ALLETE INC
Form 10-K
February 13, 2009

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

Form 10-K

(Mark One)

R Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934

For the fiscal year ended December 31, 2008

£ 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 (State or other jurisdiction of incorporation or organization)	41-0418150 (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 R 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 R

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 R 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. R

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 R	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 R

The aggregate market value of voting stock held by nonaffiliates on June 30, 2008, was $1,293,602,666.

As of February 1, 2009, there were 32,624,876 shares of ALLETE Common Stock, without par value, outstanding.

Documents Incorporated By Reference

Portions of the Proxy Statement for the 2009 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
ATC	American Transmission Company LLC
BNI Coal	BNI Coal, Ltd.
Boswell	Boswell Energy Center
Company	ALLETE, Inc. and its subsidiaries
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
FSP	Financial Accounting Standards Board Staff Position
GAAP	Accounting Principles Generally Accepted in the United States
GHG	Greenhouse Gas
Heating Degree Days	Measure of the extent to which the average daily temperature is below 65 degrees Fahrenheit, increasing demand for heating
Invest Direct	ALLETE’s Direct Stock Purchase and Dividend Reinvestment Plan
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
MPUC	Minnesota Public Utilities Commission
MW / MWh	Megawatt(s) / Megawatt-hour(s)
NextEra Energy	NextEra Energy Resources, LLC
Non-residential	Retail commercial, non-retail commercial, office, industrial, warehouse, storage and institutional
NOX	Nitrogen Oxide

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

Definitions (Continued)

Abbreviation or Acronym	Term
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
SFAS	Statement of Financial Accounting Standards No.
SO2	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 results,” “will continue, “ “could,” “may,” “potential,” “target,” “outlo 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;
- our ability to manage expansion and integrate acquisitions;
- prevailing governmental policies, regulatory actions, and legislation including those of the United States Congress, state legislatures, the FERC, the MPUC, the PSCW, and various local and county regulators, and city administrators, 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;
- 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 20 of this Form 10-K. Any forward-looking statement speaks only as of the date on which such statement is made, and we undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which that statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of these factors, nor can it assess the impact of each of these factors on the businesses of ALLETE or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. Readers are urged to carefully review and consider the various disclosures made by us in this Form 10-K and in our other reports filed with the SEC that attempt to advise interested parties of the factors that may affect our business.

Part I

Item 1. Business

In the fourth quarter of 2008, we made changes to our reportable business segments which are now comprised of Regulated Operations and Investments and Other. For additional information about our business segments, see Note 2.

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 142,000 retail customers and wholesale electric service to 16 municipalities. SWL&P provides regulated electric service, natural gas and water service in northwestern Wisconsin to 15,000 electric customers, 12,000 natural gas customers and 10,000 water customers. Our regulated utility operations include retail and wholesale activities under the jurisdiction of state and federal regulatory authorities. (See Item 1. 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 business. This segment also includes emerging technology investments ($7.4 million at December 31, 2008), a small amount of non-rate base generation, approximately 7,000 acres of land for sale in Minnesota, and earnings on cash and short-term investments.

ALLETE is incorporated under the laws of Minnesota. Our corporate headquarters are in Duluth, Minnesota. Statistical information is presented as of December 31, 2008, 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	2008	2007	2006
Consolidated Operating Revenue – Millions	$801.0	$841.7	$767.1
Percentage of Consolidated Operating Revenue			
Regulated Operations	89	86	83
Investments and Other	11	14	17
	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	2008	%	2007	%	2006	%
Millions of Kilowatt-hours						
Retail and Municipals						

Residential	1,172	9	1,141	9	1,100	9
Commercial	1,454	12	1,456	11	1,420	11
Industrial	7,192	57	7,054	55	7,206	56
Municipals (FERC rate regulated)	1,002	8	1,009	8	905	7
	10,820	86	10,660	83	10,631	83
Other Power Suppliers	1,800	14	2,157	17	2,153	17
	12,620	100	12,817	100	12,784	100

REGULATED OPERATIONS (Continued)

Industrial Customers. In 2008, our industrial customers represented 57 percent of total regulated utility kilowatt-hour sales. Our industrial customers are primarily in the taconite, paper, pulp, wood products and pipeline industries.

Industrial Customer Electric Sales Year Ended December 31	2008	%	2007	%	2006	%
Millions of Kilowatt-hours						
Taconite Producers	4,579	64	4,408	62	4,517	63
Paper, Pulp and Wood Products	1,567	22	1,613	23	1,689	23
Pipelines	582	8	562	8	550	8
Other Industrial	464	6	471	7	450	6
	7,192	100	7,054	100	7,206	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 represent 4,579 kilowatt-hours, or 64 percent, of our total industrial sales in 2008. Taconite, an iron-bearing rock of relatively low iron content, is abundantly available in 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. Strong worldwide steel demand, driven largely by extensive infrastructure development in China, resulted in very robust world iron ore demand and steel pricing for nearly a six-year period which lasted through the summer of 2008. Beginning in the fall of 2008, worldwide steel producers began to dramatically cut steel production in response to reduced demand driven largely by the world credit situation. (See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Outlook.)

In addition to serving the taconite industry, Minnesota Power also serves a number of customers in the paper, pulp and wood products industry, which represent 1,567 kilowatt-hours, or 22 percent, of our total industrial sales in 2008. 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 three wood product manufacturers.

Minnesota Power's paper and pulp customers ran at, or very near, full capacity for the majority of 2008 despite the fact that the industry continued to face high fiber, chemical, and energy costs as well as competition from exports in certain grades of paper products. Minnesota Power's customers benefited from the temporary or permanent idling of plants both in North America at mills other than those served by Minnesota Power and the idling of plants in Europe, as well as continued (but declining) 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, which represent 582 kilowatt-hours, or 8 percent, of our total industrial sales in 2008. These customers have a common reliance on the importation of Canadian crude oil. After near capacity operations in 2006, 2007, and 2008, 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 contracts with 12 Large Power Customers, 11 of which require 10 MWs or more of generating capacity and one that requires at least 8 MWs of generating capacity. These customers consist of six taconite producing facilities (two of which are owned by one company and are served under a single contract), four paper and pulp mills, two pipeline companies and one manufacturer.

Large Power Customer contracts require Minnesota Power to have a certain amount of generating capacity available. 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 Regulatory Matters – Electric Rates)

REGULATED OPERATIONS (Continued)
Large Power Customers (Continued)

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, 2009

Customer	Industry	Location	Ownership	Earliest Termination Date
Hibbing Taconite Co. (a)	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, 2013
United States Steel Corporation (USS – Minnesota Ore) (c)	Taconite	Mt. Iron, MN and Keewatin, MN	United States Steel Corporation	October 31, 2013
United Taconite LLC (a)	Taconite	Eveleth, MN	Cliffs Natural Resources Inc.	December 31, 2015
UPM, Blandin Paper Mill (b)	Paper	Grand Rapids, MN	UPM-Kymmene Corporation	February 28, 2013
Boise White Paper, LLC (d)	Paper	International Falls, MN	Boise Paper Holdings, LLC	December 31, 2013
Sappi Cloquet LLC (b)	Paper and Pulp	Cloquet, MN	Sappi Limited	February 28, 2013
NewPage Corporation – Duluth Mills	Paper and Pulp	Duluth, MN	NewPage Corporation	August 31, 2013
USG Interiors, Inc. (e)	Manufacturer	Cloquet, MN	USG Corporation	December 31, 2009
Enbridge Energy Company, Limited Partnership (e)	Pipeline	Deer River, MN Floodwood, MN	Enbridge Energy Company, Limited Partnership	June 30, 2009
Minnesota Pipeline Company (e)	Pipeline	Staples, MN Little Falls, MN Park Rapids, MN	60% Koch Pipeline Co. L.P. 40% Marathon Ashland Petroleum LLC	April 7, 2009

(a) Contract extensions at Hibbing Taconite Co. and United Taconite LLC are pending final approval from the MPUC.
(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, 2013.

(c) United States Steel Corporation includes the Minntac Plant in Mountain Iron, MN and the Keewatin Taconite Plant in Keewatin, MN.

(d) A contract amendment has been filed with the MPUC which provides for an extension of the agreement through December 31, 2013.

(e) Contracts with USG Interiors, Inc., Minnesota Pipeline Company, and Enbridge Energy Company are all in cancellation periods effective on or before December 31, 2009; new contracts are expected to be agreed upon prior to expiration.

In March 2008, Minnesota Power signed a new contract with Northshore Mining Company to meet additional load requirements. The contract was approved by the MPUC and runs through at least June 30, 2011.

In September 2008, Cliffs Natural Resources Inc. (Cliffs) and Minnesota Power signed new contracts for service to Hibbing Taconite Co. and United Taconite LLC. These electric service agreements, which are pending final MPUC approval, extend the existing contract terms out to at least December 31, 2015.

REGULATED OPERATIONS (Continued)

Residential and Commercial Customers. In 2008, our residential and commercial customers represented 21 percent of total regulated utility kilowatt-hour sales. Minnesota Power provides regulated utility electric service in northeastern Minnesota to approximately 142,000 residential and commercial customers. SWL&P provides regulated electric service, natural gas and water service in northwestern Wisconsin to 15,000 electric customers, 12,000 natural gas customers and 10,000 water customers.

Municipal Customers. In 2008, our municipal customers represented 8 percent of total regulated utility kilowatt-hour sales. Our municipal customers consist of 16 municipalities in Minnesota and 1 private utility in Wisconsin. The FERC has jurisdiction over our wholesale electric service, tariff rates, and operations. In 2008 Minnesota Power entered into new contracts with all of our municipal customers with the exception of one small customer whose contract is now in the cancellation period. The new contracts transition each customer to formula based rates, which means rates can be adjusted annually based on changes in costs. The new agreement with the private utility in Wisconsin is subject to PSCW approval. In November 2008, we filed a request with the FERC to implement the formula based rate provision in the new contracts. We anticipate final resolution and implementation of new rates in the first quarter of 2009.

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 coal, 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 SFAS 133 “Accounting for Derivative Instruments and Hedging Activities” and are not required to be recorded at fair value.

For 2009, we have sold up to 225 MWs per month to Other Power Suppliers to mitigate the demand reduction expected from our taconite customers; these contracts expire at various times during 2009.

Power Supply

In order to meet our customer’s electric requirements, we utilize a mix of Company generation and purchased power. The Company’s generation is primarily coal fired, but also includes approximately 112 MWs of hydro generation from nine 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, 2008. Minnesota Power had an annual net peak load of 1,582 MWs on January 18, 2008.

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REGULATED OPERATIONS (Continued)
Power Supply (Continued)

Regulated Utility Power Supply	Unit No.	Year Installed	Net Winter Capability	For the Year Ended December 31, 2008 Electric Requirements	
			MW	MWh	%
Coal-Fired					
Boswell Energy Center	1	1958	69		
in Cohasset, MN	2	1960	69		
	3	1973	350		
	4	1980	429		
			917	6,365,305	48.5%
Laskin Energy Center	1	1953	55		
in Hoyt Lakes, MN	2	1953	55		
			110	659,439	5.0
Taconite Harbor Energy Center	1	1957	73		
in Taconite Harbor, MN	2	1957	73		
	3	1967	74		
			220	1,473,239	11.2
Total Coal			1,247	8,497,983	64.7
Steam – Purchased					
Hibbard Energy Center in Duluth, MN	3 & 4	1949, 1951	45	61,635	0.5
Hydro					
Group consisting of nine stations in MN	Various		112	487,930	3.7
Wind					
Taconite Ridge (a)	1	2008	4	18,587	0.2
Total Company Generation			1,408	9,066,135	69.1
Long Term Purchased Power					
Square Butte burns lignite coal near Center, ND				1,943,949	14.8
Wind – Oliver County, ND				366,945	2.8
Hydro – Manitoba Hydro				390,680	3.0
Total Long Term Purchased Power				2,701,574	20.6
Other Purchased Power(b)				1,357,023	10.3
Total Purchased Power				4,058,597	30.9
Total			1,408	13,124,732	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 2008 for electric generation at Minnesota Power's coal-fired generating stations was approximately 5.2 million tons. As of December 31, 2008, Minnesota Power had a coal inventory of about 631,000 tons. Minnesota Power's primary coal supply agreements have expiration dates that are staggered from the end of 2009 through 2011. Under these agreements, Minnesota Power has the tonnage flexibility to procure 70 percent to 100 percent of its total coal requirements. In 2009, 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 Burlington Northern Santa Fe Railway Company (BNSF) entered into a long-term agreement under which BNSF transports all of Minnesota Power’s coal by unit train from the Powder River Basin directly to Minnesota Power’s generating facilities or to 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.

REGULATED OPERATIONS (Continued)
Fuel (Continued)

On January 24, 2008, we received a letter from BNSF alleging that the Company defaulted on a material obligation under the Company's Coal Transportation Agreement (CTA). In the notice, BNSF claimed the Company underpaid approximately $1.6 million for coal transportation services in 2006 and that failure to pay such amount plus interest may result in BNSF's termination of the CTA. We believe we do not owe the amount claimed. On April 1, 2008, to ensure that BNSF did not attempt to terminate the CTA, we paid under protest the full amount claimed by BNSF and filed a demand for arbitration of the issue. On April 22, 2008, BNSF filed a counterclaim in the arbitration disputing our position that we are entitled to a refund from BNSF of $1.5 million plus interest for amounts that we overpaid for 2007 deliveries. The arbitration is proceeding in connection with the claim regarding 2006 payments and the counterclaim regarding 2007 payments, and we are unable to predict the outcome at this time. The delivered costs of fuel for the Company's generation are recoverable from Minnesota Power's utility customers through the fuel adjustment clause.

Coal Delivered to Minnesota Power			
Year Ended December 31	2008	2007	2006
Average Price per Ton	$22.73	$21.78	$20.19
Average Price per MBtu	$1.25	$1.20	$1.10

Long Term Purchased Power. Minnesota Power has contracts to purchase capacity and energy from various entities. The largest contract is with Square Butte. Under an agreement with Square Butte, expiring at the end of 2026, Minnesota Power is currently entitled to approximately 50 percent of the output of a 455-MW coal-fired generating unit located near Center, North Dakota. (See Note 8. Commitments, Guarantees, and Contingencies.) The Square Butte generating unit operated by Minnkota Power burns North Dakota lignite coal supplied by BNI Coal in accordance with the terms of a contract that extends through 2026. Square Butte's cost of lignite burned in 2008 was approximately $0.93 per MBtu. 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.

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 currently have a 50 MW power purchase agreement with Manitoba Hydro that expires in April 2009. We have entered into an additional 50 MW power purchase agreement with Manitoba Hydro that begins May 2009 and runs through April 2015.

Transmission and Distribution

We have electric transmission and distribution lines of 500 kV (8 miles), 230 kV (605 miles), 161 kV (43 miles), 138 kV (126 miles), 115 kV (1,224 miles) and less than 115 kV (6,215 miles). We own and operate 165 substations with a total capacity of 10,179 megavoltamperes. Some of our transmission and distribution lines interconnect with other utilities.

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, pursuant to EITF 03-16, "Accounting for Investments in Limited Liability Companies." As of December 31, 2008, our equity investment balance in ATC was $76.9 million ($65.7 million at December 31, 2007).

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 MPUC, FERC, and PSCW had regulatory authority over 62 percent, 10 percent, and 9 percent, respectively, of our 2008 consolidated operating revenue.

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 – Winter 2008 and Rankings – July 1, 2008) ranked Minnesota Power as having the ninth lowest average retail rates out of 175 investor-owned utilities in the United States. According to this report, we had the lowest rates in Minnesota and in the region consisting of Iowa, Kansas, Minnesota, Missouri, North Dakota, South Dakota and Wisconsin.

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

Minnesota Public Utilities Commission. On May 2, 2008, Minnesota Power filed a rate increase request with the MPUC seeking an average rate increase of 8.5 percent for retail customers. The rate filing seeks a return on equity of 11.15 percent, and a capital structure consisting of 54.8 percent equity and 45.2 percent debt. On an annualized basis, the requested rate increase would generate approximately $40 million in additional revenue. Interim rates were effective on August 1, 2008, and resulted in an increase for retail customers of approximately $36 million, or 7.5 percent, on an annualized basis, subject to refund pending the final rate order. Incremental revenue in 2008 from the interim retail rate increase was approximately $13 million. The transition to a new base cost of fuel coincident with interim rates resulted in the non-recovery through the fuel adjustment clause of approximately $19 million of fuel and purchased power costs incurred in 2008. We have entered into a stipulation and settlement agreement that would allow recovery of the $19 million in 2009 and which addresses specific concerns identified by interveners in the rate case; the stipulation and settlement agreement is subject to MPUC approval. The final rate order is expected in the second quarter of 2009. We cannot predict the final level of rates that may be approved by the MPUC. Prior to the May 2008 retail rate request Minnesota Power's rates were based on a 1994 MPUC retail rate order that allowed for an 11.6 percent return on equity.

Integrated Resource Plan. In October 2007, Minnesota Power filed its Integrated Resource Plan (IRP), a comprehensive estimate of future capacity needs within the Minnesota Power service territory. In October 2008, the MPUC issued an order approving our request to re-file the IRP by October 1, 2009 in order to incorporate the North Dakota wind project and otherwise update our load forecasting and modeling in the IRP. (See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations - Outlook for additional information on the

North Dakota wind project.)

Minnesota Power plans to meet expected loads through approximately 2020 by adding a significant amount of renewable generation and some supporting peaking generation. We plan to add 300 to 500 megawatts of carbon-minimizing renewable energy to our generation mix. Besides the additional generation from renewable sources, Minnesota Power anticipates future supply will come from a combination of sources, including:

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

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

REGULATED OPERATIONS (Continued)
Regulatory Matters (Continued)

AREA and Boswell Unit 3 Emission Reduction Plans. In May 2006, the MPUC authorized current cost recovery of expenditures to reduce emissions of SO2, NOX, and mercury emissions at Taconite Harbor and Laskin under the AREA Plan. The AREA Plan has significantly reduced emissions from Taconite Harbor and Laskin, while maintaining a reliable and reasonably-priced energy supply to meet the needs of our customers. Environmental retrofits at Laskin and Taconite Harbor Units 1 and 2 are complete and in service. The environmental regulatory requirements for Taconite Harbor Unit 3 are pending finalization of the Minnesota Regional Haze implementation plan by the MPCA. We are expecting to retrofit Taconite Harbor Unit 3 by 2013 and are evaluating compliance requirements and cost recovery options for this final unit.

We are making emission reduction investments at our Boswell Unit 3 generating unit. The investments in pollution control equipment will reduce particulates, SO2, NOX, and mercury emissions to meet future federal and state requirements. The MPUC has authorized a cash return on construction work in progress during the construction phase in lieu of AFUDC-Equity and allows for a return on investment and current cost recovery of incremental operations and maintenance expenses once the new equipment is installed and the unit is placed back in service in late 2009. We began cost recovery on January 1, 2008. In September 2008, we filed a petition with the MPUC to approve the Boswell Unit 3 rate adjustment for 2009. If approved, new rates would allow cost recovery relating to additional investments planned for 2009.

Boswell NOX Reduction Plan. In September 2008, we submitted to the MPCA and MPUC a $92 million environmental initiative proposing cost recovery for NOX emission reductions from Boswell Units 1, 2, and 4. If approved by the MPUC, the Boswell NOX Reduction Plan is expected to significantly reduce NOX emissions from these units. In conjunction with the NOX reduction Plan, we plan to install an efficiency upgrade to the existing turbine/generator at Boswell Unit 4 adding approximately 60 MWs of total output with no additional emissions. A second filing requesting cost recovery for the plan will be submitted to the MPUC in the first quarter of 2009.

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 May 2007, an abbreviated filing was submitted and subsequently approved by the MPUC, allowing the continuation of Minnesota Power's 2006-2007 CIP biennial and related goals for one additional year, through 2008. For future program years, Minnesota Power will build upon current successful CIPs in an effort to meet the newly established 1.5 percent energy-saving goal. Minnesota Power's CIP investment goal was $3.7 million for 2008 ($3.2 million for 2007 and 2006), with actual spending of $4.8 million in 2008 ($3.9 million in 2007; $3.8 million in 2006).

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

On February 8, 2008, the FERC approved Minnesota Power's wholesale tariff rate increase effective March 1, 2008. Minnesota Power's wholesale customers consist of 16 municipalities in Minnesota and 1 private utility in Wisconsin. The FERC authorized an average 10.0 percent increase for wholesale municipal customers, and an overall return on equity of 11.25 percent. Incremental revenue in 2008 from the FERC authorized wholesale rate increase was approximately $6 million.

Public Service Commission of Wisconsin. 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 common 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.

Regional Organizations

Midwest Independent Transmission System Operator, Inc. Minnesota Power and SWL&P are members of MISO, a regional transmission organization. Minnesota Power and SWL&P retain ownership of their respective transmission assets and control area functions, but their transmission network is under the regional operational control of MISO, and they take and provide transmission service under 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 have been instituted by the ASM market. The MPUC held a discussion-only hearing on the joint filing in December 2008, and has indicated it will likely bring the matter back before the MPUC in the first quarter of 2009.

REGULATED OPERATIONS (Continued)
Regional Organizations (Continued)

Mid-Continent Area Power Pool (MAPP). Minnesota Power also participates in MAPP, a power pool operating in parts of eight states in the Upper Midwest and in two Canadian provinces. MAPP functions include a regional transmission committee and a generation reserve sharing pool.

Minnesota Legislation

Renewable Energy. In February 2007, Minnesota enacted a law requiring Minnesota Power to generate or procure 25 percent of our energy 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. 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

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

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. We cannot predict the timing or substance of any future legislation or regulation.

Franchises

Minnesota Power holds franchises to construct and maintain an electric distribution and transmission system in 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 business. This segment also includes emerging technology investments ($7.4 million at December 31, 2008), a small amount of non-rate base generation, approximately 7,000 acres of land for sale in Minnesota, and earnings on cash and short-term 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 coal supply agreements extending through 2026. (See Item 1. Business – Fuel and Note 8. 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 is our real estate business that has operated in Florida since 1991. Our current strategy is to complete and maintain key entitlements and infrastructure improvements which enhance values without requiring significant additional investment, and position the current property portfolio for a maximization of value and cash flow when market conditions improve.

Our two major development projects include Town Center and Palm Coast Park. A third proposed development project, Ormond Crossings, is in the permitting and planning stage. Development activities involve mainly zoning, permitting, platting, and master infrastructure construction. Development costs are financed through a combination of community development district bonds, bank loans, and internally-generated funds.

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 2006. At build-out, Town Center is expected to include approximately 3,200 residential units and 3.8 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. Major infrastructure construction 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, 3.2 million square feet of various types of non-residential space and certain public facilities. Market conditions will determine how quickly Palm Coast Park builds out.

Ormond Crossings. Ormond Crossings is an approximately 6,000-acre mixed-use development that is located in both the city of Ormond Beach in Volusia County and unincorporated Flagler County. Planning, engineering design, and permitting of the master infrastructure are ongoing. We estimate the first two phases of Ormond Crossings will include 2,500–3,200 residential units and 2.5–3.5 million square feet of various types of non-residential space. Ormond Crossings will also include approximately 2,000 acres of a regionally significant wetlands mitigation bank that was permitted by the St. Johns River Water Management District in 2008 and is expected to be permitted by the U.S. Army Corps of Engineers in 2009. Wetland mitigation credits will be used at Ormond Crossings and will be available-for-sale to other developers. Market conditions will determine when and if Ormond Crossings will be built out. We do not expect any significant activity in 2009.

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

Seller Financing. ALLETE Properties sometimes provides seller financing. At December 31, 2008, outstanding finance receivables were $13.6 million, with maturities up to 4 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.

INVESTMENTS AND OTHER (Continued)

Non-Rate Base Generation

Non-Rate base generation consists of approximately 50 MWs of generation. In 2008, we sold 0.2 million MWh of non-rate base generation (0.2 million in 2007 and 2006).

Non-Rate Base Power Supply	Unit No.	Year Installed	Year Acquired	Net Capability MW
Steam				
Wood-Fired (a)				
Cloquet Energy Center	5	2001	2001	23
in Cloquet, MN				
Rapids Energy Center (b)	6 & 7	1969, 1980	2000	29
in Grand Rapids, MN				
Hydro				
Conventional Run-of-River				
Rapids Energy Center (b)	4 & 5	1917	2000	1
in Grand Rapids, MN				

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

Other

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

Emerging Technology Investments. The majority of our emerging technology investments are minority investments in venture capital funds. We account for our investment in venture capital funds under the equity method of accounting. The total carrying value of our emerging technology portfolio was $7.4 million at December 31, 2008. (See Note 6. Investments.) Our remaining commitment of $0.7 million at December 31, 2008 may be invested in 2009. We do not have plans to make any additional investments beyond this commitment.

Environmental Matters

Our businesses are subject to regulation of environmental matters by various federal, state and local authorities. We consider our businesses to be in substantial compliance with currently applicable environmental regulations and believe all necessary permits to conduct such operations have been obtained. Due to future stricter environmental requirements through legislation and/or rulemaking, we anticipate that potential expenditures for environmental matters will be material and will require significant capital investments. (See Item 7. 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 becomes available. Accruals for environmental liabilities are included in the balance sheet at undiscounted amounts and exclude claims for recoveries from insurance or other third parties. Costs related to environmental contamination treatment and cleanup are charged to expense unless recoverable in rates from customers.

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 SO2 and system wide averaging NOX 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 permitted emission requirements.

Environmental Matters (Continued)
Air (Continued)

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. The NOV asserts 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.

The EPA has been conducting a nationwide enforcement initiative since 1999 relating to NSR requirements. In 2000, 2001, and 2002 Minnesota Power received requests from the EPA pursuant to Section 114(a) of the Clean Air Act seeking information regarding capital expenditures with respect to Boswell and Laskin. Minnesota Power responded to these requests; however, we had no further communications from the EPA regarding the information provided until receipt of the NOV.

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 SO2, NOX, and particulates in the eastern United States. Minnesota is 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, Minnesota Power has received written assurance from the EPA that it intends to publish a rule amending 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. Minnesota Power anticipates the EPA will act regarding this Minnesota administrative stay of the CAIR before CAIR compliance reporting would be required in 2010. If the CAIR ultimately goes into effect in Minnesota, we expect we will have to supplement ongoing emission control retrofits by providing for CAIR related emission allowance purchases, supplemental emission reductions or a combination of both.

Minnesota Regional Haze. The 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 of visibility-impairing emissions that were put in place between 1962 and 1977 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) that 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 has requested that companies with BART eligible units complete and submit a BART emissions control retrofit study, which we did as to Taconite Harbor Unit 3 in November 2008. The retrofit work currently underway on Boswell Unit 3 meets the BART requirement for that unit. It is uncertain what controls will ultimately be required by the MPCA at Taconite Harbor Unit 3 in connection with the regional haze rule.

EPA Clean Air Mercury Rule. In March 2005, the EPA also announced the Clean Air Mercury Rule (CAMR) that would have reduced and permanently capped emissions of electric utility mercury emissions in the continental United States. In February 2008, the Court overturned the CAMR and remanded the rulemaking to the EPA for reconsideration. In October 2008, the Department of Justice, on behalf of the EPA, petitioned the Supreme Court to review the Court’s decision in the CAMR case. It is uncertain how the Supreme Court will respond. Cost estimates for complying with CAMR or future mercury regulations under the Clean Air Act are therefore premature at this time.

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

Environmental Matters (Continued)

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

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

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. We have accrued a $0.5 million liability for this site at December 31, 2008, and have recorded a corresponding regulatory asset as we expect recovery of remediation costs to be allowed by the PSCW.

Employees

At December 31, 2008, ALLETE had 1,529 employees, of which 1,449 were full-time.

Minnesota Power and SWL&P have an aggregate 635 employees who are members of the International Brotherhood of Electrical Workers (IBEW) Local 31. The labor agreement with IBEW Local 31 expired on January 31, 2009. Both parties have agreed to extend the current agreement until a new agreement is signed. Negotiations are proceeding as anticipated and we remain optimistic of achieving a ratified agreement.

BNI Coal has 94 employees who 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 13, 2009, these are the executive officers of ALLETE.

Executive Officers	Initial Effective Date
Donald J. Shippar, Age 59	
Chairman, President and Chief Executive Officer	January 1, 2006
President and Chief Executive Officer	January 21, 2004
Executive Vice President – ALLETE and President – Minnesota Power	May 13, 2003
President and Chief Operating Officer – Minnesota Power	January 1, 2002
Robert J. Adams, Age 46	
Vice President – Business Development and Chief Risk Officer	May 13, 2008
Vice President – Utility Business Development	February 1, 2004
Deborah A. Amberg, Age 43	
Senior Vice President, General Counsel and Secretary	January 1, 2006
Vice President, General Counsel and Secretary	March 8, 2004
Steven Q. DeVinck, Age 49	
Controller	July 12, 2006
Mark A. Schober, Age 53	
Senior Vice President and Chief Financial Officer	July 1, 2006
Senior Vice President and Controller	February 1, 2004
Vice President and Controller	April 18, 2001
Donald W. Stellmaker, Age 51	
Treasurer	July 24, 2004
Claudia Scott Welty, Age 56	
Senior Vice President and Chief Administrative Officer	February 1, 2004

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

Ms. Amberg was a Senior Attorney.
Mr. DeVinck was Director of Nonutility Business Development, and Assistant Controller.
Mr. Stellmaker was Director of Financial Planning.

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 12, 2009.

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 12 Large Power Customers accounted for approximately 36 percent of our 2008 consolidated operating revenue (one of these customers accounted for 12.5 percent of consolidated revenue). These customers are involved in cyclical industries that by their nature are adversely impacted by economic downturns and are subject to strong competition in the global marketplace. An economic downturn or failure to compete effectively in the global economy could have a material adverse effect on their operations and, consequently, could negatively impact our results of operations if we are unable to remarket this energy at similar prices.

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

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

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

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

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

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

The cost of environmental emission allowances could have a negative financial impact on our 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 emission allowance pricing or regulatory recovery of these costs. We are pursuing a current cost recovery mechanism with the MPUC.

Risk Factors (Continued)

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 its customers.

Minnesota Power depends on transmission and distribution facilities owned by other utilities, and transmission facilities primarily operated by MISO, as well as its own such facilities, to deliver the electricity we produce and sell to our customers, and to other energy suppliers. If transmission capacity is inadequate our ability to sell and deliver electricity may be hindered. We may have to forego sales or we may have to buy more expensive wholesale electricity that is available in the capacity-constrained area. 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 non-rate base operations at this time.

Risk Factors (Continued)

We are dependent on good labor relations.

We believe our relations to be good with our 1,529 employees. Failure to successfully renegotiate labor agreements could adversely affect the services we provide and our results of operations. 729 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. Both parties have agreed to extend the current agreement until a new agreement is signed. Negotiations are proceeding as anticipated and we remain optimistic of achieving a ratified agreement. The labor agreement with Local 1593 at BNI Coal expires on March 31, 2011.

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

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

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

Development of real property in Florida entails an extensive approval process involving overlapping regulatory jurisdictions. Real estate projects must generally comply with the provisions of the Local Government Comprehensive Planning and Land Development Regulation Act (Growth Management Act). In addition, development projects that exceed certain specified regulatory thresholds require approval of a comprehensive DRI application. The Growth Management Act, in some instances, can significantly affect the ability of developers to obtain local government approval in Florida. In many areas, infrastructure funding has not kept pace with growth. As a result, substandard facilities and services can delay or prevent the issuance of permits. Consequently, the Growth Management Act could adversely affect the cost and our ability to develop future real estate projects. 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 return rates. 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.

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, volatility in commodity prices or events such as those currently being experienced in the United States and abroad.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

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

Item 3. Legal Proceedings

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

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

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

No matters were submitted to a vote of security holders during the fourth quarter of 2008.

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, 2009, to the holders of record on February 16, 2009.

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:

	2008			2007		
	Price Range		Dividends	Price Range		Dividends
Quarter	High	Low	Declared	High	Low	Declared
First	$39.86	$33.76	$0.43	$49.69	$44.93	$0.41
Second	46.11	38.82	0.43	51.30	45.39	0.41
Third	49.00	38.05	0.43	50.05	38.60	0.41

Fourth	44.63	28.28	0.43	46.48	38.17	0.41
Annual Total			$1.72			$1.64
Dividend Payout Ratio			61%			53%

At February 1, 2009, there were approximately 29,000 common stock shareholders of record.

Common Stock Repurchases. We did not repurchase any ALLETE common stock during the fourth quarter of 2008.

Item 6. Selected Financial Data

	2008	2007	2006	2005	2004
Operating Revenue	$801.0	$841.7	$767.1	$737.4	$704.1
Operating Expenses	679.2	710.0	628.8	692.3(g)	603.2
Income from Continuing Operations Before Change in Accounting Principle	82.5	87.6	77.3	17.6(g)	38.5
Income (Loss) from Discontinued Operations – Net of Tax	–	–	(0.9)	(4.3)(g)	73.7
Change in Accounting Principle – Net of Tax	–	–	–	–	(7.8)(h)
Net Income	82.5	87.6	76.4	13.3	104.4
Common Stock Dividends	50.4	44.3	40.7	34.4	79.7
Earnings Retained in (Distributed from) Business	$32.1	$43.3	$35.7	$(21.1)	$24.7
Shares Outstanding – Millions					
Year-End	32.6	30.8	30.4	30.1	29.7
Average (a)					
Basic	29.2	28.3	27.8	27.3	28.3
Diluted	29.3	28.4	27.9	27.4	28.4
Diluted Earnings (Loss) Per Share (b)					
Continuing Operations	$2.82	$3.08	$2.77	$0.64(g)	$1.35 (i)
Discontinued Operations (c)	–	–	(0.03)	(0.16)	2.59
Change in Accounting Principle	–	–	–	–	(0.27)
	$2.82	$3.08	$2.74	$0.48	$3.67
Total Assets	$2,134.8	$1,644.2	$1,533.4(f)	$1,398.8	$1,431.4
Long-Term Debt	588.3	410.9	359.8	387.8	389.4
Return on Common Equity	10.7%	12.4%	12.1%	2.2%(g)	8.3%
Common Equity Ratio	58.0%	63.7%	63.1%	60.7%	61.7%
Dividends Declared per Common Share	$1.72	$1.64	$1.45	$1.245	$2.8425
Dividend Payout Ratio	61%	53%	53%	259%(g)	77%
Book Value Per Share at Year-End	$25.37	$24.11	$21.90	$20.03	$21.23
Capital Expenditures by Segment (d)					
Regulated Operations	$317.0	$220.6	$107.5	$46.5	$41.7
Investments and Other (e)	5.9	3.3	1.9	12.1	16.1
Discontinued Operations	–	–	–	4.5	21.4
Total Capital Expenditures	$322.9	$223.9	$109.4	$63.1	$79.2

(a) Excludes unallocated ESOP shares.

(b) Common share and per share amounts have also been adjusted for all periods to reflect our September 20, 2004, one-for-three common stock reverse split.

(c) Operating results of our Water Services businesses and our telecommunications business are included in discontinued operations, and accordingly, amounts have been restated for all periods presented. (See Note 12. Discontinued Operations.)

(d)

In the fourth quarter of 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.)

(e) Excludes capitalized improvements on our development projects, which are included in inventory.

(f) Included $86.1 million of assets reflecting the adoption of SFAS 158 “Employers’ Accounting for Defined Benefit Pension and Other Postretirement Plans.”

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

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

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

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 142,000 retail customers and wholesale electric service to 16 municipalities. SWL&P provides regulated electric service, natural gas and water service in northwestern Wisconsin to 15,000 electric customers, 12,000 natural gas customers and 10,000 water customers. Our regulated utility operations include retail and wholesale activities under the jurisdiction of state and federal regulatory authorities. (See Item 1. 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 business. This segment also includes emerging technology investments ($7.4 million at December 31, 2008), a small amount of non-rate base generation, approximately 7,000 acres of land for sale in Minnesota, and earnings on cash and short-term investments.

ALLETE is incorporated under the laws of Minnesota. Our corporate headquarters are in Duluth, Minnesota. Statistical information is presented as of December 31, 2008, 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.

2008 Financial Overview

Net income for 2008 was $82.5 million, or $2.82 per diluted share compared to $87.6 million, or $3.08 per diluted share for 2007. Earnings per diluted share decreased approximately $0.08 compared to 2007 as a result of additional shares of common stock outstanding in 2008. (See Note 9. Common Stock and Earnings Per Share.) Net income for 2008 was down $5.1 million from 2007 reflecting:

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 interim rate increase (subject to refund) for retail customers in Minnesota, and 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.

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.

2008 Compared to 2007

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

Regulated Operations

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.

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

Higher rates resulted from the August 1, 2008 interim rate increase (subject to refund) 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
Millions		
Regulated Utility		
Retail and Municipals		
Residential	1,172	1,141
Commercial	1,372	1,373
Industrial	7,192	7,054
Municipals	1,002	1,008
Other	82	84
Total Retail and Municipals	10,820	10,660
Other Power Suppliers	1,800	2,157
Total Regulated Utility Kilowatt-hours Sold	12,620	12,817

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 reflecting higher electricity production at the Company's generation facilities. Megawatt-hour generation at our facilities and Square Butte increased 9 percent over 2007.

Operating and Maintenance Expense increased $10.0 million, or 4 percent, over 2007 primarily due to increased gas purchases, reflecting a colder 2008, and higher salaries and wages.

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. We had been seeking to have the increased depreciation rates become effective with the date of final rates in the current retail rate filing (expected to be in the second quarter of 2009).

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. Investments.)

Investments and Other

Operating revenue decreased $29.1 million, or 25 percent, from 2007 primarily due to a decrease in revenue at ALLETE Properties. Weaker real estate market conditions in Florida led to the decline. Operating revenue in 2008 included a pre-tax gain of $4.5 million on the sale of our retail shopping center in Winter Haven, Florida in May 2008, as well as $3.7 million in previously deferred revenue.

2008 Compared to 2007 (Continued)
Investments and Other (Continued)

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		8.3		6.2
		$18.3		$50.5

(a) Acreage amounts are shown on a gross basis, including wetlands and minority 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.)

Operating expenses decreased $5.7 million, or 6 percent, from 2007 reflecting a decrease in the cost of real estate sold and decreased selling expenses.

Other income increased $0.6 million, or 5 percent, from 2007 primarily due to a $3.8 million after-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.

Income Taxes – Consolidated

For the year ended December 31, 2008, the effective tax rate on income from continuing operations before minority 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.

2007 Compared to 2006

Regulated Operations

Operating revenue increased $84.6 million, or 13 percent, from 2006 primarily due to increased fuel and purchased power recoveries, increased kilowatt-hour sales to residential, commercial and municipal customers, increased power marketing prices, and rate increases at SWL&P.

Fuel and purchased power recoveries increased due to a $65.9 million increase in purchased power expense. (See Fuel and Purchased Power Expense discussion below.)

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

Revenue from sales to Other Power Suppliers increased $3.6 million from 2006 primarily due to a 3.6 percent increase in the price per kilowatt-hour.

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

2007 Compared to 2006 (Continued)
Regulated Operations (Continued)

Overall, kilowatt-hour sales were flat in 2007. Combined residential, commercial and municipal kilowatt-hour sales increased 181.0 million, or 5.3 percent, from 2006 while industrial kilowatt-hour sales decreased by 152.0 million, or 2.1 percent. The increase in residential, commercial and municipal kilowatt-hour sales was primarily because of two existing municipal customers converting to full-energy requirements and a 9.2 percent increase in Heating Degree Days. The reduction in industrial kilowatt-hour sales was primarily due to an idle production line and production delays at one of our taconite customers. In September 2007, the affected taconite customer resumed production on the idle line. Minor fluctuations in industrial kilowatt-hour sales generally do not have a large impact on revenue due to a fixed demand component of revenue that is less sensitive to changes in kilowatt-hours sales.

Kilowatt-hours Sold	2007	2006
Millions		
Regulated Utility		
Retail and Municipals		
Residential	1,141	1,100
Commercial	1,373	1,335
Industrial	7,054	7,206
Municipals	1,008	911
Other	84	79
Total Retail and Municipals	10,660	10,631
Other Power Suppliers	2,157	2,153
Total Regulated Utility	12,817	12,784

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

Operating expenses increased $76.9 million, or 14 percent, from 2006.

Fuel and Purchased Power Expense increased $65.9 million, or 23 percent, from 2006 primarily due to a $61.4 million increase in purchased power reflecting a 45 percent increase in market purchases and an 11 percent increase in market prices. The increase in purchased power expense reflects lower electricity production at the Company's generation facilities.

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

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

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

Operating and Maintenance Expense increased $11.4 million, or 5 percent, from 2006 due to a $9.0 million increase in plant maintenance primarily due to planned and unscheduled outages and salary and wage increases.

Depreciation Expense decreased $0.4 million, or 1 percent, from 2006 primarily due to the life extension of Boswell Unit 3, mostly offset by higher depreciable asset balances.

Interest expense increased $0.8 million, or 4 percent, from 2006 primarily due to higher debt balances reflecting increased construction activity. The increase was partially offset by the capitalization of more AFUDC-Debt.

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

Equity earnings increased $9.6 million in 2007 resulting from our pro-rata share of ATC's earnings as discussed in Note 6. Our initial investment in ATC began in May 2006.

2007 Compared to 2006 (Continued)

Investments and Other

Operating revenue decreased $10.0 million, or 8 percent, from 2006 primarily due to a decline in revenue from land sales at ALLETE Properties in 2007, partially offset by higher revenue at BNI Coal realized under a cost-plus coal supply agreement. Revenue from land sales at ALLETE Properties in 2007 was $44.3 million, which included $3.1 million in previously deferred revenue. In 2006, revenue from land sales was $56.1 million which included $9.7 million in previously deferred revenue.

ALLETE Properties	2007		2006	
Revenue and Sales Activity	Quantity	Amount	Quantity	Amount
Dollars in Millions				
Revenue from Land Sales				
Non-residential Sq. Ft.	580,059	$17.0	401,971	$10.8
Residential Units	736	14.8	973	15.9
Acres (a)	483	10.6	732	24.4
Contract Sales Price (b)		42.4		51.1
Revenue Recognized from				
Previously Deferred Sales		3.1		9.7
Deferred Revenue		(1.2)		(3.8)
Adjustments (c)		–		(0.9)
Revenue from Land Sales		44.3		56.1
Other Revenue		6.2		6.5
		$50.5		$62.6

(a) Acreage amounts are shown on a gross basis, including wetlands and minority 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) Contributed development dollars, which are credited to cost of real estate sold.

Operating expenses increased $4.3 million, or 5 percent, from 2006 reflecting higher coal production expense at BNI Coal and higher property taxes. The increase in property taxes is primarily due to higher assessed market values on our Minnesota land, while the increase in BNI Coal operating expenses is due to higher fuel costs, tire, and dragline repairs. At ALLETE Properties, higher community development district property tax assessments were partially offset by lower cost of sales.

Interest expense decreased $3.2 million from 2006 primarily due to more interest charged to the regulated utility in 2007 as a result of increased capital expenditures and interest on additional taxes owed on the gain on sale of our Florida Water Services Corporation assets in 2006. This decrease was partially offset by an increase of $0.5 million due to lower interest capitalization as the major infrastructure construction at Town Center was substantially completed at the end of 2006.

Other income increased $0.4 million from 2006 reflecting higher gains on Minnesota land sales and higher lease lot revenue due to leasing newly developed lots, partially offset by lower investment income as a result of lower average balances in 2007 and the release from a loan guarantee for Northwest Airlines, Inc. of $1.0 million.

Minority interest participation decreased due to lower Real Estate earnings.

Income Taxes – Consolidated

For the year ended December 31, 2007, the effective tax rate on income from continuing operations before minority interest was 34.8 percent (36.1 percent for the year ended December 31, 2006). The decrease in the effective rate compared to 2006 was primarily due to a tax benefit realized as a result of a state income tax audit settlement ($1.6 million), higher AFUDC-Equity, and a larger domestic manufacturing deduction taken in 2007 compared to 2006. The effective rate of 34.8 percent for the year ended December 31, 2007, deviated from the statutory rate (approximately 40 percent) due to the state income tax audit settlement, deductions for Medicare health subsidies and domestic manufacturing production, AFUDC-Equity and investment tax credits.

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.

Critical Accounting Estimates (Continued)

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

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

Valuation of Investments. 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, our emerging technology portfolio, and auction rate securities. As part of our emerging technology portfolio, we have several minority investments in venture capital funds and direct investments in privately-held, start-up companies. We account for our investment in venture capital funds under the equity method and account for our direct investments in privately-held companies under the cost method because of our ownership percentage. Our policy is to review these investments for impairment on a quarterly basis by assessing such factors as continued commercial viability of products, cash flow and earnings. Any impairment would reduce the carrying value of the investment and be recognized as a loss. In 2008, there were no impairment losses recognized ($0.5 million pretax in 2007 and none in 2006). (See Note 6. Investments.)

Pension and Postretirement Health and Life Actuarial Assumptions. We account for our pension and postretirement benefit obligations in accordance with the provisions of SFAS 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans," SFAS 87, "Employers' Accounting for Pensions," and SFAS 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions." These standards require the use of assumptions in determining our obligations and annual cost of our pension and postretirement benefits. An important actuarial assumption for pension and other postretirement benefit plans is the expected long-term rate of return on plan assets. In establishing this assumption, we consider the diversification and allocation of plan assets, the actual long-term historical performance for the type of securities invested in, the actual long-term historical performance of plan assets and the impact of current economic conditions, if any, on long-term historical returns. Our pension asset allocation at December 31, 2008, was approximately 46 percent equity, 32 percent debt, 16 percent private equity, and 6 percent real estate. Equity securities consist of a mix of market capitalization sizes and both domestic and international securities. We currently use an expected long-term rate of return of 8.5 percent in our actuarial determination of our pension and other postretirement expense. We annually review our expected long-term rate of return assumption and will adjust it to respond to any changing market conditions. A one-quarter percent decrease in the expected long-term rate of return would increase the annual expense for pension and other postretirement benefits by approximately $1 million, pre-tax.

For plan valuation purposes, we currently use a discount rate of 6.12 percent. The discount rate is determined considering high-quality long-term corporate bond rates at the valuation date. The discount rate is compared to the Citigroup Pension Discount Curve adjusted for ALLETE's specific cash flows. We believe the adjusted discount curve used in this comparison does not materially differ in duration and cash flows for our pension obligation. (See Note 14. 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 FIN 48, “Accounting for Uncertainty in Income Taxes – an Interpretation of FASB Statement No. 109”. 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 committed to earning a financial return that rewards our shareholders, allows for reinvestment in our businesses and sustains growth. Minnesota Power's industrial customers are facing weak conditions in the markets for their products, and have and may continue to reduce the amount of energy they use. We will work to sell this released energy in the wholesale markets, and believe that our ability to produce energy at low cost will be a competitive advantage. Our focus will be to maintain the competitively-priced production of energy, while meeting environmental requirements. Minnesota Power will also focus on maintaining competitive retail rates, as we believe this is important to the success of our customers. Information published by the Edison Electric Institute in mid-2008 ranked Minnesota Power as having the ninth lowest retail rates out of 175 investor-owned utilities in the United States.

Our strategy going forward is to focus on growth opportunities within our core business as we expect to continue making significant investments to comply with renewable and environmental requirements, maintain our existing low-cost generation fleet, and strengthen and enhance the regional transmission grid. We will also look for additional transmission and renewable energy opportunities which take advantage of our geographical location between sources of renewable energy and growing energy markets. Earnings from our ATC investment are expected to grow as we anticipate making additional investments to fund our pro-rata share of ATC's capital expansion program. We expect to invest an additional $5 to $7 million in ATC during 2009.

Regulated Operations. Minnesota Power expects significant rate base growth over the next several years as it continues its program to comply with renewable energy requirements and environmental mandates. In addition, significant investment will be made in our existing low-cost generation fleet to provide for continued future operations. We anticipate our capital investments will be recovered through a combination of current cost recovery riders and anticipated increased base electric rates. We also expect an average annual kilowatt-hour growth of approximately 1 percent from our existing customers, as well as potential long term growth from several new industrial customers planning projects in our service territory.

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

On February 8, 2008, the FERC approved Minnesota Power's wholesale tariff rate increase effective March 1, 2008. Minnesota Power's wholesale customers consist of 16 municipalities in Minnesota and 1 private utility in Wisconsin. The FERC authorized an average 10.0 percent increase for wholesale municipal customers, and an overall return on equity of 11.25 percent. Incremental revenue in 2008 from the FERC authorized wholesale rate increase was approximately $6 million.

In 2008, Minnesota Power entered into new contracts with all of our wholesale customers with the exception of one small customer whose contract is now in the cancellation period. The new contracts transition each customer to formula based rates, which means rates can be adjusted annually based on changes in costs. The new agreement with the private utility in Wisconsin is subject to PSCW approval. In November 2008, we filed a request with the FERC to implement the formula based rate provision in the new contracts. We anticipate final resolution and implementation of new rates in the first quarter of 2009.

On May 2, 2008, Minnesota Power filed a rate increase request with the MPUC seeking an average rate increase of 8.5 percent for retail customers. The rate filing seeks a return on equity of 11.15 percent, and a capital structure consisting of 54.8 percent equity and 45.2 percent debt. On an annualized basis, the requested rate increase would generate approximately $40 million in additional revenue. Interim rates were effective on August 1, 2008, and resulted in an increase for retail customers of approximately $36 million, or 7.5 percent, on an annualized basis, subject to refund pending the final rate order. Incremental revenue in 2008 from the interim retail rate increase was approximately $13 million. The transition to a new base cost of fuel coincident with interim rates resulted in the non-recovery through the fuel adjustment clause of approximately $19 million of fuel and purchased power costs incurred in 2008. We have entered into a stipulation and settlement agreement that would allow recovery of the $19 million in 2009 and which addresses specific concerns identified by interveners in the rate case; the stipulation and settlement agreement is subject to MPUC approval. The final rate order is expected in the second quarter of 2009. We cannot predict the final level of rates that may be approved by the MPUC. Prior to the May 2008 retail rate request Minnesota Power's rates were based on a 1994 MPUC retail rate order that allowed for an 11.6 percent return on equity.

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 common 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.

Outlook (Continued)
Regulated Operations (Continued)

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

Strong worldwide steel demand, driven largely by extensive infrastructure development in China, resulted in very robust world iron ore demand and steel pricing for nearly a six year period which lasted through the summer of 2008. Between 2004 and 2008 annual taconite production averaged just over 40 million tons per year from taconite mines in Northeastern Minnesota. Beginning in the fall of 2008, worldwide steel makers began to dramatically cut steel production in response to reduced demand driven largely by the world credit situation. During the fourth quarter of 2008, United States raw steel production was running at less than 50 percent of capacity and at levels not seen since the early 1980s. Currently, domestic raw steel production is at 45 percent of capacity reflecting poor demand in automobiles, durable goods, structural, and other steel products. Minnesota taconite producers began to be impacted in late 2008 and reduced production levels are expected in 2009. Consequently, 2009 demand nominations for power from our taconite customers are expected to be lower by at least 25 percent from 2008 levels. We intend to remarket 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. To date in 2009, we have sold power to Other Power Suppliers to mitigate the demand reductions made to date from our taconite customers. These contracts expire at various times during 2009, and have pricing levels similar to the rates charged to our large power customers. We will have additional power to sell in 2009 if our taconite customers continue to reduce their demand; we are unable to predict pricing levels on such sales at this time.

Minnesota Power’s paper and pulp customers ran at, or very near, full capacity for the majority of 2008 despite the fact that the industry continued to face high fiber, chemical, and energy costs as well as competition from exports in certain grades of paper products. Minnesota Power’s customers benefited from the temporary or permanent idling of plants both in North America at mills other than those served by Minnesota Power and the idling of plants in Europe, as well as continued (but declining) strength of the Canadian dollar and the Euro which has reduced imports both from Canada and Europe.

Our pipeline customers continued to operate at or above historic pumping levels during 2008 and forecast operating at record pumping levels in 2009. As Western Canadian oil sands reserves continue to develop and expand, pipeline operators served by the Company are executing expansion plans to transport additional crude oil supply to United States markets. We believe we are strategically positioned to serve these expanding pipeline facilities as Canadian supply continues to grow and displace domestic and imported Gulf Coast production.

Several natural resource-based companies continue to make progress developing new projects in Northeastern Minnesota that have the potential for long-term growth for Minnesota Power. These potential projects are in the ferrous and non-ferrous mining, paper, oil and steel related industries. They include the Polymet Mining Corp. (Polymet), Mesabi Nugget Delaware, LLC (Mesabi Nugget) and Essar Steel Limited Minnesota projects, as well as a proposed expansion at the Keewatin Taconite facility of United States Steel Corporation.

PolyMet. In 2007, the MPUC approved our contract with PolyMet, a new customer planning to start a copper, nickel and precious metals (non-ferrous) mining operation in Northeastern Minnesota. If PolyMet receives all necessary environmental permits and achieves start-up, the contract will run through at least 2018 and supply approximately 70 MWs of capacity. PolyMet continues to make progress towards production. In December 2008, PolyMet received a draft environmental impact statement from the Minnesota Department of Natural Resources.

Mesabi Nugget. In 2007, Minnesota Power entered into a contract with Mesabi Nugget, a joint venture between Steel Dynamics, Inc. and Kobe Steel Ltd. Mesabi Nugget will produce high-quality iron nuggets to supply steel mills owned by Steel Dynamics. Construction of the facility, near Hoyt Lakes, Minnesota, began in 2007 and completion is expected in late 2009. Mesabi Nugget is expected to initially be a 15-MW customer, with the potential for future load growth. The MPUC approved contract runs through at least 2017.

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

In March 2008, Minnesota Power signed a new contract with Northshore Mining Company to meet additional load requirements. The contract was approved by the MPUC and runs through at least June 30, 2011.

In September 2008, Cliffs and Minnesota Power signed new contracts for service to Hibbing Taconite Co. and United Taconite LLC. These electric service agreements, which are pending final MPUC approval, extend the existing contract terms out to at least December 31, 2015.

Outlook (Continued)
Regulated Operations (Continued)

Renewable Generation Sources. In February 2007, Minnesota enacted a law requiring Minnesota Power to generate or procure 25 percent of its energy 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, 20 percent by 2020, and 25 percent by 2025. 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. Minnesota Power believes it will meet the requirements of this legislation.

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

We are executing our renewable energy and environmental compliance strategy. Taconite Ridge Wind I, a $50 million, 25-MW wind facility located in northeastern Minnesota became operational in July 2008. In 2006 and 2007, we began long term purchase power agreements for 98 MWs of wind energy constructed in North Dakota (Oliver Wind I and II); 366,945 megawatt-hours were purchased under these agreements in 2008.

On May 13, 2008, we announced plans to develop several hundred megawatts of wind energy in North Dakota and purchase an existing 250 kV DC transmission line to transport this wind energy to our customers while gradually reducing the supply of energy currently delivered to our system on this same transmission line from Square Butte's coal-fired Milton R. Young Unit 2. The North Dakota wind project is expected to complete the 2025 renewable energy supply requirements for our retail load. In September 2008, we signed an agreement to purchase the transmission line from Square Butte Electric Cooperative for approximately $80 million. The transaction is subject to regulatory approvals and is anticipated to close in 2009.

In January 2008, Minnesota Power and Manitoba Hydro executed a term sheet to purchase surplus energy beginning in 2009 and an anticipated 250-MW capacity purchase to begin in about 2020. Minnesota Power anticipates the initial purchase of surplus energy will be about 100 MWs during high hydro production periods in the spring and fall. The 250-MW long-term purchase will require construction of hydroelectric facilities in Manitoba and major new transmission facilities between Canada and the United States. In November 2008, we signed an amendment to the term sheet extending the deadline to complete negotiations and sign a definitive agreement from November 30, 2008, to October 31, 2009. Both purchases require MPUC approval.

Integrated Resource Plan. On October 31, 2007, Minnesota Power filed its Integrated Resource Plan (IRP), a comprehensive estimate of future capacity needs within the Minnesota Power service territory. In October 2008, the MPUC issued an order approving our request to re-file the IRP by October 1, 2009 in order to incorporate the North

Dakota wind project and otherwise update our load forecasting and modeling in the IRP.

Minnesota Power plans to meet expected loads through 2020 by adding a significant amount of renewable generation and some supporting peaking generation. We plan to add 300 to 500 MWs of carbon-minimizing renewable energy to our generation mix. Besides the additional generation from renewable sources, Minnesota Power anticipates future supply could come from a combination of sources, including:

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

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

Outlook (Continued)
Regulated Operations (Continued)

Climate Change. Minnesota Power has a long history of environmental stewardship. A key component of our energy strategy is a goal to reduce overall GHG emissions.

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

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

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

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

The Company has become a "founding reporter" of The Climate Registry, an organization established to measure and publicly report GHG emissions consistently and accurately across borders and industry sectors. In becoming one of the founding reporters of The Climate Registry, we have voluntarily committed to measure, independently verify and publicly report our GHG emissions annually.

CapX 2020. Minnesota Power is a participant in the CapX 2020 initiative which represents an effort to ensure the electricity reliability of Minnesota and the surrounding region for the future. CapX 2020 includes the state's largest transmission owners, including 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.

The CapX 2020 participants filed a Certificate of Need for three 345 kV lines and associated system interconnections with the MPUC in August 2007. Following a public process, the MPUC is expected to decide on the need for these 345 kV lines by early 2009. If the MPUC issues the required Certificate of Need, the MPUC will then determine routes for the new lines in subsequent proceedings. Portions of the 345 kV lines will also require approvals by federal officials and by regulators in North Dakota, South Dakota and Wisconsin. A fourth line, a 230 kV line in north central Minnesota, is also among the CapX 2020 projects. A request for a Certificate of Need Permit for this line was filed in March 2008, and a Route Permit application was filed in June 2008. The MPUC decision on need and routing are expected in 2010.

Minnesota Power may invest in two of the lines, a 250-mile 345 kV line between Fargo, North Dakota and Monticello, Minnesota, and a 70-mile 230 kV line between Bemidji and Grand Rapids, Minnesota. Our total investment in these two lines would be approximately $80 million. Upon receipt of the required Certificates of Need, we intend to include these costs in an annual filing with the MPUC for current cost recovery of the expenditures related to our investment in the lines under a Minnesota Power transmission cost recovery tariff rider mechanism authorized by Minnesota legislation. Construction of the lines is targeted to begin in 2010 and last approximately three to four years.

Outlook (Continued)
Regulated Operations (Continued)

AREA and Boswell Unit 3 Emission Reduction Plans. In May 2006, the MPUC authorized current cost recovery of expenditures to reduce emissions of SO2, NOX, and mercury emissions at Taconite Harbor and Laskin under the AREA Plan. The AREA Plan has significantly reduced emissions from Taconite Harbor and Laskin, while maintaining a reliable and reasonably-priced energy supply to meet the needs of our customers. Environmental retrofits at Laskin and Taconite Harbor Units 1 and 2 are complete and in service. The environmental regulatory requirements for Taconite Harbor Unit 3 are pending finalization of the Minnesota Regional Haze implementation plan by the MPCA. We are expecting to retrofit Taconite Harbor Unit 3 by 2013 and are evaluating compliance requirements and cost recovery options for this final unit.

We are making emission reduction investments at our Boswell Unit 3 generating unit. The investments in pollution control equipment will reduce particulates, SO2, NOX, and mercury emissions to meet future federal and state requirements. The MPUC has authorized a cash return on construction work in progress during the construction phase in lieu of AFUDC-Equity and allows for a return on investment and current cost recovery of incremental operations and maintenance expenses once the new equipment is installed and the unit is placed back in service in late 2009. We began cost recovery on January 1, 2008. In September 2008, we filed a petition with the MPUC to approve the Boswell Unit 3 rate adjustment for 2009. If approved, new rates would allow cost recovery relating to additional investments planned for 2009.

Boswell NOX Reduction Plan. In September 2008, we submitted to the MPCA and MPUC a $92 million environmental initiative proposing cost recovery for NOX emission reductions from Boswell Units 1, 2, and 4. If approved by the MPUC, the Boswell NOX Reduction Plan is expected to significantly reduce NOX emissions from these units. In conjunction with the NOX reduction, we plan to install an efficiency improvement to the existing turbine/generator at Boswell Unit 4 adding approximately 60 MWs of total output with no additional emissions. A second filing requesting cost recovery for the plan will be submitted to the MPUC in the first quarter of 2009.

Transmission. In September 2008, we filed a petition with the MPUC seeking total 2009 cost recovery of $2.2 million for ongoing expenditures related to the Badoura and Tower transmission projects and certain MISO related transmission facility charges. The Tower and Badoura projects are being developed to address transmission inadequacies in northeastern Minnesota. Both projects will provide regional transmission benefits through increased voltage support and additional line capacity.

Depreciation. In a November 2008 Order, the MPUC increased depreciation rates for certain assets effective January 1, 2008. Minnesota Power had been seeking to have the increased depreciation rates become effective with the date of final rates in the current retail rate filing (expected to be in the second quarter of 2009). Under this order, depreciation expense increased approximately $3 million in 2008.

Investment in ATC. At December 31, 2008, our equity investment was $76.9 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 $2.7 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 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 30, 2009, we invested an additional $1.9 million into ATC. In total, we expect to invest an additional $5 to $7 million throughout 2009.

Investments and Other

BNI Coal. In 2008, BNI Coal sold approximately 4.5 million tons of coal (4.0 million tons in 2007) and anticipates similar sales in 2009.

ALLETE Properties. ALLETE Properties is our real estate business that has operated in Florida since 1991. Our current strategy is to complete and maintain key entitlements and infrastructure improvements which enhance values without requiring significant additional investment, and position the current property portfolio for a maximization of value and cash flow when market conditions improve.

Our two major development projects include Town Center and Palm Coast Park. A third proposed development project, Ormond Crossings, is in the permitting and planning stage. Development activities involve mainly zoning, permitting, platting, and master infrastructure construction. See Item 1. Business – Investments and Other for additional descriptions of each of our development projects. Development costs are financed through a combination of community development district bonds, bank loans, and internally-generated funds.

Outlook (Continued)
Investments and Other (Continued)

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%			
At December 31, 2007		991	2,289	2,228,200
Property Sold		–	–	–
At December 31, 2008		991	2,289	2,228,200
Palm Coast Park	100%			
At December 31, 2007		3,436	3,154	3,116,800
Property Sold		–	–	–
Change in Estimate		–	85	–
At December 31, 2008		3,436	3,239	3,116,800
Total Current Development Projects		4,427	5,528	5,345,000
Proposed Development Project				
Ormond Crossings	100%			
At December 31, 2008		5,968	(d)	(d)
Total of Development Projects at December 31, 2008		10,395	5,528	5,345,000

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

Other Land Available-for-Sale (a)	Total	Mixed Use	Residential	Non-residential	Agricultural
Acres (b)					
At December 31, 2007	1,573	362	248	424	539
Property Sold	(166)	(2)	(134)	(18)	(12)
Contributed Land	(54)	–	–	–	(54)
Change in Estimate	–	(7)	–	(4)	11
At December 31, 2008	1,353	353	114	402	484

(a) Other land includes land located in Palm Coast, Florida not included in development projects, Lehigh Acquisition Corporation and Cape Coral Holdings, Inc.
(b) Acreage amounts are approximate and shown on a gross basis, including wetlands and minority interest.

Pending Contracts. At December 31, 2008, total pending land sales under contract were $12.4 million ($55.2 million at December 31, 2007) and are scheduled to close at various times through 2009. However, given current market conditions it may be difficult to complete these closings in 2009. In July 2008, a $28.9 million contract with LDD Palm Coast North LLC, a subsidiary of Lowe Enterprises was terminated, and a $0.6 million contract deposit was forfeited. We are currently reviewing the best options to proceed with this property. We believe this property, along with the remaining property at Palm Coast Park, continues to have long-term value. We continue to have discussions with other buyers under pending contracts. Our objective is to proactively assist our buyers through this current period of weak market conditions, as we believe the long-term prospects for our properties are favorable. Our discussions sometimes result in adjustments to contract terms, and may include extending closing dates, revised pricing or termination. 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.

Outlook (Continued)
Investments and Other (Continued)

Emerging Technology. We have the potential to recognize gains or losses on the sale of investments in our emerging technology portfolio. We plan to sell investments in our emerging technology portfolio when publically traded shares are distributed to us. Some restrictions on sales may apply, including, but not limited to, underwriter lock-up periods that typically extend for 180 days following an initial public offering. We have committed to make up to $0.7 million in additional investments in certain emerging technology holdings. We do not have plans to make any additional investments beyond this commitment.

Income Taxes. ALLETE's aggregate federal and multi-state statutory tax rate is expected to be approximately 40 percent for 2009. 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 minority interest and income taxes, state and federal tax law changes that become effective during the year, business combinations and configuration changes, tax planning initiatives and resolution of prior years' tax matters. We expect our effective tax rate to be approximately 36 percent for 2009.

Liquidity and Capital Resources

Cash Flow Activities

ALLETE is well-positioned to meet the Company's immediate cash flow needs. With our cash balance of approximately $102 million, $160.5 million in Lines of Credit which includes a committed, syndicated, unsecured revolving line of credit of $150 million, and a debt to capital ratio of 42.2 percent at December 31, 2008, we project sufficient capital availability through the immediate term. If needed, we have the flexibility to reduce our planned capital expenditure program to meet changing capital market conditions.

Operating Activities. Cash from operating activities was $152.1 million for 2008 ($123.1 million for 2007; $142.0 million for 2006). 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 bonus depreciation provisions of the Economic Stimulus Act of 2008, and contributions to defined benefit pension and postretirement health plans increased $15.6 million during 2008.

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

Investing Activities. Cash used for investing activities was $276.1 million for 2008 ($154.1 million for 2007; $154.2 million for 2006). Cash used for investing activities was higher 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.

Cash used for investing activities was insignificantly lower in 2007 than 2006 primarily due to an increase of $81.4 million in net sales of short-term investments compared to $12.4 million in 2006. The net proceeds from the sale of short-term investments were used to fund increased additions to property, plant and equipment. Additions to property, plant and equipment were higher in 2007 than 2006 by $111.7 million primarily due to increased spending on major environmental construction projects. Cash invested in ATC decreased from $51.4 million in 2006 to $8.7 million in 2007.

Financing Activities. Cash from financing activities was $202.7 million for 2008 (cash from financing activities was $9.5 million for 2007; cash used for financing activities was $32.6 million for 2006). The increase in cash from financing activities resulted from the issuance of three series of first mortgage bonds: $60 million in February 2008; $75 million in May 2008; and $38 million in December 2008. In addition, 1.8 million shares of common stock were issued for net proceeds of $71.1 million. Financing activities increased to support our current capital expenditure program.

Cash from financing activities was higher in 2007 than 2006 primarily due to additional long-term debt issued in 2007, which included $60 million of first mortgage bonds, $50.0 million of senior unsecured notes and $12.5 million in collateralized tax exempt bonds at SWL&P. The increase in new long-term debt was offset partially by the retirement of $20.0 million in first mortgage bonds, $2.5 million in variable demand revenue refunding bonds and $6.5 million in SWL&P first mortgage bonds.

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

Working Capital. Additional working capital, if and when needed, generally is provided by the sale of commercial paper. We have 0.8 million original issue shares of our common stock available for issuance through Invest Direct, our direct stock purchase and dividend reinvestment plan. Additionally, we have 0.9 million original issue shares of common stock available for issuance through a Distribution Agreement with KCCI, Inc. We have consolidated bank lines of credit aggregating $160.5 million, the majority of which expire in January 2012. In January 2006, we renewed, increased and extended a committed, syndicated, unsecured revolving credit facility (Line) with Bank of America as Agent, and four other banks, for $150 million. No individual bank has more than 25 percent participation in the Line. The Line was subsequently extended for an additional year in December 2006 and currently matures on January 11, 2012. At our request and subject to certain conditions, the Line may be increased to $200 million and extended for two additional 12-month periods. We may prepay amounts outstanding under the Line in whole or in part at our discretion. Additionally, we may irrevocably terminate or reduce the size of the Line prior to maturity. The Line may be used for general corporate purposes, working capital and to provide liquidity in support of our commercial paper program. The amount and timing of future sales of our securities will depend upon market conditions and our specific needs. We may sell securities to meet capital requirements, to provide for the retirement or early redemption of issues of long-term debt, to reduce short-term debt and for other corporate purposes.

Auction Rate Securities. As of December 31, 2008, we held $15.2 million of investments ($23.1 million at December 31, 2007) consisting of three auction rate municipal bonds (auction rate securities) with stated maturity dates ranging between 15 and 28 years. These ARS consist of guaranteed student loans insured or reinsured by the federal government and were historically auctioned every 35 days to set new rates and provide a liquidating event in which investors could either buy or sell securities. The auctions have been unable to sustain themselves during 2008 due to the overall lack of credit market liquidity and we have been unable to liquidate all of our ARS. As a result, we have classified the 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. In the meantime, these securities will pay a default rate which is typically above market interest rates.

The Company has used a discounted cash flow model to determine the estimated fair value of its investment in ARS as of December 31, 2008. The assumptions used in preparing the discounted cash flow model include the following: estimated interest rates, estimated discount rates (using yields of comparable traded instruments adjusted for illiquidity and other risk factors), 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. Based upon the results of the discounted cash flow model and the fact that these ARS consist of guaranteed student loans insured or reinsured by the federal government no other than temporary impairment loss has been reported.

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

On February 1, 2008, we issued $60 million in principal amount of First Mortgage Bonds, 4.86% Series due April 1, 2013, in the private placement market. We have the option to prepay all or a portion of the bonds at our discretion, subject to a make-whole provision. The bonds are subject to additional terms and conditions which are customary for this type of transaction. We used the proceeds from the sale of the bonds to fund utility capital expenditures and for general corporate purposes.

On May 14, 2008, we issued $75 million in principal amount of First Mortgage Bonds, 6.02% Series due May 1, 2023, in the private placement market. We have the option to prepay all or a portion of the bonds at our discretion, subject to a make-whole provision. The bonds are subject to additional terms and conditions which are customary for this type of transaction. We used the proceeds from the sale of the bonds to fund utility capital expenditures and for general corporate purposes.

We issued $80 million in principal amount of First Mortgage Bonds in the private placement market in three series as follows:

Issue Date	Maturity	Amount	Coupon
December 15, 2008	January 15, 2014	$18 Million	6.94%
December 15, 2008	January 15, 2016	$20 Million	7.70%
January 15, 2009	January 15, 2019	$42 Million	8.17%

Liquidity and Capital Resources (Continued)
Securities (Continued)

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 intend to use the proceeds from the sale of the bonds to fund utility capital expenditures and for general corporate purposes.

On February 19, 2008, we entered into a Distribution Agreement with KCCI, Inc. with respect to the issuance and sale of up to 2.5 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 Distribution Agreement, which terminates on June 30, 2009. For the year ended December 31, 2008, 1,556,200 shares of common stock have been issued under this agreement resulting in net proceeds of $60.8 million.

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 of less than or equal to 0.65 to 1.00 measured quarterly. As of December 31, 2008 our ratio was approximately 0.40 to 1.00. Failure to meet this covenant could give rise to an event of default, if not corrected after notice from the lender, in which event ALLETE may need to pursue alternative sources of funding. Some of ALLETE's debt arrangements contain "cross-default" provisions that would result in an event of default if there is a failure under other financing arrangements to meet payment terms or to observe other covenants that would result in an acceleration of payments due. As of December 31, 2008, ALLETE was in compliance with its financial covenants.

Off-Balance Sheet Arrangements. Off-balance sheet arrangements are discussed in Note 8.

Contractual Obligations and Commercial Commitments. Our long-term debt obligations, including long-term debt due within one year, represent the principal amount of bonds, notes and loans which are recorded on our consolidated balance sheet, plus interest. The table below assumes the interest rate in effect at December 31, 2008, remains constant through the remaining term. (See Note 8. Commitment, Guarantees and Contingencies.)

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 8. 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. Our payment obligation is suspended if Square Butte fails to deliver any power, whether produced or purchased, for a period of one year. Square Butte's fixed costs consist primarily of debt service. The following table reflects our share of future debt service based on our output entitlement of 50 percent. For further information on Square Butte see Note. 8 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 II located near Center, North Dakota. We began purchasing the output from Oliver Wind I, a 50-MW facility, in December 2006 and the output from Oliver Wind II, a 48-MW facility in November 2007. Each agreement is for 25 years and provides for the purchase of all output from the facilities. There are no fixed capacity charges, and we only pay for energy as it is delivered to us.

	Payments Due by Period			
Contractual Obligations	Less than	1 to 3	4 to 5	After

As of December 31, 2008	Total	1 Year	Years	Years	5 Years
Millions					
Long-Term Debt (a)	$979.6	$40.1	$106.6	$140.8	$692.1
Operating Lease Obligations	93.7	8.3	24.8	15.1	45.5
FIN 48 – Uncertain Tax Positions	1.2	1.0	0.2	–	–
Unconditional Purchase Obligations	352.9	77.1	63.3	28.8	183.7
	$1,427.4	$126.5	$194.9	$184.7	$921.3

(a) Includes interest and assumes variable interest rates in effect at December 31, 2008, remains constant through remaining term.

We expect to contribute approximately $30 - $35 million to our defined benefit pension plans and $11 million to our postretirement health and life plans in 2009. We are unable to predict contribution levels to our defined benefit pension or postretirement health and life plans after 2009.

Liquidity and Capital Resources (Continued)

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

Credit Ratings	Standard & Poor's	Moody's
Issuer Credit Rating	BBB+	Baa1
Commercial Paper	A-2	P-2
Senior Secured		
First Mortgage Bonds	A–	A3
Pollution Control Bonds	A–	A3
Unsecured Debt		
Collier County Industrial Development Revenue Bonds – Fixed Rate	BBB	–

Payout Ratio. In 2008, we paid out 61 percent (53 percent in 2007; 53 percent in 2006) of our per share earnings in dividends.

On January 22, 2009, our Board of Directors increased the dividend on ALLETE common stock by 2.3 percent, declaring a dividend of $0.44 per share payable on March 1, 2009, to shareholders of record at the close of business on February 16, 2009.

Capital Requirements

ALLETE's projected capital expenditures for the years 2009 through 2013 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	2009	2010	2011	2012	2013	Total
Regulated Utility Operations						
Base and Other	$197	$125	$109	$114	$128	$673
Current Cost Recovery (a)						
Environmental	43	9	37	56	112	257
Renewable	29	138	16	15	–	198
Transmission	3	17	18	18	17	73
Generation	21	17	–	–	–	38
Total Current Cost Recovery	96	181	71	89	129	566
Regulated Utility Capital Expenditures	293	306	180	203	257	1,239
Other	7	8	11	8	26	60
Total Capital Expenditures	$300	$314	$191			