technologies focusing on lower rank sub-bituminous and lignite fuel energy conversion technologies and carbon control options. These provide Minnesota Power the ability to assess what technologies will best fit the economic fuels that are available in our region and when they may be available.

We also participate in research through the Plains CO_2 Reduction Partnership (PCOR). PCOR is looking at CO_2 capture technology through research conducted at the Energy and Environmental Research Center, University of North Dakota. Minnesota Power is a partner, along with a number of other utilities, technology providers, and consultants, to further research on CO_2 capture techniques, operational issues and costs. The partnership is funded by the members as well as the Department of Energy.

We cannot predict whether our participation in any of these activities will result in a benefit to ALLETE or impact the future financial position or results of operations of the Company.

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.

Environmental Matters (Continued)

Solid and Hazardous Waste. The Resource Conservation and Recovery Act of 1976 regulates the management and disposal of solid 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 is in the process of voluntarily replacing its remaining PCB capacitor banks. Known PCB-contaminated oil in substation equipment was replaced by June 2007. We are in material compliance with these rules.

Coal Ash Management Facilities. Minnesota Power generates coal ash at all five of its steam electric stations. Two facilities store ash in onsite impoundments (ash ponds) with engineered liners and containment dikes. Another facility stores dry ash in a landfill with an engineered liner and leachate collection system. Two facilities generate a combined wood and coal ash that is either land applied as an approved beneficial use, or trucked to state permitted landfills. Minnesota Power continues to monitor state and federal legislative and regulatory activities that may affect its ash management practices. The EPA is expected to propose new regulations in February 2010 pertaining to the management of coal ash by electric utilities. It is unknown how potential coal ash management rule changes will affect Minnesota Power's facilities. On March 9, 2009, the EPA requested information from Minnesota Power (and other utilities) on its ash storage impoundments at Boswell and Laskin. On June 22, 2009, Minnesota Power received an additional EPA information request pertaining to Boswell. Minnesota Power responded to both these information requests. On August 19, 2009, the Minnesota DNR visited both the Boswell and Laskin ash ponds. The purpose of the inspection was to assess the structural integrity of the ash ponds, as well as review operational and maintenance procedures. There were no significant findings or concerns from the DNR staff during the inspections.

Manufactured Gas Plant Site. We are reviewing and addressing environmental conditions at a former manufactured gas plant site within the City of Superior, Wisconsin, and formerly operated by SWL&P. We have been working with the WDNR to determine the extent of contamination and the remediation of contaminated locations. At December 31, 2009, we have a $0.5 million liability for this site, which was accrued on December 31, 2003, and a corresponding regulatory asset as we expect recovery of remediation costs to be allowed by the PSCW.

Employees

At December 31, 2009, ALLETE had 1,474 employees, of which 1,411 were full-time.

Minnesota Power and SWL&P have an aggregate 614 employees who are members of the International Brotherhood of Electrical Workers (IBEW) Local 31. Throughout 2009, Minnesota Power, SWL&P and IBEW Local 31 worked under contract extensions of the agreements which expired on January 31, 2009. On April 10, 2009, IBEW Local 31 requested binding arbitration in accordance with the provisions of the contracts which also provided Minnesota Power and SWL&P with the protections of no strike clauses. Arbitration hearings took place October 5, 2009, with final resolution for Minnesota Power occurring in January 2010. The terms of the agreement are retro active to February 1, 2009, and will expire on January 31, 2012. SWL&P continues to work with its union and the arbitrator to resolve the remaining differences between the parties.

BNI Coal has 137 employees, of which 100 are members of the IBEW Local 1593. BNI Coal and IBEW Local 1593 have a labor agreement which expires on March 31, 2011.

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

As of February 12, 2010, these are the executive officers of ALLETE:

Executive Officers	Initial Effective Date
Donald J. Shippar, Age 60	
Chairman and Chief Executive Officer	May 12, 2009
Chairman, President and Chief Executive Officer	January 1, 2006
President and Chief Executive Officer	January 21, 2004
Alan R. Hodnik, Age 50	
President – ALLETE	May 12, 2009
Chief Operating Officer – Minnesota Power	May 8, 2007
Senior Vice President – Minnesota Power Operations	September 22, 2006
Vice President – Minnesota Power Generation	May 1, 2005
Robert J. Adams, Age 47	
Vice President – Business Development and Chief Risk Officer	May 13, 2008
Vice President – Utility Business Development	February 1, 2004
Deborah A. Amberg, Age 44	
Senior Vice President, General Counsel and Secretary	January 1, 2006
Vice President, General Counsel and Secretary	March 8, 2004
Steven Q. DeVinck, Age 50	
Controller and Vice President – Business Support	December 17, 2009
Controller	July 12, 2006
Mark A. Schober, Age 54	
Senior Vice President and Chief Financial Officer	July 1, 2006
Senior Vice President and Controller	February 1, 2004
Donald W. Stellmaker, Age 52	
Treasurer	July 24, 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.

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

Mr. Hodnik was General Manager of Thermal Operations.

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 11, 2010.

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 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 ten Large Power Customers accounted for approximately 23 percent of our 2009 consolidated operating revenue (36 percent in 2008). One of these customers accounted for 8 percent of consolidated revenue in 2009 (12.5 percent in 2008). 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 if we are unable to remarket at similar prices the energy that would otherwise have been sold to such Large Power Customers.

Our operations are 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, the PSCW and the NDPSC. 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 statutes and regulations, and we cannot provide assurance 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 operations could be adversely impacted by emissions of greenhouse gases (GHG) that are linked to global climate change.

The scientific community generally accepts that emissions of GHGs are linked to global climate change. Climate change creates physical and financial risk. These physical risks could include, but are not limited to, increased or decreased precipitation and water levels in lakes and rivers; increased temperatures; and the intensity and frequency of extreme weather events. These all have the potential to affect the Company’s business and operations.

Our operations could be adversely 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 to reduce GHGs such as carbon dioxide, a by-product of burning fossil fuels, are being discussed within Minnesota, among a group of Midwestern states that includes Minnesota, in the United States Congress and worldwide. We currently use coal as the primary fuel in 95 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.

The cost of environmental emission allowances could have a negative financial impact on our operations.

Minnesota Power is subject to numerous environmental laws and regulations which cap emissions and could require us to purchase environmental emissions allowances to be in compliance. The laws and regulations expose us to emission allowance price fluctuations which could increase our cost of operations. We are unable to predict the emission allowance pricing, regulatory recovery or ratepayer impact of these costs.

Our 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 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. 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 electrical generating operations must have adequate and reliable transmission and distribution facilities to deliver electricity to our 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. 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.

In our 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 wholesale power sales.

We are dependent on good labor relations.

We believe our relations to be good with our 1,474 employees. Failure to successfully renegotiate labor agreements could adversely affect the services we provide and our results of operations. Currently, 714 of our employees are members of either the IBEW Local 31 or Local 1593. The labor agreement with Local 31 at Minnesota Power and SWL&P expired on January 31, 2009. A new agreement between Minnesota Power and Local 31 went into effect in January 2010. The terms of the agreement are retroactive to February 1, 2009 and will expire on January 31, 2012. SWL&P continues to work with its union and the arbitrator to resolve the remaining differences between the parties. The labor agreement with Local 1593 at BNI Coal expires on March 31, 2011.

The current downturn in economic conditions may continue to adversely affect our real estate investment.

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

Our real estate investment 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, 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 of and our ability to develop future real estate projects. 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.

Market performance and other changes could decrease the value of pension and postretirement health benefit plan assets, which then could require significant additional funding and increase annual expense.

The performance of the capital markets affects the values of the assets that are held in trust to satisfy future obligations under our pension and postretirement benefit plans. We have significant obligations to these plans and the Company holds significant assets in these trusts. These assets are subject to market fluctuations and will yield uncertain returns, which may fall below our projected rates of return. A decline in the market value of the pension and postretirement benefit plan assets will increase the funding requirements under our benefit plans if the actual asset returns do not recover. Additionally, our pension and postretirement benefit plan liabilities are sensitive to changes in interest rates. As interest rates decrease, the liabilities increase, potentially increasing benefit expense and funding requirements.

Risk Factors (Continued)

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.

We rely on access to financing sources and capital markets. If we do not have access to sufficient capital in the amount and at the times needed, our ability to execute our business plans, make capital expenditures or pursue acquisitions that we may otherwise rely on for future growth could be impaired.

We rely on access to capital markets as sources of liquidity for capital requirements not satisfied by our cash flow from operations. If we are not able to access capital on satisfactory terms, the ability to implement our business plans may be adversely affected. Market disruptions or a downgrade of our credit ratings may increase the cost of borrowing or adversely affect our ability to access financial markets. Such disruptions could include a severe prolonged economic downturn, the bankruptcy of non-affiliated industry leaders in the same line of business or financial services sector, deterioration in capital market conditions, or volatility in commodity prices.

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 2009.

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 $0.44 per share on our common stock will be paid on March 1, 2010, to the holders of record on February 15, 2010.

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:

	2009			2008		
	Price Range		Dividends	Price Range		Dividends
Quarter	High	Low	Declared	High	Low	Declared
First	$33.27	$23.35	$0.44	$39.86	$33.76	$0.43
Second	29.14	24.45	0.44	46.11	38.82	0.43
Third	34.57	27.75	0.44	49.00	38.05	0.43
Fourth	35.29	32.23	0.44	44.63	28.28	0.43
Annual Total			$1.76			$1.72

At February 1, 2010, there were approximately 29,000 common stock shareholders of record.

Common Stock Repurchases. We did not repurchase any ALLETE common stock during 2009.

Item 6. Selected Financial Data

	2009	2008	2007	2006	2005
Millions					
Operating Revenue	$759.1	$801.0	$841.7	$767.1	$737.4
Operating Expenses	653.1	679.2	710.0	628.8	692.3 *(e)*
Income from Continuing Operations Before Non-Controlling Interest – Net of Tax	60.7	83.0	89.5	81.9	20.3 *(e)*
Income (Loss) from Discontinued Operations – Net of Tax	–	–	–	(0.9)	(4.3) *(e)*
Net Income	60.7	83.0	89.5	81.0	16.0
Less: Non-Controlling Interest in Subsidiaries	(0.3)	0.5	1.9	4.6	2.7
Net Income Attributable to ALLETE	61.0	82.5	87.6	76.4	13.3
Common Stock Dividends	56.5	50.4	44.3	40.7	34.4
Earnings Retained in (Distributed from) Business	$4.5	$32.1	$43.3	$35.7	$(21.1)
Shares Outstanding – Millions					
Year-End	35.2	32.6	30.8	30.4	30.1
Average *(a)*					
Basic	32.2	29.2	28.3	27.8	27.3
Diluted	32.2	29.3	28.4	27.9	27.4
Diluted Earnings (Loss) Per Share					
Continuing Operations	$1.89	$2.82	$3.08	$2.77	$0.64 *(e)*
Discontinued Operations *(b)*	–	–	–	(0.03)	(0.16)
	$1.89	$2.82	$3.08	$2.74	$0.48
Total Assets	$2,393.1	$2,134.8	$1,644.2	$1,533.4 *(d)*	$1,398.8
Long-Term Debt	695.8	588.3	410.9	359.8	387.8
Return on Common Equity	6.9%	10.7%	12.4%	12.1%	2.2% *(e)*
Common Equity Ratio	57.0%	58.0%	63.7%	63.1%	60.7%
Dividends Declared per Common Share	$1.76	$1.72	$1.64	$1.45	$1.245
Dividend Payout Ratio	93%	61%	53%	53%	259% *(e)*
Book Value Per Share at Year-End	$26.39	$25.37	$24.11	$21.90	$20.03
Capital Expenditures by Segment *(c)*					
Regulated Operations	$299.2	$317.0	$220.6	$107.5	$46.5
Investments and Other	4.5	5.9	3.3	1.9	12.1
Discontinued Operations	–	–	–	–	4.5
Total Capital Expenditures	$303.7	$322.9	$223.9	$109.4	$63.1

(a) Excludes unallocated ESOP shares.

(b) Operating results of our Water Services businesses and our telecommunications business are included in discontinued operations, and accordingly, amounts have been restate for all periods presented.

(c) In 2008, we made changes to our reportable business segments in our continuing effort to manage and measure performance of our operations based on the nature of products and services provided and customers served. (See Note 2. Business Segments.)

(d) Included $86.1 million of assets reflecting the adoption of Plan Accounting – Defined Benefit Pension Plans, and Health and Welfare Benefit Plans.

(e) Impacted by a $50.4 million, or $1.84 per share, charge related to the assignment of the Kendall County power purchase agreement.

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

Regulated Operations includes our regulated utilities, Minnesota Power and SWL&P, as well as our investment in ATC, a Wisconsin-based regulated utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota and Illinois. Minnesota Power provides regulated utility electric service in northeastern Minnesota to 144,000 retail customers and wholesale electric service to 16 municipalities. Minnesota Power also provides regulated utility electric service to 1 private utility in Wisconsin. SWL&P provides regulated electric, 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. Business – Regulated Operations – Regulatory Matters.)

Investments and Other is comprised primarily of BNI Coal, our coal mining operations in North Dakota, and ALLETE Properties, our Florida real estate investment. This segment also includes a small amount of non-rate base generation, approximately 7,000 acres of land available-for-sale in Minnesota, and earnings on cash and investments.

ALLETE is incorporated under the laws of Minnesota. Our corporate headquarters are in Duluth, Minnesota. Statistical information is presented as of December 31, 2009, 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.

2009 Financial Overview

The following net income discussion summarizes a comparison of the year ended December 31, 2009, to the year ended December 31, 2008.

Net income attributable to ALLETE for 2009 was $61.0 million, or $1.89 per diluted share compared to $82.5 million, or $2.82 per diluted share for 2008. Earnings per diluted share decreased approximately $0.19 compared to 2008 as a result of additional shares of common stock outstanding in 2009. (See Note 12. Common Stock and Earnings Per Share.)

Regulated Operations net income attributable to ALLETE was $65.9 million in 2009 ($67.9 million in 2008). The decrease is primarily attributable to lower net income at Minnesota Power due to a 4.1 percent decrease in kilowatt-hour sales, higher depreciation and interest expense, and the accrual of retail rate refunds related to 2008. These decreases were partially offset by increased FERC-approved wholesale rates and MPUC-approved current cost recovery revenue. In addition, 2009 reflected $1.4 million in additional after-tax earnings from our investment in ATC as a result of additional investments made to fund our pro-rata share of ATC's voluntary capital contribution program.

Investments and Other reflected a net loss attributable to ALLETE of $4.9 million in 2009 ($14.6 million of net income attributable to ALLETE in 2008). The decrease is primarily attributable to a $6.5 million reduction in earnings at ALLETE Properties and the absence of non-recurring items recorded in 2008. In 2009, ALLETE Properties recorded a net loss of $4.7 million versus net income of $1.8 million in 2008. In 2008, we recorded a $3.8 million non-recurring gain on the sale of certain available-for-sale securities and $5.8 million in non-recurring tax benefits and related interest due to the closing of a tax year and the completion of an IRS review.

2009 Compared to 2008

See Note 2. Business Segments for financial results by segment.

Regulated Operations

Operating revenue decreased $30.4 million, or 4 percent, from 2008 due to lower fuel and purchased power recoveries, lower retail and municipal kilowatt-hour sales, lower natural gas revenue at SWL&P, and the accrual of prior year retail rate refunds related to our 2008 retail rate case. These decreases were partially offset by higher sales to Other Power Suppliers, higher FERC-approved wholesale rates and increased revenue from MPUC-approved current cost recovery riders.

Lower fuel and purchased power recoveries along with a decrease in retail and municipal kilowatt-hour sales combined for a total revenue reduction of $116.2 million. Fuel and purchased power recoveries decreased due to a reduction in fuel and purchased power expense. (See Fuel and Purchased Power Expense.) Total kilowatt-hour sales to retail and municipal customers decreased 26 percent from 2008 primarily due to idled production lines and temporary closures at some of our taconite customers' plants.

Natural gas revenue at SWL&P was lower by $7.8 million due to a 27 percent decrease in the price of natural gas and a 9 percent decline in sales. Natural gas revenue is primarily a flow-through of the natural gas costs. (See Operating and Maintenance Expense.)

Prior year retail rate refunds resulting from the 2009 MPUC Order and August 2009 Reconsideration Order were recorded in 2009 and resulted in a reduction in revenues of $7.6 million.

The decrease in kilowatt-hour sales to retail and municipal customers has been partially offset by revenue from marketing the power to Other Power Suppliers, which increased $77.2 million in 2009. Sales to Other Power Suppliers are sold at market-based prices into the MISO market on a daily basis or through bilateral agreements of various durations.

Higher rates from the March 1, 2008, and February 1, 2009, FERC-approved wholesale rate increases for our municipal customers increased revenue by $13.2 million.

MPUC-approved current cost recovery rider revenue increased $10.4 million in 2009 from 2008 primarily due to increased capital expenditures related to our Boswell Unit 3 emission reduction plan.

Kilowatt-hours Sold	**2009**	**2008**	**Quantity Variance**	**% Variance**
Millions				
Regulated Utility				
Retail and Municipals				
Residential	1,164	1,172	(8)	(0.7) %
Commercial	1,420	1,454	(34)	(2.3) %
Industrial	4,475	7,192	(2,717)	(37.8) %
Municipals	992	1,002	(10)	(1.0) %
Total Retail and Municipals	8,051	10,820	(2,769)	(25.6) %
Other Power Suppliers	4,056	1,800	2,256	125.3 %
Total Regulated Utility Kilowatt-hours Sold	12,107	12,620	(513)	(4.1) %

Revenue from electric sales to taconite customers accounted for 15 percent of consolidated operating revenue in 2009 (26 percent in 2008). The decrease in revenue from our taconite customers was partially offset by revenue from electric sales to Other Power Suppliers, which accounted for 20 percent of consolidated operating revenue in 2009 (10 percent in 2008). Revenue from electric sales to paper and pulp mills accounted for 9 percent of consolidated operating revenue in 2009 (9 percent in 2008). Revenue from electric sales to pipelines and other industrials accounted for 7 percent of consolidated operating revenue in 2009 (7 percent in 2008).

Operating expenses decreased $20.1 million, or 3 percent, from 2008.

Fuel and Purchased Power Expense decreased $26.1 million, or 9 percent, from 2008 due to decreased power generation attributable to lower kilowatt-hour sales, as well as a reduction in wholesale electricity prices. Minnesota Power's coal generating fleet produced fewer kilowatt-hours of electricity due to planned outages to implement environmental retrofits and to respond to decreased demand from our taconite customers.

Operating and Maintenance Expense decreased $3.5 million from 2008 primarily due to $7.4 million in lower natural gas costs at SWL&P from a decline in the price and quantity of natural gas purchased. This decrease was partially offset by increased salaries and benefits costs, rate case expenses and plant maintenance.

2009 Compared to 2008 (Continued)
Regulated Operations (Continued)

Depreciation Expense increased $9.5 million, or 19 percent, from 2008 reflecting higher property, plant and equipment balances placed in service.

Interest expense increased $4.3 million, or 18 percent, from 2008 primarily due to additional long-term debt issued to fund new capital investments and $0.5 million related to retail rate refunds.

Equity earnings increased $2.2 million, or 14 percent, from 2008 reflecting higher earnings from our increased investment in ATC. (See Note 6. Investment in ATC.)

Investments and Other

Operating revenue decreased $11.5 million, or 13 percent, from 2008 primarily due to a $14.3 million reduction in sales revenue at ALLETE Properties. In 2009, ALLETE Properties sold approximately 35 acres of properties located outside of our three main development projects for $3.8 million; no other sales were made in 2009 due to the continued lack of demand for our properties as a result of poor real estate market conditions in Florida. In 2008, ALLETE Properties sold approximately 219 acres of property located outside of our three main development projects for $6.3 million and recognized $3.7 million of previously deferred revenue under percentage of completion accounting. Revenue at ALLETE Properties in 2008 also included a pre-tax gain of $4.5 million from the sale of a retail shopping center in Winter Haven, Florida.

ALLETE Properties	**2009**		**2008**	
Revenue and Sales Activity	**Quantity**	**Amount**	**Quantity**	**Amount**
Dollars in Millions				
Revenue from Land Sales				
Acres *(a)*	35	$3.8	219	$6.3
Contract Sales Price *(b)*		3.8		6.3
Revenue Recognized from Previously Deferred Sales		–		3.7
Revenue from Land Sales		3.8		10.0
Other Revenue *(c)*		0.2		8.3
Total ALLETE Properties Revenue		$4.0		$18.3

(a) Acreage amounts are shown on a gross basis, including wetlands and non-controlling interest.
(b) Reflected total contract sales price on closed land transactions. Land sales are recorded using a percentage-of-completion method. (See Note 1. Operations and Significant Accounting Policies.)
(c) Included a $4.5 million pre-tax gain from the sale of a shopping center in Winter Haven, Florida in 2008.

BNI Coal, which operates under a cost-plus contract, recorded additional revenue of $5.6 million as a result of higher expenses. (See Operating Expenses.)

Operating expenses decreased $6.0 million, or 7 percent, from 2008 reflecting lower fuel costs at our non-regulated generating facilities and decreased expense at ALLETE Properties due to both lower cost of land sold and reductions in general and administrative expenses. Expenses incurred as a result of a planned maintenance outage at a non-regulated generating facility in the third quarter of 2008 also contributed to the decrease in 2009. Partially offsetting these decreases was an increase in expense at BNI Coal due to higher permitting costs relating to mining expansion, a warranty credit in 2008, and dragline repairs in 2009. These costs were recovered through the cost-plus contract. (See Operating Revenue.)

Interest expense increased $3.2 million from 2008 primarily due to a decrease in the proportion of ALLETE interest expense assigned to Minnesota Power. We record interest expense for Minnesota Power regulated operations based on Minnesota Power's authorized capital structure and allocate the balance to Investments and Other. Effective August 1, 2008, the proportion of interest expense assigned to Minnesota Power decreased to reflect the authorized capital structure inherent in interim rates that commenced on that date. Interest expense was also higher in 2009 as 2008 included a $0.6 million reversal of interest expense previously accrued due to the closing of a tax year.

Other income (expense) decreased $16.0 million from 2008 primarily due to a $6.5 million pre-tax gain realized from the sale of certain available-for-sale securities in the first quarter of 2008, lower earnings on excess cash in 2009 of $1.9 million, and $1.4 million of interest income related to tax benefits recognized in the third quarter of 2008. Losses incurred on emerging technology investments totaled $4.6 million in 2009, and were $3.9 million higher than similar losses recorded in 2008.

2009 Compared to 2008 (Continued)

Income Taxes – Consolidated

For the year ended December 31, 2009, the effective tax rate was 33.7 percent (34.3 percent for the year ended December 31, 2008). The effective tax rate in each period deviated from the statutory rate (approximately 41 percent for 2009) due to deductions for Medicare health subsidies, AFUDC-Equity, investment tax credits, wind production tax credits, and depletion. In addition, the effective rate for 2009 was impacted by lower pre-tax income. In 2008, non-recurring tax benefits due to the closing of a tax year and the completion of an IRS review totaled $4.6 million.

2008 Compared to 2007

Regulated Operations

Regulated Operations contributed income of $67.9 million in 2008 ($62.4 million in 2007). The increase in earnings is primarily the result of higher rates and higher income from our investment in ATC. Higher rates resulted from a March 1, 2008, increase in FERC-approved wholesale rates, an August 1, 2008, MPUC-approved interim rate increase (subject to refund) for retail customers in Minnesota, and MPUC-approved current cost recovery on our environmental retrofit projects. These rate increases were partially offset by the expiration of sales contracts to Other Power Suppliers, and higher operations and maintenance expense, depreciation expense, and interest expense

Operating revenue decreased $11.6 million, or 2 percent, from 2007 primarily due to decreased fuel and purchased power recoveries and the expiration of sales contracts to Other Power Suppliers. These decreases were partially offset by higher rates and kilowatt-hour sales to retail and municipal customers.

Fuel and purchased power recoveries decreased due to a $42.0 million reduction in fuel and purchased power expense. (See Fuel and Purchased Power Expense discussion below.)

Revenue from sales to Other Power Suppliers decreased $21.1 million from 2007 due to the expiration of sales contracts.

Higher rates resulted from the August 1, 2008, interim rate increase for retail customers in Minnesota of approximately $13 million, current cost recovery on our environmental retrofit projects of approximately $21 million, and the March 1, 2008, increase in FERC-approved wholesale rates of approximately $6 million.

Kilowatt-hour sales to our retail and municipal customers increased 2 percent from 2007 primarily due to a 2 percent increase in industrial load. The increase in industrial sales was primarily due to an idled production line and production delays at one of our taconite customers in 2007. Total regulated utility kilowatt-hour sales were down 2 percent as the expiration of sales contracts to Other Power Suppliers more than offset the increased retail and municipal sales.

Kilowatt-hours Sold	**2008**	**2007**	**Quantity Variance**	**% Variance**
Millions				
Regulated Utility				
Retail and Municipals				
Residential	1,172	1,141	31	2.7%
Commercial	1,454	1,457	(3)	(0.2)%
Industrial	7,192	7,054	138	2.0%
Municipals	1,002	1,008	(6)	(0.6)%
Total Retail and Municipals	10,820	10,660	160	1.5%
Other Power Suppliers	1,800	2,157	(357)	(16.6)%
Total Regulated Utility Kilowatt-hours Sold	12,620	12,817	(197)	(1.5)%

Revenue from electric sales to taconite customers accounted for 26 percent of consolidated operating revenue in 2008 (24 percent in 2007). Revenue from electric sales to paper and pulp mills accounted for 9 percent of consolidated operating revenue in 2008 (9 percent in 2007). Revenue from electric sales to pipelines and other industrials accounted for 7 percent of consolidated operating revenue in 2008 (7 percent in 2007).

Operating expenses decreased $25.1 million, or 4 percent, from 2007.

Fuel and Purchased Power Expense decreased $42.0 million, or 12 percent, from 2007 primarily due to a decrease in purchased power expense, as a result of higher electricity production at the Company's generation facilities. Megawatt-hour generation at our facilities and Square Butte increased 9 percent over 2007.

2008 Compared to 2007 (Continued)
Regulated Operations (Continued)

Operating and Maintenance Expense increased $10.0 million, or 4 percent, over 2007 primarily due to $3.3 million in increased natural gas purchases at SWL&P, reflecting a colder 2008, $2.5 million higher salaries and wages, $1.8 million in increased transmission costs, and $1.5 million in conservation improvement costs.

Depreciation Expense increased $6.9 million, or 16 percent, from 2007 reflecting higher property, plant, and equipment balances placed in service and higher annual depreciation rates for distribution and transmission effective January 1, 2008.

Interest expense increased $3.0 million, or 14 percent, from 2007 primarily due to higher long-term debt balances from increased construction activity.

Equity earnings increased $2.7 million, or 21 percent, from 2007 reflecting higher earnings from our investment in ATC. (See Note 6. Investment in ATC.)

Investments and Other

Investments and Other reflected net income of $14.6 million in 2008 ($25.2 million in 2007). The decrease in 2008 is primarily due to lower net income at ALLETE Properties, which continues to experience difficult real estate market conditions in Florida. This decrease was partially offset by the sale of certain available-for-sale securities in the first quarter of 2008, and tax benefits and related interest recognized in the third quarter of 2008.

Operating revenue decreased $29.1 million, or 25 percent, from 2007 primarily due to a decrease in sales revenue at ALLETE Properties in 2008. ALLETE Properties sold 219 acres of property in 2008 compared to 483 acres in 2007. In addition, 580,059 of non-residential square footage and 736 residential units were sold in 2007 compared to no non-residential or residential sales in 2008. Operating revenue in 2008 included a pre-tax gain of $4.5 million for the sale of our retail shopping center in Winter Haven, Florida in May 2008.

ALLETE Properties	**2008**		**2007**	
Revenue and Sales Activity	**Quantity**	**Amount**	**Quantity**	**Amount**
Dollars in Millions				
Revenue from Land Sales				
Non-residential Sq. Ft.	–	–	580,059	$17.0
Residential Units	–	–	736	14.8
Acres *(a)*	219	$6.3	483	10.6
Contract Sales Price *(b)*		6.3		42.4
Revenue Recognized from Previously Deferred Sales		3.7		3.1
Deferred Revenue		–		(1.2)
Revenue from Land Sales		10.0		44.3
Other Revenue *(c)*		8.3		6.2
Total ALLETE Properties Revenue		$18.3		$50.5

(a) Acreage amounts are shown on a gross basis, including wetlands and non-controlling interest.
(b) Reflected total contract sales price on closed land transactions. Land sales are recorded using a percentage-of-completion method. (See Note 1. Operations and Significant Accounting Policies.)
(c) Included a $4.5 million pre-tax gain from the sale of a shopping center in Winter Haven, Florida in 2008.

Operating expenses decreased $5.7 million, or 6 percent, from 2007, primarily due to a $4.8 million decrease in the cost of real estate sold in Florida.

Interest expense increased $0.7 million in 2008 primarily due to higher interest expense at ALLETE, a portion of which is assigned to Minnesota Power and the remainder is reflected in the Investments and Other segment.

Other income increased $0.6 million, or 5 percent, from 2007 primarily due to a $6.5 million pre-tax gain realized from the sale of certain available-for-sale securities in the first quarter of 2008 and interest income related to tax benefits recognized in the third quarter of 2008. The gain was triggered when securities were sold to reallocate investments to meet defined investment allocations based upon an approved investment strategy. The increase was partially offset by fewer gains from land sales in Minnesota during 2008, and lower earnings on cash and short-term investments reflecting lower average cash balances, and the 2007 release from a loan guarantee for Northwest Airlines, Inc. of $1.0 million.

2008 Compared to 2007 (Continued)

Income Taxes – Consolidated

For the year ended December 31, 2008, the effective tax rate on income from continuing operations before non-controlling interest was 34.3 percent (34.8 percent for the year ended December 31, 2007). The effective tax rate in both years deviated from the statutory rate (approximately 40 percent) primarily due to the recognition of various tax benefits as well as deductions for Medicare health subsidies, AFUDC-Equity, investment tax credits, and wind production tax credits. In 2007, a tax benefit was realized as a result of a state income tax audit settlement ($1.6 million). In 2008, non-recurring tax benefits due to the closing of a tax year and the completion of an IRS review totaled $4.6 million.

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.

Regulatory Accounting. Our regulated utility operations are subject to the guidance on accounting for the effects of certain types of regulation. This guidance 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. Regulatory Matters.)

Valuation of Investments. Our long-term investment portfolio includes the real estate assets of ALLETE Properties, debt and equity securities consisting primarily of securities held to fund employee benefits, auction rate securities, and investments in emerging technology funds. 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. Our consideration of possible impairment for our real estate assets requires us to make judgments with respect to the current fair values of this real estate. The poor market conditions for real estate in Florida at this time require us to make certain assumptions in the determination of fair values due to the lack of current comparable sales activity. Any impairment would reduce the carrying value of our investments and be recognized as a loss. In 2009, we recorded an impairment loss on these investments of $1.1 million pretax (none in 2008; $0.5 million pretax in 2007), primarily due to our emerging technology funds. (See Note 7. Investments.)

Pension and Postretirement Health and Life Actuarial Assumptions. We account for our pension and postretirement benefit obligations in accordance with the accounting standards for defined benefit pension and other postretirement plans. 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 the expected long-term return on plan assets, we take into account the actual long-term historical performance of our plan assets, the actual long-term historical performance for the type of securities we are invested in, and apply the historical performance utilizing the target allocation of our plan assets to forecast an expected long-term return. Our expected rate of return is then selected after considering the results of each of those factors, in addition to considering the impact of current economic conditions, if applicable, on long-term historical returns. Our pension asset allocation at December 31, 2009, was approximately 53 percent equity, 28 percent debt, 14 percent private equity, and 5 percent real estate. Our postretirement health and life asset allocation at December 31, 2009, was approximately 54 percent equity, 38 percent debt, and 8 percent private equity. Equity securities consist of a mix of market capitalization sizes with domestic and international securities. We currently use an expected long-term rate of return of 8.5 percent in our actuarial determination of our pension and other postretirement expense. We review our expected long-term rate of return assumption annually 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 $1.3 million, pre-tax.

The discount rate is computed using the Citigroup Pension Discount Curve adjusted for ALLETE's projected cash flows to match our plan characteristics. The Citigroup Pension Discount Curve is determined using high-quality long-term corporate bond rates at the valuation date. We believe the adjusted discount curve used in this comparison does not materially differ in duration and cash flows for our pension obligation. (See Note 16. Pension and Other Postretirement Benefit Plans.)

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 sales/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 in accordance with the guidance for accounting for uncertainty in income taxes. We must also assess our ability to generate capital gains to realize tax benefits associated with capital losses. Capital losses may be deducted only to the extent of capital gains realized during the year of the loss or during the two prior or five succeeding years for federal purposes. We have recorded a valuation allowance against our deferred tax assets associated with realized capital losses to the extent it has been determined that it is more-likely-than-not that some portion or all of the deferred tax asset will not be realized.

Outlook

ALLETE is an energy company committed to earning a financial return that rewards our shareholders, allows for reinvestment in our businesses and sustains growth. To accomplish this, we intend to take the actions necessary to earn our allowed rate of return in our regulated businesses, while we pursue growth initiatives in renewable energy, transmission and other energy-centric businesses.

We believe that over the long term, wind energy will play an increasingly important role in our nation's energy mix. We intend to pursue the establishment of a renewable energy business focused initially on developing wind assets in North Dakota and the upper Midwest. We intend to develop wind resources which will be used to meet renewable supply requirements of our regulated businesses as well as wind resources that will be marketed to others. We will capitalize on our existing presence in North Dakota through BNI Coal, our recently acquired DC transmission line and our Bison 1 wind project. Through BNI Coal we have a long-term business presence and established landowner relationships in North Dakota. See page 38 for more discussion on the DC line acquisition and our Bison I project. For projects to be marketed to others, we intend to secure long-term power purchase agreements prior to construction of the wind generation facilities. Establishment of the business is subject to appropriate MPUC approvals.

We also plan to make investments in upper Midwest transmission opportunities that strengthen or enhance the regional transmission grid, or take advantage of our geographical location between sources of renewable energy and end users. In addition, we plan to make additional investments to fund our pro rata share of ATC's future capital expansion program. Minnesota Power is also participating with other regional utilities in making regional transmission investments as a member of the CapX2020 initiative. The CapX2020 initiative is discussed in more detail on page 40.

We are also exploring investing in other energy-centric businesses that will complement an entrance into the renewable energy business, or leverage demand trends related to transmission, environmental control or energy efficiency.

ALLETE intends to sell its Florida land assets at reasonable prices, over time or in bulk transactions, and reinvest the proceeds in its growth initiatives. ALLETE Properties does not intend to acquire additional real estate.

Regulated Operations. Minnesota Power's long-term strategy is to maintain its competitively priced production of energy, reduce customer concentration exposure, comply with environmental permit conditions and renewable requirements, and earn our allowed rate of return. Keeping the production of energy competitive enables Minnesota Power to effectively compete in the wholesale power markets, and minimizes retail rate increases to help maintain the viability of its customers. As part of maintaining cost competitiveness, Minnesota Power intends to reduce its exposure to possible future carbon and GHG legislation by reshaping its generation portfolio, over time, to reduce its reliance on coal. Minnesota Power intends to reduce its customer concentration risk to reduce exposure to cyclical industries; this may include restructuring commercial contracts, additional sales to other regional power suppliers, and reshaping our power supply to be more flexible to swings in customer demand. We will monitor and review environmental proposals and may challenge those that add considerable cost with limited environmental benefit. Current economic conditions require a very careful balancing of the benefit of further environmental controls with the impacts of the costs of those controls on our customers as well as on the company, and its competitive position. We will pursue current cost recovery riders to recover environmental and renewable investments, and will work with our legislators and regulators to earn a fair return.

Rates. Entities within our Regulated Operations segment file for periodic rate revisions with the MPUC, the FERC or the PSCW.

Outlook (Continued)
Rates (Continued)

2008 Rate Case. In May 2008, Minnesota Power filed a retail rate increase request with the MPUC seeking additional revenues of approximately $40 million annually; the request also sought an 11.15 percent return on equity, and a capital structure consisting of 54.8 percent equity and 45.2 percent debt. As a result of a May 2009 Order and an August 2009 Reconsideration Order, the MPUC granted Minnesota Power a revenue increase of approximately $20 million, including a return on equity of 10.74 percent and a capital structure consisting of 54.79 percent equity and 45.21 percent debt. Rates went into effect on November 1, 2009.

Interim rates, subject to refund, were in effect from August 1, 2008 through October 31, 2009. During 2009, Minnesota Power recorded a $21.7 million liability for refunds of interim rates, including interest, required to be made as a result of the May 2009 Order and the August 2009 Reconsideration Order. In 2009, $21.4 million was refunded, with a remaining $0.3 million balance to be refunded in early 2010; $7.6 million of the refunds required to be made were related to interim rates charged in 2008.

With the May 2009 Order, the MPUC also approved the stipulation and settlement agreement that affirmed the Company's continued recovery of fuel and purchased power costs under the former base cost of fuel that was in effect prior to the retail rate filing. The transition to the former base cost of fuel began with the implementation of final rates on November 1, 2009. Any revenue impact associated with this transition will be identified in a future filing related to the Company's fuel clause operation.

2010 Rate Case. Minnesota Power previously stated its intention to file for additional revenues to recover the costs of significant investments to ensure current and future system reliability, enhance environmental performance and bring new renewable energy to northeastern Minnesota. As a result, Minnesota Power filed a retail rate increase request with the MPUC on November 2, 2009, seeking a return on equity of 11.50 percent, a capital structure consisting of 54.29 percent equity and 45.71 percent debt, and on an annualized basis, an $81.0 million net increase in electric retail revenue.

Minnesota law allows the collection of interim rates while the MPUC processes the rate filing. On December 30, 2009, the MPUC issued an Order (the Order) authorizing $48.5 million of Minnesota Power's November 2, 2009, interim rate increase request of $73.0 million. The MPUC cited exigent circumstances in reducing Minnesota Power's interim rate request. Because the scope and depth of this reduction in interim rates was unprecedented, and because Minnesota law does not allow Minnesota Power to formally challenge the MPUC's action until a final decision in the case is rendered, on January 6, 2010, Minnesota Power sent a letter to the MPUC expressing its concerns about the Order and requested that the MPUC reconsider its decision on its own motion. Minnesota Power described its belief the MPUC's decision violates the law by prejudging the merits of the rate request prior to an evidentiary hearing and results in the confiscation of utility property. Further, the Company is concerned that the decision will have negative consequences on the environmental policy directions of the State of Minnesota by denying recovery for statutory mandates during the pendency of the rate proceeding. The MPUC has not acted in response to Minnesota Power's letter.

The rate case process requires public hearings and an evidentiary hearing before an administrative law judge, both of which are scheduled for the second quarter of 2010. A final decision on the rate request is expected in the fourth quarter. We cannot predict the final level of rates that may be approved by the MPUC, and we cannot predict whether a legal challenge to the MPUC's interim rate decision will be forthcoming or successful.

FERC-Approved Wholesale Rates. Minnesota Power's non-affiliated municipal customers consist of 16 municipalities in Minnesota and 1 private utility in Wisconsin. SWL&P, a wholly-owned subsidiary of ALLETE, is also a customer of Minnesota Power. In 2008, Minnesota Power entered into new contracts with these customers which transitioned customers to formula-based rates, allowing rates to be adjusted annually based on changes in cost. In February 2009, the FERC approved our municipal contracts which expire December 31, 2013. Under the formula-based rates provision, wholesale rates are set at the beginning of the year based on expected costs and provide for a true-up calculation for actual costs. Wholesale rate increases totaling approximately $6 million and $10 million annually were implemented on February 1, 2009 and January 1, 2010, respectively, with approximately $6 million of additional revenues under the true-up provision accrued in 2009, which will be billed in 2010.

2009 Wisconsin Rate Increase. SWL&P's current retail rates are based on a December 2008 PSCW retail rate order that became effective January 1, 2009, and allows for an 11.1 percent return on equity. The new rates reflected a 3.5 percent average increase in retail utility rates for SWL&P customers (a 13.4 percent increase in water rates, a 4.7 percent increase in electric rates, and a 0.6 percent decrease in natural gas rates). On an annualized basis, the rate increase will generate approximately $3 million in additional revenue.

Industrial Customers. Electric power is one of several key inputs in the taconite mining, paper production, and pipeline industries. In 2009, approximately 37 percent (57 percent in 2008), of our Regulated Utility kilowatt-hour sales were made to our industrial customers, which includes the taconite, paper and pulp, and pipeline industries.

Beginning in the fall of 2008, worldwide steel makers began to dramatically cut steel production in response to reduced demand driven largely by the global credit concerns. United States raw steel production ran at approximately 50 percent of capacity in 2009, reflecting poor demand in automobiles, durable goods, and structural and other steel products.

Outlook (Continued)
Industrial Customers (Continued)

In late 2008, Minnesota taconite producers began to feel the impacts of decreased steel demand, and reduced taconite production levels occurred in 2009. Annual taconite production in Minnesota was approximately 18 million tons in 2009 (40 million tons in 2008 and 39 million tons in 2007). Consequently, 2009 kilowatt-hour sales to our taconite customers were lower by approximately 54 percent from 2008 levels, and we sold available power to Other Power Suppliers to partially mitigate the earnings impact of these lower taconite sales.

Raw steel production in the United States is projected to improve in 2010, and is estimated to run at approximately 60 percent of capacity. As a result, Minnesota Power expects an increase in taconite production in 2010 compared to 2009, although production will still be less than previous years' levels. We will continue to market available power to Other Power Suppliers in an effort to mitigate the earnings impact of these lower industrial sales. Sales to Other Power Suppliers are dependent upon the availability of generation and are sold at market-based prices into the MISO market on a daily basis or through bilateral agreements of various durations. We can make no assurances that our power marketing efforts will fully offset the reduced earnings resulting from lower demand nominations from our industrial customers.

Minnesota Power's paper and pulp customers ran at, or very near, full capacity for the majority of 2009, despite the fact that the industry as a whole experienced the impacts of the global recession in reduced sales of nearly every paper grade. Federal tax credits provided a subsidy for paper producers which allowed them to remain competitive. Minnesota Power's paper and pulp customers benefited from the temporary or permanent idling of competitor plants both in North America and in Europe, as well as continued strength of the Canadian dollar and the Euro which has reduced imports both from Canada and Europe.

Our pipeline customers continued to operate at near capacity levels. As Western Canadian oil sands reserves continue to develop and expand, pipeline operators served by the Company are executing expansion plans to transport 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. We believe we are strategically positioned to serve these expanding pipeline facilities.

Prospective Additional Load. Several companies in northeastern Minnesota continue to progress in development of natural resource based projects that represent long-term growth potential and load diversity for Minnesota Power. These potential projects are in the ferrous and non-ferrous mining and steel industries. These projects include PolyMet Mining Corporation (PolyMet), Mesabi Nugget Delaware, LLC (Mesabi Nugget), and United States Steel Corporation's expansion at its Keewatin Taconite facility. Additionally, Essar Steel Limited Minnesota (Essar), continues to work with local agencies on infrastructure development for its taconite mine, direct reduction iron-making facility, and steel mill within the Nashwauk, MN municipal utility service boundary.

PolyMet. Minnesota Power has executed a long-term contract with PolyMet, a new industrial customer planning to start a copper-nickel and precious metal (non-ferrous) mining operation in northeastern Minnesota. PolyMet is currently in the environmental permitting process, and the public comment period on its Draft Environmental Impact Statement (DEIS) closed on February 3, 2010. Assuming that the DEIS is judged to be complete, the Minnesota Department of Natural Resources and the U.S. Army Corps of Engineers may issue a Statement of Adequacy by mid-year 2010, with issuance of environmental permitting to follow. Should these events occur, operations could begin in late 2011 and Minnesota Power will begin to supply approximately 70 MW of power through a contract lasting at least through 2018.

Mesabi Nugget. The construction of the initial Mesabi Nugget facility is essentially complete and the first production occurred in January 2010. Steel Dynamics, Inc., the principal owner of Mesabi Nugget, has indicated that commissioning and production ramp-up activities will occur throughout 2010, with full production levels expected to be reached during the year. Mesabi Nugget is currently pursuing permits for taconite mining activities on lands formerly mined by Erie Mining Company and LTV Steel Mining Company near Hoyt Lakes, MN. Assuming receipt of environmental permits to mine by the end of 2010, mining activities could begin in 2011, which would allow Mesabi Nugget to self-supply its own taconite concentrates and would result in increased electrical loads. Minnesota Power has a 15 MW long-term power supply contract with Mesabi Nugget lasting at least through 2017.

Keewatin Taconite. In February 2008, United States Steel Corporation announced its intent to restart a pellet line at its Keewatin Taconite processing facility (Keetac). This pellet line, which has been idled since 1980, could be restarted and updated as part of a $300 million investment, bringing about 3.6 million tons of additional pellet making capability to northeastern Minnesota. The public comment period for a Draft Environmental Impact Statement for the Keetac facility ended on January 26, 2010.

Outlook (Continued)

Renewable Energy*.* In February 2007, Minnesota enacted a law requiring 25 percent of Minnesota Power's total retail energy sales in Minnesota come from renewable energy sources by 2025. The law also requires Minnesota Power to meet interim milestones of 12 percent by 2012, 17 percent by 2016, and 20 percent by 2020. Minnesota Power has identified a plan to meet the renewable goals set by Minnesota and has included this in the most recent filing of the IRP with the MPUC. The law 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 the enactment of this law and this activity continues.

We are executing our renewable energy strategy. In 2006 and 2007, we entered into two long-term power purchase agreements for a total of 98 MWs of wind energy constructed in North Dakota (Oliver Wind I and II). Taconite Ridge Wind I, our $50 million, 25-MW wind facility located in northeastern Minnesota became operational in 2008.

North Dakota Wind Project. On December 31, 2009, we purchased an existing 250 kV DC transmission line from Square Butte for $69.7 million. The 465-mile transmission line runs from Center, North Dakota to Duluth, Minnesota. We expect to use this line to transport increasing amounts of wind energy from North Dakota while gradually phasing out coal-based electricity currently being delivered to our system over this transmission line from Square Butte's lignite coal-fired generating unit. Acquisition of this transmission line was approved by the MPUC and the FERC. In addition, the FERC issued an order on November 24, 2009, authorizing acquisition of the transmission facilities and conditionally accepting, upon compliance and other filings, the proposed tariff revisions, interconnection agreement and other related agreements.

On July 7, 2009, the MPUC approved our petition seeking current cost recovery of investments and expenditures related to Bison I and associated transmission upgrades. We anticipate filing a petition with the MPUC in the first quarter of 2010 to establish customer billing rates for the approved cost recovery. Bison I is the first portion of several hundred MWs of our North Dakota Wind Project, which upon completion will fulfill the 2025 renewable energy supply requirement for our retail load. Bison I, located near Center, North Dakota, will be comprised of 33 wind turbines with a total nameplate capacity of 75.9 MWs and will be phased into service in late 2010 and 2011.

On September 29, 2009, the NDPSC authorized site construction for Bison I. On October 2, 2009, Minnesota Power filed a route permit application with the NDPSC for a 22 mile, 230 kV Bison I transmission line that will connect Bison I to the DC transmission line at the Square Butte Substation in Center, North Dakota. An order is expected in the first quarter of 2010.

Manitoba Hydro. Minnesota Power has a long-term power purchase agreement with Manitoba Hydro expiring in 2015. (See Item 1. Business – Power Supply.) In addition, Minnesota Power is currently negotiating definitive agreements on two additional purchased power transactions with Manitoba Hydro: an initial purchase of surplus energy over the next ten years, followed by an anticipated long-term purchase of a 250-MW capacity and energy agreement beginning in approximately 2020. 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. Transmission studies and definitive agreement negotiations are ongoing. Both purchases require MPUC approval.

Hibbard Renewable Energy Center. On September 30, 2009, we purchased boilers and associated systems previously owned by the City of Duluth. This facility was initially built in the late 1930s as a coal burning power plant, and retrofitted to burn wood-based biomass fuel as well as coal. Over time, Minnesota Power intends to invest approximately $20 million to upgrade the boilers and associated systems to increase biomass energy generation at the plant. Hibbard's current generating capacity is approximately 50 MWs. This purchase will help us achieve Minnesota's mandate of providing 25 percent of our retail energy from renewable resources by 2025.

Integrated Resource Plan*.* On October 5, 2009, Minnesota Power filed with the MPUC its 2010 Integrated Resource Plan, a comprehensive estimate of future capacity needs within Minnesota Power's service territory. Minnesota Power does not anticipate the need for new base load generation within the Minnesota Power service territory over the next 15 years, and plans to meet estimated future customer demand while achieving:

- Increased system flexibility to adapt to volatile business cycles and varied future industrial load scenarios;
- Reductions in the emission of GHGs (primarily carbon dioxide); and
- Compliance with mandated renewable energy standards.

To achieve these objectives over the coming years, we plan to reshape our generation portfolio by adding 300 to 500 megawatts of renewable energy to our generation mix, and exploring options to incorporate peaking or intermediate resources. Our 76 MW Bison I Wind Project in North Dakota is expected to be in service in late 2010 and 2011.

We project average annual long-term growth of approximately one percent in electric usage over the next 15 years. We will also focus on conservation and demand side management to meet the energy savings goals established in Minnesota legislation.

Outlook (Continued)

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

- Expand our renewable energy supply.
- Improve the efficiency of our coal-based generation facilities, as well as other process efficiencies.
- Provide energy conservation initiatives with our customers and demand side efforts.
- Support research of technologies to reduce carbon emissions from generation facilities and support carbon sequestration efforts.
- Achieve overall carbon emission reductions.

The scientific community generally accepts that emissions of GHGs are linked to global climate change. Climate change creates physical and financial risk. These physical risks could include, but are not limited to, increased or decreased precipitation and water levels in lakes and rivers; increased temperatures; and the intensity and frequency of extreme weather events. These all have the potential to affect the Company's business and operations.

Federal Legislation. We believe that future regulations may restrict the emissions of GHGs from our generation facilities. Several proposals at the Federal level to "cap" the amount of GHG emissions have been made. On June 26, 2009, the U.S. House of Representatives passed H.R. 2454, the American Clean Energy and Security Act of 2009. H.R. 2454 is a comprehensive energy bill that also includes a cap-and-trade program. H.R. 2454 allocates a significant number of emission allowances to the electric utility sector to mitigate cost impacts on consumers. Based on the emission allowance allocations, we expect we would have to purchase additional allowances. We're unable to predict at this time the value of these allowances.

On September 30, 2009, the Senate introduced S. 1733, the Senate version of H.R. 2454. This legislation proposes a more stringent, near-term greenhouse emissions reduction target in 2020 of 20 percent below 2005 levels, as compared to the 17 percent reduction proposed by H.R. 2454.

Congress may consider proposals other than cap-and-trade programs to address GHG emissions. We are unable to predict the outcome of H.R. 2454, S. 1733, or other efforts that Congress may make with respect to GHG emissions, and the impact that any GHG emission regulations may have on the Company. 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.

Greenhouse Gas Reduction. In 2007, Minnesota passed legislation establishing non-binding targets for carbon dioxide reductions. This legislation establishes a goal of reducing statewide GHG emissions across all sectors 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.

Midwestern Greenhouse Gas Reduction Accord. Minnesota is also participating in the Midwestern Greenhouse Gas Reduction Accord (the Accord), a regional effort to develop a multi-state approach to GHG emission reductions. The Accord includes an agreement to develop a multi-sector cap-and-trade system to help meet the targets established by the group.

Greenhouse Gas Emissions Reporting. In May 2008, Minnesota passed legislation that required the MPCA to track emissions and make interim emissions reduction recommendations towards meeting the State's goal of reducing GHG by 80 percent by 2050. GHG emissions from 2008 were reported in 2009.

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.

International Climate Change Initiatives. The United States is not a party to the Kyoto Protocol, which is a protocol to the United Nations Framework Convention on Climate Change (UNFCCC) that requires developed countries to cap GHG emissions at certain levels during the 2008 to 2012 time period. In December 2009, leaders of developed and developing countries met in Copenhagen, Denmark, under the UNFCCC and issued the Copenhagen Accord. The Copenhagen Accord provides a mechanism for countries to make economy-wide GHG emission mitigation commitments for reducing emissions of GHG by 2020 and provide for developed countries to fund GHG emissions mitigation projects in developing countries. President Obama participated in the development of, and endorsed the Copenhagen Accord.

EPA Greenhouse Gas Reporting Rule. On September 22, 2009, the EPA issued the final rule mandating that certain GHG emission sources, including electric generating units, are required to report emission levels. The rule is intended to allow the EPA to collect accurate and timely data on GHG emissions that can be used to form future policy decisions. The rule was effective January 1, 2010, and all GHG emissions must be reported on an annual basis by March 31 of the following year. Currently, we have the equipment and data tools necessary to report our 2010 emissions to comply with this rule.

Outlook (Continued)
Climate Change (Continued)

Title V Greenhouse Gas Tailoring Rule. On October 27, 2009, the EPA issued the proposed Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas Tailoring rule. This proposed regulation addresses the six primary greenhouse gases and new thresholds for when permits will be required for new facilities and existing facilities which undergo major modifications. The rule would require large industrial facilities, including power plants, to obtain construction and operating permits that demonstrate Best Available Control Technologies (BACT) are being used at the facility to minimize GHG emissions. The EPA is expected to propose BACT standards for GHG emissions from stationary sources.

For our existing facilities, the proposed rule does not require amending our existing Title V operating permits to include BACT for GHGs. However, modifying or installing units with GHG emissions that trigger the PSD permitting requirements could require amending operating permits to incorporate BACT to control GHG emissions.

EPA Endangerment Findings. On December 15, 2009, the EPA published its findings that the emissions of six GHG, including CO_2, methane, and nitrous oxide, endanger human health or welfare. This finding may result in regulations that establish motor vehicle GHG emissions standards in 2010. There is also a possibility that the endangerment finding will enable expansion of the EPA regulation under the Clean Air Act to include GHGs emitted from stationary sources. A petition for review of the EPA's endangerment findings was filed by the Coalition for Responsible Regulation, et. al. with the United States District Court Circuit Court of Appeals on December 23, 2009.

Coal Ash Management Facilities. Minnesota Power generates coal ash at all five of its steam electric stations. Two facilities store ash in onsite impoundments (ash ponds) with engineered liners and containment dikes. Another facility stores dry ash in a landfill with an engineered liner and leachate collection system. Two facilities generate a combined wood and coal ash that is either land applied as an approved beneficial use, or trucked to state permitted landfills. Minnesota Power continues to monitor state and federal legislative and regulatory activities that may affect its ash management practices. The EPA is expected to propose new regulations in February 2010 pertaining to the management of coal ash by electric utilities. It is unknown how potential coal ash management rule changes will affect Minnesota Power's facilities. On March 9, 2009, the EPA requested information from Minnesota Power (and other utilities) on its ash storage impoundments at Boswell and Laskin. On June 22, 2009, Minnesota Power received an additional EPA information request pertaining to Boswell. Minnesota Power responded to both these information requests. On August 19, 2009, the Minnesota DNR visited both the Boswell and Laskin ash ponds. The purpose of the inspection was to assess the structural integrity of the ash ponds, as well as review operational and maintenance procedures. There were no significant findings or concerns from the DNR staff during the inspections.

CapX2020*.* Minnesota Power is a participant in the CapX2020 initiative which represents an effort to ensure electric transmission and distribution reliability in Minnesota and the surrounding region for the future. CapX2020, which includes Minnesota's largest transmission owners, consists of electric cooperatives, municipals and investor-owned utilities, and has assessed 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.

Minnesota Power intends to invest in two 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. The MPUC issued the Certificate of Need for the 230 kV line in July 2009. The MPUC decision on the Route Permit application is expected in 2010. Our total investment in these lines is expected to be approximately $100 million. We intend to seek recovery of these costs in a filing with the MPUC in the first quarter of 2010, under a Minnesota Power transmission cost recovery tariff rider authorized by Minnesota legislation. Construction of the lines is targeted to begin in late 2010 and may take up to four years.

Emission Reduction Plans*.* We have made investments in pollution control equipment at our Boswell Unit 3 generating unit that reduces particulates, SO_2, NO_x and mercury emissions to meet future federal and state requirements. This equipment was placed in service in November 2009. During the construction phase, the MPUC authorized a cash return on construction work in progress in lieu of AFUDC, and this amount was collected through a current cost recovery rider. Our 2010 rate case proposes to move this project from a current cost recovery rider to base rates.

The environmental regulatory requirements for Taconite Harbor Unit 3 are pending approval of the Minnesota Regional Haze implementation by the EPA. We are evaluating compliance requirements for this Unit. Environmental retrofits at Laskin and Taconite Harbor Units 1 and 2 have been completed and are in-service.

Boswell NO_X Reduction Plan. In September 2008, we submitted to the MPCA and MPUC a $92 million environmental initiative proposing cost recovery for expenditures relating to NO_X emission reductions from Boswell Units 1, 2, and 4. The Boswell NO_X Reduction Plan is expected to significantly reduce NO_X emissions from these units. In conjunction with the NO_X reduction, we plan to make an efficiency improvement to our existing turbine/generator at Boswell Unit 4 adding approximately 60 MWs of total output. The Boswell 1, 2 and 4, selective non-catalytic reduction NO_X controls are currently in service, while the Boswell 4 low NO_X burners and turbine efficiency projects are anticipated to be in service in late 2010. Our 2010 rate case seeks recovery for this project in base rates.

Outlook (Continued)

Transmission. We have an approved cost recovery rider in-place for certain transmission expenditures, and our current billing factor was approved by the MPUC in June 2009. The billing factor allows us to charge our retail customers on a current basis for the costs of constructing certain transmission facilities plus a return on the capital invested. Our 2010 rate case proposes to move completed transmission projects from the current cost recovery rider to base rates.

Power Sales Agreement. On October 29, 2009, Minnesota Power entered into an agreement to sell Basin 100 MWs of capacity and energy for the next ten years. The transaction is scheduled to begin in May 2010, following the expiration of two wholesale power sales contracts on April 30, 2010. The Basin agreement contains a fixed monthly schedule of capacity charges with an annual escalation provision. The energy charge is based on a fixed monthly schedule and provides for annual escalation based on our cost of fuel. The agreement allows us to recover a pro-rata share of increased costs related to emissions that may occur during the last five years of the contract. (See Item 3. Power Marketing.)

Investment in ATC. At December 31, 2009, our equity investment was $88.4 million, representing an approximate 8 percent ownership interest. 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. ATC rates are based on a 12.2 percent return on common equity dedicated to utility plant. ATC has identified $2.5 billion in future projects needed over the next 10 years to improve the adequacy and reliability of the electric transmission system. This investment is expected to be funded through a combination of internally generated cash, debt, and investor contributions. As additional opportunities arise, we plan to make additional investments in ATC through general capital calls based upon our pro-rata ownership interest in ATC. On January 29, 2010, we invested an additional $1.2 million in ATC. In total, we expect to invest approximately $2 million throughout 2010. (See Note 6. Investment in ATC.)

Investments and Other

BNI Coal. In 2009, BNI Coal sold approximately 4.2 million tons of coal (4.5 million tons in 2008) and anticipates similar sales in 2010.

ALLETE Properties. ALLETE Properties represents our Florida real estate investment. Our current strategy for the assets is to complete and maintain key entitlements and infrastructure improvements without requiring significant additional investment, and sell the portfolio over time or in bulk transactions. ALLETE intends to sell its Florida land assets at reasonable prices when opportunities arise, and reinvest the proceeds in its growth initiatives. ALLETE does not intend to acquire additional Florida real estate.

Our two major development projects are Town Center and Palm Coast Park. Ormond Crossings, a third major project that is currently in the planning stage, received land use approvals in December 2006. However, due to a change in the Florida law that became effective in July 2009, those approvals are being revised. It is anticipated that the City of Ormond Beach, FL will approve a new Development Agreement for Ormond Crossings in the first quarter of 2010. The new agreement will facilitate development of the project as currently planned. Separately, Lake Swamp wetland mitigation bank was permitted on land that was previously part of Ormond Crossings.

Summary of Development Projects Land Available-for-Sale	**Ownership**	**Total Acres** ***(a)***	**Residential Units** ***(b)***	**Non-residential Sq. Ft.** ***(b, c)***
Current Development Projects				
Town Center	80%	854	2,264	2,238,400
Palm Coast Park	100%	3,143	3,154	3,555,000
Total Current Development Projects		3,997	5,418	5,793,400
Proposed Development Project				
Ormond Crossings	100%	2,924	*(d)*	*(d)*
Other				
Lake Swamp Wetland Mitigation Project	100%	3,034	*(e)*	*(e)*
Total of Development Projects		9,955	5,418	5,793,400

(a) Acreage amounts are approximate and shown on a gross basis, including wetlands and non-controlling interest.
(b) Estimated and includes non-controlling 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 that was approved by the City of Ormond Beach is being replaced by a development agreement to facilitate development of Ormond Crossings as currently planned. At build-out, we expect the project to include 2,950 residential units, 4.87 million square feet of various types of non-residential space and public facilities.
(e) Lake Swamp wetland mitigation bank is a regionally significant wetlands mitigation bank that was permitted by the St. Johns River Water Management District in 2008 and by the U.S. Army Corps of Engineers in December 2009. Wetland mitigation credits will be used at Ormond Crossings and will also be available for sale to developers of other projects that are located in the bank's service area.

Outlook (Continued)
Investments and Other (Continued)

Other Land Available-for-Sale *(a)*	Total	Mixed Use	Residential	Non-residential	Agricultural
Acres *(b)*					
Other Land	1,277	394	113	267	503

(a) Other land includes land located in Palm Coast, Lehigh, and Cape Coral, Florida.
(b) Acreage amounts are approximate and shown on a gross basis, including wetlands and non-controlling interest.

Long-term finance receivables as of December 31, 2009, were $12.9 million, which included $7.8 million due from an entity which filed for voluntary Chapter 11 bankruptcy protection in June 2009. The estimated fair value of the collateral relating to these receivables was greater than the $7.8 million amount due at December 31, 2009, and no impairment was recorded on these receivables; however, $0.3 million of impairments was recorded on other receivables.

If a purchaser defaults on a sales contract, the legal remedy is usually 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.

ALLETE intends to sell its Florida land assets at reasonable prices when opportunities arise. However, if weak market conditions continue for an extended period of time, the impact on our future operations would be the continuation of little to no sales while still incurring operating expenses such as community development district assessments and property taxes. This could result in annual net losses for ALLETE Properties similar to 2009.

Income Taxes*.* ALLETE's aggregate federal and multi-state statutory tax rate is approximately 41 percent for 2010. 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, wind production 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 non-controlling 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 2010.

Liquidity and Capital Resources

Liquidity Position. ALLETE is well-positioned to meet the Company's immediate cash flow needs. At December 31, 2009, we have a cash balance of approximately $26 million, $87.8 million of unused lines of credit ($157.0 million net of $69.2 million drawn down as of December 31, 2009), and a debt-to-capital ratio of 43 percent. In the first quarter 2010, we expect to use proceeds from the sale of $80 million First Mortgage Bonds to repay the amount drawn down on the line of credit.

Capital Structure. ALLETE's capital structure for each of the last three years is as follows:

Year Ended December 31	2009	%	2008	%	2007	%
Millions						
Common Equity	$929.5	57	$827.1	57	$742.6	63
Non-Controlling Interest	9.5	–	9.8	1	9.3	1
Long-Term Debt (Including Current Maturities)	701.0	43	598.7	42	422.7	36
Short-Term Debt	1.9	–	6.0	–	–	–
	$1,641.9	100	$1,441.6	100	$1,174.6	100

Liquidity and Capital Resources (Continued)

Cash Flows. Selected information from ALLETE's Consolidated Statement of Cash Flows is as follows:

Year Ended December 31	2009	2008	2007
Millions			
Cash and Cash Equivalents at Beginning of Period	$102.0	$23.3	$44.8
Cash Flows from (used for)			
Operating Activities	137.4	153.6	124.2
Investing Activities	(320.0)	(276.1)	(154.1)
Financing Activities	106.3	201.2	8.4
Change in Cash and Cash Equivalents	(76.3)	78.7	(21.5)
Cash and Cash Equivalents at End of Period	$25.7	$102.0	$23.3

Operating Activities. Cash from operating activities was $137.4 million for 2009 ($153.6 million for 2008; $124.2 million for 2007). Cash from operating activities was lower in 2009 primarily due to lower net income, an increase in accounts receivable, and higher deferred regulatory assets, partially offset by higher deferred tax and depreciation expense. Accounts receivable increased due a receivable for 2009 income tax refunds primarily resulting from substantial income tax deductions under the bonus depreciation provision of the American Recovery and Reinvestment Act of 2009 (the Act). Deferred regulatory assets increased due to the collection of certain current cost recovery rider revenue attributable to 2009 being deferred into a later year. Deferred tax expense increased also due to the bonus depreciation provisions of the Act, and depreciation expense increased in conjunction with the increase in property, plant and equipment.

Cash from operating activities was higher in 2008 than 2007 due to an increase in deferred income tax expense and decreased working capital requirements, which was partially offset by lower net income and higher contributions to defined benefit pension and postretirement health plans (included in Other Liabilities on the Consolidated Statement of Cash Flows). Working capital requirements decreased mainly due to lower uncollected purchased power costs (included in Prepayments and Other on the Consolidated Statement of Cash Flows). Deferred income tax expense increased due to the Economic Stimulus Act of 2008, and contributions to defined benefit pension and postretirement health plans increased $15.6 million during 2008.

Investing Activities. Cash used for investing activities was $320.0 million for 2009 ($276.1 million for 2008; $154.1 million for 2007). Cash used for investing activities was higher than 2008 reflecting increased capital additions to property, plant, and equipment. Capital additions to property, plant, and equipment increased due to the purchase of an existing 250 kV DC transmission line for $69.7 million offset by a decrease in other capital additions because of the completion of some major capital projects in 2008 and 2009. In addition, 2008 included higher net sales of short-term investments and proceeds from the sale of assets (retail shopping center) in Winter Haven, Florida.

Cash used for investing activities was higher in 2008 than 2007 reflecting increased capital additions to property, plant, and equipment which were partially offset by the proceeds from the sale of assets (retail shopping center) in Winter Haven, Florida. Capital additions to property, plant, and equipment increased due to construction activity for environmental retrofit projects, AREA Plan projects, Taconite Ridge, and additional investments in ATC.

Financing Activities. Cash from financing activities was $106.3 million for 2009 ($201.2 million for 2008; $8.4 million for 2007). Cash from financing activities was lower in 2009 than 2008 due to less debt and common stock issuance. During 2009, $111.4 million of debt was issued, while in 2008 $198.7 million of debt was issued. During 2009, proceeds from common stock issuances totaled $65.2 million, while in 2008, proceeds from common stock issuances totaled $71.1 million. Lower debt and common stock issuance in 2009 was a result of issuing capital in 2008 ahead of the need for this capital.

Cash from financing activities was higher in 2008 than 2007 primarily from the issuance of debt for $198.7 million. In addition, common stock was issued for net proceeds of $71.1 million. Financing activities increased to support our capital expenditure program.

Working Capital. Additional working capital, if and when needed, generally is provided by consolidated bank lines of credit or the sale of securities or commercial paper. We have available consolidated bank lines of credit aggregating $87.8 million, the majority of which expire in January 2012. In addition, we have 0.4 million original issue shares of our common stock available for issuance through Invest Direct, our direct stock purchase and dividend reinvestment plan, and 3.3 million original issue shares of common stock available for issuance through a Distribution Agreement with KCCI, Inc. The amount and timing of future sales of our securities will depend upon market conditions and our specific needs.

Securities. In January 2009, we issued $42.0 million in principal amount of unregistered First Mortgage Bonds (Bonds) in the private placement market. The Bonds mature January 15, 2019, and carry a coupon rate of 8.17 percent. We have the option to prepay all or a portion of the Bonds at our discretion, subject to a make-whole provision. The Bonds are subject to additional terms and conditions which are customary for this type of transaction. We are using the proceeds from the sale of the Bonds to fund utility capital expenditures and for general corporate purposes. The Bonds were sold in reliance on exemption from registration under Section 4(2) of the Securities Act of 1933, as amended, to institutional accredited investors.

In December 2009, we agreed to sell $80.0 million in principal amount of First Mortgage Bonds (Bonds) in the private placement market in three series as follows:

Issue Date (on or about)	Maturity	Principal Amount	Coupon
February 17, 2010	April 15, 2021	$15 Million	4.85%
February 17, 2010	April 15, 2025	$30 Million	5.10%
February 17, 2010	April 15, 2040	$35 Million	6.00%

We expect to use the proceeds from the February 2010 sale of Bonds to pay down the syndicated revolving credit facility, to fund utility capital investments or for general corporate purposes.

We entered into a Distribution Agreement with KCCI, Inc., originating in February 2008 and subsequently amended in February 2009, with respect to the issuance and sale of up to an aggregate of 6.6 million shares of our common stock, without par value. The shares may be offered for sale, from time to time, in accordance with the terms of the agreement pursuant to Registration Statement No. 333-147965. During 2009, 1.7 million shares of common stock were issued under this agreement resulting in net proceeds of $51.9 million. In 2008, 1.6 million shares were issued for net proceeds of $60.8 million.

In March 2009, we contributed 463,000 shares of ALLETE common stock, with an aggregate value of $12.0 million, to our pension plan. On May 19, 2009, we registered the 463,000 shares of ALLETE common stock with the SEC pursuant to Registration Statement No. 333-147965.

In 2009, we issued 0.4 million shares of common stock through Invest Direct, Employee Stock Purchase Plan and Retirement Savings and Stock Ownership Plan resulting in net proceeds of $13.3 million. These shares of common stock were registered under the following Registration Statement Nos. 333-150681, 333-105225, and 333-124455, respectively.

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 ratio of its Funded Debt to Total Capital (as the amounts are calculated in accordance with the respective long-term debt arrangements) of less than or equal to 0.65 to 1.00 measured quarterly. As of December 31, 2009, our ratio was approximately 0.41 to 1.00. Failure to meet this covenant would give rise to an event of default if not cured 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, 2009, ALLETE was in compliance with its financial covenants.

Off-Balance Sheet Arrangements. Off-balance sheet arrangements are discussed in Note 11. Commitments, Guarantees and Contingencies.

Liquidity and Capital Resources (Continued)

Contractual Obligations and Commercial Commitments. Minnesota Power has contractual obligations and other commitments that will need to be funded in the future, in addition to its capital expenditure programs. The following is a summarized table of contractual obligations and other commercial commitments at December 31, 2009.

	Payments Due by Period				
Contractual Obligations As of December 31, 2009	**Total**	**Less than 1 Year**	**1 to 3 Years**	**4 to 5 Years**	**After 5 Years**
Millions					
Long-Term Debt *(a)*	$1,172.1	$41.5	$196.6	$98.2	$835.8
Pension and Other Postretirement Benefit Plans	194.1	36.6	105.4	52.1	–
Operating Lease Obligations	89.1	8.8	26.4	15.8	38.1
Uncertain Tax Positions *(b)*	–	–	–	–	–
Unconditional Purchase Obligations	394.0	114.1	102.7	30.4	146.8
	$1,849.3	$201.0	$431.1	$196.5	$1,020.7

(a) Includes interest and assumes variable interest rates in effect at December 31, 2009, remains constant through remaining term.
(b) Excludes $9.5 million of noncurrent unrecognized tax benefits due to uncertainty regarding the timing of future cash payments related to the guidance in accounting for uncertain tax positions.

Long-Term Debt. 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 above assumes the interest rate in effect at December 31, 2009, remains constant through the remaining term. (See Note 10. Short-Term and Long-Term Debt.)

Pension and Other Postretirement Benefit Plans. The funded status of the defined pension and other postretirement benefit obligations refers to the difference between plan assets and estimated obligations under the plans. The funded status may change over time due to several factors, including contribution levels, assumed discount rates and actual and assumed rates of return on plan assets.

Management considers various factors when making funding decisions such as regulatory requirements, actuarially determined minimum contribution requirements, and contributions required to avoid benefit restrictions for the pension plans. Estimated defined benefit pension contributions for years 2010 through 2014 are expected to be up to $25 million per year, and are based on estimates and assumptions that are subject to change. Funding for the other postretirement benefit plans is impacted by utility regulatory requirements. Estimated postretirement health and life contributions for years 2010 through 2014 are approximately $11 million per year, and are based on estimates and assumptions that are subject to change.

Unconditional Purchase Obligations. Unconditional purchase obligations represent our Square Butte power purchase agreements, minimum purchase commitments under coal and rail contracts, and purchase obligations for certain capital expenditure projects. (See Note 11. Commitments, Guarantees and Contingencies.)

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. 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. The table above reflects our share of future debt service based on our output entitlement of 50 percent. This debt service may be reduced if the contingent power sales agreement with Minnkota Power goes into effect in 2013. For further information on Square Butte see Note 11. Commitments, Guarantees and Contingencies.

We have two wind power purchase agreements with an affiliate of NextEra Energy to purchase the output from two wind facilities, Oliver Wind I and Oliver Wind 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.

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.

Liquidity and Capital Resources (Continued)
Credit Ratings (Continued)

Credit Ratings	Standard & Poor's	Moody's
Issuer Credit Rating	BBB+	Baa1
Commercial Paper	A-2	P-2
Senior Secured		
First Mortgage Bonds *(a)*	A–	A2
Unsecured Debt		
Collier County Industrial Development Revenue Bonds – Fixed Rate	BBB	–

(a) Includes collateralized pollution control bonds.

Common Stock Dividends. ALLETE is committed to providing an attractive, secure dividend to its shareholders while, at the same time, funding its growth strategy. The Company's long-term objective is to maintain a dividend payout ratio similar to our peers and provide for future dividend increases. In 2009, we paid out 93 percent (61 percent in 2008; 53 percent in 2007) of our per share earnings in dividends. On January 21, 2010, our Board of Directors declared a dividend of $0.44 per share, unchanged from 2009, which is payable on March 1, 2010, to shareholders of record at the close of business on February 15, 2010.

Capital Requirements

ALLETE's projected capital expenditures for the years 2010 through 2014 are presented in the table below. Actual capital expenditures may vary from the estimates due to changes in forecasted plant maintenance, regulatory decisions or approvals, future environmental requirements, base load growth or capital market conditions.

Capital Expenditures	2010	2011	2012	2013	2014	Total
Regulated Utility Operations						
Base and Other	$156	$82	$81	$82	$89	$490
Current Cost Recovery *(a)*						
Environmental	2	–	–	–	–	2
Renewable	81	66	–	–	–	147
Transmission	5	21	27	42	13	108
Generation	–	–	–	–	–	–
Total Current Cost Recovery	88	87	27	42	13	257
Regulated Utility Capital Expenditures	244	169	108	124	102	747
Other	6	18	24	8	8	64
Total Capital Expenditures	$250	$187	$132	$132	$110	$811

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

We intend to finance expenditures from both internally generated funds and incremental debt and equity.

Environmental and Other Matters

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 11. Commitments, Guarantees and Contingencies. (See Item 1. Business – Environmental Matters.)

Market Risk

Securities Investments

Available-for-Sale Securities. At December 31, 2009, our available-for-sale securities portfolio consisted of securities established to fund certain employee benefits and auction rate securities. (See Note 7. Investments.)

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, 2009.

Market Risk (Continued)
Interest Rate Risk (Continued)

	Expected Maturity Date							
Interest Rate Sensitive Financial Instruments	**2010**	**2011**	**2012**	**2013**	**2014**	**Thereafter**	**Total**	**Fair Value**
Dollars in Millions								
Long-Term Debt								
Fixed Rate *(a)*	$1.6	$1.6	$1.6	$71.1	$19.6	$528.1	$623.6	$657.3
Average Interest Rate – %	5.9	5.9	5.9	5.2	6.9	5.9	5.8	
Variable Rate	$3.6	$12.3	$1.7	$2.8	–	$57.0	$77.4	$77.5
Average Interest Rate – % *(b)*	0.4	3.6	1.9	0.3	–	0.3	0.9	

(a) The $65 million line of credit is included in the fixed rate maturity of $528.1 as it will be refinanced with long-term debt in the first quarter of 2010.

(b) Assumes rate in effect at December 31, 2009, remains constant through remaining term.

Interest rates on variable rate long-term debt are reset on a periodic basis reflecting current market conditions. Based on the variable rate debt outstanding at December 31, 2009, 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.

Commodity Price Risk. Our regulated utility operations in Minnesota and Wisconsin incur costs for fuel (primarily coal and related transportation), power, and natural gas purchased for resale in our regulated service territories. Our regulated utilities' exposure to price risk for these commodities is significantly mitigated by the current ratemaking process and regulatory environment, which allows recovery of fuel costs in excess of those in the 2008 retail rate case filing. Conversely, costs below those in the 2008 retail rate case filing result in a credit to our ratepayers. 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 energy and purchased power. From time to time, our utility operations may have excess energy that is temporarily not required by retail and wholesale customers in our regulated service territory. We actively sell this energy to the wholesale market to optimize the value of our generating facilities.

In 2009 kilowatt-hour sales to our taconite customers were lower by approximately 54 percent from 2008 levels. During 2009, we sold available power to Other Power Suppliers to partially mitigate the earnings impact of these lower industrial sales. Minnesota Power expects an increase in taconite production in 2010 compared to 2009, although production will still be less than previous years' levels.

For the year ended December 31, 2009, we have entered into financial derivative instruments to manage price risk for certain power marketing contracts. Outstanding derivative contracts at December 31, 2009, consist of cash flow hedges for an energy sale that includes pricing based on daily natural gas prices, and FTRs purchased to manage congestion risk for forward power sales contracts. These derivative instruments are recorded on our consolidated balance sheet at fair value. As of December 31, 2009, we recorded approximately $0.7 million of derivatives in other assets on our consolidated balance sheet of which the entire balance relates to our FTRs. These derivative instruments settle monthly throughout the first five months of 2010. (See Note 8. Derivatives.)

Approximately 200 MWs of capacity and energy from our Taconite Harbor facility in northern Minnesota has been sold through two sales contracts totaling 175 MWs (201 MWs 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 fuel, subject to a small minimum annual escalation. The other contract provides that the energy charge will be the greater of the fixed minimum charge or an annual 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 liability. Outages with less than two months notice are subject to an annual duration limitation typical of this type of contract. These contracts qualify for the normal purchase normal sale exception under the guidance for derivative instruments and hedging activities and are not required to be recorded at fair value.

We are exposed to credit risk primarily through our power marketing activities. We use credit policies to manage credit risk, which includes utilizing an established credit approval process and monitoring counterparty limits.

Market Risk (Continued)
Power Marketing (Continued)

Power Sales Agreement. On October 29, 2009, Minnesota Power entered into an agreement to sell Basin 100 MWs of capacity and energy for the next ten years. The transaction is scheduled to begin in May 2010, following the expiration of two wholesale power sales contracts on April 30, 2010. The Basin agreement contains a fixed monthly schedule of capacity charges with a minimum annual escalation provision. The energy charge is based on a fixed monthly schedule and provides for annual escalation based on our cost of fuel. The agreement allows us to recover a pro-rata share of increased costs related to emissions that may occur during the last five years of the contract.

New Accounting Standards

New accounting standards are discussed in Note 1.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – 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, 2009 and 2008, and for each of the three years in the period ended December 31, 2009, and supplementary data, 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. 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, 2009.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2009, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Item 9A. Controls and Procedures (Continued)

Changes in Internal Controls

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.

Item 9B. Other Information

None.

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 2010 Annual Meeting of Shareholders (2010 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 2010 Proxy Statement will be filed with the SEC within 120 days after the end of our 2009 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 – 2009" sections in our 2010 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 "Securities Owned by Certain Beneficial Owners," the "Securities owned by Directors and Management" and the "Equity Compensation Plan Information" sections in our 2010 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 2010 Proxy Statement.

We have adopted a Related Person Transaction Policy which is available on our website at www.allete.com. Print copies are available without 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 Accounting Fees and Services

The information required by this Item is incorporated by reference herein from the "Audit Committee Report" section in our 2010 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, dated as of May 12, 2009, (filed as Exhibit 3 to the June 30, 2009, Form 10-Q, 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 Mellon (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
Twenty-seventh	February 1, 2008	1-3548 (2007 Form 10-K)	4(a)3
Twenty-eighth	May 1, 2008	1-3548 (June 30, 2008 Form 10-Q)	4
Twenty-ninth	November 1, 2008	1-3548 (2008 Form 10-K)	4(a)3
Thirtieth	January 1, 2009	1-3548 (2008 Form 10-K)	4(a)4

Exhibit Number

*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 National Association, 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
Ninth	October 1, 2007	1-3548 (2007 Form 10-K)	4(c)3
Tenth	October 1, 2007	1-3548 (2007 Form 10-K)	4(c)4
Eleventh	December 1, 2008	1-3548 (2008 Form 10-K)	4(c)3

*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(d)1	-	Fourth Amended and Restated Committed Facility Letter, dated January 11, 2006, by and among ALLETE and LaSalle Bank National Association, as Agent.
*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 (filed as Exhibit 10(d)3 to the 2006 Form 10-K, File No. 1-3548).
*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 dated December 16, 2005, among ALLETE, Wisconsin Public Service Corporation and WPS Investments, LLC.
+10(h)1	-	ALLETE Executive Annual Incentive Plan as amended and restated with amendments through January 1, 2010.
+*10(h)2	-	Form of ALLETE Executive Annual Incentive Plan Form of Awards Effective 2009 (filed as Exhibit 10(h)7 to the 2008 Form 10-K, File No. 1-3548).
+10(h)3	-	Form of ALLETE Executive Annual Incentive Plan Form of Awards Effective 2010.
+*10(i)1	-	ALLETE and Affiliated Companies Supplemental Executive Retirement Plan I (SERP I), as amended and restated, effective January 1, 2009, (filed as Exhibit 10(i)4 to the 2008 Form 10-K, File No. 1-3548).
+*10(i)2	-	ALLETE and Affiliated Companies Supplemental Executive Retirement Plan II (SERP II), effective January 1, 2009, (filed as Exhibit 10(i)5 to the 2008 Form 10-K, File No. 1-3548).
+*10(i)3	-	January 2009 Amendment to the ALLETE and Affiliated Companies Supplemental Executive Retirement Plan II (SERP II), effective January 20, 2009, (filed as Exhibit 10(i)6 to the 2008 Form 10-K, File No. 1-3548).
+*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).

Exhibit Number

+*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 Nonqualified Stock Option Grant Effective 2007 (filed as Exhibit 10(m)6 to the 2006 Form 10-K, File No. 1-3548).
+*10(m)4	-	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2007 (filed as Exhibit 10(m)7 to the 2006 Form 10-K, File No. 1-3548).
+*10(m)5	-	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2008 (filed as Exhibit 10(m)10 to the 2007 Form 10-K, File No. 1-3548).
+*10(m)6	-	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2009 (filed as Exhibit 10(m)11 to the 2008 Form 10-K, File No. 1-3548).
+*10(m)7	-	Form of ALLETE Executive Long-Term Incentive Compensation Plan – Restricted Stock Unit Grant Effective 2009 (filed as Exhibit 10(m)12 to the 2008 Form 10-K, File No. 1-3548).
+10(m)8	-	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2010.
+10(m)9	-	Form of ALLETE Executive Long-Term Incentive Compensation Plan – Restricted Stock Unit Grant Effective 2010.
+*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).
+*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 (filed as Exhibit 10(n)4 to the 2006 Form 10-K, File No. 1-3548).
+*10(n)5	-	May 2009 Amendment to the ALLETE Director Stock Plan (filed as Exhibit 10(b) to the June 30, 2009, Form 10-Q, File No. 1-3548).
+*10(n)6	-	ALLETE Non-Management Director Compensation Summary Effective February 15, 2007 (filed as Exhibit 10(n)6 to the 2006 Form 10-K, File No. 1-3548).
+*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).

Exhibit Number

+*10(o)5	-	ALLETE Non-Employee Director Compensation Deferral Plan II, effective May 1, 2009 (filed as Exhibit 10(a) to the June 30, 2009, 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, (filed as Exhibit 10(q) to the 2007 Form 10-K, File No. 1-3548).
12	-	Computation of Ratios of Earnings to Fixed Charges.
21	-	Subsidiaries of the Registrant.
23(a)	-	Consent of Independent Registered Public Accounting Firm.
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 12, 2010, announcing earnings for the year ended December 31, 2009. **(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 and Series 1997C 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 pursuant to Item 15(b).*

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 12, 2010

By Donald J. Shippar
Donald J. Shippar
Chairman 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
Donald J. Shippar Donald J. Shippar	Chairman, Chief Executive Officer and Director (Principal Executive Officer)	February 12, 2010
Alan R. Hodnik Alan R. Hodnik	President and Director	February 12, 2010
Mark A. Schober Mark A. Schober	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 12, 2010
Steven Q. DeVinck Steven Q. DeVinck	Controller and Vice President – Business Support (Principal Accounting Officer)	February 12, 2010

Signatures (Continued)

Signature	Title	Date
Kathleen A. Brekken Kathleen A. Brekken	Director	February 12, 2010
Kathryn W. Dindo Kathryn W. Dindo	Director	February 12, 2010
Heidi J. Eddins Heidi J. Eddins	Director	February 12, 2010
Sidney W. Emery, Jr. Sidney W. Emery, Jr.	Director	February 12, 2010
James S. Haines, Jr James S. Haines, Jr	Director	February 12, 2010
James J. Hoolihan James J. Hoolihan	Director	February 12, 2010
Madeleine W. Ludlow Madeleine W. Ludlow	Director	February 12, 2010
George L. Mayer George L. Mayer	Director	February 12, 2010
Douglas C. Neve Douglas C. Neve	Director	February 12, 2010
Jack I. Rajala Jack I. Rajala	Director	February 12, 2010
Leonard C. Rodman Leonard C. Rodman	Director	February 12, 2010
Bruce W. Stender Bruce W. Stender	Director	February 12, 2010

Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying 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, 2009 and 2008, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2009 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, 2009, 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 audits 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 opinions.

As discussed in Note 1 to the consolidated financial statements, the Company changed the manner in which it accounts for uncertain tax positions in 2007.

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.

PricewaterhouseCoopers LLP
Minneapolis, Minnesota
February 12, 2010

Consolidated Financial Statements

ALLETE Consolidated Balance Sheet

As of December 31	2009	2008
Millions		
Assets		
Current Assets		
Cash and Cash Equivalents	$25.7	$102.0
Accounts Receivable (Less Allowance of $0.9 and $0.7)	118.5	76.3
Inventories	57.0	49.7
Prepayments and Other	24.3	24.3
Total Current Assets	225.5	252.3
Property, Plant and Equipment – Net	1,622.7	1,387.3
Regulatory Assets	293.2	249.3
Investment in ATC	88.4	76.9
Other Investments	130.5	136.9
Other Assets	32.8	32.1
Total Assets	$2,393.1	$2,134.8
Liabilities and Equity		
Liabilities		
Current Liabilities		
Accounts Payable	$62.1	$75.7
Accrued Taxes	20.6	12.9
Accrued Interest	11.1	8.9
Long-Term Debt Due Within One Year	5.2	10.4
Notes Payable	1.9	6.0
Other	32.2	36.8
Total Current Liabilities	133.1	150.7
Long-Term Debt	695.8	588.3
Deferred Income Taxes	253.1	169.6
Regulatory Liabilities	47.1	50.0
Other Liabilities	325.0	339.3
Total Liabilities	1,454.1	1,297.9
Commitments and Contingencies (Note 11)		
Equity		
ALLETE's Equity		
Common Stock Without Par Value, 80.0 Shares Authorized, 35.2 and 32.6 Shares Outstanding	613.4	534.1
Unearned ESOP Shares	(45.3)	(54.9)
Accumulated Other Comprehensive Loss	(24.0)	(33.0)
Retained Earnings	385.4	380.9
Total ALLETE Equity	929.5	827.1
Non-Controlling Interest in Subsidiaries	9.5	9.8
Total Equity	939.0	836.9
Total Liabilities and Equity	$2,393.1	$2,134.8

The accompanying notes are an integral part of these statements.

ALLETE Consolidated Statement of Income

Year Ended December 31 Millions Except Per Share Amounts	2009	2008	2007
Operating Revenue			
Operating Revenue	$766.7	$801.0	$841.7
Prior Year Rate Refunds	(7.6)	–	–
Total Operating Revenue	759.1	801.0	841.7
Operating Expenses			
Fuel and Purchased Power	279.5	305.6	347.6
Operating and Maintenance	308.9	318.1	313.9
Depreciation	64.7	55.5	48.5
Total Operating Expenses	653.1	679.2	710.0
Operating Income	106.0	121.8	131.7
Other Income (Expense)			
Interest Expense	(33.8)	(26.3)	(22.6)
Equity Earnings in ATC	17.5	15.3	12.6
Other	1.8	15.6	15.5
Total Other Income (Expense)	(14.5)	4.6	5.5
Income Before Non-Controlling Interest and Income Taxes	91.5	126.4	137.2
Income Tax Expense	30.8	43.4	47.7
Net Income	60.7	83.0	89.5
Less: Non-Controlling Interest in Subsidiaries	(0.3)	0.5	1.9
Net Income Attributable to ALLETE	$61.0	$82.5	$87.6
Average Shares of Common Stock			
Basic	32.2	29.2	28.3
Diluted	32.2	29.3	28.4
Basic Earnings Per Share of Common Stock	$1.89	$2.82	$3.09
Diluted Earnings Per Share of Common Stock	$1.89	$2.82	$3.08
Dividends Per Share of Common Stock	$1.76	$1.72	$1.64

The accompanying notes are an integral part of these statements.

ALLETE Consolidated Statement of Cash Flows

Year Ended December 31	2009	2008	2007
Millions			
Operating Activities			
Net Income	$60.7	$83.0	$89.5
Allowance for Funds Used During Construction	(5.8)	(3.3)	(3.8)
Loss (Income) from Equity Investments, Net of Dividends	0.1	(3.1)	(2.7)
Gain on Sale of Assets	(0.2)	(4.8)	(2.2)
Gain on Sale of Available-for-sale Securities	–	(6.4)	–
Loss on Impairment of Assets	3.1	–	0.3
Depreciation Expense	64.7	55.5	48.5
Amortization of Debt Issuance Costs	0.9	0.8	1.0
Deferred Income Tax Expense	75.2	38.8	14.0
Stock Compensation Expense	2.1	1.8	2.0
Bad Debt Expense	1.3	0.7	1.0
Changes in Operating Assets and Liabilities			
Accounts Receivable	(43.5)	2.4	(6.6)
Inventories	(7.3)	(0.2)	(6.1)
Prepayments and Other	–	11.2	(11.7)
Accounts Payable	10.5	(14.1)	9.4
Other Current Liabilities	5.3	5.9	(10.0)
Regulatory and Other Assets	(18.3)	(1.8)	0.9
Regulatory and Other Liabilities	(11.4)	(12.8)	0.7
Cash from Operating Activities	137.4	153.6	124.2
Investing Activities			
Proceeds from Sale of Available-for-sale Securities	8.9	62.3	449.7
Payments for Purchase of Available-for-sale Securities	(2.2)	(44.8)	(368.3)
Investment in ATC	(7.8)	(7.4)	(8.7)
Changes to Other Investments	(0.7)	(9.2)	(12.4)
Additions to Property, Plant and Equipment	(318.5)	(301.1)	(210.2)
Proceeds from Sale of Assets	0.3	20.4	1.5
Other	–	3.7	(5.7)
Cash for Investing Activities	(320.0)	(276.1)	(154.1)
Financing Activities			
Proceeds from Issuance of Common Stock	65.2	71.1	20.6
Proceeds from Issuance of Long-Term Debt	111.4	198.7	123.9
Changes in Notes Payable	(4.1)	6.0	–
Reductions of Long-Term Debt	(9.1)	(22.7)	(90.7)
Debt Issuance Costs	(0.6)	(1.5)	(1.1)
Dividends on Common Stock	(56.5)	(50.4)	(44.3)
Cash from Financing Activities	106.3	201.2	8.4
Change in Cash and Cash Equivalents	(76.3)	78.7	(21.5)
Cash and Cash Equivalents at Beginning of Period	102.0	23.3	44.8
Cash and Cash Equivalents at End of Period	$25.7	$102.0	$23.3

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 as of December 31, 2006	$665.8	$307.8	$(8.8)	$(71.9)	$438.7
Comprehensive Income					
Net Income	89.5	89.5			
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	93.8				
Non-Controlling Interest in Subsidiaries	(1.9)	(1.9)			
Comprehensive Income Attributable to ALLETE	91.9				
Adjustment to apply accounting standards for Income Taxes	(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 as of December 31, 2007	742.6	350.4	(4.5)	(64.5)	461.2
Comprehensive Income					
Net Income	83.0	83.0			
Other Comprehensive Income – Net of Tax					
Unrealized Loss on Securities – Net	(6.0)		(6.0)		
Reclassification Adjustment for Gains Included in Income	(3.7)		(3.7)		
Defined Benefit Pension and Other Postretirement Plans	(18.8)		(18.8)		
Total Comprehensive Income	54.5				
Non-Controlling Interest in Subsidiaries	(0.5)	(0.5)			
Comprehensive Income Attributable to ALLETE	54.0				
Adjustment to apply change in Pension and Postretirement measurement date	(1.6)	(1.6)			
Common Stock Issued – Net	72.9				72.9
Dividends Declared	(50.4)	(50.4)			
ESOP Shares Earned	9.6			9.6	
Balance as of December 31, 2008	827.1	380.9	(33.0)	(54.9)	534.1
Comprehensive Income					
Net Income	60.7	60.7			
Other Comprehensive Income – Net of Tax					
Unrealized Gain on Securities – Net	2.8		2.8		
Defined Benefit Pension and Other Postretirement Plans	6.2		6.2		
Total Comprehensive Income	69.7				
Non-Controlling Interest in Subsidiaries	0.3	0.3			
Comprehensive Income Attributable to ALLETE	70.0				
Common Stock Issued – Net	79.3				79.3
Dividends Declared	(56.5)	(56.5)			
ESOP Shares Earned	9.6			9.6	
Balance as of December 31, 2009	$929.5	$385.4	$(24.0)	$(45.3)	$613.4

The accompanying notes are an integral part of these statements.

Notes to Consolidated Financial Statements

Note 1. 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.

Subsequent Events. The Company performed an evaluation of subsequent events for potential recognition and disclosure through the time of issuing the financial statements on February 12, 2010.

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 Operations and Investments and Other segments were determined in accordance with the guidance on segment reporting. 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.

Regulated Operations includes retail and wholesale rate-regulated electric, natural gas, and water services in northeastern Minnesota and northwestern Wisconsin along with our Investment in ATC. Minnesota Power provides regulated utility electric service to 144,000 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. Regulated utility rates are under the jurisdiction of Minnesota, 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 and renewable energy 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. Our Investment in ATC includes our approximate 8 percent equity ownership interest in ATC, a Wisconsin-based 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. Investment in ATC.)

Investments and Other is comprised primarily of BNI Coal, our coal mining operations in North Dakota, and ALLETE Properties, our Florida real estate investment. This segment also includes a small amount of non-rate base generation, approximately 7,000 acres of land available-for-sale in Minnesota, and earnings on cash and investments.

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 2009, Square Butte supplied approximately 50 percent (227.5 MWs) of its output to Minnesota Power under a long-term contract. (See Note 11. Commitments, Guarantees and Contingencies.) Coal sales are recognized when delivered at the cost of production plus a specified profit per ton of coal delivered.

ALLETE Properties represents our Florida real estate investment. Our current strategy for the assets is to complete and maintain key entitlements and infrastructure improvements without requiring significant additional investment, and sell the portfolio over time or in bulk transactions.

Full profit recognition is recorded on sales upon closing, provided that cash collections are at least 20 percent of the contract price and the other requirements under the guidance 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. 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. On December 31, 2009 and 2008, we had no deferred profit recorded on our consolidated balance sheet. Certain contracts with customers allow us to receive participation revenue from land sales to third parties if various formula-based criteria are achieved.

Note 1. Operations and Significant Accounting Policies (Continued)

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 Other 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 the accounting guidance for Real Estate. The cost of real estate 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. (See Note 7. Investments.)

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 non-rate base 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 guidance on accounting for Regulated Operations. Our Regulated Operations capitalize AFUDC, which includes both an interest and equity component. (See Note 3. Property, Plant and Equipment.)

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 the accounting guidance for impairment or 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.

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 As of December 31	**2009**	**2008**
Millions		
Trade Accounts Receivable		
Billed	$56.5	$61.1
Unbilled	15.1	15.9
Less: Allowance for Doubtful Accounts	0.9	0.7
Total Trade Accounts Receivable	70.7	76.3
Income Taxes Receivable	47.8	–
Total Accounts Receivable – Net	$118.5	$76.3

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 industrial customers. Receivables from these customers totaled approximately $10 million at December 31, 2009 ($11 million at December 2008). 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.

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

Inventories As of December 31	**2009**	**2008**
Millions		
Fuel	$23.0	$16.6
Materials and Supplies	34.0	33.1
Total Inventories	$57.0	$49.7

Note 1. Operations and Significant Accounting Policies (Continued)

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 Year Ended December 31	**2009**	**2008**	**2007**
Millions			
Cash Paid During the Period for			
Interest – Net of Amounts Capitalized	$29.8	$25.2	$26.3
Income Taxes	$1.1	$6.5	$34.2
Noncash Investing and Financing Activities			
Changes in Accounts Payable for Capital Additions to Property, Plant and Equipment	$24.1	$17.1	$9.8
AFUDC – Equity	$5.8	$3.3	$3.8
ALLETE Common Stock contributed to the Pension Plan	$(12.0)	–	–

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 (ARS), classified as available-for-sale securities, are recorded at cost because their cost approximates fair market value. We use the specific identification method as the basis for determining the cost of securities sold. Our policy is to review available-for-sale securities for other than temporary impairment on a quarterly basis by assessing such factors as the share price trends and the impact of overall market conditions. (See Note 7. Investments.)

Accounting for Stock-Based Compensation. We apply the fair value recognition guidance for share-based payments. Under this method, we recognize stock-based compensation expense for all share-based payments granted, net of an estimated forfeiture rate and only for those shares expected to vest over the required service period of the award. (See Note 17. Employee Stock and Incentive Plans.)

Prepayments and Other Current Assets As of December 31	**2009**	**2008**
Millions		
Deferred Fuel Adjustment Clause	$15.5	$13.1
Other	8.8	11.2
Total Prepayments and Other Current Assets	$24.3	$24.3

Other Liabilities As of December 31	**2009**	**2008**
Millions		
Future Benefit Obligation Under Defined Benefit Pension and Other Postretirement Plans	$231.2	$251.8
Asset Retirement Obligation (See Note 3. Property, Plant and Equipment)	44.6	39.5
Other	49.2	48.0
Total Other Liabilities	$325.0	$339.3

Environmental Liabilities. We review environmental matters for disclosure 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 11. Commitments, Guarantees and Contingencies.)

Note 1. Operations and Significant Accounting Policies (Continued)

Derivatives. We review all material power purchase and sales contracts for derivative treatment to determine if they qualify for the normal purchase normal sale exception under the guidance for derivatives and hedging. (See Note 8. Derivatives.)

Income Taxes. We file a consolidated federal income tax return. We account for income taxes using the liability method as prescribed by the guidance in 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 guidance for uncertainty in income taxes. Under this guidance 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. The term “more-likely-than-not” means more than 50 percent. (See Note 14. Income Tax Expense.)

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.

New Accounting Standards.

Codification. In June 2009, the FASB approved the FASB Accounting Standards Codification (Codification) as the single source of authoritative nongovernmental GAAP. The Codification is an online research system that reorganizes the thousands of GAAP pronouncements into a topical structure. The Codification was launched on July 1, 2009, at which time all existing accounting standards documents were superseded and all existing accounting literature not included in the Codification was considered non-authoritative, except for guidance issued by the SEC, which remains a source of authoritative GAAP. The Codification was effective September 30, 2009.

Subsequent Events. In May 2009, the FASB issued guidance on accounting for, and disclosure of, events that occur after the balance sheet date but before financial statements are issued or are available to be issued. Entities are required to disclose the date through which subsequent events have been evaluated and the basis for that date. The guidance on subsequent events was adopted on June 30, 2009, and did not have a material impact on our consolidated financial position, results of operations, or cash flows.

Non-controlling Interests. In December 2007, the FASB issued amended guidance to improve the relevance, comparability, and transparency of the financial information a reporting entity provides in its consolidated financial statements with regards to non-controlling interests. Non-controlling interest in a subsidiary is defined as an ownership interest in the consolidated entity that should be reported as equity in the consolidated financial statements. The amended guidance changes the presentation of the consolidated income statement by requiring consolidated net income to include amounts attributable to the parent and the non-controlling interest. A single method of accounting was established for changes in a parent’s ownership interest in a subsidiary which do not result in deconsolidation. Expanded disclosures that clearly identify and distinguish between the interests of the parent and the interests of the non-controlling owners of a subsidiary are also required. The guidance for non-controlling interests was adopted on January 1, 2009. ALLETE Properties does have certain non-controlling interests in consolidated subsidiaries. The presentation of our consolidated financial statements was impacted, but the adoption of the guidance for non-controlling interests did not have a material impact on our consolidated financial position, results of operations or cash flows.

Derivatives and Hedging. In March 2008, the FASB issued guidance that amends and expands the disclosure requirements for derivatives and hedging. The guidance requires enhanced disclosures about how and why an entity uses derivative instruments, how derivative instruments and related hedged items are accounted for and how derivative instruments and related hedged items affect an entity’s financial position, financial performance, and cash flows. Qualitative disclosures about objectives and strategies for using derivatives, quantitative disclosures about fair value amounts of and gains and losses on derivative instruments and disclosures about credit-risk-related contingent features in derivative agreements are also required. The guidance on derivatives and hedging was adopted on January 1, 2009. As the amended guidance provides only disclosure requirements, the adoption of this standard did not have an impact on our consolidated financial position, results of operations or cash flows. (See Note 8. Derivatives.)

Financial Instruments. In April 2009, the FASB issued amended guidance to require disclosure about fair value of financial instruments for interim reporting periods of publicly traded companies in addition to annual financial statements. This amended guidance was adopted on June 30, 2009. As the amended guidance provided only disclosure requirements, the adoption of this standard did not have a material impact on our consolidated financial position, results of operations or cash flows. (See Note 9. Fair Value.)

Note 1. Operations and Significant Accounting Policies (Continued)

Fair Value. In April 2009, the FASB issued additional guidance for applying the provisions of fair value. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants under current market conditions. This guidance requires an evaluation of whether there has been a significant decrease in the volume and level of activity for the asset or liability in relation to normal market activity for the asset or liability. If there has, transactions or quoted prices may not be indicative of fair value and a significant adjustment may need to be made to those prices to estimate fair value. Additionally, an entity must consider whether the observed transaction was orderly (that is, not distressed or forced). If the transaction was orderly, the obtained price can be considered a relevant observable input for determining fair value. If the transaction is not orderly, other valuation techniques must be used when estimating fair value. This additional guidance on fair value was adopted on June 30, 2009, and did not have a material impact on our consolidated financial position, results of operations or cash flows.

In August 2009, the FASB issued an amendment to the guidance for fair value measurement and disclosure of liabilities. This amendment provides clarification for measuring the fair value of liabilities in circumstances in which a quoted price in an active market for the identical liability is not available. The adoption of this standard on September 30, 2009, did not have an impact on our consolidated financial position, results of operations or cash flows.

In September 2009, the FASB issued an amendment to the fair value measurement and disclosure of investments in certain entities that calculate net asset value per share. This amendment requires disclosures, by major category of investment, about the attributes of investments, such as the nature of any restrictions on the investor's ability to redeem its investments at the measurement date, any unfunded commitments, and the investment strategies of the investees. The amended guidance was adopted on December 31, 2009. As the amended guidance provides only disclosure requirements, the adoption of this standard did not have an impact on our consolidated financial position, results of operations or cash flows.

In January 2010, FASB issued an amendment to the fair value measurement and disclosure standard improving disclosures about fair value measurements. This amendment requires disclosure about recurring or nonrecurring fair value measurements, such as transfers in and out of Levels 1 and 2 and activity in Level 3 fair value measurements. Separate disclosures on amounts of significant transfers in and out and reasons for the transfers for Level 1 and Level 2 fair value measurements are required. In Level 3 reconciliations, the activity, such as information about purchases, sales, issuances and settlements, must be presented separately. The guidance for the Level 1 and Level 2 disclosures and clarifications is effective on January 1, 2010. The guidance for the activity in Level 3 disclosures is effective January 1, 2011. As the amended guidance provides only disclosure requirements, the adoption of the amendments will not have an impact on our consolidated financial position, results of operations or cash flows.

Other-Than-Temporary Impairments. In April 2009, the FASB issued amended guidance on other-than-temporary impairments. If it is more likely than not that an impaired security will be sold before the recovery of its cost basis, either due to the investor's intent to sell or because it will be required to sell the security, the entire impairment is recognized in earnings. Otherwise, only the portion of the impaired debt security related to estimated credit losses is recognized in earnings, while the remainder of the impairment is recorded in other comprehensive income and recognized over the remaining life of the debt security. In addition, the guidance expands the presentation and disclosure requirements for other-than-temporary impairments for both debt and equity securities. The amended guidance for other-than-temporary impairments was adopted on June 30, 2009, and did not have an impact on our consolidated financial position, results of operations or cash flows.

Pensions and Other Postretirement Benefits. In December 2008, the FASB issued guidance that amends employers' disclosures about pensions and other postretirement benefits. These changes provide guidance on disclosures about plan assets, investment strategies, major categories of plan assets, concentrations of risk within plan assets, and valuation techniques used to measure the fair value of plan assets. These disclosure requirements will be effective for fiscal years ending after December 15, 2009. Upon initial adoption, the requirements within this guidance are not required for earlier periods that are presented for comparative purposes. This amended guidance was adopted on December 31, 2009. As the amended guidance provides only disclosure requirements, the adoption of this standard did not have an impact on our consolidated financial position, results of operations or cash flows. (See Note 16. Pension and Other Postretirement Benefit Plans.)

Transfers of Financial Assets. In June 2009, the FASB issued amended guidance for the transfers of financial assets. The guidance was issued with the objective of improving the relevance, representational faithfulness, and comparability of the information that a reporting entity provides in its financial statements about a transfer of financial assets; the effects of a transfer on its financial position, financial performance, and cash flows; and a transferor's continuing involvement, if any, in transferred financial assets. Key provisions of the amended guidance include (1) the removal of the concept of qualifying special purpose entities, (2) the introduction of the concept of a participating interest, in circumstances in which a portion of a financial asset has been transferred, and (3) the requirement that to qualify for sale accounting, the transferor must evaluate whether it maintains effective control over transferred financial assets either directly or indirectly. The amended guidance also requires enhanced disclosures about transfers of financial assets and a transferor's continuing involvement. The amended guidance is effective January 1, 2010, and is required to be applied prospectively. We are currently assessing the impact of the adoption on our consolidated financial position, results of operations and cash flows, but we do not believe it will have a material impact on the Company.

Note 1. Operations and Significant Accounting Policies (Continued)

Variable Interest Entities. In June 2009, the FASB issued guidance amending the manner in which entities evaluate whether consolidation is required for variable interest entities (VIEs). A company must first perform a qualitative analysis in determining whether it must consolidate a VIE, and if the qualitative analysis is not determinative, must perform a quantitative analysis. The guidance requires continuous evaluation of VIEs for consolidation, rather than upon the occurrence of triggering events. Additional enhanced disclosures about how an entity's involvement with a VIE affects its financial statements and exposure to risk will also be required. This guidance is effective January 1, 2010. We are currently assessing the impact of this amended guidance on our consolidated financial position, results of operations and cash flows, but we do not believe it will have a material impact on the Company.

Note 2. Business Segments

Regulated Operations includes our regulated utilities, Minnesota Power and SWL&P, as well as our investment in ATC, a Wisconsin-based utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota, and Illinois. Investments and Other is comprised primarily of BNI Coal, our coal mining operations in North Dakota, and ALLETE Properties, our Florida real estate investment. This segment also includes a small amount of non-rate base generation, approximately 7,000 acres of land available-for-sale in Minnesota, and earnings on cash and investments. For a description of our reportable business segments, see Item 1. Business.

	Consolidated	Regulated Operations	Investments and Other
Millions			
2009			
Operating Revenue	$766.7	$689.4	$77.3
Prior Year Rate Refunds	(7.6)	(7.6)	–
Total Operating Revenue	759.1	681.8	77.3
Fuel and Purchased Power	279.5	279.5	–
Operating and Maintenance	308.9	235.8	73.1
Depreciation Expense	64.7	60.2	4.5
Operating Income (Loss)	106.0	106.3	(0.3)
Interest Expense	(33.8)	(28.3)	(5.5)
Equity Earnings in ATC	17.5	17.5	–
Other Income (Expense)	1.8	5.8	(4.0)
Income (Loss) Before Non-Controlling Interest and Income Taxes	91.5	101.3	(9.8)
Income Tax Expense (Benefit)	30.8	35.4	(4.6)
Net Income (Loss)	60.7	65.9	(5.2)
Less: Non-Controlling Interest in Subsidiaries	(0.3)	–	(0.3)
Net Income (Loss) Attributable to ALLETE	$61.0	$65.9	$(4.9)
Total Assets	$2,393.1	$2,184.0	$209.1
Capital Additions	$303.7	$299.2	$4.5

Note 2. Business Segments (Continued)

Millions	Consolidated	Regulated Operations	Investments and Other
2008			
Operating Revenue	$801.0	$712.2	$88.8
Fuel and Purchased Power	305.6	305.6	–
Operating and Maintenance	318.1	239.3	78.8
Depreciation Expense	55.5	50.7	4.8
Operating Income	121.8	116.6	5.2
Interest Expense	(26.3)	(24.0)	(2.3)
Equity Earnings in ATC	15.3	15.3	–
Other Income	15.6	3.6	12.0
Income Before Non-Controlling Interest and Income Taxes	126.4	111.5	14.9
Income Tax Expense (Benefit)	43.4	43.6	(0.2)
Net Income	83.0	67.9	15.1
Less: Non-Controlling Interest in Subsidiaries	0.5	–	0.5
Net Income Attributable to ALLETE	$82.5	$67.9	$14.6
Total Assets	$2,134.8	$1,832.1	$302.7
Capital Additions	$322.9	$317.0	$5.9

Millions	Consolidated	Regulated Operations	Investments and Other
2007			
Operating Revenue	$841.7	$723.8	$117.9
Fuel and Purchased Power	347.6	347.6	–
Operating and Maintenance	313.9	229.3	84.6
Depreciation Expense	48.5	43.8	4.7
Operating Income	131.7	103.1	28.6
Interest Expense	(22.6)	(21.0)	(1.6)
Equity Earnings in ATC	12.6	12.6	–
Other Income	15.5	4.1	11.4
Income Before Non-Controlling Interest and Income Taxes	137.2	98.8	38.4
Income Tax Expense	47.7	36.4	11.3
Net Income	89.5	62.4	27.1
Less: Non-Controlling Interest in Subsidiaries	1.9	–	1.9
Net Income Attributable to ALLETE	$87.6	$62.4	$25.2
Total Assets	$1,644.2	$1,396.6	$247.6
Capital Additions	$223.9	$220.6	$3.3

Note 3. Property, Plant and Equipment

Property, Plant and Equipment As of December 31	2009	2008
Millions		
Regulated Utility	$2,415.7	$1,837.2
Construction Work in Progress	89.6	303.0
Accumulated Depreciation	(928.8)	(806.8)
Regulated Utility Plant – Net	1,576.5	1,333.4
Non-Rate Base Energy Operations	87.0	94.0
Construction Work in Progress	3.6	3.9
Accumulated Depreciation	(45.5)	(47.2)
Non-Rate Base Energy Operations Plant – Net	45.1	50.7
Other Plant – Net	1.1	3.2
Property, Plant and Equipment – Net	$1,622.7	$1,387.3

Note 3. Property, Plant and Equipment (Continued)

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	2 to 34 years	Non-Rate Base Operations	3 to 61 years
	Transmission	42 to 61 years	Other Plant	5 to 25 years
	Distribution	14 to 65 years		

Asset Retirement Obligations. We recognize, at fair value, obligations associated with the retirement of certain tangible, long-lived assets that result from the acquisition, construction or development and/or normal operation of the asset. Asset retirement obligations (ARO) 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 indeterminate useful lives. The associated retirement costs are capitalized as part of the related long-lived asset and depreciated over the useful life of the asset. 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.

Long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for future plant removal costs in depreciation rates. These plant removal cost recoveries were included in accumulated depreciation. With the adoption of ARO guidance, accumulated plant removal costs were reclassified either as AROs or as a regulatory liability for non-ARO obligations. To the extent annual accruals for plant removal costs differ from accruals under approved depreciation rates, a regulatory asset has been established in accordance with the guidance for AROs. (See Note 5. Regulatory Matters.)

Asset Retirement Obligation

Millions	
Obligation as of December 31, 2007	$36.5
Accretion Expense	2.0
Additional Liabilities Incurred in 2008	1.0
Obligation as of December 31, 2008	39.5
Accretion Expense	2.3
Additional Liabilities Incurred in 2009	2.8
Obligation as of December 31, 2009	$44.6

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 remaining 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 cost of Boswell Unit 4, which is included in property, plant and equipment at December 31, 2009, was $331 million ($328 million at December 31, 2008). The corresponding accumulated depreciation balance was $178 million at December 31, 2009 ($173 million at December 31, 2008).

Note 5. Regulatory Matters

Electric Rates. Entities within our Regulated Operations segment file for periodic rate revisions with the MPUC, the FERC or the PSCW.

2008 Rate Case. In May 2008, Minnesota Power filed a retail rate increase request with the MPUC seeking additional revenues of approximately $40 million annually; the request also sought an 11.15 percent return on equity, and a capital structure consisting of 54.8 percent equity and 45.2 percent debt. As a result of a May 2009 Order and an August 2009 Reconsideration Order, the MPUC granted Minnesota Power a revenue increase of approximately $20 million, including a return on equity of 10.74 percent and a capital structure consisting of 54.79 percent equity and 45.21 percent debt. Rates went into effect on November 1, 2009.

Note 5. Regulatory Matters (Continued)

Interim rates, subject to refund, were in effect from August 1, 2008 through October 31, 2009. During 2009, Minnesota Power recorded a $21.7 million liability for refunds of interim rates, including interest, required to be made as a result of the May 2009 Order and the August 2009 Reconsideration Order. In 2009, $21.4 million was refunded, with a remaining $0.3 million balance to be refunded in early 2010; $7.6 million of the refunds required to be made were related to interim rates charged in 2008.

With the May 2009 Order, the MPUC also approved the stipulation and settlement agreement that affirmed the Company's continued recovery of fuel and purchased power costs under the former base cost of fuel that was in effect prior to the retail rate filing. The transition to the former base cost of fuel began with the implementation of final rates on November 1, 2009. Any revenue impact associated with this transition will be identified in a future filing related to the Company's fuel clause operation.

2010 Rate Case. Minnesota Power previously stated its intention to file for additional revenues to recover the costs of significant investments to ensure current and future system reliability, enhance environmental performance and bring new renewable energy to northeastern Minnesota. As a result, Minnesota Power filed a retail rate increase request with the MPUC on November 2, 2009, seeking a return on equity of 11.50 percent, a capital structure consisting of 54.29 percent equity and 45.71 percent debt, and on an annualized basis, an $81.0 million net increase in electric retail revenue.

Minnesota law allows the collection of interim rates while the MPUC processes the rate filing. On December 30, 2009, the MPUC issued an Order (the Order) authorizing $48.5 million of Minnesota Power's November 2, 2009, interim rate increase request of $73.0 million. The MPUC cited exigent circumstances in reducing Minnesota Power's interim rate request. Because the scope and depth of this reduction in interim rates was unprecedented, and because Minnesota law does not allow Minnesota Power to formally challenge the MPUC's action until a final decision in the case is rendered, on January 6, 2010, Minnesota Power sent a letter to the MPUC expressing its concerns about the Order and requested that the MPUC reconsider its decision on its own motion. Minnesota Power described its belief that the MPUC's decision violates the law by prejudging the merits of the rate request prior to an evidentiary hearing and results in the confiscation of utility property. Further, the Company is concerned that the decision will have negative consequences on the environmental policy directions of the State of Minnesota by denying recovery for statutory mandates during the pendency of the rate proceeding. The MPUC has not acted in response to Minnesota Power's letter.

The rate case process requires public hearings and an evidentiary hearing before an administrative law judge, both of which are scheduled for the second quarter of 2010. A final decision on the rate request is expected in the fourth quarter. We cannot predict the final level of rates that may be approved by the MPUC, and we cannot predict whether a legal challenge to the MPUC's interim rate decision will be forthcoming or successful.

FERC-Approved Wholesale Rates. Minnesota Power's non-affiliated municipal customers consist of 16 municipalities in Minnesota and 1 private utility in Wisconsin. SWL&P, a wholly-owned subsidiary of ALLETE, is also a private utility in Wisconsin and a customer of Minnesota Power. In 2008, Minnesota Power entered into new contracts with these customers which transitioned customers to formula-based rates, allowing rates to be adjusted annually based on changes in cost. In February 2009, the FERC approved our municipal contracts which expire December 31, 2013. Under the formula-based rates provision, wholesale rates are set at the beginning of the year based on expected costs and provide for a true-up calculation for actual costs. Wholesale rate increases totaling approximately $6 million and $10 million annually were implemented on February 1, 2009 and January 1, 2010, respectively, with approximately $6 million of additional revenues under the true-up provision accrued in 2009, which will be billed in 2010.

2009 Wisconsin Rate Increase. SWL&P's current retail rates are based on a December 2008 PSCW retail rate order that became effective January 1, 2009, and allows for an 11.1 percent return on equity. The new rates reflected a 3.5 percent average increase in retail utility rates for SWL&P customers (a 13.4 percent increase in water rates, a 4.7 percent increase in electric rates, and a 0.6 percent decrease in natural gas rates). On an annualized basis, the rate increase will generate approximately $3 million in additional revenue.

Deferred Regulatory Assets and Liabilities. Our regulated utility operations are subject to the accounting guidance on Regulated Operations. We capitalize incurred costs, as regulatory assets, which are probable of recovery in future utility rates. Regulatory liabilities represent amounts expected to be credited to customers in rates. No regulatory assets or liabilities are currently earning a return.

Note 5. Regulatory Matters (Continued)

Deferred Regulatory Assets and Liabilities **As of December 31**	**2009**	**2008**
Millions		
Deferred Regulatory Assets		
Future Benefit Obligations Under		
Defined Benefit Pension and Other Postretirement Plans *(a)*	235.8	216.5
Boswell Unit 3 Environmental Rider *(b)*	20.9	3.8
Deferred Fuel *(c)*	20.8	13.1
Income Taxes	15.7	12.2
Asset Retirement Obligation	6.3	5.1
Deferred MISO Costs	2.4	3.9
Premium on Reacquired Debt	2.0	2.2
Other	4.8	5.6
Total Deferred Regulatory Assets	$308.7	$262.4
Deferred Regulatory Liabilities		
Income Taxes	$25.9	$28.7
Plant Removal Obligations	16.9	15.9
Accrued MISO Refund	–	4.7
Other	4.3	0.7
Total Deferred Regulatory Liabilities	$47.1	$50.0

(a) See Note 16. Pension and Other Postretirement Benefit Plans.
(b) MPUC-approved current cost recovery rider. Our 2010 rate case proposes to move this project from a current cost recovery rider to base rates.
(c) As of December 31, 2009, $5 million of this balance relates to deferred fuel costs incurred under the former base cost of fuel calculation. Any revenue impact associated with this transition will be identified in a future filing related to the Company's fuel clause operation.

Current and Non-Current Deferred Regulatory Assets and Liabilities **As of December 31**	**2009**	**2008**
Millions		
Total Current Deferred Regulatory Assets *(a)*	$15.5	$13.1
Total Non-Current Deferred Regulatory Assets	293.2	249.3
Total Deferred Regulatory Assets	308.7	262.4
Total Current Deferred Regulatory Liabilities	–	–
Total Non-Current Deferred Regulatory Liabilities	47.1	50.0
Total Deferred Regulatory Liabilities	$47.1	$50.0

(a) Current deferred regulatory assets are included in prepayments and other on the consolidated balance sheet.

Note 6. Investment in ATC

Investment in ATC. Our wholly-owned subsidiary Rainy River Energy owns approximately 8 percent of ATC, a Wisconsin-based 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. As of December 31, 2009, our equity investment balance in ATC was $88.4 million ($76.9 million at December 31, 2008). On January 29, 2010, we invested an additional $1.2 million in ATC. In total, we expect to invest approximately $2 million throughout 2010.

ALLETE's Interest in ATC **Year Ended December 31**	**2009**	**2008**
Millions		
Equity Investment Beginning Balance	$76.9	$65.7
Cash Investments	7.8	7.4
Equity in ATC Earnings	17.5	15.3
Distributed ATC Earnings	(13.8)	(11.5)
Equity Investment Ending Balance	$88.4	$76.9

Note 6. Investment in ATC (Continued)

ATC Summarized Financial Data Year Ended December 31 **Income Statement Data**	**2009**	**2008**	**2007**
Millions			
Revenue	$521.5	$466.6	$408.0
Operating Expense	230.3	209.0	198.2
Other Expense	77.8	69.6	55.7
Net Income	$213.4	$188.0	$154.1
ALLETE's Equity in Net Income	**$17.5**	**$15.3**	**$12.6**

Balance Sheet Data			
Millions			
Current Assets	$51.1	$50.8	$48.3
Non-Current Assets	2,767.3	2,480.0	2,189.0
Total Assets	2,818.4	2,530.8	2,237.3
Current Liabilities	285.5	252.0	317.1
Long-Term Debt	1,259.6	1,109.4	899.1
Other Non-Current Liabilities	76.9	120.2	108.5
Members' Equity	1,196.4	1,049.2	912.6
Total Liabilities and Members' Equity	$2,818.4	$2,530.8	$2,237.3

Note 7. Investments

Investments. At December 31, 2009, our long-term investment portfolio included the real estate assets of ALLETE Properties, debt and equity securities consisting primarily of securities held to fund employee benefits, ARS, and land held-for-sale in Minnesota.

Investments **As of December 31**	**2009**	**2008**
Millions		
ALLETE Properties	$93.1	$84.9
Available-for-sale Securities	29.5	32.6
Other	7.9	19.4
Total Investments	$130.5	$136.9

ALLETE Properties **As of December 31**	**2009**	**2008**
Millions		
Land Held-for-Sale Beginning Balance	$71.2	$62.6
Additions during period: Capitalized Improvements	5.6	10.5
Deductions during period: Cost of Real Estate Sold	(1.9)	(1.9)
Land Held-for-Sale Ending Balance	74.9	71.2
Long-Term Finance Receivables	12.9	13.6
Other	5.3	0.1
Total Real Estate Assets	$93.1	$84.9

Land Held-for-Sale. Land held-for-sale is recorded at the lower of cost or fair value determined by the evaluation of individual land parcels. Land values are reviewed for impairment and no impairments were recorded for the year ended December 31, 2009 (none in 2008).

Note 7. Investments (Continued)

Long-Term Finance Receivables. Long-term finance receivables, which are collateralized by property sold, accrue interest at market-based rates and are net of an allowance for doubtful accounts of $0.4 million at December 31, 2009 ($0.1 million at December 31, 2008). The allowance for doubtful accounts includes $0.3 million of impairments that were recorded for other receivables during the year ended December 31, 2009. The majority are receivables having maturities up to four years. Finance receivables totaling $7.8 million at December 31, 2009, were due from an entity which filed for voluntary Chapter 11 bankruptcy protection in June 2009. The estimated fair value of the collateral relating to these receivables was greater than the $7.8 million amount due at December 31, 2009 and no impairment was recorded on these receivables. Due to the lack of recent market activity, we estimated fair value based primarily on recent property tax assessed values. This valuation technique constitutes a Level 3 non-recurring fair value measurement.

Available-for-Sale Investments. We account for our available-for-sale portfolio in accordance with the guidance for certain investments in debt and equity securities. Our available-for-sale securities portfolio consisted of securities established to fund certain employee benefits and auction rate securities.

Available-For-Sale Securities

Million		**Gross Unrealized**		
As of December 31	**Cost**	**Gain**	**(Loss)**	**Fair Value**
2009	$33.1	$0.1	$(3.7)	$29.5
2008	$40.5	–	$(7.9)	$32.6
2007	$45.3	$8.4	$(0.1)	$53.6

	Net	**Gross Realized**		**Net Unrealized Gain (Loss) in Other**
Year Ended December 31	**Proceeds**	**Gain**	**(Loss)**	**Comprehensive Income**
2009	$6.7	–	–	$4.5
2008	$17.5	$6.5	$(0.1)	$(9.7)
2007	$81.4	–	–	$1.4

Auction Rate Securities. Included in Available-for-Sale Securities as of December 31, 2009, is an auction rate municipal bond of $6.7 million ($15.2 million at December 31, 2008) with a stated maturity date of March 1, 2024. The ARS consists of guaranteed student loans insured or reinsured by the federal government. ARS were historically auctioned every 35 days to set new rates and provided a liquidating event in which investors could either buy or sell securities. Beginning in 2008, the auctions have been unable to sustain themselves due to the overall lack of market liquidity and we have been unable to liquidate all of our ARS. As a result, we have classified our ARS as long-term investments and have the ability to hold these securities to maturity, until called by the issuer, or until liquidity returns to this market.

The Company used a discounted cash flow model to determine the estimated fair value of its investment in the ARS as of December 31, 2009. The assumptions used in preparing the discounted cash flow model include the following: the effective interest rate, amount of cash flows, and expected holding periods of the ARS. These inputs reflect the Company’s judgments about assumptions that market participants would use in pricing ARS including assumptions about risk.

Of the remaining ARS outstanding as of December 31, 2009, approximately $0.3 million was called at par value effective March 1, 2010. We anticipate the remainder of our ARS will be redeemed in the second quarter of 2010, as we received a Notice of Contemplated Refunding on January 29, 2010. The investment remains classified as long-term until officially called by the bondholders.

Note 8. Derivatives

During 2009 we entered into financial derivative instruments to manage price risk for certain power marketing contracts. Outstanding derivative contracts at December 31, 2009, consist of cash flow hedges for an energy sale that includes pricing based on daily natural gas prices, and Financial Transmission Rights (FTRs) purchased to manage congestion risk for forward power sales contracts. These derivative instruments are recorded on our consolidated balance sheet at fair value. During 2009, we purchased $2.4 million of FTRs and expensed $1.7 million through our consolidated statement of income. As of December 31, 2009, approximately $0.7 million remains in other assets on our consolidated balance sheet. These derivative instruments settle monthly throughout the first five months of 2010.

Note 8. Derivatives (Continued)

Changes in the derivatives' fair value are recognized currently in earnings unless specific hedge accounting criteria is met. Favorable changes in fair value of $0.3 million and $0.1 million were recorded in operating revenue in the first and second quarters of 2009, respectively; and a $0.4 million decrease was recorded in the third quarter of 2009 when the corresponding energy swap contract ended.

The mark-to-market fluctuations on the cash flow hedge were recorded in other comprehensive income on the consolidated balance sheet; a $0.1 million increase in fair value was recorded in the first quarter of 2009, and a decrease of $0.1 million was recorded in the second quarter of 2009. There were no mark-to-market changes in the third or fourth quarters of 2009.

Note 9. Fair Value

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. These inputs, which are used to measure fair value, are prioritized through the fair value hierarchy. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are as follows:

Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reported date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. This category includes primarily mutual fund investments held to fund employee benefits.

Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reported date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, such as treasury securities with pricing interpolated from recent trades of similar securities, or priced with models using highly observable inputs, such as commodity options priced using observable forward prices and volatilities. This category includes deferred compensation, fixed income securities, and derivative instruments consisting of cash flow hedges.

Level 3 — Significant inputs that are generally less observable from objective sources. The types of assets and liabilities included in Level 3 are those with inputs requiring significant management judgment or estimation, such as the complex and subjective models and forecasts used to determine the fair value. This category includes ARS consisting of guaranteed student loans and derivative instruments consisting of FTRs.

The following tables set forth by level within the fair value hierarchy our assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2009 and December 31, 2008. Each asset and liability is classified based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

	At Fair Value as of December 31, 2009			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Equity Securities	$17.8	–	–	$17.8
Corporate Debt Securities	–	$6.4	–	6.4
Derivatives	–	–	$0.7	0.7
Debt Securities Issued by States of the United States (ARS)	–	–	6.7	6.7
Money Market Funds	1.4	–	–	1.4
Total Fair Value of Assets	$19.2	$6.4	$7.4	$33.0
Liabilities:				
Deferred Compensation	–	$14.6	–	$14.6
Total Fair Value of Liabilities	–	$14.6	–	$14.6
Total Net Fair Value of Assets (Liabilities)	$19.2	$(8.2)	$7.4	$18.4

Note 9. Fair Value (Continued)

Recurring Fair Value Measures Activity in Level 3	Derivatives	Debt Securities Issued by the States of the United States (ARS)
Millions		
Balance as of December 31, 2008	–	$15.2
Purchases, sales, issuances and settlements, net *(a)*	$0.7	(8.5)
Level 3 transfers in	–	–
Balance as of December 31, 2009	$0.7	$6.7

(a) ARS called during 2009 at par value.

	At Fair Value as of December 31, 2008			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Equity Securities	$13.5	–	–	$13.5
Corporate Debt Securities	–	$3.3	–	3.3
Debt Securities Issued by States of the United States (ARS)	–	–	$15.2	15.2
Money Market Funds	10.6	–	–	10.6
Total Fair Value of Assets	$24.1	$3.3	$15.2	$42.6
Liabilities:				
Deferred Compensation	–	$13.5	–	$13.5
Total Fair Value of Liabilities	–	$13.5	–	$13.5
Total Net Fair Value of Assets (Liabilities)	$24.1	$(10.2)	$15.2	$29.1

Recurring Fair Value Measures Activity in Level 3	Debt Securities Issued by the States of the United States (ARS)
Millions	
Balance as of December 31, 2007	–
Purchases, sales, issuances and settlements, net *(a)*	$(10.0)
Level 3 transfers in	25.2
Balance as of December 31, 2008	$15.2

(a) 2008 includes a $5.2 million transfer of ARS to our Voluntary Employee Benefit Association trust used to fund postretirement health and life benefits.

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	Carrying Amount	Fair Value
Millions		
Long-Term Debt, Including Current Portion		
December 31, 2009	$701.0	$734.8
December 31, 2008	$598.7	$561.6

Note 10. Short-Term and Long-Term Debt

Short-Term Debt. Total short-term debt outstanding as of December 31, 2009, was $5.2 million ($10.4 million at December 31, 2008) and consisted of long-term debt due within one year. (See ALLETE consolidated balance sheet.)

Note 10. Short-Term and Long-Term Debt (Continued)

As of December 31, 2009, we had bank lines of credit aggregating $157.0 million ($160.5 million at December 31, 2008), the majority of which expire in January 2012. These bank lines of credit make financing available through short-term bank loans and provide credit support for commercial paper. At December 31, 2009, $69.2 million ($7.3 million at December 31, 2008) was drawn on our lines of credit leaving a $87.8 million balance available for use ($153.2 million at December 31, 2008). In December 2009, we drew $65.0 million on our $150.0 million syndicated revolving credit facility to temporarily fund the purchase of the 250 kV DC transmission line. In December 2009, we agreed to sell $80.0 million of First Mortgage Bonds in February 2010 (see Long-Term Debt, below). We intend to use proceeds from these bonds to repay the amount drawn on the line, resulting in $65.0 million of our line of credit being classified as long-term at December 31, 2009.

On November 12, 2009, BNI Coal replaced a $6.0 million Promissory Note and Supplement (Line of Credit) with CoBANK, ACB with a $3.0 million Line of Credit and a $3.0 million term loan with CoBANK, ACB. The Line of Credit has a variable interest rate with the option to fix the rate based on LIBOR plus a certain spread. The term of the Line of Credit is 24 months. The Line of Credit is being used for general corporate purposes. As of December 31, 2009, $1.9 million was drawn on the Line of Credit. The $3.0 million term loan has a fixed interest rate of 5.19 percent and is payable in 28 equal quarterly installments commencing January 20, 2010, and ending on October 20, 2016.

Long-Term Debt. The aggregate amount of long-term debt maturing during 2010 is $5.2 million ($13.9 million in 2011; $3.3 million in 2012; $73.9 million in 2013; $19.6 million in 2014; and $520.1 million thereafter). Substantially all of our electric plant is subject to the lien of the mortgages collateralizing various first mortgage bonds. The mortgages contain non-financial covenants customary in utility mortgages, including restrictions on our ability to incur liens, dispose of assets, and merge with other entities.

In January 2009, we issued $42.0 million in principal amount of unregistered First Mortgage Bonds (Bonds) in the private placement market. The Bonds mature January 15, 2019, and carry a coupon rate of 8.17 percent. We used the proceeds from the sale of the Bonds to fund utility capital investments and for general corporate purposes.

In December 2009, we agreed to sell $80.0 million in principal amount of First Mortgage Bonds (Bonds) in the private placement market in three series as follows:

Issue Date (on or about)	Maturity	Principal Amount	Coupon
February 17, 2010	April 15, 2021	$15 Million	4.85%
February 17, 2010	April 15, 2025	$30 Million	5.10%
February 17, 2010	April 15, 2040	$35 Million	6.00%

We expect to use the proceeds from the February 2010 sale of Bonds to pay down the syndicated revolving credit facility, to fund utility capital investments or for general corporate purposes.

For the January 2009 and the February 2010 bond issuances (the Bonds), we have the option to prepay all or a portion of the Bonds at our discretion, subject to a make-whole provision. The Bonds are subject to the terms and conditions of our utility mortgage. The Bonds were sold or will be sold in reliance on an exemption from registration under Section 4(2) of the Securities Act of 1933, as amended, to institutional accredited investors.

Note 10. Short-Term and Long-Term Debt (Continued)

Long-Term Debt As of December 31	2009	2008
Millions		
First Mortgage Bonds		
4.86% Series Due 2013	$60.0	$60.0
6.94% Series Due 2014	18.0	18.0
7.70% Series Due 2016	20.0	20.0
8.17% Series Due 2019	42.0	–
5.28% Series Due 2020	35.0	35.0
4.95% Pollution Control Series F Due 2022	111.0	111.0
6.02% Series Due 2023	75.0	75.0
5.99% Series Due 2027	60.0	60.0
5.69% Series Due 2036	50.0	50.0
SWL&P First Mortgage Bonds		
7.25% Series Due 2013	10.0	10.0
Senior Unsecured Notes 5.99% Due 2017	50.0	50.0
Variable Demand Revenue Refunding Bonds Series 1997 A, B, and C Due 2009 – 2020	28.3	28.3
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
Line of Credit Facility *(a)*	65.0	–
Other Long-Term Debt, 2.0% – 8.0% Due 2009 – 2037	42.9	47.6
Total Long-Term Debt	701.0	598.7
Less: Due Within One Year	5.2	10.4
Net Long-Term Debt	$695.8	$588.3

(a) The $80 million First Mortgage Bonds due in 2021, 2025 and 2040 to be issued on or about February 17, 2010, will replace the balance due on the Line of Credit Facility as of December 31, 2009.

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 ratio of its Funded Debt to Total Capital (as the amounts are calculated in accordance with the respective long-term debt arrangements) of less than or equal to 0.65 to 1.00, measured quarterly. As of December 31, 2009, our ratio was approximately 0.41 to 1.00. Failure to meet this covenant would give rise to an event of default, if not cured 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. None of ALLETE's long-term debt arrangements or credit facilities contain credit rating triggers that would cause an event of default or acceleration of repayment of outstanding balances. As of December 31, 2009, ALLETE was in compliance with its financial covenants.

Note 11. Commitments, Guarantees and Contingencies

Off-Balance Sheet Arrangements

Power Purchase Agreements. Our long-term power purchase agreements (PPA) have been evaluated under the accounting guidance for variable interest entities. We have determined that either we have no variable interest in the PPA, or where we do have variable interests, we are not the primary beneficiary; therefore, consolidation is not required. These conclusions are based on the following factors: we have no equity investment in these facilities and do not incur actual or expected losses related to the loss of facility value, and we do not have significant control over the operations of each of these facilities. Our financial exposure relating to these PPAs is limited to our fixed capacity and energy payments.

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 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.

Note 11. Commitments, Guarantees and Contingencies (Continued)

Minnesota Power is obligated to pay its pro rata share of Square Butte's costs based on Minnesota Power's entitlement to Unit output. Our output entitlement under the Agreement is 50 percent for the remainder of the contract. 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, 2009, Square Butte had total debt outstanding of $351.0 million. Annual debt service for Square Butte is expected to be approximately $34 million in each of the five years, 2010 through 2014. 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 2009 was $53.9 million ($56.7 million in 2008; $57.3 million in 2007). This reflects Minnesota Power's pro rata share of total Square Butte costs, based on the 50 percent output entitlement in 2009, the 55 percent output entitlement in 2008 and the 60 percent output entitlement in 2007. Included in this amount was Minnesota Power's pro rata share of interest expense of $11.0 million in 2009 ($11.6 million in 2008; $11.0 million in 2007). Minnesota Power's payments to Square Butte are approved as a purchased power expense for ratemaking purposes by both the MPUC and the FERC.

In conjunction with the DC line purchase in December 2009, Minnesota Power entered into a contingent new Power Sales Agreement with Minnkota Power. Under the new Power Sales Agreement, Minnesota Power will be able to sell a portion of our output from Square Butte to Minnkota, resulting in Minnkota's net entitlement increasing and Minnesota Power's net entitlement decreasing until Minnesota Power's share is eliminated at the end of 2025.

No power will be sold under this agreement until Minnkota Power has placed in service a new AC transmission line, which is anticipated to occur in late 2013. This new AC transmission line will allow Minnkota to transmit their entitlement from Square Butte to their customers, and allow Minnesota Power additional capacity on the recently acquired DC line to transmit new wind generation.

Wind Power Purchase Agreements. We have two wind power purchase agreements with an affiliate of NextEra Energy to purchase the output from two wind facilities, Oliver Wind I (50 MWs) and Oliver Wind II (48 MWs), located near Center, North Dakota. Each agreement is for 25 years and provides for the purchase of all output from the facilities.

Hydro Power Purchase Agreement. We also have a power purchase agreement with Manitoba Hydro that began in May 2009 and expires in April 2015. Under the agreement with Manitoba Hydro, Minnesota Power will purchase 50 MW of capacity and the energy associated with that capacity. Both the capacity price and the energy price are adjusted annually by the change in a governmental inflationary index.

North Dakota Wind Project. On December 31, 2009, we purchased an existing 250 kV DC transmission line from Square Butte for $69.7 million. The 465-mile transmission line runs from Center, North Dakota, to Duluth, Minnesota. We expect to use this line to transport increasing amounts of wind energy from North Dakota while gradually phasing out coal-based electricity currently being delivered to our system over this transmission line from Square Butte's lignite coal-fired generating unit. Acquisition of this transmission line was approved by an MPUC order dated December 21, 2009. In addition, the FERC issued an order on November 24, 2009, authorizing acquisition of the transmission facilities and conditionally accepting, upon compliance and other filings, the proposed tariff revisions, interconnection agreement and other related agreements.

On July 7, 2009, the MPUC approved our petition seeking current cost recovery of investments and expenditures related to Bison I and associated transmission upgrades. Bison I is the first portion of several hundred MWs of our North Dakota Wind Project, which upon completion will help fulfill the 2025 renewable energy supply requirement for our retail load. Bison I, located near Center, North Dakota, will be comprised of 33 wind turbines with a total nameplate capacity of 75.9 MWs and will be phased into service in late 2010 and 2011. We anticipate filing a petition with the MPUC in the first quarter 2010 to establish customer billing rates for the approved cost recovery.

On September 29, 2009, the NDPSC authorized site construction for Bison I. On October 2, 2009, Minnesota Power filed a route permit application with the NDPSC for a 22 mile, 230 kV Bison I transmission line that will connect Bison I to the DC transmission line at the Square Butte Substation in Center, North Dakota. An order is expected in the first quarter 2010.

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 value, 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 $8.8 million in 2010, $8.9 million in 2011, $9.0 million in 2012, $8.5 million in 2013, $8.2 million in 2014 and $45.7 million thereafter. Total rent and lease expense was $9.3 million in 2009 ($8.5 million in 2008; $8.4 million in 2007).

Note 11. Commitments, Guarantees and Contingencies (Continued)

Coal, Rail and Shipping Contracts. We have two primary coal supply agreements with expiration dates through December 2011. We also have rail and shipping agreements for the transportation of all of our coal, with expiration dates through January 2012. Two of our rail and shipping agreements contain options to extend the agreements, which options Minnesota Power may exercise unilaterally. The term extensions are for an additional two year term and an additional four year term. Our minimum annual payment obligations under these coal, rail and shipping agreements are currently $35.7 million in 2010 and $7.6 million in 2011, with no specific commitments beyond 2011. Our minimum annual payment obligations will increase when annual nominations are made for coal deliveries in future years.

Environmental Matters.

Our businesses are subject to regulation of environmental matters by various federal, state and local authorities. Currently, a number of regulatory changes are under consideration by both the Congress and the EPA. Most notably, clean energy technologies and the regulation of GHGs have taken a lead in these discussions. Minnesota Power's fossil fueled facilities will likely to be subject to regulation under these climate change policies. Our intention is to reduce our exposure to possible future carbon and GHG legislation by reshaping our generation portfolio, over time, to reduce our reliance on coal.

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 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 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 become available. Accruals for environmental liabilities are included in the consolidated 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.

Clean Air Act. 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 average NO_X limits. 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. Minnesota Power's generating facilities are currently in compliance with applicable emission requirements.

New Source Review. On August 8, 2008, Minnesota Power received a Notice of Violation (NOV) from the United States EPA asserting violations of the New Source Review (NSR) requirements of the Clean Air Act at Boswell Units 1-4 and Laskin Unit 2. The NOV also asserts that the Boswell Unit 4 Title V permit was violated, and that seven projects undertaken at these coal-fired plants between the years 1981 and 2000 should have been reviewed under the NSR requirements. Minnesota Power believes the projects were in full compliance with the Clean Air Act, NSR requirements and applicable permits.

We are engaged in discussions with the EPA regarding resolution of these matters, but we are unable to predict the outcome of these discussions. Since 2006, Minnesota Power has significantly reduced, and continues to reduce, emissions at Boswell and Laskin. The resolution could result in civil penalties and the installation of control technology, some of which is already planned or completed for other regulatory requirements. Any costs of installing pollution control technology would likely be eligible for recovery in rates over time subject to MPUC and FERC approval in a rate proceeding. We are unable to predict the ultimate financial impact or the resolution of these matters at this time.

EPA Clean Air Interstate Rule. In March 2005, the EPA announced the Clean Air Interstate Rule (CAIR) that sought to reduce and permanently cap emissions of SO_2, NO_X, and particulates in the eastern United States. Minnesota was included as one of the 28 states considered as "significantly contributing" to air quality standards non-attainment in other downwind states. On July 11, 2008, the United States Court of Appeals for the District of Columbia Circuit (Court) vacated the CAIR and remanded the rulemaking to the EPA for reconsideration while also granting our petition that the EPA reconsider including Minnesota as a CAIR state. In September 2008, the EPA and others petitioned the Court for a rehearing or alternatively requested that the CAIR be remanded without a court order. In December 2008, the Court granted the request that the CAIR be remanded without a court order, effectively reinstating a January 1, 2009 compliance date for the CAIR, including Minnesota. However, in the May 12, 2009 Federal Register the EPA issued a proposed rule that would amend the CAIR to stay its effectiveness with respect to Minnesota until completion of the EPA's determination of whether Minnesota should be included as a CAIR state. The formal administrative stay of CAIR for Minnesota was published in the November 3, 2009, Federal Register with an effective date of December 3, 2009.

Note 11. Commitments, Guarantees and Contingencies (Continued)
Environmental Matters (Continued)

Minnesota Regional Haze. The federal regional haze rule requires states to submit state implementation plans (SIPs) to the EPA to address regional haze visibility impairment in 156 federally-protected parks and wilderness areas. Under the regional haze rule, certain large stationary sources, that were put in place between 1962 and 1977 with emissions contributing to visibility impairment are required to install emission controls, known as best available retrofit technology (BART). We have certain steam units, Boswell Unit 3 and Taconite Harbor Unit 3, which are subject to BART requirements.

Pursuant to the regional haze rule, Minnesota was required to develop its SIP by December 2007. As a mechanism for demonstrating progress towards meeting the long-term regional haze goal, in April 2007, the MPCA advanced a draft conceptual SIP which relied on the implementation of CAIR. However, a formal SIP was never filed due to the Court's review of CAIR as more fully described above under "EPA Clean Air Interstate Rule." Subsequently, the MPCA requested that companies with BART eligible units complete and submit a BART emissions control retrofit study, which was done on Taconite Harbor Unit 3 in November 2008. The retrofit work completed in 2009 at Boswell Unit 3 meets the BART requirement for that unit. On December 15, 2009, the MPCA approved the SIP for submittal to the EPA for review and approval. It is uncertain what controls will ultimately be required at Taconite Harbor Unit 3 in connection with the regional haze rule.

EPA National Emission Standards for Hazardous Air Pollutants. In March 2005, the EPA also announced the Clean Air Mercury Rule (CAMR) that would have reduced and permanently capped electric utility mercury emissions in the continental United States through a cap-and-trade program. In February 2008, the United States Court of Appeals for the District of Columbia Circuit vacated the CAMR and remanded the rulemaking to the EPA for reconsideration. In October 2008, the EPA petitioned the Supreme Court to review the Court's decision in the CAMR case. In January 2009, the EPA withdrew its petition, paving the way for possible regulation of mercury and other hazardous air pollutant emissions through Section 112 of the Clean Air Act, setting Maximum Achievable Control Technology standards for the utility sector. In December 2009, Minnesota Power and other utilities received an Information Collection Request from the EPA, requiring that emissions data be provided and stack testing be performed in order to develop an improved database with which to base future regulations. Cost estimates for complying with potential future mercury and other hazardous air pollutant regulations under the Clean Air Act cannot be estimated at this time.

Minnesota Mercury Emission Reduction Act. This legislation requires Minnesota Power to file mercury emission reduction plans for Boswell Units 3 and 4, with a goal of 90 percent reduction in mercury emissions. The Boswell Unit 3 emission reduction plan was filed with the MPCA in October 2006. Mercury control equipment has been installed and was placed into service in November 2009. (See Item 1. Business – Regulated Operations – Minnesota Public Utilities Commission – Emission Reduction Plans.) A mercury emissions reduction plan for Boswell Unit 4 is required by July 1, 2011, with implementation no later than December 31, 2014. The legislation calls for an evaluation of a mercury control alternative which provides for environmental and public health benefits without imposing excessive costs on the utility's customers. Cost estimates for the Boswell Unit 4 emission reduction plan are not available at this time.

Ozone. The EPA is attempting to control, more stringently, emissions that result in ground level ozone. In January 2010, the EPA proposed to reduce the eight-hour ozone standard and to adopt a secondary standard for the protection of sensitive vegetation from ozone-related damage. The EPA projects stating rules to address attainment of these new, more stringent standards will not be required until December 2013.

EPA Greenhouse Gas Reporting Rule. On September 22, 2009, the EPA issued the final rule mandating that certain GHG emission sources, including electric generating units, are required to report emission levels. The rule is intended to allow the EPA to collect accurate and timely data on GHG emissions that can be used to form future policy decisions. The rule was effective January 1, 2010, and all GHG emissions must be reported on an annual basis by March 31 of the following year. Currently, we have the equipment and data tools necessary to report our 2010 emissions to comply with this rule.

Title V Greenhouse Gas Tailoring Rule. On October 27, 2009, the EPA issued the proposed Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas Tailoring rule. This proposed regulation addresses the six primary greenhouse gases and new thresholds for when permits will be required for new facilities and existing facilities which undergo major modifications. The rule would require large industrial facilities, including power plants, to obtain construction and operating permits that demonstrate Best Available Control Technologies (BACT) are being used at the facility to minimize GHG emissions. The EPA is expected to propose BACT standards for GHG emissions from stationary sources.

For our existing facilities, the proposed rule does not require amending our existing Title V operating permits to include BACT for GHGs. However, modifying or installing units with GHG emissions that trigger the PSD permitting requirements could require amending operating permits to incorporate BACT to control GHG emissions.

Note 11. Commitments, Guarantees and Contingencies (Continued)
Environmental Matters (Continued)

EPA Endangerment Findings. On December 15, 2009, the EPA published its findings that the emissions of six GHG, including CO_2, methane, and nitrous oxide, endanger human health or welfare. This finding may result in regulations that establish motor vehicle GHG emissions standards in 2010. There is also a possibility that the endangerment finding will enable expansion of the EPA regulation under the Clean Air Act to include GHGs emitted from stationary sources. A petition for review of the EPA's endangerment findings was filed by the Coalition for Responsible Regulation, et. al. with the United States District Court Circuit Court of Appeals on December 23, 2009.

Coal Ash Management Facilities. Minnesota Power generates coal ash at all five of its steam electric stations. Two facilities store ash in onsite impoundments (ash ponds) with engineered liners and containment dikes. Another facility stores dry ash in a landfill with an engineered liner and leachate collection system. Two facilities generate a combined wood and coal ash that is either land applied as an approved beneficial use, or trucked to state permitted landfills. Minnesota Power continues to monitor state and federal legislative and regulatory activities that may affect its ash management practices. The USEPA is expected to propose new regulations in February 2010, pertaining to the management of coal ash by electric utilities. It is unknown how potential coal ash management rule changes will affect Minnesota Power's facilities. On March 9, 2009, the EPA requested information from Minnesota Power (and other utilities) on its ash storage impoundments at Boswell and Laskin. On June 22, 2009, Minnesota Power received an additional EPA information request pertaining to Boswell. Minnesota Power responded to both these information requests. On August 19, 2009, Dam Safety officials from the Minnesota DNR visited both the Boswell and Laskin ash ponds. The purpose of the inspection was to assess the structural integrity of the ash ponds, as well as review operational and maintenance procedures. There were no significant findings or concerns from the DNR staff during the inspections.

Manufactured Gas Plant Site. We are reviewing and addressing environmental conditions at a former manufactured gas plant site within the City of Superior, Wisconsin and formerly operated by SWL&P. We have been working with the WDNR to determine the extent of contamination and the remediation of contaminated locations. At December 31, 2009 we have a $0.5 million liability for this site, and a corresponding regulatory asset as we expect recovery of remediation costs to be allowed by the PSCW.

BNI Coal. As of December 31, 2009, BNI Coal had surety bonds outstanding of $18.4 million related to the reclamation liability for closing costs associated with its mine and mine facilities. Although the coal supply agreements obligate the customers to provide for the closing costs, an additional guarantee is required by federal and state regulations. In addition to the surety bonds, BNI has secured a Letter of Credit with CoBANK, ACB for an additional $10.0 million, of which $6.7 million is needed to meet the requirements for BNI's total reclamation liability currently estimated at $25.1 million.

ALLETE Properties. As of December 31, 2009, ALLETE Properties, through its subsidiaries, had surety bonds outstanding of $19.1 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 $10.2 million, and ALLETE Properties does not believe it is likely that any of these outstanding bonds will be drawn upon.

Community Development District Obligations. In March 2005, the Town Center District issued $26.4 million of tax-exempt, 6 percent Capital Improvement Revenue Bonds, Series 2005; and in May 2006, the Palm Coast Park District issued $31.8 million of tax-exempt, 5.7 percent Special Assessment Bonds, Series 2006. The Capital Improvement Revenue Bonds and the Special Assessment Bonds are payable through property tax assessments on the land owners over 31 years (by May 1, 2036, and 2037, respectively). The bond proceeds were used to pay for the construction of a portion of the major infrastructure improvements in each district, 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 each district. The assessments were billed to the landowners in November 2006, for Town Center and November 2007, for Palm Coast Park. 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, 2009, we owned 69 percent of the assessable land in the Town Center District (69 percent at December 31, 2008) and 86 percent of the assessable land in the Palm Coast Park District (86 percent at December 31, 2008). At these ownership levels our annual assessments are $1.4 million for Town Center and $1.9 million for Palm Coast Park. 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 12. Common Stock and Earnings Per Share

Summary of Common Stock		Shares	Equity
		Thousands	Millions
Balance as of December 31, 2006		30,436	$438.7
2007	Employee Stock Purchase Plan	17	0.7
	Invest Direct	331	15.1
	Options and Stock Awards	43	6.7
Balance as of December 31, 2007		30,827	$461.2
2008	Employee Stock Purchase Plan	17	0.6
	Invest Direct	161	6.9
	Options and Stock Awards	24	4.6
	Equity Issuance Program	1,556	60.8
Balance as of December 31, 2008		32,585	$534.1
2009	Employee Stock Purchase Plan	24	0.7
	Invest Direct	456	13.6
	Options and Stock Awards	8	1.1
	Equity Issuance Program	1,685	51.9
	Contributions to Pension	463	12.0
Balance as of December 31, 2009		35,221	$613.4

Equity Issuance Program. We entered into a Distribution Agreement with KCCI, Inc., originating in February 2008 and subsequently amended in February 2009, with respect to the issuance and sale of up to an aggregate of 6.6 million shares of our common stock, without par value. The shares may be offered for sale, from time to time, in accordance with the terms of the agreement pursuant to Registration Statement No. 333-147965. During 2009, 1.7 million shares of common stock were issued under this agreement resulting in net proceeds of $51.9 million. In 2008, 1.6 million shares were issued for net proceeds of $60.8 million. (See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources.)

Contributions to Pension. In March 2009, we contributed 0.5 shares of ALLETE common stock, with an aggregate value of $12.0 million, to our pension plan. On May 19, 2009, we registered the 0.5 shares of ALLETE common stock with the SEC pursuant to Registration Statement No. 333-147965. (See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Liquidity and Capital Resources.)

Authorized Common Stock. On May 12, 2009, shareholders approved an amendment to the Company's Amended and Restated Articles of Incorporation to increase the number of authorized shares of common stock from 43.3 million to 80.0 million.

Shareholder Rights Plan. On July 25, 1996, ALLETE adopted a shareholder rights plan, which was amended and restated on July 12, 2006 (collectively, the "Rights Plan"). The amendment to the Rights Plan, among other things, extended the final expiration date of the Rights Plan to July 11, 2009. The Rights Plan expired according to its terms on July 11, 2009. As a result, ALLETE's preferred share purchase rights issued in accordance with the Rights Plan are no longer outstanding.

Earnings Per Share. The difference between basic and diluted earnings per share arises, if any, from outstanding stock options, non-vested restricted stock, and performance share awards granted under our Executive and Director Long-Term Incentive Compensation Plans. In accordance with accounting standards for earnings per share, for 2009, 0.6 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 (0.6 million shares were excluded for 2008 and 0.2 million in 2007).

Note 12. Common Stock and Earnings Per Share (Continued)

Reconciliation of Basic and Diluted Earnings Per Share Year Ended December 31	Basic	Dilutive Securities	Diluted
Millions Except Per Share Amounts			
2009			
Net Income Attributable to ALLETE	$61.0	–	$61.0
Common Shares	32.2	–	32.2
Per Share of Common Stock	$1.89	–	$1.89
2008			
Net Income Attributable to ALLETE	$82.5	–	$82.5
Common Shares	29.2	0.1	29.3
Per Share of Common Stock	$2.82	–	$2.82
2007			
Net Income Attributable to ALLETE	$87.6	–	$87.6
Common Shares	28.3	0.1	28.4
Per Share of Common Stock	$3.09	–	$3.08

Note 13. Other Income (Expense)

Year Ended December 31	2009	2008	2007
Millions			
Loss on Emerging Technology Investments	$(4.6)	$(0.7)	$(1.3)
AFUDC - Equity	5.8	3.3	3.8
Investments and Other Income *(a)*	0.6	13.0	13.0
Total Other Income	$1.8	$15.6	$15.5

(a) In 2008, Investment and Other Income included a gain from the sale of certain available-for-sale securities. The gain was triggered when securities were sold to reallocate investments to meet defined investment allocations based upon an approved investment strategy. In 2007, Investment and Other Income primarily included earnings on excess cash and Minnesota land sales.

Note 14. Income Tax Expense

Income Tax Expense Year Ended December 31	2009	2008	2007
Millions			
Current Tax Expense (Benefit)			
Federal *(a)*	$(42.6)	$6.2	$26.5
State	(1.8)	(1.6)	7.2
Total Current Tax Expense (Benefit)	(44.4)	4.6	33.7
Deferred Tax Expense			
Federal	66.0	29.3	10.7
State	10.3	13.4	4.7
Change in Valuation Allowance	(0.1)	(2.9)	(0.3)
Investment Tax Credit Amortization	(1.0)	(1.0)	(1.1)
Total Deferred Tax Expense	75.2	38.8	14.0
Total Income Tax Expense	$30.8	$43.4	$47.7

(a) Due to the bonus depreciation provisions in the American Recovery and Reinvestment Act of 2009, we are in a net operating loss position for 2009. The loss will be utilized by carrying it back against prior years' taxable income.

Note 14. Income Tax Expense (Continued)

Reconciliation of Taxes from Federal Statutory Rate to Total Income Tax Expense Year Ended December 31	2009	2008	2007
Millions			
Income Before Non-Controlling Interest and Income Taxes	$91.5	$126.4	$137.2
Statutory Federal Income Tax Rate	35%	35%	35%
Income Taxes Computed at 35 percent Statutory Federal Rate	$32.0	$44.2	$48.0
Increase (Decrease) in Tax Due to:			
Amortization of Deferred Investment Tax Credits	(1.0)	(1.0)	(1.1)
State Income Taxes – Net of Federal Income Tax Benefit	5.4	4.8	7.4
Depletion	(0.9)	(0.8)	(0.9)
Regulatory Differences for Utility Plant	(2.5)	(1.6)	(2.2)
Production Tax Credit	(1.2)	(0.4)	–
Positive Resolution of Audit Issues	–	–	(1.6)
Other	(1.0)	(1.8)	(1.9)
Total Income Tax Expense	$30.8	$43.4	$47.7

The effective tax rate on income from continuing operations before non-controlling interest was 33.7 percent for 2009; (34.3 percent for 2008; 34.8 percent for 2007). The 2009 effective tax rate was primarily impacted by deductions for AFUDC-Equity (included in Regulatory Differences for Utility Plant, above), investment tax credits, wind production tax credits and depletion. The 2008 effective tax rate was impacted by deductions for AFUDC-Equity (included in Regulatory Differences for Utility Plant, above), investment tax credits, wind production tax credits, depletion, recognition of a benefit on the reversal of a previously uncertain tax position ($1.7 million included in Other, above) and a benefit for the reversal of a state income tax valuation allowance ($2.9 million included in State Income Taxes, above).

Deferred Tax Assets and Liabilities As of December 31	2009	2008
Millions		
Deferred Tax Assets		
Employee Benefits and Compensation *(a)*	$118.2	$125.2
Property Related	46.5	36.4
Investment Tax Credits	10.0	10.7
Other	14.4	16.3
Gross Deferred Tax Assets	189.1	188.6
Deferred Tax Asset Valuation Allowance	(0.3)	(0.4)
Total Deferred Tax Assets	$188.8	$188.2
Deferred Tax Liabilities		
Property Related	$294.1	$235.6
Regulatory Asset for Benefit Obligations	96.5	87.7
Unamortized Investment Tax Credits	14.1	15.1
Partnership Basis Differences	14.6	3.7
Other	28.2	16.8
Total Deferred Tax Liabilities	$447.5	$358.9
Net Deferred Income Taxes	$258.7	$170.7
Recorded as:		
Net Current Deferred Tax Liabilities *(b)*	$5.6	$1.1
Net Long-Term Deferred Tax Liabilities	253.1	169.6
Net Deferred Income Taxes	$258.7	$170.7

(a) Includes Unfunded Employee Benefits
(b) Included in Other Current Liabilities.

As of December 31, 2009 we had a federal net operating loss of $85.7 million primarily due to the bonus depreciation provisions in the American Recovery and Reinvestment Act of 2009. In 2010, this federal net operating loss will be fully utilized by carrying it back against prior years' taxable income. We also have various state net operating loss carryforwards totaling $23.8 million available to reduce future taxable income. We expect to fully utilize the tax benefit of these losses prior to their expirations in 2024 through 2029.

Note 14. Income Tax Expense (Continued)

Gross Unrecognized Income Tax Benefits	2009	2008	2007
Millions			
Balance at January 1	$8.0	$5.3	$10.4
Additions for Tax Positions Related to the Current Year	0.5	0.7	0.8
Reductions for Tax Positions Related to the Current Year	–	–	–
Additions for Tax Positions Related to Prior Years	1.0	4.5	–
Reduction for Tax Positions Related to Prior Years	–	(2.5)	(2.4)
Settlements	–	–	(3.5)
Balance as of December 31	$9.5	$8.0	$5.3

The gross amount of unrecognized tax benefits as of December 31, 2009, includes $1.5 million of net unrecognized tax benefits that, if recognized, would affect the annual effective income tax rate.

As of December 31, 2009, we had $0.9 million ($0.6 million for 2008) of accrued interest related to unrecognized tax benefits included in the consolidated balance sheet. We classify interest related to unrecognized tax benefits as interest expense and tax-related penalties in operating expenses in the consolidated statement of income. In 2009, we recognized $0.4 million of interest expense ($0.4 million for 2008 and $0.1 million for 2007). There were no penalties recognized for 2009, 2008 or 2007.

We file a consolidated federal income tax return in the United States and various state jurisdictions. ALLETE is no longer subject to federal examination for years before 2005 or state examinations for years before 2004.

During the next 12 months it is reasonably possible the amount of unrecognized tax benefits could be reduced by $3.6 million due to statute expirations and anticipated audit settlements. This amount is primarily due to timing issues.

Note 15. Other Comprehensive Income (Loss)

Other Comprehensive Income (Loss) Year Ended December 31	2009	2008	2007
Millions			
Net Income	$60.7	$83.0	$89.5
Other Comprehensive Income			
Unrealized Gain on Securities Net of income taxes of $1.7, $(3.7), and $0.3	2.8	(6.0)	1.1
Reclassification Adjustment for Losses Included in Income Net of income taxes of $–, $(2.7), and $–	–	(3.7)	–
Defined Benefit Pension and Other Postretirement Plans Net of income taxes of $4.1, $(13.3), and $2.3	6.2	(18.8)	3.2
Total Other Comprehensive Income (Loss)	9.0	(28.5)	4.3
Total Comprehensive Income	$69.7	$54.5	$93.8
Less: Non-Controlling Interest in Subsidiaries	(0.3)	0.5	1.9
Comprehensive Income Attributable to ALLETE	$70.0	$54.0	$91.9

Accumulated Other Comprehensive Income (Loss) As of December 31	2009	2008
Millions		
Unrealized Gain (Loss) on Securities	$(1.8)	$(4.6)
Defined Benefit Pension and Other Postretirement Plans	(22.2)	(28.4)
Total Accumulated Other Comprehensive Loss	$(24.0)	$(33.0)

Note 16. Pension and Other Postretirement Benefit Plans

We have noncontributory union and non-union defined benefit pension plans covering eligible employees. The plans provide defined benefits based on years of service and final average pay. In 2009, we made a total of $32.9 million ($10.9 million in 2008) in contributions to ALLETE's defined benefit pension plans of which $12.0 million was contributed in shares of ALLETE common stock. We also have defined contribution pension plans covering substantially all employees. The 2009 plan year employer contributions, which are made through our employee stock ownership plan, totaled $9.1 million ($7.1 million for the 2008 plan year.) (See Note 12. Common Stock and Earnings Per Share and Note 17. Employee Stock and Incentive Plans)

Note 16. Pension and Other Postretirement Benefit Plans (Continued)

In 2006, amendments were made to the non-union defined benefit pension plan and the Retirement Savings and stock Ownership Plan (RSOP). The non-union defined benefit pension plan was amended to suspend further crediting of service to the plan and closed the plan to new participants. In conjunction with the change, contributions were increased to the RSOP.

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 irrevocable grantor trusts. In 2009 we made a net contribution of $0.3 million to the grantor trust and $9.3 million to the VEBAs. In 2008 $3.7 million was contributed to the VEBAs.

Management considers various factors when making funding decisions such as regulatory requirements, actuarially determined minimum contribution requirements, and contributions required to avoid benefit restrictions for the pension plans. Estimated defined benefit pension contributions for years 2010 through 2014 are expected to be up to $25 million per year, and are based on estimates and assumptions that are subject to change. Funding for the other postretirement benefit plans is impacted by utility regulatory requirements. Estimated postretirement health and life contributions for years 2010 through 2014 are approximately $11 million per year, and are based on estimates and assumptions that are subject to change.

Accounting for Defined Benefit Pension and Postretirement Benefit Plans 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.

The defined benefit pension and postretirement health and life benefit costs recognized annually by our regulated companies are expected to be recovered through rates filed with our regulatory jurisdictions. As a result, these amounts that are required to otherwise be recognized in accumulated other comprehensive income have been recognized as a long-term regulatory asset on our consolidated balance sheet, in accordance with the accounting requirements for Regulated Operations. The defined benefit pension and postretirement health and life benefit costs associated with our other non-rate base operations are recognized in accumulated other comprehensive income.

During the year ended December 31, 2008, we were required to change our measurement date from September 30 to December 31. 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. Also on January 1, 2008, we recorded $0.8 million relating to three months of amortization for transition obligations, prior service costs, and prior gains and losses within accumulated other comprehensive income.

Pension Obligation and Funded Status

Year Ended December 31	2009	2008
Millions		
Accumulated Benefit Obligation	$435.9	$406.6
Change in Benefit Obligation		
Obligation, Beginning of Year	$440.4	$421.9
Service Cost	5.7	7.3
Interest Cost	26.2	31.8
Actuarial Loss (Gain)	14.6	3.2
Benefits Paid	(25.5)	(29.9)
Participant Contributions	3.9	6.1
Obligation, End of Year	$465.3	$440.4
Change in Plan Assets		
Fair Value, Beginning of Year	$273.7	$405.6
Actual Return on Plan Assets	41.6	(120.2)
Employer Contribution	37.8	18.2
Benefits Paid	(25.5)	(29.9)
Fair Value, End of Year	$327.6	$273.7
Funded Status, End of Year	$(137.7)	$(166.7)

Net Pension Amounts Recognized in Consolidated Balance Sheet Consist of:		
Current Liabilities	$(0.9)	$(0.9)
Noncurrent Liabilities	$(136.8)	$(165.8)

Note 16. Pension and Other Postretirement Benefit Plans (Continued)

The pension costs that are reported as a component within our consolidated balance sheet, reflected in regulatory long-term assets and accumulated other comprehensive income, consist of the following:

Unrecognized Pension Costs		
Year Ended December 31	**2009**	**2008**
Millions		
Net Loss	$196.5	$193.2
Prior Service Cost	1.8	2.4
Transition Obligation	–	–
Total Unrecognized Pension Costs	$198.3	$195.6

Components of Net Periodic Pension Expense			
Year Ended December 31	**2009**	**2008**	**2007**
Millions			
Service Cost	$5.7	$5.8	$5.3
Interest Cost	26.2	25.4	23.4
Expected Return on Plan Assets	(33.8)	(32.5)	(30.6)
Amortization of Loss	3.4	1.6	4.9
Amortization of Prior Service Costs	0.6	0.6	0.6
Net Pension Expense	$2.1	$0.9	$3.6

Other Changes in Pension Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income and Regulatory Assets		
Year Ended December 31	**2009**	**2008**
Millions		
Net Loss (Gain)	$6.8	$164.0
Amortization of Prior Service Costs	(0.6)	(0.6)
Amortization of Loss (Gain)	(3.4)	(1.6)
Total Recognized in Other Comprehensive Income and Regulatory Assets	$2.8	$161.8

Information for Pension Plans with an Accumulated Benefit Obligation in Excess of Plan Assets		
Year Ended December 31	**2009**	**2008**
Millions		
Projected Benefit Obligation	$465.3	$440.4
Accumulated Benefit Obligation	$435.9	$406.6
Fair Value of Plan Assets	$327.6	$273.7

Note 16. Pension and Other Postretirement Benefit Plans (Continued)

Postretirement Health and Life Obligation and Funded Status Year Ended December 31	2009	2008
Millions		
Change in Benefit Obligation		
Obligation, Beginning of Year	$166.9	$153.7
Service Cost	4.1	5.0
Interest Cost	10.0	11.7
Actuarial Loss	18.4	4.0
Participant Contributions	1.7	2.0
Plan Amendments	(1.3)	–
Benefits Paid	(7.7)	(9.5)
Obligation, End of Year	$192.1	$166.9
Change in Plan Assets		
Fair Value, Beginning of Year	$78.6	$90.9
Actual Return on Plan Assets	13.9	(25.2)
Employer Contribution	9.9	20.3
Participant Contributions	1.6	1.9
Benefits Paid	(7.6)	(9.3)
Fair Value, End of Year	$96.4	$78.6
Funded Status, End of Year	$(95.7)	$(88.3)

Net Postretirement Health and Life Amounts Recognized in Consolidated Balance Sheet Consist of:		
Current Liabilities	$(0.8)	$(0.7)
Noncurrent Liabilities	$(94.8)	$(87.6)

According to the accounting guidance for Retirement Benefits 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 $18.2 million in irrevocable grantor trusts is included in Other Investments on our consolidated balance sheet at December 31, 2009 ($14.1 million at December 31, 2008).

The postretirement health and life costs that are reported as a component within our consolidated balance sheet, reflected in regulatory long-term assets and accumulated other comprehensive income, consist of the following:

Unrecognized Postretirement Health and Life Costs Year Ended December 31	2009	2008
Millions		
Net Loss	$69.6	$59.2
Prior Service Cost	(1.3)	–
Transition Obligation	6.9	9.4
Total Unrecognized Postretirement Health and Life Costs	$75.2	$68.6

Components of Net Periodic Postretirement Health and Life Expense Year Ended December 31	2009	2008	2007
Millions			
Service Cost	$4.1	$4.0	$4.2
Interest Cost	10.0	9.4	7.8
Expected Return on Plan Assets	(8.3)	(7.2)	(6.5)
Amortization of Loss	2.5	1.4	1.0
Amortization of Transition Obligation	2.5	2.5	2.4
Net Postretirement Health and Life Expense	$10.8	$10.1	$8.9

Note 16. Pension and Other Postretirement Benefit Plans (Continued)

Other Changes in Postretirement Benefit Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income and Regulatory Assets

Year Ended December 31	**2009**	**2008**
Millions		
Net Loss (Gain)	$12.9	$38.3
Prior Service Cost (Credit) Arising During the Period	(1.3)	–
Amortization of Transition Obligation	(2.5)	(2.5)
Amortization of Loss (Gain)	(2.5)	(1.4)
Total Recognized in Other Comprehensive Income and Regulatory Assets	$6.6	$34.4

Estimated Future Benefit Payments

	Pension	**Postretirement Health and Life**
Millions		
2010	$26.4	$7.5
2011	$26.9	$8.4
2012	$27.8	$9.2
2013	$28.8	$10.0
2014	$29.9	$10.9
Years 2015 – 2019	$165.0	$65.5

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, 2010, are as follows:

	Pension	**Postretirement Health and Life**
Millions		
Net Loss	$6.6	$4.8
Prior Service Costs	$0.5	$(0.1)
Transition Obligations	–	$2.5
Total Pension and Postretirement Health and Life Costs	$7.1	$7.2

Weighted-Average Assumptions Used to Determine Benefit Obligation

Year Ended December 31	**2009**	**2008**
Discount Rate	5.81%	6.12%
Rate of Compensation Increase	4.3 – 4.6%	4.3 – 4.6%
Health Care Trend Rates		
Trend Rate	8.5%	9%
Ultimate Trend Rate	5%	5%
Year Ultimate Trend Rate Effective	2017	2012

Weighted-Average Assumptions Used to Determine Net Periodic Benefit Costs

Year Ended December 31	**2009**	**2008**	**2007**
Discount Rate	6.12%	6.25%	5.75%
Expected Long-Term Return on Plan Assets			
Pension	8.5%	9.0%	9.0%
Postretirement Health and Life	6.8 – 8.5%	7.2 – 9.0%	5.0 – 9.0%
Rate of Compensation Increase	4.3 – 4.6%	4.3 – 4.6%	4.3 – 4.6%

Note 16. Pension and Other Postretirement Benefit Plans (Continued)

In establishing the expected long-term return on plan assets, we take into account the actual long-term historical performance of our plan assets, the actual long-term historical performance for the type of securities we are invested in, and apply the historical performance utilizing the target allocation of our plan assets to forecast an expected long-term return. Our expected rate of return is then selected after considering the results of each of those factors, in addition to considering the impact of current economic conditions, if applicable, on long-term historical returns.

The discount rate is computed using the Citigroup Pension Discount Curve adjusted for ALLETE's projected cash flows to match our plan characteristics. The Citigroup Pension Discount Curve is determined using high-quality long-term corporate bond rates at the valuation date.

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	$2.1	$(1.8)
Effect on Postretirement Health and Life Obligation	$23.6	$(20.9)

Actual Plan Asset Allocations

	Pension		Postretirement Health and Life *(a)*	
	2009	**2008**	**2009**	**2008**
Equity Securities	53%	46%	54%	47%
Debt Securities	28%	32%	38%	40%
Real Estate	5%	6%	–	–
Private Equity	14%	16%	8%	9%
Cash	–	–	–	4%
	100%	100%	100%	100%

(a) Includes VEBAs and irrevocable grantor trusts.

Pension plan equity securities included $9.9 million, or 3.0 percent, of ALLETE common stock at December 31, 2009 (none at December 31, 2008).

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. The majority of debt securities are made up of investment grade bonds.

Plan Asset Target Allocations

	Pension	Postretirement Health and Life *(a)*
Equity Securities	50%	48%
Debt Securities	30%	34%
Real Estate	10%	9%
Private Equity	10%	9%
	100%	100%

(a) Includes VEBAs and irrevocable grantor trusts.

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated, or generally unobservable. We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. These inputs, which are used to measure fair value, are prioritized through the fair value hierarchy. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are as follows:

Level 1 — Quoted prices are available in active markets for identical assets as of the reported date. Active markets are those in which transactions for the asset occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reported date. The types of assets included in Level 2 are typically either comparable to actively traded securities or contracts, such as treasury securities with pricing interpolated from recent trades of similar securities, or priced with models using highly observable inputs, such as commodity options priced using observable forward prices and volatilities.

Level 3 — Significant inputs that are generally less observable from objective sources. The types of assets included in Level 3 are those with inputs requiring significant management judgment or estimation, such as the complex and subjective models and forecasts used to determine the fair value.

Pension Fair Value

	At Fair Value as of December 31, 2009			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Equity Securities				
U.S. Large-cap *(a)*	$23.2	$27.5	$5.2	$55.9
U.S. Mid-cap Growth *(a)*	8.9	10.6	2.0	21.5
U.S. Small-cap *(a)*	8.6	10.1	1.9	20.6
International	–	66.4	–	66.4
ALLETE	9.9	–	–	9.9
Debt Securities:				
Mutual Funds	32.0	–	–	32.0
Fixed Income	–	59.3	–	59.3
Other Types of Investments:				
Private Equity Funds	–	–	44.7	44.7
Real Estate	–	–	17.3	17.3
Total Fair Value of Assets	$82.6	$173.9	$71.1	$327.6

(a) The underlying investments classified under U.S. Equity Securities represent Money Market Funds and U.S. Government Bonds (Level 1), Hedge Funds (Level 2), and Auction Rate Securities (Level 3), which are combined with futures, which settle daily, in a portable alpha program to achieve the returns of the U.S. Equity Securities Large-cap, Mid-cap Growth, and Small-cap funds. Our exposure with respect to these investments includes both the futures and the underlying investments.

Recurring Fair Value Measures Activity in Level 3	**Equity Securities (Auction Rate Securities)**	**Private Equity Funds**	**Real Estate**
Millions			
Balance as of December 31, 2008	$10.2	$43.2	$17.0
Actual Return on Plan Assets	0.1	(8.7)	(8.6)
Purchases, sales, and settlements, net	(1.1)	10.2	8.9
Balance as of December 31, 2009	$9.1	$44.7	$17.3

Note 16. Pension and Other Postretirement Benefit Plans (Continued)

Postretirement Health and Life Fair Value

	At Fair Value as of December 31, 2009			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Equity Securities				
U.S. Large-cap	$13.4	–	–	$13.4
U.S. Mid-cap Growth	9.0	–	–	9.0
U.S. Small-cap	6.3	–	–	6.3
International	21.4	–	–	21.4
Debt Securities:				
Mutual Funds	5.5	–	–	5.5
Fixed Income	–	$31.4	–	31.4
Other Types of Investments:				
Private Equity Funds	–	–	$9.4	9.4
Total Fair Value of Assets	$55.6	$31.4	$9.4	$96.4

Recurring Fair Value Measures Activity in Level 3	**Private Equity Funds**
Millions	
Balance as of December 31, 2008	$7.9
Actual Return on Plan Assets	(1.1)
Purchases, sales, and settlements, net	2.6
Balance as of December 31, 2009	$9.4

Accounting and disclosure requirements for the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Act) provides guidance for employers that sponsor postretirement health care plans that provide prescription drug benefits. We provide postretirement health benefits that include prescription drug benefits, which qualify us for the federal subsidy under the Act. The expected reimbursement for Medicare health subsidies reduced our after-tax postretirement medical expense by $2.0 million for 2009 ($1.2 million for 2008; $2.3 million in 2007). In 2005 we enrolled with the Centers for Medicare and Medicaid Services' (CMS) and began recovering the subsidy in 2007. We received a reimbursement of $0.6 million in 2009 and $0.3 million in 2007.

Note 17. 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 $6.5 million in 2009 ($10.1 million in 2008; $9.2 million in 2007).

Note 17. Employee Stock and Incentive Plans (Continued)

According to the accounting guidance for stock compensation, 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	**2009**	**2008**	**2007**
Millions			
ESOP Shares			
Allocated	2.2	2.0	1.8
Unallocated	1.5	1.9	2.2
Total	3.7	3.9	4.0
Fair Value of Unallocated Shares	$49.0	$61.3	$87.1

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 1.4 million shares of common stock reserved for issuance under the Executive Plan, with 0.6 million of these shares available for issuance as of December 31, 2009.

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 3,879 options were outstanding under the Director Plan at December 31, 2009.

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.

In 2009, no stock options were granted under our Executive Long-Term Incentive Compensation Plan. The following assumptions were used in determining the fair value of stock options granted during 2008 and 2007, respectively, under the Black-Scholes option-pricing model:

	2008	**2007**
Risk-Free Interest Rate	2.8%	4.8%
Expected Life	5 Years	5 Years
Expected Volatility	20%	20%
Dividend Growth Rate	4.4%	5.0%

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 the performance share awards plan, the number of shares earned is contingent upon attaining specific performance targets over a three-year performance period. Performance goals are measured by total shareholder return relative to a group of peer companies. 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 determined by the probability of meeting the total shareholder return goals. 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.

Note 17. Employee Stock and Incentive Plans (Continued)

Restricted Stock Units. Under the restricted stock units plan, shares vest at the end of a three-year period, at which time the restrictions will be removed. In the case of qualified retirement, death or disability, a pro-rata portion of the award will be earned at the conclusion of the vesting period. In the case of termination of employment for any other 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. The fair value of these awards is equal to the grant date fair value. Compensation cost is recognized over the three-year vesting 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 to apply fair value accounting to these awards.

Retirement Savings & Stock Ownership Plan (RSOP). The RSOP is a contributory defined contribution plan subject to the provisions of the Employee Retirement Income Security Act of 1974, as amended, and qualifies as an employee stock ownership plan and profit sharing plan. The RSOP provides eligible employees an opportunity to save for retirement.

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

Share-Based Compensation Expense **Year Ended December 31**	**2009**	**2008**	**2007**
Millions			
Stock Options	$0.3	$0.7	$0.8
Performance Shares	1.5	1.1	1.0
Restricted Stock Units	0.3	–	–
Total Share-Based Compensation Expense	$2.1	$1.8	$1.8
Income Tax Benefit	$0.8	$0.7	$0.7

There were no capitalized stock-based compensation costs at December 31, 2009, 2008, or 2007.

As of December 31, 2009, the total unrecognized compensation cost for the performance share awards and restricted stock units not yet recognized in our statements of income was $1.8 million and $0.5 million, respectively. These amounts are expected to be recognized over a weighted-average period of 1.7 years and 2.0 years, respectively.

The following table presents information regarding our outstanding stock options as of December 31, 2009.

	Number of Options	**Weighted-Average Exercise Price**	**Aggregate Intrinsic Value**	**Weighted-Average Remaining Contractual Term**
			Millions	
Outstanding as of December 31, 2008	672,419	$39.99	$(5.2)	6.9 years
Granted *(a)*	–	–		
Exercised	4,508	$18.85		
Forfeited	21,676	$42.62		
Outstanding as of December 31, 2009	646,235	$40.05	$(4.8)	5.9 years
Exercisable as of December 31, 2009	512,743	$37.34	$(3.7)	5.4 years

(a) Restricted stock units were issued in 2009, instead of stock options.

The weighted-average grant-date fair value of options was $6.18 for 2009 ($6.18 for 2008; $6.92 for 2007). 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 $0.1 million during 2009 ($0.2 million in 2008; $0.4 million in 2007).

Note 17. Employee Stock and Incentive Plans (Continued)

As of December 31, 2009, options outstanding consisted of 0.1 million with exercise prices ranging from $18.85 to $29.79, 0.4 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 2.1 years; all were exercisable as of December 31, 2009, at a weighted average price of $27.34. The options with exercise prices ranging from $37.76 to $41.35 have an average remaining contractual life of 6.3 years; 0.2 million were exercisable as of December 31, 2009, at a weighted average price of $39.47. The options with exercise prices ranging from $44.15 to $48.65 have an average remaining contractual life of 6.5 years; less than 0.2 million were exercisable as of December 31, 2009, at a weighted average price of $46.36.

Performance Shares. The following table presents information regarding our non-vested performance shares as of December 31, 2009.

	Number of Shares	**Weighted-Average Grant Date Fair Value**
Non-vested as of December 31, 2008	79,238	$47.94
Granted	69,800	$35.06
Unearned Grant Award	(24,615)	$41.97
Forfeited	(2,598)	$38.78
Non-vested as of December 31, 2009	121,825	$41.96

Less than 0.1 million performance share were granted in February 2009 for the performance period ending in 2011. 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 $2.2 million.

No performance shares were awarded in February 2010 for the three-year performance period ending in 2009, as performance targets were not met. However, in accordance with the accounting guidance for stock compensation, no compensation expense previously recognized in connection with those grants will be reversed.

Restricted Stock Units. The following table presents information regarding our non-vested restricted stock units as of December 31, 2009.

	Number of Shares	**Weighted-Average Grant Date Fair Value**
Non-vested as of December 31, 2008	–	–
Granted	30,465	$29.41
Forfeited	(1,482)	$29.41
Non-vested as of December 31, 2009	28,983	$29.41

Less than 0.1 million restricted stock units were granted in February 2009 for the vesting period ending in 2011. The grant date fair value of the restricted stock unit awards was $0.9 million.

Note 18. 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				
2009				
Operating Revenue	$199.6	$164.7	$178.8	$216.0
Operating Income	$31.1	$15.7	$25.4	$33.8
Net Income Attributable to ALLETE	$16.9	$9.4	$16.0	$18.7
Earnings Per Share of Common Stock				
Basic	$0.55	$0.29	$0.49	$0.56
Diluted	$0.55	$0.29	$0.49	$0.56
2008				
Operating Revenue	$213.4	$189.8	$201.7	$196.1
Operating Income	$31.3	$17.5	$33.2	$39.8
Net Income Attributable to ALLETE	$23.6	$10.7	$24.7	$23.5
Earnings Per Share of Common Stock				
Basic	$0.82	$0.37	$0.85	$0.78
Diluted	$0.82	$0.37	$0.85	$0.78

Schedule II

ALLETE
Valuation and Qualifying Accounts and Reserves

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
2008 Trade Accounts Receivable	1.0	1.0	–	1.3	0.7
Finance Receivables – Long-Term	0.2	–	–	0.1	0.1
2009 Trade Accounts Receivable	0.7	1.3	–	1.1	0.9
Finance Receivables – Long-Term	0.1	0.3	–	–	0.4
Deferred Asset Valuation Allowance					
2007 Deferred Tax Assets	3.6	(0.3)	–	–	3.3
2008 Deferred Tax Assets	3.3	(2.9)	–	–	0.4
2009 Deferred Tax Assets	0.4	(0.1)	–	–	0.3

(a) Includes uncollectible accounts written off.

Exhibit 12

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

Year Ended December 31	2009	2008	2007	2006	2005
Millions					
Earnings as defined:					
Pretax Income Before Non-Controlling Interest	$91.5	$126.4	$137.2	$128.2	$19.8
Add: Fixed Charges	38.3	30.3	26.6	27.7	27.3
Less: Non-Controlling Interest *(a)*	–	–	–	–	–
Undistributed Income from Less than 50 percent Owned Equity Investment	3.7	3.8	3.3	2.3	–
Earnings as defined:	126.1	152.9	160.5	153.6	47.1
Fixed Charges:					
Interest on Long-Term Debt	34.2	27.4	23.2	22.8	23.4
Other Interest Charges	1.6	0.4	1.5	2.9	1.1
Interest Component of All Rentals (b)	2.5	2.5	1.9	2.0	2.8
Total Fixed Charges	38.3	30.3	26.6	27.7	27.3
Ratio of Earnings to Fixed Charges	3.29	5.05	6.03	5.55	1.73

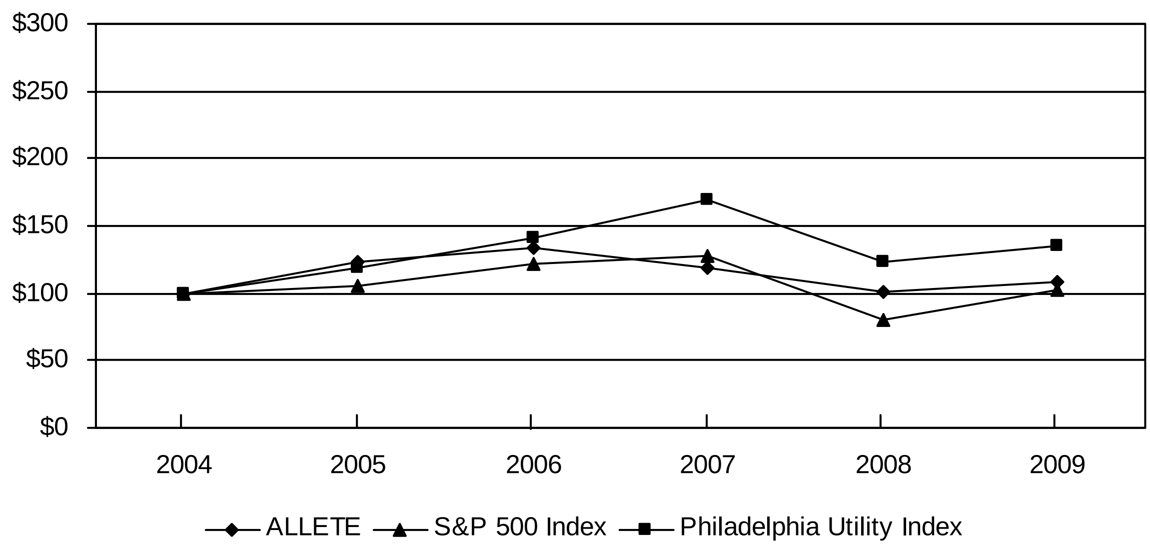
(a) Pre-tax income of subsidiaries that have not incurred fixed charges.
(b) Represents interest portion of rents estimated at 33 1/3 percent.

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 NASDAQ Philadelphia 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 electric energy.

The calculations assume a $100 investment on December 31, 2004, and reinvestment of dividends.

Total Shareholder Return for the
Five Years Ending December 31, 2009



	2004	**2005**	**2006**	**2007**	**2008**	**2009**
ALLETE	$100	$123	$134	$119	$101	$108
S&P 500 Index	$100	$105	$121	$128	$81	$102
Philadelphia Utility Index	$100	$118	$142	$169	$123	$135