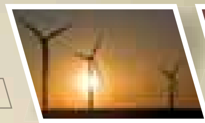
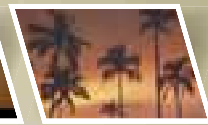
Annual Report 06 Form 10-K

ALLETE

DEAR shareholders

ALLETE in 2006 recorded another year of **strong** growth in earnings from continuing operations. Based on our positive outlook for the future, in January of 2007 we announced a dividend increase of 13 percent, equivalent to $1.64 per share annually. ALLETE is committed to earning a financial return that rewards its shareholders, allows for reinvestment in its businesses and sustains its growth. To achieve this, we will invest in **growth opportunities** at our existing businesses and pursue strategic opportunites in other areas. We've attained many of the objectives outlined in the corporate strategy we adopted three years ago, and we're determined to achieve all of them.

Our electric utility, Minnesota Power, is fortunate to serve a region that in recent years has seen taconite mining and processing operate at full production and the petroleum pipeline business continue to grow. A few months ago Minnesota Power signed a long-term agreement to supply electricity to a precious metals mining concern, Polymet Mining. If its business plan is realized, and we believe it will be, the company would join the ranks of our largest power customers. Several other natural resource-based companies have made progress in developing new projects in northeastern Minnesota. If some or all of these projects are completed, Minnesota Power could serve between 100 and 400 megawatts of new electric load.

Our investment in the American Transmission Company, which started in 2006, has begun to yield a significant return and will be a major factor in our earnings growth for 2007. In early 2007, ALLETE will own an estimated eight percent of ATC, a company dedicated to modernizing and making more efficient the electric power grid in the Midwest.

Dedication to preserving the environment is a core value for our company. It's also the impetus behind an ambitious air emissions control upgrade now underway at Minnesota Power generating stations. We plan to invest approximately $260 million on equipment and processes that will dramatically reduce air emissions. Work on environmental retrofits at the Laskin and Taconite Harbor Energy Centers is underway; construction at Boswell Energy Center is the next step. This investment will substantially increase the size of our regulated utility business. Minnesota Power's embrace of renewable energy is symbolized by a new 50-megawatt wind energy facility in North Dakota that recently began producing electricity and a second, 48-megawatt wind farm that will also be constructed for our use by FPL Energy.

Our real estate business continues to attract keen buyer interest in fast-growing Florida. ALLETE Properties' three major real estate developments, all at different levels of maturation, are moving forward on schedule. Infrastructure is substantially completed for the Town Center at Palm Coast project. We closed our first sales contracts and infrastructure construction is in progress at Palm Coast Park. And the largest of the three projects, Ormond Crossings, received development order approval from the city of Ormond Beach late in 2006.

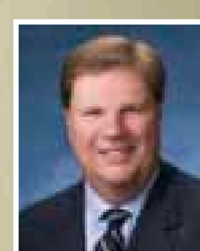
ALLETE continues to explore opportunities for growing its real estate business, and our search has expanded outside of Florida to other areas of the southeast. We are also thoroughly researching options for investing in a business outside the realm of energy or real estate. With a strong cash position and earnings stream, ALLETE can take a disciplined, diligent approach to making the right decision about diversification.

In closing, I want to thank Peter Johnson and Nick Smith, who are retiring from the ALLETE Board of Directors, for their many years of dedicated service. Their conscientious stewardship of this company will be missed.

Thank you, shareholders, for supporting us as we move forward into a future bright with potential. My fellow employees and I greatly appreciate your investment in ALLETE.

Sincerely,

Donald Shippar
Chairman, President and
Chief Executive Officer



Form 10-K

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

(Mark One)

☑ Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended **December 31, 2006**

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

Commission File No. **1-3548**

ALLETE, Inc.

(Exact name of registrant as specified in its charter)

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

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

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

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

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

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

None

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

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

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

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

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

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

The aggregate market value of voting stock held by nonaffiliates on June 30, 2006, was $1,427,346,731.

As of February 1, 2007, there were 30,446,854 shares of ALLETE Common Stock, without par value, outstanding.

Documents Incorporated By Reference

Portions of the Proxy Statement for the 2007 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
ADESA	ADESA, Inc.
AICPA	American Institute of Certified Public Accountants
ALLETE	ALLETE, Inc.
ALLETE Properties	ALLETE Properties, LLC
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
Constellation Energy Commodities	Constellation Energy Commodities Group, Inc.
DOC	Minnesota Department of Commerce
DRI	Development of Regional Impact
EITF	Emerging Issues Task Force
Enventis Telecom	Enventis Telecom, Inc.
EPA	Environmental Protection Agency
ESOP	Employee Stock Ownership Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Florida Landmark	Florida Landmark Communities, Inc.
Florida Water	Florida Water Services Corporation
Form 8-K	ALLETE Current Report on Form 8-K
Form 10-K	ALLETE Annual Report on Form 10-K
Form 10-Q	ALLETE Quarterly Report on Form 10-Q
FPL Energy	FPL Energy, LLC
FPSC	Florida Public Service Commission
FSP	Financial Accounting Standards Board Staff Position
GAAP	Accounting Principles Generally Accepted in the United States
Invest Direct	ALLETE's Direct Stock Purchase and Dividend Reinvestment Plan
IPO	Initial Public Offering
kV	Kilovolt(s)
Laskin	Laskin Energy Center
MBtu	Million British thermal units
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) / Megawatthour(s)

Definitions (Continued)

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

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

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

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

- our ability to successfully implement our strategic objectives;
- our ability to manage expansion and integrate acquisitions;
- prevailing governmental policies and regulatory actions, 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 and capital investments, present or prospective wholesale and retail competition (including but not limited to transmission costs), and zoning and permitting of land held for resale;
- effects of restructuring initiatives in the electric industry;
- economic and geographic factors, including political and economic risks;
- changes in and compliance with laws and policies;
- weather conditions;
- natural disasters and pandemic diseases;
- war and acts of terrorism;
- wholesale power market conditions;
- population growth rates and demographic patterns;
- effects of competition, including competition for retail and wholesale customers;
- changes in the real estate market;
- pricing and transportation of commodities;
- changes in tax rates or policies or in rates of inflation;
- unanticipated project delays or changes in project costs;
- availability of construction materials and skilled construction labor for capital projects;
- unanticipated changes in operating expenses and capital expenditures;
- global and domestic economic conditions;
- our ability to access capital markets and bank financing;
- changes in interest rates and the performance of the financial markets;
- our ability to replace a mature workforce, and retain qualified, skilled and experienced personnel; and
- the outcome of legal and administrative proceedings (whether civil or criminal) and settlements that affect the business and profitability of ALLETE.

Additional disclosures regarding factors that could cause our results and performance to differ from results or performance anticipated by this report are discussed in Item 1A under the heading “Risk Factors” beginning on page 24 of this Form 10-K. Any forward-looking statement speaks only as of the date on which such statement is made, and we undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which that statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of these factors, nor can it assess the impact of each of these factors on the businesses of ALLETE or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. Readers are urged to carefully review and consider the various disclosures made by us in this Form 10-K and in our other reports filed with the SEC that attempt to advise interested parties of the factors that may affect our business.

Part I

Item 1. Business

ALLETE has been incorporated under the laws of Minnesota since 1906. ALLETE's corporate headquarters are in Duluth, Minnesota. As of December 31, 2006, we had approximately 1,500 employees, 100 of which were part-time. Statistical information is presented as of December 31, 2006, 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.

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.

ALLETE is a diversified company providing fundamental products and services. This includes our two core businesses—**Energy** and **Real Estate**, as well as former operations in the water, paper, telecommunication and automotive industries.

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

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

  In 2004 and 2005, Nonregulated Energy Operations also included nonregulated generation from our Taconite Harbor facility in northern Minnesota, and generation secured through the Kendall County power purchase agreement. Effective January 1, 2006, Taconite Harbor was integrated into our Regulated Utility business to help meet forecasted base load energy requirements. In April 2005, the Kendall County power purchase agreement was assigned to Constellation Energy Commodities.
- **Investment in ATC** includes our equity ownership interest in ATC.

Real Estate includes our Florida real estate operations.

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

Year Ended December 31	**2006**	**2005**	**2004**
Consolidated Operating Revenue – Millions	$767.1	$737.4	$704.1
Percentage of Consolidated Operating Revenue			
Regulated Utility			
Industrial			
Taconite Producers	24%	23%	25%
Paper and Wood Products	9	9	9
Pipelines and Other Industries	6	6	7
Total Industrial	39	38	41
Residential	10	10	11
Commercial	11	11	11
Municipals	5	5	4
Other Power Suppliers	12	7	5
Other Revenue	6	7	7
Total Regulated Utility	83	78	79
Nonregulated Energy Operations	9	16	15
Real Estate	8	6	6
	100%	100%	100%

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

Discontinued Operations. In the past five years, we also had business operations in the automotive, water and telecommunications industries.

Spin-Off of Automotive Services. Through a June 2004 IPO, our Automotive Services business, doing business as ADESA, Inc. (NYSE: KAR), issued 6.3 million shares of common stock, representing 6.6% of ADESA's common stock outstanding. In September 2004, we spun off the business by distributing to ALLETE shareholders all of ALLETE's remaining 93.4% of ADESA common stock.

Sale of Water Services Businesses. In early 2005, we completed the exit from our Water Services businesses with the sale of our wastewater assets in Georgia. In mid-2004, we sold our North Carolina water and wastewater assets, and our remaining 72 water and wastewater systems in Florida. Substantially all of our water assets in Florida were sold in 2003, under condemnation or imminent threat of condemnation. The net cash proceeds from the sale of all water and wastewater assets, after transaction costs, retirement of most Florida Water debt and payment of income taxes, were approximately $300 million.

Sale of Enventis Telecom. On December 30, 2005, we sold all the stock of our telecommunications subsidiary, Enventis Telecom for $35.5 million. The transaction resulted in an after-tax loss of $3.6 million, which was included in our 2005 loss from discontinued operations. Net cash proceeds realized from the sale were approximately $29 million after transaction costs, repayment of debt and payment of income taxes.

Energy – Regulated Utility

Minnesota Power, an operating division of ALLETE, provides regulated utility electric service in a 26,000 square-mile service territory in northeastern Minnesota to 140,000 retail customers and wholesale electric service to 16 municipalities. **SWL&P** provides regulated utility electric, natural gas and water service in northwestern Wisconsin to 14,000 electric customers, 12,000 natural gas customers and 10,000 water customers.

Minnesota Power had an annual net peak load of 1,586 MW on July 28, 2006. Our regulated power supply sources are listed below.

Regulated Utility Power Supply	Unit No.	Year Installed	Net Winter Capability	For the Year Ended December 31, 2006 Electric Requirements	
			MW	MWh	%
Steam					
Coal-Fired					
Boswell Energy Center	1	1958	69		
in Cohasset, MN	2	1960	69		
	3	1973	351		
	4	1980	428		
			917	6,380,647	48.9%
Laskin Energy Center	1	1953	55		
in Hoyt Lakes, MN	2	1953	55		
			110	623,975	4.8
Taconite Harbor Energy Center	1, 2 & 3	1957, 1957			
in Taconite Harbor, MN		1967	220	1,466,803	11.2
Purchased Steam					
Hibbard Energy Center in Duluth, MN	3 & 4	1949, 1951	50	79,731	0.6
Total Steam			1,297	8,551,156	65.5
Hydro					
Group consisting of ten stations in MN	Various		115	343,729	2.6
Total Company Generation			1,412	8,894,885	68.1
Purchased Power					
Square Butte burns lignite coal near Center, ND			299	2,069,700	15.9
Oliver Wind I Energy Center near Center, ND			50	12,696	–
All Other – Net			–	2,071,481	16.0
Total Purchased Power			349	4,153,877	31.9
Total			1,761	13,048,762	100.0%

Energy – Regulated Utility (Continued)

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 (1,209 miles) and less than 115 kV (6,875 miles). We own and operate 169 substations with a total capacity of 9,525 megavoltamperes. Some of our transmission and distribution lines interconnect with other utilities.

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

Split Rock Energy was a joint venture between Minnesota Power and Great River Energy. In March 2004, we terminated our ownership interest upon receipt of FERC approval.

Electric Sales

Our regulated utility operations include retail and wholesale activities under the jurisdiction of state and federal regulatory authorities. (See Regulatory Issues.)

Regulated Utility Electric Sales Year Ended December 31	**2006**	**2005**	**2004**
Millions of Kilowatthours			
Retail and Municipals			
Residential	1,100	1,102	1,053
Commercial	1,335	1,327	1,282
Industrial	7,206	7,130	7,071
Municipals and Other	990	956	902
	10,631	10,515	10,308
Other Power Suppliers *(a)*	2,153	1,142	918
	12,784	11,657	11,226

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

Approximately 60% of the ore consumed by integrated steel facilities in the United States originates from six taconite customers of Minnesota Power. Taconite, an iron-bearing rock of relatively low iron content that is abundantly available in Minnesota, is an important domestic source of raw material for the steel industry. Taconite processing plants use large quantities of electric power to grind the ore-bearing rock, and agglomerate and pelletize the iron particles into taconite pellets. Strong worldwide steel demand, driven largely by extensive infrastructure development in China, has resulted in very robust world iron ore demand and steel pricing. This globalization of demand has positively impacted Minnesota taconite producers, which all produced near their rated capacities in both 2006 and 2005. Annual taconite production in Minnesota was 40 million tons in 2006 (41 million tons in both 2005 and 2004) and is estimated to be 40 million tons in 2007. Recent consolidation activities, combined with the strong steel market, have placed the Minnesota taconite producers in a strong competitive position.

In addition to serving the taconite industry, Minnesota Power also serves a number of customers in the paper and pulp, and wood products industry. In total, we serve four major paper and pulp mills directly and one paper mill indirectly by providing wholesale service to the retail provider of the mill. Minnesota Power also serves four wood products manufacturers. In 2006, approximately 90% of our revenue from this industry sector came from the paper and pulp producers, and 10% came from the wood products customers.

Minnesota Power's paper and pulp customers ran at or very near full capacity in 2006 despite the fact that the industry continued to face high fiber, chemical and energy costs as well as competition from exports in certain grades. Minnesota Power's customers benefited from the temporary or permanent idling of capacity in North America at mills other than those served by Minnesota Power and from the strength of the Euro. Wood products customers ran at reduced capacity levels or were temporarily idled in the last third of 2006 because of high wood prices and a decreasing number of new housing starts.

The pipeline and refining industry is the third key industrial segment served by Minnesota Power with services provided to two crude oil pipelines and one refinery. These customers have a common reliance on the importation of Canadian crude oil. After years of near capacity operation in 2005 and 2006, both pipeline operators are executing expansion plans to transport newly developed Western Canadian crude oil reserves (Alberta Oil Sands) to United States markets. Access to traditional Midwest markets is being expanded to Southern markets as the Canadian supply is displacing domestic production and deliveries imported from the Gulf Coast.

Energy – Regulated Utility (Continued)

Large Power Customer Contracts. Minnesota Power has large power customer contracts with 12 customers (Large Power Customers), 11 of which require 10 MW or more of generating capacity and one that requires at least 8 MW of generating capacity. In 2006, a contract for approximately 70 MW was successfully negotiated with PolyMet Mining, a new customer planning to start a copper, nickel and precious metals (non-ferrous) mining operation by late 2008. If PolyMet's environmental permits are received and start-up is achieved, the contract with PolyMet Mining will run through at least 2018. The PolyMet Mining contract requires MPUC approval.

Large Power Customer contracts require Minnesota Power to have a certain amount of generating capacity available. (See Minimum Revenue and Demand Under Contract table below.) In turn, each Large Power Customer is required to pay a minimum monthly demand charge that covers the fixed costs associated with having this capacity available to serve the customer, including a return on common equity. Most contracts allow customers to establish the level of megawatts subject to a demand charge on a biannual (power pool season) or four-month basis and require that a portion of their megawatt needs be committed on a take-or-pay basis for at least a portion of the agreement. In addition to the demand charge, each Large Power Customer is billed an energy charge for each kilowatthour used that recovers the variable costs incurred in generating electricity. Six of the Large Power Customers have interruptible service for a portion of their needs, which provides a discounted demand rate and energy priced at Minnesota Power's incremental cost after serving all firm power obligations. Minnesota Power also provides incremental production service for customer demand levels above the contract 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 continue past the contract termination date, unless the required advance notice of cancellation has been given. The advance notice of cancellation varies from one to four years. Such contracts minimize the impact on earnings that otherwise would result from significant reductions in kilowatthour sales to such customers. Large Power Customers are required to take all of their purchased electric service requirements from Minnesota Power for the duration of their contracts. The rates and corresponding revenue associated with capacity and energy provided under these contracts are subject to change through the same regulatory process governing all retail electric rates. (See Regulatory Issues – Electric Rates.)

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

Minimum Revenue and Demand Under Contract As of February 1, 2007	**Minimum Annual Demand Revenue** ***(a,b)***	**Monthly Megawatts**
2007	$62.5 million	390
2008	$29.3 million	167
2009	$25.9 million	148
2010	$25.8 million	148
2011	$16.1 million	88

(a) Based on past experience, we believe revenue from our Large Power Customers will be substantially in excess of the minimum contract amounts. For example, in our 2005 Form 10-K we stated 2006 minimum annual revenue from these Large Power Customers would be $61.3 million. Actual 2006 demand revenue from these Large Power Customers was $116.9 million.

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

Energy – Regulated Utility (Continued)

Contract Status for Minnesota Power Large Power Customers
As of February 1, 2007

Customer	Industry	Location	Ownership	Earliest Termination Date
Hibbing Taconite Co. *(a)*	Taconite	Hibbing, MN	62.3% Mittal Steel USA Inc. 23% Cleveland-Cliffs Inc 14.7% Stelco Inc.	February 28, 2011
Mittal Steel USA – Minorca Mine	Taconite	Virginia, MN	Mittal Steel USA Inc.	December 31, 2012
United States Steel Corporation (USS) Minntac	Taconite	Mt. Iron, MN	USS	October 31, 2013
USS Keewatin Taconite	Taconite	Keewatin, MN	USS	October 31, 2013
United Taconite LLC *(a)*	Taconite	Eveleth, MN	70% Cleveland-Cliffs Inc 30% Laiwu Steel Group	February 28, 2011
UPM, Blandin Paper Mill *(a)*	Paper	Grand Rapids, MN	UPM-Kymmene Corporation	February 28, 2011
Boise White Paper, LLC	Paper	International Falls, MN	Madison Dearborn Partnership	December 31, 2008
Sappi Cloquet LLC *(a)*	Paper	Cloquet, MN	Sappi Limited	February 28, 2011
Stora Enso North America, Duluth Paper Mill and Duluth Recycled Pulp Mill	Paper and Pulp	Duluth, MN	Stora Enso Oyj	August 31, 2013
USG Interiors, Inc. *(b)*	Manufacturer	Cloquet, MN	USG Corporation	February 28, 2008
Enbridge Energy Company, Limited Partnership *(b)*	Pipeline	Deer River, MN Floodwood, MN	Enbridge Energy Company, Limited Partnership	February 28, 2008
Minnesota Pipeline Company *(b)*	Pipeline	Staples, MN Little Falls, MN Park Rapids, MN	60% Koch Pipeline Co. L.P. 40% Marathon Ashland Petroleum LLC	February 28, 2008

(a) The contract will terminate four years from the date of written notice from either Minnesota Power or the customer. No notice of contract cancellation has been given by either party. Thus, the earliest date of cancellation is February 28, 2011.

(b) The contract will terminate one year from the date of written notice from either Minnesota Power or the customer. No notice of contract cancellation has been given by either party. Thus, the earliest date of cancellation is February 28, 2008.

Purchased Power

Minnesota Power has contracts to purchase capacity and energy from various entities, the largest is with Square Butte. Under an agreement with Square Butte expiring at the end of 2026, Minnesota Power is currently entitled to approximately 60% (55% beginning in 2008; 50% in 2009 and thereafter) of the output of a 455-MW coal-fired generating unit located near Center, North Dakota. (See Note 8.)

In May 2005, Minnesota Power entered into a 25-year agreement with an affiliate of FPL Energy to purchase all of the renewable energy from Oliver Wind I, an approximately 50-MW (nameplate) wind facility in North Dakota. Oliver Wind I commenced commercial operation in late December 2006 and is comprised of 22 new 2.3-MW wind turbines. In addition, in December 2006, Minnesota Power and an affiliate of FPL Energy reached an agreement for Minnesota Power to purchase an additional 48 MW of wind energy from an expansion of Oliver Wind I. If regulatory approvals and permits are received, FPL Energy expects the expansion, Oliver Wind II, to be operational by late 2007. Minnesota Power is also continuing to pursue additional agreements for wind energy from new facilities being planned within Minnesota Power's service territory. The projects, expected to be operational in late 2007 or 2008, would be smaller in size than the North Dakota projects and would be subject to negotiation and execution of power purchase agreements, as well as regulatory approvals.

Energy – Regulated Utility (Continued)

Fuel

Minnesota Power purchases low-sulfur, sub-bituminous coal from the Powder River Basin coal region located in Montana and Wyoming. Coal consumption in 2006 for electric generation at Minnesota Power's coal-fired generating stations was about 5 million tons. As of December 31, 2006, Minnesota Power had a coal inventory of about 800,000 tons. Minnesota Power has two coal supply agreements with expiration dates extending through 2009 and one contract with an initial term expiring in 2008. Under these agreements, Minnesota Power has the tonnage flexibility to procure 70% to 100% of its total coal requirements. In 2007, Minnesota Power will obtain coal under these coal supply agreements and in the spot market. This diversity in coal supply options allows Minnesota Power to manage market price and supply risk and to take advantage of favorable spot market prices. Minnesota Power is exploring 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 and Santa Fe Railway Company (Burlington Northern) entered into a long-term agreement under which Burlington Northern transports all of Minnesota Power's coal by unit train from the Powder River Basin directly to Minnesota Power's generating facilities or to a designated interconnection point. Minnesota Power also has agreements with the Canadian National Railway and Midwest Energy Resources Company to transport coal from the Burlington Northern interconnection point to certain Minnesota Power facilities.

Coal Delivered to Minnesota Power **Year Ended December 31**	**2006**	**2005**	**2004**
Average Price per Ton	$20.19	$19.76	$19.01
Average Price per MBtu	$1.10	$1.08	$1.04

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 expiring in 2027. Square Butte's cost of lignite burned in 2006 was approximately 85 cents per MBtu. The lignite acreage that has been dedicated to Square Butte by BNI Coal is located on lands essentially all of which are under private control and presently leased by BNI Coal. This lignite supply is sufficient to provide fuel for the anticipated useful life of the generating unit.

Regulatory Issues

We are subject to the jurisdiction of various regulatory authorities. The MPUC has regulatory authority over Minnesota Power's service area in Minnesota, retail rates, retail services, issuance of securities and other matters. The FERC has jurisdiction over the licensing of hydroelectric projects, the establishment of rates and charges for the sale of electricity for resale and transmission of electricity in interstate commerce, and certain accounting and record-keeping practices. The PSCW has regulatory authority over the retail sales of electricity, natural gas and water by SWL&P. The MPUC, FERC and PSCW had regulatory authority over 56%, 8% and 8%, respectively, of our 2006 consolidated operating revenue.

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

In addition to Large Power Customer contracts, Minnesota Power also has contracts with large industrial and commercial customers with monthly demands of more than 2 MW but less than 10 MW of capacity. The terms of these contracts vary depending upon the customer's demand for power and the cost of extending Minnesota Power's facilities to provide electric service.

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.

Energy – Regulated Utility (Continued)

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

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

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

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

Municipal and Wholesale Customers. Minnesota Power has contracts with 16 Minnesota municipalities receiving wholesale electric service. One contract expires April 2008 (31,000 MWh purchased in 2006), while the other 15 are for service through at least January 2011. In 2006, these municipal customers purchased 813,000 MWh from Minnesota Power. Minnesota Power also has a contract for wholesale service with Dahlberg Light & Power Company (Dahlberg) in Wisconsin. Dahlberg purchased 111,000 MWh in 2006.

Midwest Independent Transmission System Operator, Inc. (MISO). Minnesota Power and SWL&P are members of MISO. MISO was the first regional transmission organization (RTO) approved by the FERC as meeting its Order No. 2000 criteria. Minnesota Power and SWL&P retain ownership of their respective transmission assets and control area functions, but their transmission network is under the regional operational control of MISO, and they take and provide transmission service under MISO open access transmission tariff. MISO continues its efforts to standardize rates, terms and conditions of transmission service over its broad region, which encompasses all or parts of 15 states and one Canadian province, and over 100,000 MW of generating capacity.

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

Minnesota Public Utilities Commission. Minnesota Power's retail rates are based on a 1994 MPUC retail rate order that allows for an 11.6% return on common equity dedicated to utility plant. Minnesota Power does not expect to file a request to increase rates for its retail utility operations during 2007. We will, however, continue to monitor the costs of serving our retail customers and evaluate the need for a rate filing in the future. Retail rates will be adjusted without a rate proceeding to reflect recovery of costs related to the Arrowhead Regional Emission Abatement plan (see AREA Plan).

Large Power Contracts. In 2006, the MPUC approved Minnesota Power's new electric service agreement through August 2013 with Stora Enso's Duluth mills and a new electric service agreement through February 2011 with Blandin Paper's Grand Rapids facilities. Also in 2006, Minnesota Power reached an agreement with PolyMet Mining to provide all of its electric service needs through at least 2018. PolyMet Mining plans to begin commercial operations by late 2008, pending completion of financing arrangements and receipt of regulatory approvals. Once fully operational, it is anticipated that PolyMet will require approximately 70 MW. The PolyMet Mining electric service agreement requires MPUC approval.

Energy – Regulated Utility (Continued)

Resource Plan. In September 2004, Minnesota Power filed its Integrated Resource Plan (Resource Plan) with the MPUC. A November 2006 update to our Advance Forecast contained a revised projection showing our winter peak demand by customers in our service territory is expected to increase at an average annual growth rate of 1.5% through 2011. We project an additional capacity need of approximately 150 MW by 2010, with another 200 MW of capacity need anticipated by 2015. These forecasted capacity needs are a combination of increased customer demand and decreases in our existing capacity supply. Increased demand is anticipated from residential and smaller commercial growth as well as from a positive outlook for our Large Power Customers in northeastern Minnesota. Minnesota Power will also realize a reduction in generating resource supply over the next two years under the terms of a long-term energy supply contract with Square Butte. The combination of increased demand and reduced supply means Minnesota Power will need to secure additional capacity and energy to serve our customers in future years. In the Resource Plan, we provided several options designed to replace the Square Butte reductions and meet the predicted growing demand in the region.

In 2006, the MPUC approved our Resource Plan. One of the key components of the Resource Plan was the redirection of our Taconite Harbor generating facility from Nonregulated Energy Operations to Regulated Utility operations effective January 1, 2006. We have also entered into a 50-MW long-term power purchase agreement with Manitoba Hydro, which will be effective from May 2009 to April 2015. This agreement was executed in June 2006 and filed for approval with the MPUC in January 2007. The MPUC also approved expansion of our renewable generating assets to meet Minnesota's Renewable Energy Objective which seeks a 10% supply of qualified renewable energy resources for each Minnesota utility by 2015. In 2006, Oliver Wind I, a 50-MW wind facility in North Dakota, was constructed and placed in service. We began purchasing Oliver Wind I output under a 25-year power purchase agreement with an affiliate of FPL Energy in late December 2006.

Minnesota Power has executed a power purchase agreement for an additional 48 MW of wind energy from an expansion of Oliver Wind I. The expansion, Oliver Wind II, is expected to be completed and operational by late 2007. Minnesota Power is also pursuing additional agreements for wind energy from new facilities being planned within Minnesota Power's service territory and is considering 10 MW of additional hydro generation through an expansion of the Fond du Lac hydroelectric station.

The Company is required to file its next Resource Plan with the MPUC by November 1, 2007.

We are exploring various construction and purchase options for our anticipated resource needs in 2015. These options include:

- *North Dakota Generation Study*. In December 2005, Minnesota Power, Basin Electric Power Cooperative, Minnkota Power and Montana-Dakota Utilities Company announced a project development agreement to evaluate the feasibility of a joint lignite-fueled generating resource in the vicinity of the existing Milton R. Young generating station (which includes Square Butte) near Center, North Dakota. The feasibility study is currently underway and any final resource decision by Minnesota Power is subject to MPUC and other approvals.
- *Mesaba Energy Project.* Excelsior Energy Inc. (Excelsior) is a Minnesota-based independent energy development company. Excelsior has proposed to construct two 600-MW (net) coal-gasification generation units in northern Minnesota. This project is in the early development stages but may be an option for our long-term forecasted energy and capacity needs. Excelsior says the facility could be operational in 2011, but it needs to obtain necessary permits and financing. In 2003, the Minnesota legislature enacted several provisions that provide Excelsior with special considerations, including requiring utilities within the state to "consider" Excelsior before pursuing new fossil-fuel-fired resource additions. This was done as part of Xcel Energy Inc.'s (Xcel) Prairie Island nuclear waste storage reauthorization. Excelsior is "entitled" to enter into a 450-MW power sales agreement with Xcel, subject to MPUC approval. In December 2005, Excelsior filed with the MPUC a petition for approval of terms and conditions for the sale of power to Xcel under these statutory provisions. Other utilities in the state, including Minnesota Power, "must consider" Excelsior before pursuing new fossil-fuel-fired resource additions. In January 2006, Minnesota Power filed comments with the MPUC in Excelsior's proposed power purchase agreement proceeding. Our comments focused on the importance to the state of maintaining a range of base load energy options including multiple fuel types and generating technologies. In April 2006, the MPUC referred Excelsior's petition to an administrative law proceeding to further develop the record in the case for subsequent MPUC deliberations. Minnesota Power continues to be a participant in these proceedings, focusing its comments on energy policy and infrastructure impacts.
- *Natural Gas Combined Cycle Generation.* Minnesota Power is also continuing to study the feasibility of the construction of a natural gas-fired electric generating facility which could be located in northwestern Wisconsin or northeastern Minnesota.

Energy – Regulated Utility (Continued)

Arrowhead Regional Emission Abatement Plan (AREA Plan). In May 2006, the MPUC approved Minnesota Power's \$60 million environmental initiative. The AREA Plan approval allows Minnesota Power to recover Minnesota jurisdictional costs for SO_2, NO_X and mercury emission reductions made at its Taconite Harbor and Laskin facilities without a rate proceeding. The Minnesota cost recovery includes return on investment, depreciation, and incremental operations and maintenance expenses. The AREA Plan is expected to significantly reduce emissions from Taconite Harbor and Laskin, while maintaining a reliable and reasonably-priced energy supply to meet the needs of our customers. We believe that control and abatement technologies applicable to these plants have matured to the point where further significant air emission reductions can be attained in a relatively cost-effective manner.

Taconite Harbor will employ an innovative multi-emission reduction technology, while Laskin will receive a retrofit focused on lowering NO_X emissions. The Company estimates an emission reduction of over 60% for NO_X at both facilities and a 65% reduction in SO_2 emissions at Taconite Harbor. Laskin already has relatively low emission levels of SO_2 due to existing emission reduction technology. Additionally, with the emerging technology being applied at Taconite Harbor, there is the potential for a 90% reduction in mercury emissions.

Minnesota Power completed installation of new equipment at the first of two Laskin units in November 2006, with the first of three Taconite Harbor unit installations anticipated to be completed by mid-2007. Work on all units at Taconite Harbor and Laskin is anticipated to be completed by the end of 2008. Cost recovery filings are required to be made 90 days prior to the anticipated in-service date for the equipment at each unit, with rate recovery beginning the month following the in-service date. We began cost recovery of AREA plan costs in December 2006 with the placement in service of Laskin Unit 2. We filed with the MPUC for cost recovery on Laskin Unit 1 in January 2007 and expect to begin cost recovery in May 2007. We anticipate beginning cost recovery on Taconite Harbor Unit 2 in mid-2007 and Taconite Harbor Units 1 and 3 in 2008. AREA plan expenditures as of December 31, 2006, were \$11.4 million.

Boswell Unit 3 Emission Reduction Plan. In May 2006, we announced plans to make emission reduction investments at our Boswell Unit 3 generating unit. Plans include reductions of particulate, SO_2, NO_X and mercury emissions to meet pending federal and state requirements. The estimated capital cost for these reductions is approximately \$200 million, of which \$14 million was spent in 2006 for design engineering and related costs. The balance is expected to be spent from 2007 through 2009. In October 2006, we submitted a filing to the MPCA for approval of the Boswell Unit 3 emission reduction plan. A filing with the MPUC for approval of Minnesota jurisdictional related expenditures on Boswell Unit 3 was made in January 2007 to allow cost recovery on these investments without a rate proceeding. MPUC approval would authorize a cash return on construction work in progress during the construction phase and allow recovery for a return on investment, depreciation, and incremental operations and maintenance expenses once the unit is placed into service in late 2009. We expect to begin cost recovery on construction work in progress in 2008. In 2007, we will be filing with the MPUC a request to extend the asset life for depreciation purposes on Boswell Unit 3 from 8 years to 29 years. We anticipate approval of this filing in 2007.

Conservation Improvement Programs (CIP). Minnesota requires investor-owned electric utilities to spend a minimum of 1.5% of gross annual retail electric revenue on CIP 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 recovery, all CIP expenditures, as well as a carrying charge on the deferred account balance. Minnesota Power's CIP investment goal was \$3.2 million for 2006 (\$3.2 million for 2005; \$3.1 million for 2004), with actual spending of \$3.8 million in 2006 (\$3.6 million in 2005; \$3.1 million in 2004).

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

Energy – Regulated Utility (Continued)

Competition

We believe the overall impact of the EPAct 2005 on the electric utility industry has been positive and are continuing to evaluate the effects on our business as this legislation is being implemented. This federal legislation is designed to bring more certainty to energy markets in which ALLETE participates, as well as to provide investment incentives for energy efficiency, energy infrastructure (such as electric transmission lines) and energy production. The FERC has the responsibility of implementing numerous new standards as a result of the promulgation of EPAct 2005. So far the FERC's regulatory efforts appear to be generally positive for the utility industry.

EPAct 2005's repeal of the PUHCA 1935 should result in more capital flowing into the industry, while providing additional operational flexibility. The PUHCA 1935 repeal may also allow an acceleration of merger activity, as well as spawn moves by state regulators to adopt PUHCA-like regulations, although both events are speculative and difficult to predict.

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

Franchises

Minnesota Power holds franchises to construct and maintain an electric distribution and transmission system in 90 cities and towns located within its electric service territory. SWL&P holds similar franchises for electric, natural gas and/or water systems in 15 cities and towns within its service territory. The remaining cities and towns served do not require a franchise to operate within their boundaries. Our exclusive service territories are established by state regulatory agencies.

Energy – Nonregulated Energy Operations

BNI Coal owns and operates a lignite mine in North Dakota. BNI Coal is a low-cost supplier of lignite in North Dakota, producing about 4 million tons annually. Two electric generating cooperatives, Minnkota Power and Square Butte, presently consume virtually all of BNI Coal's production of lignite under cost plus a fixed fee coal supply agreements expiring in 2027. (See Fuel and Note 8.) The mining process disturbs and reclaims approximately 210 acres per year. Laws require that the reclaimed land be at least as productive as it was prior to mining. The average cost to reclaim one acre of land is about $15,000, however, could be as high as $30,000. Reclamation costs are included in the cost of coal passed through to customers. In September 2004, BNI Coal entered into a master lease agreement with Farm Credit Leasing Services Corporation (Farm Credit). Under this agreement, BNI Coal leases a dragline that went into operation September 30, 2004. BNI Coal is obligated to make lease payments totaling $2.8 million annually for the 23-year lease term, which expires in 2027. BNI Coal will have the option at the end of the lease term to renew the lease at a fair market rental, to purchase the dragline at fair market value, or to surrender the dragline to Farm Credit and pay a $3.0 million termination fee. With lignite reserves of an estimated 600 million tons and new dragline equipment, BNI Coal has ample capacity to expand production.

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

Nonregulated Power Supply	Unit No.	Year Installed	Year Acquired	Net Capability
				MW
Steam				
Wood-Fired *(a)*				
Cloquet Energy Center in Cloquet, MN	5	2001	2001	22
Rapids Energy Center *(b)* in Grand Rapids, MN	6 & 7	1969, 1980	2000	30
Hydro				
Conventional Run-of-River				
Rapids Energy Center *(b)* in Grand Rapids, MN	4 & 5	1917	2000	1

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

Energy – Nonregulated Energy Operations (Continued)

Taconite Harbor. In 2002, we commenced operation of the Taconite Harbor generating facilities, which we purchased in 2001. The generation output was primarily sold in the wholesale market and was sold in limited circumstances to Minnesota Power's retail utility customers. Under the terms of our Resource Plan, we have operated the Taconite Harbor facility as a rate-based asset within the Minnesota retail jurisdiction since January 1, 2006. Prior to January 1, 2006, we operated our Taconite Harbor facility as nonregulated generation. (See Energy – Regulated Utility – Minnesota Public Utilities Commission.)

Rainy River Energy has been engaged in the acquisition and development of nonregulated generation and wholesale power marketing. On April 1, 2005, Rainy River Energy completed the assignment of its power purchase agreement with LSP-Kendall Energy, LLC, the owner of an energy generation facility located in Kendall County, Illinois, to Constellation Energy Commodities. Rainy River Energy paid Constellation Energy Commodities $73 million in cash to assume the power purchase agreement, which is in effect through mid-September 2017. In addition, consent, advisory and closing costs of $4.9 million were incurred to complete the transaction. As a result of this transaction, ALLETE incurred a $77.9 million ($50.4 million after tax, or $1.84 per diluted share) charge in 2005.

Rainy River Energy Corporation - Wisconsin continues to study the feasibility of the construction of a natural gas-fired electric generating facility in northwestern Wisconsin. In accordance with the PSCW's final order approving the project, Rainy River Energy Corporation - Wisconsin undertook preliminary site preparation work in late 2003.

Minnesota Land. We have about 15,000 acres of land in northern Minnesota, which is available for sale. We acquired this land in 2001 at the time we purchased Taconite Harbor from LTV Steel Mining Co. The cost basis of this land was $4.3 million at December 31, 2006.

Energy – Investment in ATC

In December 2005, we entered into an agreement with Wisconsin Public Service Corporation and WPS Investments, LLC that provides for our Wisconsin subsidiary, Rainy River Energy Corporation - Wisconsin, to invest $60 million in ATC. ATC is a Wisconsin-based public utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota and Illinois. ATC provides transmission service under rates regulated by the FERC that are set in accordance with the FERC's policy of establishing the independent operation and ownership of, and investment in, transmission facilities. In May 2006, the PSCW reviewed and approved the request that allows us to invest in ATC. During 2006, we invested $51.4 million in ATC. We plan to invest an additional $8.6 million in ATC in early 2007 to reach our $60 million investment commitment and estimated 8% ownership interest. As of December 31, 2006, our equity investment balance in ATC was $53.7 million, representing approximately a 7% ownership interest. (See Note 6.) We will have the opportunity to make additional investments in ATC through general capital calls based upon our pro-rata investment level in ATC.

Real Estate

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

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

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

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

Real Estate (Continued)

Town Center. Town Center, which is located in the city of Palm Coast, is a mixed-use development with a neo-traditional downtown core area. Surrounded by major arterial roads, including Interstate 95, Town Center is adjacent to the Florida Hospital-Flagler, the Flagler County Airport and the Flagler Palm Coast High School. Sites have also been set aside for a new city hall, an arts and entertainment center, and other public uses. At build-out, Town Center is expected to include over 2,900 residential units, including lodging facilities, and 3.7 million square feet of various types of commercial space, including a movie theater. Future market conditions will determine how quickly Town Center is built out.

Construction of the major infrastructure improvements commenced in March 2005 and was substantially complete at the end of 2006. Infrastructure improvements include 3.6 miles of roads, a master storm water management system, underground utilities, street lights, sidewalks and bike paths, and extensive landscaping.

In March 2005, the Town Center at Palm Coast Community Development District (Town Center District) issued $26.4 million of tax exempt, 6% Capital Improvement Revenue Bonds, Series 2005, which are payable over 31 years (by May 1, 2036). The bond proceeds (less capitalized interest, a debt service reserve fund and cost of issuance) were used to pay for the construction of a portion of the major infrastructure improvements at Town Center. The bonds are being repaid by special assessments on all buildable land within Town Center. The special assessments were billed to Town Center landowners beginning in November 2006. To the extent that we still own land at the time of the assessment, we recognize the cost of our portion of these assessments based upon our ownership of benefited property. At December 31, 2006, we owned approximately 73% of the assessable land in the Town Center District. As we sell property, the obligation to pay special assessments will pass to the new landowners.

Additional Town Center development costs not funded through the Town Center District bond financing, estimated at $30 million (up to $11 million can be offset through traffic impact fee credits received over the life of the project), are being partially funded through an $8.5 million revolving development loan. The borrower is Florida Landmark. The development loan is guaranteed by Lehigh Acquisition Corporation. Florida Landmark is a wholly-owned subsidiary of Lehigh Acquisition Corporation which is an 80% owned subsidiary of ALLETE.

Pending land sales under contract for properties at Town Center were $40.1 million at December 31, 2006. We have the opportunity to receive participation revenue as part of one of these sales contracts. Among the pending Town Center sales contracts is a contract with Developers Realty Corporation (DRC) to develop projects in the downtown core area and a large retail shopping center on a 50-acre tract. DRC has entered into an agreement to form a joint venture with Weingarten Realty Investors (Weingarten). DRC/Weingarten has a commitment from a major national retail anchor for the retail shopping center.

Throughout 2005 and 2006, we focused on platting phases 1 and 2, which include the major roads and lots for a variety of uses, and developing the major infrastructure at Town Center. During that period, our marketing program targeted a blend of office, retail, commercial, residential and mixed-use project developers. In December 2006, a Publix grocery store anchored retail center opened and construction started on an 84,000 square foot medical center. Twenty other projects are in the permitting stage, 11 of which are expected to break ground in 2007. Future marketing efforts will focus on attracting the following additional land uses to Town Center: residential apartments, assisted living facilities, business park uses, and restaurants.

Palm Coast Park. Palm Coast Park, which is located in the city of Palm Coast, is a 4,700-acre mixed-use development bisected by a 6-mile segment of U.S. Highway 1 about one mile from an existing Interstate 95 interchange and bounded on the west by a Florida East Coast Railroad rail line. At build-out, the project will include approximately 3.2 million square feet of commercial space and about 3,900 residential units ranging from affordable condominium units and apartments to estate golf course homes. Future market conditions will determine how quickly Palm Coast Park is built out.

In May 2006, the Palm Coast Park Community Development District (Palm Coast Park District) issued $31.8 million of tax exempt, 5.7% Special Assessment Bonds, Series 2006, which are payable over 31 years (by May 1, 2037). The bond proceeds (less capitalized interest, a debt service reserve fund and cost of issuance) are being used to pay for the construction of the major infrastructure improvements at Palm Coast Park and to mitigate traffic and environmental impacts. The bonds will be repaid by special assessments on all buildable land within Palm Coast Park. The special assessments will be billed to Palm Coast Park landowners beginning in November 2007. To the extent that we still own land at the time of the assessment, we will recognize the cost of our portion of these assessments based upon our ownership of benefited property. At December 31, 2006, we owned approximately 97% of the assessable land in the Palm Coast Park District. As we sell property, the obligation to pay special assessments will pass to the new landowners.

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

Major infrastructure construction began in December 2006 and is expected to be completed in 2007. Commercial and industrial lots will be offered for sale in 2007, with closings anticipated to begin in 2008.

Real Estate (Continued)

Pending land sales under contract for properties at Palm Coast Park were $62.8 million at December 31, 2006. We have the opportunity to receive participation revenue as part of these sales contracts. One of the pending sales contracts is for the sale of five residential tracts and one commercial tract for $52.5 million. That sales contract provides for closings in 2007, 2008 and 2009. The project, which is named Sawmill Creek, will include up to 1,469 residential housing units, a championship golf course and neighborhood retail office space, along with a community park and elementary school. Other contracts include a residential tract for an affordable condominium project and a 600-unit single-family residential project that will be connected to the existing Matanzas Woods golf course neighborhood.

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

The Development of Regional Impact (DRI) development order for Ormond Crossings was approved by the city of Ormond Beach in December 2006, and provides for 5 million square feet of various types of commercial land uses and up to 3,700 residential units to be built in four phases. The Flagler County DRI development order is under review by the Flagler County Commission and, if approved, we will receive entitlements for up to 700 additional residential units. Actual build-out, however, will consider market demand as well as infrastructure and mitigation costs. Most of the developable part of Ormond Crossings is located in the city of Ormond Beach, so the project is not dependent upon receiving any further land use approvals from Flagler County. The Flagler County portion of the project will be mainly permitted for a wetland mitigation bank. Applications to permit the wetland mitigation bank were submitted in 2006 to St. Johns River Water Management District and the U.S. Army Corps of Engineers. Wetland mitigation credits will be used in connection with the permitting of development at Ormond Crossings and can also be sold to other developers.

After an agreement is finalized with the Florida Department of Transportation concerning traffic mitigation costs, we will determine the best economic build-out of the project. The agreement and economic analysis are expected to be completed in 2007.

Engineering design and permitting will be ongoing as the project is developed. We anticipate Ormond Crossings land sales closings starting in 2009.

Other Land. In addition to the major development projects, land inventories in Florida include 3,300 acres of other property. Several smaller development projects are under way to plat these properties, add infrastructure, and modify and enhance existing entitlements.

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

ALLETE Properties occasionally provides seller financing. At December 31, 2006, outstanding finance receivables were $18.3 million, with maturities ranging up to ten years. These finance receivables accrue interest at market-based rates and are collateralized by the financed properties.

Real Estate (Continued)

Summary of Development Projects For the Year Ended December 31, 2006	Ownership	Total Acres *(a)*	Residential Units *(b)*	Commercial Sq. Ft. *(b,c)*
Town Center	80%			
At December 31, 2005		1,480	2,833	2,927,700
Property Sold		(124)	(773)	(401,971)
Change in Estimate *(a)*		–	162	179,581
		1,356	2,222	2,705,310
Palm Coast Park	100%			
At December 31, 2005		4,705	3,600	3,200,000
Property Sold		(368)	(200)	–
Change in Estimate *(a)*		–	360	(43,200)
		4,337	3,760	3,156,800
Ormond Crossings	100%			
At December 31, 2005		5,960	*(d)*	*(d)*
Change in Estimate *(a)*		–		
		5,960		
		11,653	5,982	5,862,110

(a) Acreage amounts are approximate and shown on a gross basis, including wetlands and minority interest. Acreage amounts may vary due to platting or surveying activity. Wetland amounts vary by property and are often not formally determined prior to sale.
(b) Estimated and includes minority interest. The actual property breakdown at full build-out may be different than these estimates.
(c) Includes industrial, office and retail square footage.
(d) A development order approval from the city of Ormond Crossings was received in December 2006, for up to 3,700 residential units and 5 million commercial square feet. A development order from Flagler County is currently under review, and if approved, Ormond Crossings will receive entitlements for up to 700 additional residential units. Actual build-out, however, will consider market demand as well as infrastructure and mitigation costs.

Summary of Other Land Inventories For the Year Ended December 31, 2006	Ownership	Total	Mixed Use	Residential	Commercial	Agricultural
Acres *(a)*						
Palm Coast Holdings	80%					
At December 31, 2005		2,566	1,692	346	281	247
Property Sold		(321)	(288)	–	(30)	(3)
Contributed Land		(12)	–	–	(4)	(8)
Change in Estimate *(a)*		(97)	–	–	–	(97)
		2,136	1,404	346	247	139
Lehigh	80%					
At December 31, 2005		613	390	140	74	9
Property Sold		(390)	(390)	–	–	–
		223	–	140	74	9
Cape Coral	100%					
At December 31, 2005		41	–	1	40	–
Property Sold		(11)	–	–	(11)	–
		30	–	1	29	–
Other *(b)*	100%					
At December 31, 2005		944	–	–	–	944
Property Sold		(10)	–	–	–	(10)
		934	–	–	–	934
		3,323	1,404	487	350	1,082

(a) Acreage amounts are approximate and shown on a gross basis, including wetlands and minority interest. Acreage amounts may vary due to platting or surveying activity. Wetland amounts vary by property and are often not formally determined prior to sale. The actual property breakdown at full build-out may be different than these estimates.
(b) Includes land located in Ormond Beach, Florida, and other land located in Palm Coast, Florida not included in development projects.

Real Estate (Continued)

Regulation

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

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

Competition

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

Other

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

Emerging Technology Portfolio. As part of our emerging technology portfolio, we have several minority investments in venture capital funds and direct investments in privately-held, start-up companies. Since 1985, we have invested in start-up companies, which are developing technologies that may be utilized by the electric utility industry. We are committed to invest an additional $2.5 million in 2007 and do not have plans to make any additional investments. The investments were first made through emerging technology funds (Funds) initiated by other electric utilities and us. We have also made investments directly in privately-held companies.

Companies in the Funds' portfolios may complete IPOs, and the Funds may, in some instances, distribute publicly tradable shares to us. Some restrictions on sales may apply, including, but not limited to, underwriter lock-up periods that typically extend for 180 days following an IPO.

We account for our investment in venture capital funds under the equity method (see Note 15) and account for our direct investments in privately-held companies under the cost method because of our ownership percentage. The total carrying value of our emerging technology portfolio was $9.2 million at December 31, 2006, and December 31, 2005. Our policy is to review these investments quarterly for impairment by assessing such factors as continued commercial viability of products, cash flow and earnings. Any impairment would reduce the carrying value of the investment. Our basis in direct investments in privately-held companies included in the emerging technology portfolio was zero at December 31, 2006, and December 31, 2005. In 2005, we recorded $5.1 million ($3.3 million after tax) of impairments related to our direct investments in certain privately-held, start-up companies whose future business prospects had significantly diminished. Developments at these companies indicated that future commercial viability was unlikely, as was new financing necessary to continue development. In 2004, we recorded $6.5 million ($4.1 million after tax) of impairments.

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

Air. *Clean Air Act.* Minnesota Power's generating facilities mainly burn low-sulfur western sub-bituminous coal. Square Butte, located in North Dakota, burns lignite coal. All of these facilities are equipped with pollution control equipment such as scrubbers, bag houses or electrostatic precipitators. Permitted emission requirements are currently being met. The federal Clean Air Act Amendments of 1990 (Clean Air Act) created emission allowances for SO_2. Each allowance is an authorization to emit one ton of SO_2, and each utility must have sufficient allowances to cover its annual emissions. Most Minnesota Power facilities have surplus SO_2 emission allowances, which were sufficient to cover the transfer of Taconite Harbor's generating assets to our Regulated Utility effective January 1, 2006, as approved by the MPUC. Square Butte is meeting its SO_2 emission allowance requirements through increased use of its existing scrubber.

In accordance with the Clean Air Act, the EPA has established NO_X limitations for electric generating units. To meet NO_X limitations, Minnesota Power installed advanced low-emission burner technology and associated control equipment to operate the Boswell and Laskin facilities at or below the compliance emission limits. NO_X limitations at Taconite Harbor and Square Butte are currently being met by combustion tuning.

Clean Air Interstate Rule and Clean Air Mercury Rule. In March 2005, the EPA announced the final Clean Air Interstate Rule (CAIR) that reduces and permanently caps emissions of SO_2 and NO_X in the eastern United States. The CAIR includes Minnesota as one of the 28 states it considers an "eastern" state. The EPA also announced the final Clean Air Mercury Rule (CAMR) that reduces and permanently caps electric utility mercury emissions nationwide. The CAIR and the CAMR regulations have been challenged in the court system, which may delay implementation or modify provisions. Minnesota Power is participating in a legal challenge to the CAIR, but is not participating in the challenge of the CAMR. However, if the CAMR and the CAIR do go into effect, Minnesota Power expects to be required to (1) make emissions reductions, (2) purchase mercury, SO_2 and NO_X allowances through the EPA's cap-and-trade system, or (3) use a combination of both.

We believe that CAIR contains flaws in its methodology and application, which will cause Minnesota Power to incur significantly higher compliance costs. Minnesota Power petitioned that the EPA review its CAIR determinations that affected Minnesota. In July 2005, Minnesota Power also filed a Petition for Review with the U.S. Court of Appeals for the District of Columbia Circuit. The Company also filed a Petition for Reconsideration with the EPA. In November 2005, the EPA agreed to reconsider certain aspects of its CAIR, including the Minnesota Power petition addressing modeling used to determine Minnesota's inclusion in the CAIR region and claims about inequities in the SO_2 allowance methodology. In March 2006, the EPA announced that it would not make any changes to the CAIR as a result of the Petitions for Reconsideration. Petitions for Review, including Minnesota Power's, remain pending at the Court of Appeals. If the Petition for Review is successful, the Company expects to incur lower compliance costs, consistent with the rules applicable to those states considered "western" states under the CAIR. Resolution of the CAIR Petition for Review with the Court of Appeals is anticipated in 2008.

Mercury Emissions. The Minnesota mercury emissions budget under the first phase of the CAMR, requiring roughly a 20% reduction in nationwide utility mercury emissions beginning in 2010, is similar to current Minnesota statewide emissions requirements. The second phase allocation, requiring approximately a 70% reduction in nationwide utility mercury emissions effective in 2018, will require that Minnesota generation sources provide for substantial mercury emission reductions or procure mercury emission credits from other sources that have a surplus of allowances. However, mercury emission reductions expected as a result of implementing AREA at Taconite Harbor, and implementation of the 2006 Minnesota Mercury Emission Reduction Law which applies to Boswell Units 3 and 4, are anticipated to meet Minnesota Power's 2018 emission reduction requirements of the second phase of CAMR. (See Minnesota Mercury Emission Law.) Minnesota Power is continuing to review the new mercury rule and considers the outcome of legal challenges as being critical before specific compliance measures can be established or assessed.

Environmental Matters (Continued)

Minnesota Mercury Emission Law. This legislation requires Minnesota Power to file mercury emission reduction plans for its Boswell Units 3 and 4. The Boswell Unit 3 emission reduction plan was filed with the MPCA in October 2006. Minnesota Power is required to install mercury emission reduction technology and equipment by December 31, 2010. 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. One plan must attain the mercury reduction goal of 90%. Alternate mercury plans, with the percentage of reduction elected by the utility, are also required to be filed. Minnesota Power may apply mercury emissions achieved under its Arrowhead Regional Emission Abatement plan at Taconite Harbor toward the reduction goal required under approved plans for Boswell Units 3 and 4. Filed plans must be reviewed and approved by the MPCA and the MPUC under criteria that include, among other things, technical feasibility, environmental benefit, cost effectiveness and rate impact. The new law encourages multi-emission reduction plans and also extends a statutory provision for current cost recovery outside of a rate case for approved emission reduction expenditures, including mercury and other types of emissions, from 2006 through 2013. The legislation generally comports with Minnesota Power's plans for its Boswell Units 3 and 4 mercury and other emission reduction retrofits. Total pollution control capital costs planned for Boswell Unit 3 are estimated at approximately $200 million, of which $14 million was spent in 2006 for design engineering and related costs. The balance is expected to be spent from 2007 through 2009. The Boswell Unit 3 emission reduction plan provides significant cost-effective emission reductions through the use of integrated control technologies appropriate for the size, location and use of Boswell Unit 3. Minnesota Power anticipates that costs for these expenditures will be recovered from retail customers on a current basis, subject to approval by the MPUC. (See Regulatory Issues – Minnesota Public Utilities Commission – Boswell Unit 3 Emission Reduction Plan.)

New Source Review Rules. In December 2002, the EPA issued changes to the existing New Source Review rules, which modified the procedures for MPCA review of projects at our electric generating facilities. These changes have been incorporated in Minnesota and have not had a material impact on our operations. In October 2003, the EPA announced additional changes clarifying the application of certain sections of the New Source Review rules. In December 2003, the U.S. Court of Appeals for the District of Columbia Circuit (Court) stayed the implementation of the October 2003 rule pending further review. In March 2006, the Court vacated most of the EPA's 2003 rule. These changes are not expected to have a material impact on Minnesota Power.

Water. The Federal Water Pollution Control Act requires National Pollutant Discharge Elimination System (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.

FERC Licenses. Minnesota Power holds FERC licenses authorizing the ownership and operation of seven hydroelectric generating projects with a total generating capacity of about 115 MW.

Laskin NPDES Permit Modification. In June 2006, Minnesota Power filed an application with the MPCA for a variance from a wastewater discharge standard for mercury included in its NPDES permit for Laskin. The variance requested an extension for Laskin to meet mercury discharge requirements which will become effective March 23, 2007, as set forth in Laskin's NPDES permit issued by the MPCA in May 2005. In view of the EPA's proposed changes relating to the implementation of mercury water policy and recent developments in mercury treatment technologies, the MPCA believes it is more appropriate at this time to forego the processing of mercury variances. Instead, a permit modification will be used which will contain a compliance schedule that specifies interim actions and limits that lead to compliance with the final limits by March 31, 2010. This approach will allow Minnesota Power to further investigate treatment alternatives. In October 2006, Minnesota Power submitted a letter withdrawing its variance request. However, we are continuing discussions on interim limits with the MPCA. The MPCA placed a draft permit modification on 30-day public notice on December 20, 2006. The comment period for the draft permit modification closes March 7, 2007.

Solid and Hazardous Waste. The Resource Conservation and Recovery Act of 1976 regulates the management and disposal of solid wastes and hazardous wastes. As a result of this legislation, the EPA has promulgated various hazardous waste rules. We are required to notify the EPA of hazardous waste activity and, consequently, routinely submit the necessary reports to the EPA. State environmental agencies are responsible for administering solid and hazardous waste rules on the local level with oversight by the EPA. We are in material compliance with these rules.

PCB Inventories. In response to the EPA Region V's request for utilities to participate in the Great Lakes Initiative by voluntarily removing remaining polychlorinated biphenyl (PCB) inventories, Minnesota Power replaced its remaining PCB capacitor banks in 2005. PCB-contaminated oil in substation equipment was largely replaced by the end of 2006.

Environmental Matters (Continued)

SWL&P Manufactured Gas Plant. In May 2001, SWL&P received notice from the WDNR that the city of Superior had found soil contamination on property adjoining a former Manufactured Gas Plant (MGP) site owned and operated by SWL&P from 1889 to 1904. The WDNR requested SWL&P to initiate an environmental investigation. The WDNR also issued SWL&P a Responsible Party letter in February 2002. In February 2003, SWL&P submitted a Phase II environmental site investigation report to the WDNR. This report identified some MGP-like chemicals that were found in the soil near the former plant site. The investigation continued through the fall of 2006. It is anticipated that the final report for this portion of the investigation will be completed during the first quarter of 2007. Although it is not possible to quantify the total potential clean-up costs until the investigation is completed, a $0.5 million liability was recorded in December 2003 based on initial studies to address the known areas of contamination. The Company has recorded a corresponding amount as a regulatory asset. The PSCW has approved SWL&P's deferral of these MGP environmental investigation and potential clean-up costs for future recovery in rates, subject to a regulatory prudency review. In May 2005, the PSCW approved the collection through rates of $150,000 of site investigation costs that had been incurred at the time SWL&P filed its 2006 rate request. In December 2006, the PSCW approved the recovery of an additional $186,000 of site investigation costs that were incurred through 2005. ALLETE maintains pollution liability insurance coverage that includes coverage for SWL&P. A claim has been filed with respect to this matter. The insurance carrier has issued a reservation of rights letter and the Company continues to work with the insurer to determine the availability of insurance coverage.

Employees

At December 31, 2006, ALLETE had approximately 1,500 employees, of which 1,400 were full-time.

Minnesota Power and SWL&P have 612 employees who are members of the International Brotherhood of Electrical Workers (IBEW), Local 31. The labor agreement with Local 31 expires on January 31, 2009.

BNI Coal has 94 employees who are members of the IBEW Local 1593. BNI Coal and Local 1593 have a labor agreement, which expires on March 31, 2008.

Executive Officers of the Registrant

Executive Officers	Initial Effective Date
Donald J. Shippar, Age 57	
Chairman, President and Chief Executive Officer	January 1, 2006
President and Chief Executive Officer	January 21, 2004
Executive Vice President – ALLETE and President – Minnesota Power	May 13, 2003
President and Chief Operating Officer – Minnesota Power	January 1, 2002
Deborah A. Amberg, Age 41	
Senior Vice President, General Counsel and Secretary	January 1, 2006
Vice President, General Counsel and Secretary	March 8, 2004
Steven Q. DeVinck, Age 47	
Controller	July 12, 2006
Laura A. Holquist, Age 45	
President – ALLETE Properties	September 6, 2001
Mark A. Schober, Age 51	
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 49	
Treasurer	July 24, 2004
Timothy J. Thorp, Age 52	
Vice President – Investor Relations	July 1, 2004
Vice President – Investor Relations and Corporate Communications	November 16, 2001
Claudia Scott Welty, Age 54	
Senior Vice President and Chief Administrative Officer	February 1, 2004

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

Ms. Amberg was a Senior Attorney.

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

Mr. Stellmaker was Director of Financial Planning.

Ms. Welty was Vice President Strategy and Technology Development.

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

The present term of office of the executive officers listed above extends to the first meeting of our Board of Directors after the next annual meeting of shareholders. Both meetings are scheduled for May 8, 2007.

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 4 of this Form 10-K and the factors described below. The risks and uncertainties described in this Form 10-K are not the only ones facing our Company. Additional risks and uncertainties that we are not presently aware of, or that we currently consider immaterial, may also affect our business operations. Our business, financial condition or results of operations could suffer if the concerns set forth below are realized.

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

Our 12 Large Power Customers account for approximately 33% of our 2006 consolidated operating revenue (one of these customers accounted for 12%). 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 and the communities that we serve.

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

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

Our Regulated Utility and Nonregulated Energy Operations could be significantly impacted by initiatives designed to reduce the impact of greenhouse gas emissions such as carbon dioxide from our generating facilities.

Proposals for voluntary initiatives and mandatory controls are being discussed both in the United States and worldwide to reduce greenhouse gases such as carbon dioxide, a by-product of burning fossil fuels. We currently use coal as the primary fuel in 96% of the energy produced by our generating facilities.

We have implemented greenhouse gas emission reduction or offset measures at our Regulated Utility and Nonregulated Energy Operations generating facilities. These efforts currently result in over one million tons of carbon dioxide reductions or offsets annually. We are participating in research and study initiatives to mitigate the potential impact to our business. There is no assurance that our current reduction efforts will mitigate the impact of any new regulations.

We cannot be certain whether new laws or regulations will be adopted to reduce greenhouse gases and what effect 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 those costs are not fully recoverable from customers.

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

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

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

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

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

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

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

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

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

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

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

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

Risk Factors (Continued)

We are dependent on good labor relations.

We believe our relations to be good with our approximately 1,500 employees. Failure to successfully renegotiate labor agreements could adversely affect the services we provide and our results of operations. Approximately 700 of these employees are members of either the International Brotherhood of Electrical Workers Local 31 or Local 1593. The labor agreement with Local 31 at Minnesota Power and SWL&P expires on January 31, 2009, and the labor agreement with Local 1593 at BNI Coal expires on March 31, 2008.

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

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

We are exposed to risks associated with real estate development.

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

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

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

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

The Growth Management Act requires counties and cities to adopt comprehensive plans guiding and controlling future real property development in their respective jurisdictions. After a local government adopts its comprehensive plan, all development orders and development permits must be consistent with the plan. Each plan must address such topics as future land use, capital improvements, traffic circulation, sanitation, sewage, potable water, drainage and solid waste disposal. The local governments' comprehensive plans must also establish "levels of service" with respect to certain specified public facilities and services to residents. Local governments are prohibited from issuing development orders or permits if facilities and services are not operating at established levels of service, or if the projects for which permits are requested will reduce the level of service for public facilities below the level of service established in the local government's comprehensive plan. If the proposed development would reduce the established level of services below the level set by the plan, the development order will require that, at the outset of the project, the developer either sufficiently improve the services to meet the required level or provide financial assurances that the additional services will be provided as the project progresses.

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 our ability to develop future real estate projects.

The DRI review process includes an evaluation of a project's impact on the environment, infrastructure and government services, and requires the involvement of numerous state and local environmental, zoning and community development agencies. Local government approval of any DRI is subject to appeal to Florida's Governor and Cabinet by the Florida Department of Community Affairs, and adverse decisions by the Governor and Cabinet are subject to judicial appeal. The DRI approval process is usually lengthy and costly, and conditions, standards or requirements may be imposed on a developer with respect to a particular project, which may materially increase the cost of the project.

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

Competition for land could adversely affect our real estate business.

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

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

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

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Properties are included in the discussion of our business 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 business 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 or results of operations.

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 2006.

Part II

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

We have paid dividends without interruption on our common stock since 1948. A quarterly dividend of $0.41 per share on our common stock will be paid on March 1, 2007, to the holders of record on February 15, 2007. Our common stock is listed on the New York Stock Exchange under the symbol ALE and our CUSIP number is 018522300. Dividends paid per share, and the high and low prices for our common stock for the periods indicated as reported by the New York Stock Exchange on its NYSEnet website, are in the accompanying chart.

The amount and timing of dividends payable on our common stock are within the sole discretion of our Board of Directors. In 2006, we paid out 53% of our per share earnings in dividends.

Our Articles of Incorporation, and Mortgage and Deed of Trust contain provisions, which under certain circumstances would restrict the payment of common stock dividends. As of December 31, 2006, no retained earnings were restricted as a result of these provisions. At February 1, 2007, there were approximately 31,000 common stock shareholders of record.

	2006			2005		
	Price Range		Dividends	Price Range		Dividends
Quarter	High	Low	Paid	High	Low	Paid
First	$47.81	$42.99	$0.3625	$44.40	$35.65	$0.3000
Second	48.55	44.34	0.3625	50.33	40.12	0.3150
Third	49.30	43.26	0.3625	51.70	42.80	0.3150
Fourth	47.84	42.55	0.3625	47.36	41.28	0.3150
Annual Total			$1.4500			$1.2450

Common Stock Repurchases. We did not repurchase any ALLETE common stock during the fourth quarter of 2006.

Item 6. Selected Financial Data

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

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

	2006	2005	2004	2003	2002
Millions					
Balance Sheet					
Assets					
Current Assets	$ 287.7	$ 373.5	$ 355.0	$ 216.1	$ 184.8
Discontinued Operations – Current	–	0.4	13.1	483.9	477.3
Property, Plant and Equipment	921.6	860.4	849.6	888.2	852.0
Investments	189.1	117.7	124.5	175.7	170.9
Other Assets	135.0 *(a)*	44.6	52.8	59.0	61.9
Discontinued Operations – Other	–	2.2	36.4	1,278.4	1,400.3
	$1,533.4	$1,398.8	$1,431.4	$3,101.3	$3,147.2
Liabilities and Shareholders' Equity					
Current Liabilities	$ 143.5	$ 106.7	$ 91.7	$ 182.1	$ 436.2
Discontinued Operations – Current	–	13.0	24.5	344.1	302.0
Long-Term Debt	359.8	387.8	389.4	513.9	566.9
Mandatorily Redeemable Preferred Securities	–	–	–	–	75.0
Other Liabilities	364.3 *(a)*	288.5	295.3	300.1	292.2
Discontinued Operations	–	–	–	300.9	242.5
Shareholders' Equity	665.8	602.8	630.5	1,460.2	1,232.4
	$1,533.4	$1,398.8	$1,431.4	$3,101.3	$3,147.2
Income Statement					
Operating Revenue					
Regulated Utility	$639.2	$575.6	$555.0	$510.0	$497.9
Nonregulated Energy Operations	65.0	113.9	106.8	106.6	84.7
Real Estate	62.6	47.5	41.9	42.6	33.6
Other	0.3	0.4	0.4	0.4	0.3
Total Operating Revenue	767.1	737.4	704.1	659.6	616.5
Operating Expenses					
Fuel and Purchased Power	281.7	273.1	286.2	252.5	234.8
Operating and Maintenance	296.0	293.5	270.1	260.5	254.4
Kendall County Charge	–	77.9	–	–	–
Depreciation	48.7	47.8	46.9	48.9	47.0
Total Operating Expenses	626.4	692.3	603.2	561.9	536.2
Operating Income from Continuing Operations	140.7	45.1	100.9	97.7	80.3
Other Income (Expense)					
Interest Expense	(27.4)	(26.4)	(31.7)	(50.5)	(49.3)
Other	14.9	1.1	(12.2)	2.3	6.9
Total Other Expense	(12.5)	(25.3)	(43.9)	(48.2)	(42.4)
Income from Continuing Operations Before Minority Interest and Income Taxes	128.2	19.8	57.0	49.5	37.9
Minority Interest	4.6	2.7	2.1	2.6	1.0
Income from Continuing Operations Before Income Taxes	123.6	17.1	54.9	46.9	36.9
Income Tax Expense (Benefit)	46.3	(0.5)	16.4	17.7	12.3
Income from Continuing Operations Before Change in Accounting Principle	77.3	17.6	38.5	29.2	24.6
Income (Loss) from Discontinued Operations – Net of Tax	(0.9)	(4.3)	73.7	207.2	112.6
Change in Accounting Principle – Net of Tax	–	–	(7.8) *(b)*	–	–
Net Income	76.4	13.3	104.4	236.4	137.2
Common Stock Dividends	40.7	34.4	79.7	93.2	89.2
Earnings Retained in (Distributed from) Business	$ 35.7	$ (21.1)	$ 24.7	$143.2	$ 48.0

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

(b) Reflected the cumulative effect on prior years (to December 2003) of changing to the equity method of accounting for investments in limited liability companies included in our emerging technology portfolio. (See Note 15.)

	2006	2005	2004	2003	2002
Shares Outstanding – Millions					
Year-End	30.4	30.1	29.7	29.1	28.5
Average *(a)*					
Basic	27.8	27.3	28.3	27.6	27.0
Diluted	27.9	27.4	28.4	27.8	27.2
Diluted Earnings (Loss) Per Share					
Continuing Operations	$2.77	$0.64 *(c,d)*	$1.35 *(e)*	$1.05	$0.91 *(h)*
Discontinued Operations	(0.03)	(0.16)	2.59	7.47 *(g)*	4.13
Change in Accounting Principle	–	–	(0.27)	–	–
	$2.74	$0.48	$3.67	$8.52	$5.04
Return on Common Equity	12.1%	2.2% *(c,d)*	8.3%	17.7%	11.4%
Common Equity Ratio	63.1%	60.7%	61.7%	64.4%	51.7%
Dividends Paid Per Share	$1.4500	$1.2450	$2.8425	$3.3900	$3.3000
Dividend Payout Ratio	53%	259% *(c,d)*	77%	40%	66%
Book Value Per Share at Year-End	$21.90	$20.03	$21.23	$50.18	$43.24
Employees at Year-End	1,468	1,459	1,515	13,115	14,181
Income (Loss)					
Regulated Utility	$46.8 *(b)*	$ 45.7	$ 37.7	$ 32.4	$ 46.0
Nonregulated Energy Operations	3.7 *(b)*	(48.5) *(c)*	(2.9)	1.1	(11.3)*(h)*
Investment in ATC	1.9	–	–	–	–
Real Estate	22.8	17.5	14.3	13.6	10.8
Other	2.1	2.9 *(d)*	(10.6) *(e)*	(17.9)	(20.9)
Continuing Operations	77.3	17.6	38.5	29.2	24.6
Discontinued Operations	(0.9)	(4.3)	73.7	207.2 *(g)*	112.6
Change in Accounting Principle	–	–	(7.8) *(f)*	–	–
Net Income	$76.4	$ 13.3	$104.4	$236.4	$137.2
Average Electric Customers – Thousands	153.7	151.8	150.1	148.2	146.8
Electric Sales – Millions of MWh					
Regulated Utility	12.8 *(b)*	11.7	11.2	11.1	11.1
Nonregulated Energy Operations	0.2 *(b)*	1.5	1.5	1.5	1.2
Company Use and Losses	0.3	0.5	0.9	0.7	0.7
	13.3	13.7	13.6	13.3	13.0
Power Supply – Millions of MWh					
Regulated Utility					
Steam Generation	8.6 *(b)*	7.2	6.5	7.1	7.2
Hydro Generation	0.3	0.5	0.5	0.4	0.5
Long-Term Purchases – Square Butte	2.1	2.3	2.0	2.3	2.3
Purchased Power	2.1	2.1	3.0	1.9	1.8
	13.1	12.1	12.0	11.7	11.8
Nonregulated Energy Operations					
Steam	0.2 *(b)*	1.4	1.3	1.3	0.9
Purchased Power	–	0.2	0.3	0.3	0.3
	0.2	1.6	1.6	1.6	1.2
	13.3	13.7	13.6	13.3	13.0
Coal Sold – Millions of Tons	4.2	4.5	4.2	4.3	4.6
Real Estate Sales					
Town Center – Commercial Square Feet	401,971	643,000	–	–	–
Residential Units	773	–	–	–	–
Palm Coast – Residential Units	200	–	–	–	–
Other Land – Acres	732	1,102	1,479	1,394	641
Lots	–	7	211	265	1,425
Capital Additions – Millions					
Continuing Operations	$109.4	$58.6	$57.8	$ 68.7	$ 81.7
Discontinued Operations	–	4.5	21.4	67.6	119.5
	$109.4	$63.1	$79.2	$136.3	$201.2

(a) Excludes unallocated ESOP shares.

(b) Effective January 1, 2006, our Taconite Harbor generating facility was redirected from Nonregulated Energy Operations to Regulated Utility.

(c) Impacted by a $50.4 million, or $1.84 per share, charge related to the assignment of the Kendall County power purchase agreement. (See Note 10.)

(d) Impacted by a $2.5 million, or $0.09 per share, deferred tax benefit due to comprehensive state tax planning initiatives and a $3.7 million, or $0.13 per share, current tax benefit due to a positive resolution of income tax audit issues.

(e) Included a $10.9 million, or $0.38 per share, after-tax debt prepayment cost incurred as part of ALLETE's financial restructuring in preparation for the spin-off of Automotive Services (see Note 11) and an $11.5 million, or $0.41 per share, gain on the sale of ADESA shares related to the Company's ESOP (see Note 17).

(f) Reflected the cumulative effect on prior years (to December 2003) of changing to the equity method of accounting for investments in limited liability companies included in our emerging technology portfolio. (See Note 15.)

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

(h) Included a $5.5 million, or $0.20 per share, charge related to the indefinite delay of a generation project in Superior, Wisconsin.

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 4 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.

Executive Summary

ALLETE is a diversified company providing fundamental products and services since 1906. This includes our two core businesses—**Energy** and **Real Estate**, as well as our former operations in the water, paper, telecommunications and automotive industries.

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

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

  In 2004 and 2005, Nonregulated Energy Operations also included nonregulated generation (non-rate base generation sold at market-based rates primarily to the wholesale market) from our Taconite Harbor facility in northern Minnesota, and generation secured through the Kendall County power purchase agreement.
- **Investment in ATC** includes our equity ownership interest in ATC.

Real Estate includes our Florida real estate operations.

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

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

Our management believes that we can best grow earnings through the combined financial performance of a limited number of significant business units. In addition to providing earnings growth opportunities, this mix of diverse businesses helps mitigate the potential financial risk inherent in the economic cycles of each individual business.

We believe that, in order to enhance our ability to achieve our long-term annual earnings growth goals, we must pursue a strategy of further expansion of our energy and/or real estate businesses, and/or a new industry segment outside of these two businesses. We will be disciplined and patient in our approach, with the direct involvement of our senior executives and Board of Directors.

We have provided fundamental products and services for 100 years, and we expect that our diversification efforts beyond our existing Energy and Real Estate businesses will generally be similarly focused. We currently anticipate that the size of an investment in a new industry segment could be in the range of $100 million to $500 million.

We achieved several milestones during 2006 that lay the groundwork for future success. These achievements include:

- Commencing ALLETE's investment in ATC;
- Starting construction on an aggressive air emissions control plan with current cost recovery;
- Purchasing electricity from a new 50-MW wind facility in North Dakota and signing an agreement to purchase power from a second 48-MW wind facility;
- Maintaining a high level of electric sales to industrial customers;
- Signing a long-term contract for approximately 70 MW with a new large industrial customer, PolyMet Mining;
- Receiving development order approval for our Ormond Crossings real estate project; and
- Closing the first sales contracts at our Palm Coast Park development.

Executive Summary (Continued)

Millions Except Per Share Amounts	2006 *(a)*	2005	2004
Operating Revenue			
Regulated Utility	$639.2	$575.6	$555.0
Nonregulated Energy Operations	65.0	113.9	106.8
Real Estate	62.6	47.5	41.9
Other	0.3	0.4	0.4
	$767.1	$737.4	$704.1
Operating Expenses			
Regulated Utility	$543.8	$486.0	$476.3
Nonregulated Energy Operations	61.4	186.6 *(b)*	108.6
Real Estate	18.3	15.6	15.1
Other	2.9	4.1	3.2
	$626.4	$692.3	$603.2
Interest Expense			
Regulated Utility	$20.2	$17.4	$18.5
Nonregulated Energy Operations	3.3	6.6	4.9
Real Estate	–	0.1	0.3
Other	3.9	2.3	8.0
	$27.4	$26.4	$31.7
Other Income (Expense)			
Regulated Utility	$ 0.9	$0.7	$ 0.1
Nonregulated Energy Operations	2.2	1.7	0.6
Investment in ATC	3.0	–	–
Other	8.8	(1.3)	(12.9) *(d)*
	$14.9	$1.1	$(12.2)
Income (Loss)			
Regulated Utility	$46.8	$45.7	$ 37.7
Nonregulated Energy Operations	3.7	(48.5) *(b)*	(2.9)
Investment in ATC	1.9	–	–
Real Estate	22.8	17.5	14.3
Other	2.1	2.9 *(c)*	(10.6) *(d)*
Continuing Operations	77.3	17.6	38.5
Discontinued Operations	(0.9)	(4.3)	73.7
Change in Accounting Principle	–	–	(7.8)
Net Income	$76.4	$13.3	$104.4
Diluted Average Shares of Common Stock	27.9	27.4	28.4
Diluted Earnings (Loss) Per Share of Common Stock			
Continuing Operations	$2.77	$0.64 *(b,c)*	$1.35 *(d)*
Discontinued Operations	(0.03)	(0.16)	2.59
Change in Accounting Principle	–	–	(0.27)
	$2.74	$0.48	$3.67
Return on Common Equity	12.1%	2.2% *(b,c)*	8.3%

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

(b) Impacted by a $77.9 million ($50.4 million after tax, or $1.84 per share) charge related to the assignment of the Kendall County power purchase agreement in April 2005. (See Note 10.)

(c) Impacted by 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.

(d) Included an $18.5 million ($10.9 million after tax, or $0.38 per share) debt prepayment cost incurred as part of ALLETE's financial restructuring in preparation for the spin-off of Automotive Services and an $11.5 million, or $0.41 per share, gain on the sale of ADESA shares related to our ESOP.

Executive Summary (Continued)

Net income for 2006 was $76.4 million, or $2.74 per diluted share ($13.3 million, or $0.48 per diluted share for 2005; $104.4 million, or $3.67 per diluted share for 2004). Net income for 2006 was up $63.1 million from 2005 reflecting:

- the absence of the Kendall County Charge ($50.4 million recorded in 2005);
- the absence of Kendall County operating losses ($1.9 million recorded in 2005);
- the absence of emerging technology impairments ($3.3 million recorded in 2005);
- the absence of the loss on the sale of our telecommunication business ($3.6 million recorded in 2005);
- increased income from Real Estate ($5.3 million);
- increased earnings on cash and short-term investments ($2.6 million);
- income from our investment in ATC ($1.9 million in 2006); and
- increased income from Regulated Utility ($1.1 million).

These factors were partially offset by the absence of tax benefits recorded in 2005—a $3.7 million current tax benefit due to the positive resolution of income tax audit issues and a $2.5 million deferred tax benefit due to comprehensive state tax planning initiatives.

Financial results for continuing operations for the periods discussed in this Form 10-K were significantly impacted by the following five transactions not representative of ongoing operations:

- **Kendall County Charge.** In 2005, we incurred a $77.9 million ($50.4 million after tax, or $1.84 per share) charge due to the assignment of the Kendall County power purchase agreement to Constellation Energy Commodities (Kendall County Charge). (See Note 10.)
- **Positive Resolution of Tax Audit Issues.** In 2005, we recognized a $3.7 million, or $0.13 per share, current tax benefit due to a positive resolution of income tax audit issues.
- **State Tax Planning Initiatives.** In 2005, we implemented comprehensive state tax planning initiatives, which resulted in current and ongoing tax savings, and a deferred tax benefit of $2.5 million, or $0.09 per share.
- **Debt Prepayment Cost.** In 2004, we incurred an $18.5 million ($10.9 million after tax, or $0.38 per share) debt prepayment cost as part of ALLETE's financial restructuring in preparation for the spin-off of Automotive Services.
- **Gain on Sale of ADESA Shares.** In 2004, we recognized a nontaxable $11.5 million, or $0.41 per share, gain on the sale of ADESA shares related to our ESOP. (See Note 17.)

Income from continuing operations was $77.3 million, or $2.77 per diluted share, for 2006, an increase of $59.7 million, or $2.13 per diluted share, from 2005. Excluding the three 2005 transactions not representative of ongoing operations mentioned above, 2006 diluted earnings per share from continuing operations was up 23% from 2005, exceeding our expected earnings growth for 2006 of 15% to 20%. (See Non-GAAP Financial Measures.)

Financial results by segment for the periods presented and discussed in this Form 10-K were impacted by the integration of our Taconite Harbor facility into the Regulated Utility segment effective January 1, 2006. The redirection of Taconite Harbor from our Nonregulated Energy Operations segment to our Regulated Utility segment was in accordance with the Company's Resource Plan, as approved by the MPUC, to help meet forecasted base load energy requirements. Under the terms of our Resource Plan, we have operated the Taconite Harbor facility as a rate-based asset within the Minnesota retail jurisdiction since January 1, 2006. Prior to January 1, 2006, we operated our Taconite Harbor facility as nonregulated generation. Historical financial results of Taconite Harbor for periods prior to the 2006 redirection are included in our Nonregulated Energy Operations segment.

Kilowatthours Sold	**2006**	**2005**	**2004**
Millions			
Regulated Utility			
Retail and Municipals			
Residential	1,100	1,102	1,053
Commercial	1,335	1,327	1,282
Industrial	7,206	7,130	7,071
Municipals	911	877	823
Other	79	79	79
Total Retail and Municipals	10,631	10,515	10,308
Other Power Suppliers	2,153	1,142	918
Total Regulated Utility	12,784	11,657	11,226
Nonregulated Energy Operations	240	1,521	1,496
Total Kilowatthours Sold	13,024	13,178	12,722

Executive Summary (Continued)

Real Estate Revenue and Sales Activity	**2006 Quantity**	**2006 Amount**	**2005 Quantity**	**2005 Amount**	**2004 Quantity**	**2004 Amount**
Dollars in Millions						
Revenue from Land Sales						
Town Center Sales						
Commercial Sq. Ft.	401,971	$10.8	643,000	$15.2	–	–
Residential Units	773	12.9	–	–	–	–
Palm Coast Park						
Residential Unit	200	3.0	–	–	–	–
Other Land Sales						
Acres	732	24.4	1,102	38.1	1,479	$32.8
Lots	–	–	7	0.4	211	4.5
Contract Sales Price *(a)*		51.1		53.7		37.3
Revenue Recognized from Previously Deferred Sales		9.7		–		–
Deferred Revenue		(3.8)		(10.0)		(1.5)
Adjustments *(b)*		(0.9)		(1.7)		–
Revenue from Land Sales		56.1		42.0		35.8
Other Revenue		6.5		5.5		6.1
		$62.6		$47.5		$41.9

(a) Reflected total contract sales price on closed land transactions. Land sales are recorded using a percentage-of-completion method. (See Critical Accounting Estimates and Note 2.)
(b) Contributed development dollars, which are credited to cost of real estate sold.

Net Income

Regulated Utility contributed income of $46.8 million in 2006 ($45.7 million in 2005; $37.7 million in 2004). Earnings were slightly higher in 2006 than 2005 as demand from our industrial customers continued to be strong. Kilowatthour sales to industrial customers increased 76 million, or 1%, in 2006. Overall, Regulated Utility kilowatthour sales increased 1,127 million, or 10%, reflecting the inclusion of Taconite Harbor and its pre-existing wholesale energy sales obligations in Regulated Utility since January 1, 2006.

In 2005, income was higher than 2004 due to a 4% increase in overall regulated utility kilowatthour electric sales. Healthier economic conditions in Minnesota Power's service territory combined with warmer weather in the summer of 2005 contributed to the increase in kilowatthour sales. Higher pension expense ($1.0 million) and an increase in maintenance expense ($2.0 million) were partially offset by the absence of Split Rock Energy expenses ($1.2 million) and lower interest expense ($0.6 million).

Nonregulated Energy Operations reported income of $3.7 million in 2006 (a loss of $48.5 million in 2005; a loss of $2.9 million in 2004). In April 2005, we completed the assignment of our Kendall County power purchase agreement to Constellation Energy Commodities. As a result of this transaction, we incurred a charge to operating expenses totaling $50.4 million after tax in the second quarter of 2005. In 2006, financial results reflected the absence of income from Taconite Harbor, which is now reported as part of Regulated Utility, and operating losses from Kendall County ($1.9 million in 2005; $8.5 million in 2004). In 2004, the Kendall County operating loss included a $0.7 million cost to terminate a transmission contract.

Income from our coal operations was up $0.2 million from 2005 primarily due to a 16% increase in the delivery price per ton reflecting higher reimbursable coal production expenses. Tons of coal sold were down 7% from 2005 in part due to an outage at Minnkota Power's Unit 1 in 2006. In 2005, income from our coal operations was up $1.3 million from 2004, primarily due to a 7% increase in tons of coal sold.

Investment in ATC contributed income of $1.9 million in 2006. We began investing in ATC in May 2006. As of December 31, 2006, our equity investment balance in ATC was $53.7 million, representing approximately a 7% ownership interest. (See Notes 6 and 8.)

Net Income (Continued)

Real Estate contributed income of $22.8 million in 2006 ($17.5 million in 2005; $14.3 million in 2004), reflecting continued strong demand for real estate in Florida. Income was higher in 2006 primarily due to the recognition of deferred earnings from prior land sales. The timing of the closing of real estate sales varies from period to period and impacts comparisons between years. As of December 31, 2006, we had $4.1 million of deferred profit on sales of real estate, before taxes and minority interest, on our balance sheet. Most of this deferred profit relates to Town Center which will be recognized over the next several years as development obligations are completed. Since land is being sold before completion of the project infrastructure, revenue and cost of real estate sold are recorded using a percentage-of-completion method as development obligations are completed. (See Note 2.)

Real Estate Pending Contracts At December 31, 2006	**Quantity** *(a)*	**Contract Sales Price**
Dollars in Millions		
Town Center		
Commercial Sq. Ft.	786,400	$ 24.2
Residential Units	1,010	15.9
Palm Coast Park		
Commercial Sq. Ft.	50,000	2.5
Residential Units	2,409	60.3
Other Land *(b)*		
Acres	196	10.9
Total Pending Land Sales Under Contract		$113.8

(a) Acreage amounts are approximate and shown on a gross basis, including wetlands and minority interest. Acreage amounts may vary due to platting or surveying activity. Wetland amounts vary by property and are often not formally determined prior to sale. Commercial square feet and residential units are estimated and include minority interest. The actual property allocation at full build-out may be different than these estimates.

(b) Includes land located in Ormond Beach and Palm Coast in northeast Florida and other land located in Cape Coral in southwest Florida, all of which are not included in development projects.

At December 31, 2006, total pending land sales under contract were $113.8 million and are anticipated to close at various times through 2012. Prices on these contracts range from $20 to $50 per commercial square foot, $8,000 to $34,000 per residential unit and $11,000 to $1,774,200 per acre for all other properties. Prices per acre are stated on a gross acreage basis and are dependent on the type and location of the properties sold. The majority of the other properties under contract are zoned commercial or mixed use. In addition to minimum base price contracts, certain contracts allow us to receive participation revenue from land sales to third parties if various formula-based criteria are achieved.

If a purchaser defaults under terms of a contract, our remedies generally include retention of the purchaser's deposit and the ability to remarket the property to other prospective buyers. In many cases, the purchaser has also incurred significant costs in planning, designing and marketing of the property under contract before the contract closes.

Other reflected income of $2.1 million in 2006 ($2.9 million of income in 2005; a $10.6 million loss in 2004). In 2006, income from Other was down $0.8 million from 2005 primarily due to the absence of tax benefits recorded in 2005—a $3.7 million current tax benefit due to the positive resolution of income tax audit issues and a $2.5 million deferred tax benefit due to comprehensive state tax planning initiatives. In addition, a $0.9 million increase in interest expense was more than offset by a $2.6 increase in earnings on cash and short-term investments, the absence of impairments of $3.3 million related to certain investments in our emerging technology portfolio and the absence of a $0.6 million charge recognized in 2005 for the probable payment under our guarantee of Northwest Airlines debt.

In 2005, income from Other was up $13.5 million from 2004. Financial results for 2005 reflected the $3.7 million current tax benefit and the $2.5 million deferred tax benefit previously mentioned, a $3.4 million decline in interest expense as a result of lower debt balances, and a $1.9 million increase in earnings on cash and short-term investments. Cash was higher in 2005 than 2004 due to proceeds received from the sale of Enventis Telecom in 2005 as well as earnings on proceeds received from the sale of our Water Services businesses in 2004 and 2003, and proceeds received from ADESA in 2004. Equity losses related to investments in venture capital funds declined in 2005 ($0 in 2005; $1.6 million in 2004) as did impairments related to certain investments in our emerging technology portfolio ($3.3 million in 2005; $4.1 million in 2004). Financial results for 2004 also included an $11.5 million gain on the sale of ADESA stock related to our ESOP (see Note 17), which was partially offset by a $10.9 million debt prepayment cost associated with the retirement of long-term debt as a part of our financial restructuring in preparation for the spin-off of ADESA.

Net Income (Continued)

Discontinued Operations includes our Automotive Services business that was spun off on September 20, 2004, costs incurred by ALLETE associated with the spin-off of ADESA, our Water Services businesses that we sold over the three-year period from 2003 to 2005 and our telecommunications business, which we sold in December 2005. Discontinued operations reflected a $0.9 million loss in 2006 (a $4.3 million loss in 2005; $73.7 million of income in 2004).

In 2006, discontinued operations reflected a $0.9 million loss resulting from additional legal and administrative expenses related to exiting the Water Services businesses (a $2.5 million loss in 2005; a $1.3 million loss in 2004). In 2005, administrative and other expenses were incurred to support Florida Water transfer proceedings. A $1.0 million rate-base settlement charge related to the sale of 63 of Florida Water systems to Aqua Utilities Florida, Inc. was also recorded in 2005. Gains in 2004 from the sale of our North Carolina assets and the remaining systems in Florida were offset by an adjustment to gains reported in 2003. The adjustment to gains reported in 2003 resulted primarily from an arbitration award in December 2004 relating to a gain-sharing provision on a system sold in 2003. The majority of our Florida systems were sold in the fourth quarter of 2003. North Carolina assets were sold in June 2004. Our wastewater assets in Georgia were sold in February 2005.

Automotive Services contributed income of $74.4 million in 2004.

Financial results for our telecommunications business reflected a loss of $1.8 million in 2005 (income of $0.6 million in 2004). In 2005, we recorded a $3.6 million loss on the sale of this business. In 2005, income from operations was $1.2 million higher than 2004 primarily due to increased margins on telecommunication services.

Change in Accounting Principle reflected the cumulative effect on prior years (to December 31, 2003) of changing to the equity method of accounting for investments in limited liability companies included in our emerging technology portfolio. (See Note 15.)

2006 Compared to 2005

Regulated Utility

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

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

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

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

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

2006 Compared to 2005 (Continued)

Nonregulated Energy Operations

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

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

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

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

Investment in ATC

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

Real Estate

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

Operating expenses were up $2.7 million, or 17%, from 2005 reflecting a $1.6 million increase in the cost of real estate sold ($10.2 million in 2006; $8.6 million in 2005) due to the recognition of the cost of real estate sold at our Town Center development project which were previously deferred under the percentage-of-completion method. Selling expenses increased $0.6 million due to higher broker commission in 2006 and recognition of prior year's selling expenses at our Town Center development project which were previously deferred under the percentage-of-completion method. Property tax expense was $0.2 million higher in 2006 due to increased assessment values and higher rates. At December 31, 2006, cost of real estate sold totaling $1.3 million ($2.2 million at December 31, 2005) and selling expenses of $0.2 million ($0.3 million at December 31, 2005), primarily related to Town Center land sales, were deferred until development obligations are completed.

Other

Operating expenses were down $1.2 million, or 29%, from 2005, reflecting lower general and administrative expenses in 2006.

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

Other income (expense) reflected $10.1 million more income in 2006 due to a $4.4 million increase in earnings on cash and short-term investments due to higher rates and higher average balances in 2006, the absence of $5.1 million of impairments related to certain investments in our emerging technology portfolio recorded in 2005 and the absence of a $1.0 million charge recognized in 2005 for the probable payment under our guarantee of Northwest Airlines debt.

2006 Compared to 2005 (Continued)

Income Taxes

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

2005 Compared to 2004

Regulated Utility

Operating revenue was up $20.6 million, or 4%, from 2004. Revenue from other power suppliers was up $15.4 million from 2004 due to a 224 million, or 24%, increase in kilowatthour sales and higher market prices. In 2005, changes in scheduled plant outages resulted in more energy available for sale than in 2004. Transmission revenue was up $4.2 million from 2004, reflecting increased MISO-related revenue. Revenue from sales to retail and municipal customers was down $2.4 million, primarily due to lower fuel clause recoveries in 2005. (See operating expenses below.) Kilowatthour sales to retail and municipal customers remained strong—up 207 million, or 2%, from 2004, reflecting increased usage. Residential and municipal customer usage was higher in 2005 due to higher than normal summer temperatures in 2005. Commercial usage was higher due to stronger economic conditions in our electric service territory in 2005. Sales to industrial customers were similar to last year because, as in 2004, the Company's industrial customers were operating at high production levels, with taconite and paper production at or near capacity. Overall, regulated utility kilowatthour sales were up 431 million, or 4%, from 2004. Revenue from natural gas sales was up $2.5 million due to increased prices in the natural gas component of sales.

Operating expenses were up $9.7 million, or 2%, from 2004. Fuel and purchased power expense was down $1.4 million from 2004 due to fewer outages. In 2004, increased purchased power was necessitated by outages at Company generating facilities and the Square Butte generating facility. Maintenance expense was up $3.4 million from 2004, reflecting planned maintenance performed at Boswell Units 1, 2 and 3 during 2005, partially offset by lower maintenance expense related to Boswell Unit 4 and Laskin Unit 1. In 2004, maintenance expense increased due to maintenance scheduled for 2005 and 2006 that was performed while Boswell Unit 4 was down as a result of a generator failure. Other operating expenses were $7.7 million higher in 2005—MISO transmission costs increased $4.1 million, natural gas purchases increased $2.6 million due to higher prices and pension expense increased $1.7 million primarily due to a reduction in the discount rate (5.75% in 2005; 6.00% in 2004). These increases were partially offset by the absence of $2.0 million of expenses related to Split Rock Energy, which we exited in March 2004.

Interest expense was down $1.1 million from 2004, primarily due to lower effective interest rates (6.07% in 2005; 6.67% in 2004).

Nonregulated Energy Operations

Operating revenue was up $7.1 million, or 7%, from 2004. Revenue from Taconite Harbor increased $14.0 million from 2004, primarily due to higher demand as a result of two 5-year contracts (175 MW in total) that began in May 2005. Coal revenue, realized under cost plus a fixed fee agreements, was up $5.0 million from 2004, reflecting a 7% increase in tons of coal sold and an 8% increase in the delivery price per ton due to higher reimbursable coal production expenses. (See operating expenses below.) BNI Coal sold fewer tons of coal in 2004 due to a scheduled outage at the Square Butte generating facility. Revenue from Kendall County was down $13.4 million from 2004, reflecting the absence of operations since April 2005 when the Kendall County power purchase agreement was assigned to Constellation Energy Commodities. Overall, nonregulated kilowatthour sales were up 2% from 2004.

Operating expenses were up $78.0 million, or 72%, from 2004, primarily due to the $77.9 million charge related to the assignment of the Kendall County power purchase agreement to Constellation Energy Commodities in April 2005. Nonregulated generation fuel and purchased power expense was down $11.7 million from 2004, reflecting the absence of Kendall County operations. Operating and maintenance expenses at Taconite Harbor were higher in 2005, reflecting a $2.3 million increase in SO_2 emission allowance expense, a $1.0 million increase in contract services due to a longer than anticipated scheduled outage as well as unscheduled outages, and a $1.2 million increase in depreciation expense as a result of capitalized projects being completed and placed into operation. Expenses related to our coal operations were up $3.9 million, in part due to higher expenses associated with equipment repairs, increased fuel costs and a $2.1 million increase in lease expense related to the dragline.

2005 Compared to 2004 (Continued)

Nonregulated Energy Operations (Continued)

Interest expense was up $1.7 million from 2004, reflecting higher allocations in 2005.

Other income (expense) reflected $1.1 million more income in 2005. Income from customer contract services was up $0.4 million from 2004. Income from Minnesota land sales was up $0.7 million from 2004, primarily due to an adjustment recorded as a result of an MPUC land reevaluation.

Real Estate

Operating revenue was up $5.6 million, or 13%, from 2004, reflecting strong land sales offset by the deferral of revenue associated with certain real estate sales. Revenue from land sales was $42.0 million in 2005 ($35.8 million in 2004). Town Center land sales accounted for $4.5 million of land sale revenue in 2005. In 2005, revenue of $10.0 million, primarily related to Town Center land sales, was deferred until development obligations are completed ($1.5 million in 2004). Revenue from lot sales was lower in 2005 because in January 2004 we sold the remaining 184 lots at Sugarmill Woods for $3.9 million, essentially exiting the lot sales business. In 2005, 1,102 acres and 7 lots were sold. Town Center sales included assignments of rights to build up to 643,000 square feet of commercial space. In 2004, 1,479 acres and 211 lots were sold. Revenue from our brokerage business, Cape Properties, Inc., was down $0.7 million, reflecting unusually strong sales in 2004.

Operating expenses were up $0.5 million, or 3%, from 2004. Cost of real estate sold was $2.1 million higher in 2005 ($8.6 million in 2005; $6.5 million in 2004) due to the type and location of real estate sold. In 2005, cost of real estate sold totaling $2.2 million ($0.4 million in 2004) and selling expense of $0.3 million, primarily related to Town Center land sales, were deferred until development obligations are completed. Expenses for our brokerage business were down $0.2 million due to unusually strong sales in 2004. Selling expenses were down $1.1 million from 2004 due to lower transaction costs and fewer brokerage commissions on 2005 sales. Property taxes were down $0.3 million from 2004, reflecting a reduction in land owned.

Other

Operating expenses were up $0.9 million, or 28%, from 2004, primarily due to increased compensation expenses.

Interest expense was down $5.7 million from 2004, primarily due to lower debt balances. The Company repaid a $53 million balance on a credit agreement in April 2004 and $125 million of 7.80% Senior Notes in July 2004. A combination of internally-generated funds, proceeds from the sale of our Water Services assets and proceeds received from ADESA were used to repay the debt.

Other income (expense) reflected $11.6 million less expense in 2005. Other income (expense) in 2005 reflected a $3.2 million increase in earnings on excess cash, a $1.2 million decrease in equity losses from our emerging technology investments and a $1.0 million charge to recognize the probable payment under our guarantee of Northwest Airlines debt. We also recorded $5.1 million of impairments related to certain investments in our emerging technology portfolio in 2005 ($6.5 million in 2004). In 2004, other income (expense) included an $18.5 million debt prepayment cost related to the early redemption of $125 million in senior notes, an $11.5 million gain on the sale of ADESA shares held in our ESOP (see Note 17), and $0.9 million of income from a rabbi trust established to secure certain deferred executive compensation.

Income Taxes. The effective tax rate from continuing operations before minority interest was a 2.5% benefit in 2005 (28.8% expense in 2004). Income taxes in 2005 were affected by three major items, the adjustment of our deferred taxes from comprehensive state tax planning initiatives, a current tax benefit from the positive resolution of audit issues and the inability to use state capital loss carryforwards. The adjustment of our deferred tax assets and liabilities resulted in a deferred tax benefit. We received an audit report resolving open issues that resulted in a current tax benefit. These items decreased our overall tax expense. The emerging technology investment impairments recorded in March 2005 and the Kendall County Charge recorded in April 2005 created capital losses. The current benefit for these items was limited to a federal benefit for income tax purposes. The state tax benefit from these items is not expected to be realized currently or in future periods. The benefit related to these state net capital loss carryforwards was fully offset by a valuation allowance. This resulted in an increase in our overall tax expense. Current taxes also increased in 2005 due to the expiration of the accelerated depreciation deduction allowed by the Jobs and Growth Tax Relief Act of 2003, which expired December 31, 2004. An increase in the Federal Medicare subsidy and the new Domestic Manufacturing Deduction contributed to lower taxes in 2005. Income taxes for 2004 were primarily affected as a result of the benefit of the nontaxable gain from the sale of ADESA common stock in our ESOP. (See Note 13.)

Non-GAAP Financial Measures

We prepare financial statements in accordance with GAAP. Along with this information, we disclose and discuss certain non-GAAP financial information in our quarterly earnings releases, on investor conference calls and during investor conferences and related events. Management believes that non-GAAP financial data supplements our GAAP financial statements by providing investors with additional information which enhances the investors' overall understanding of our financial performance and the comparability of our operating results from period to period. The presentation of this additional information is not meant to be considered in isolation or as a substitute for our results of operations prepared and presented in accordance with GAAP.

As earlier mentioned, financial results for 2005 were significantly impacted by the following transactions:

- A $50.4 million after tax, or $1.84 per share, charge due to the assignment of the Kendall County power purchase agreement to Constellation Energy Commodities (see Note 10);
- A $3.7 million, or $0.13 per share, current tax benefit due to a positive resolution of income tax audit issues; and
- A $2.5 million, or $0.09 per share, deferred tax benefit due to comprehensive state tax planning initiatives.

In 2004, financial results were significantly impacted by the following transactions:

- A $10.9 million after tax, or $0.38 per share, debt prepayment cost as part of ALLETE's financial restructuring in preparation for the spin-off of Automotive Services (see Note 11); and
- An $11.5 million after tax, or $0.41 per share, gain on the sale of ADESA shares related to our ESOP (see Note 17).

Since these transactions significantly impacted the financial results from continuing operations in 2005 and 2004, we believe that for comparative purposes and a more accurate reflection of our ongoing operations, it is useful to present diluted earnings per share from continuing operations for each applicable period excluding the impact of these items. The table below reconciles actual reported diluted earnings per share from continuing operations before change in accounting principle to the adjusted results that exclude these transactions in the respective periods.

For the Year Ended December 31	2006	2005	2004
Diluted Earnings Per Share of Common Stock			
Continuing Operations Before Change in Accounting Principle	$2.77	$0.64	$1.35
Add: Kendall County Charge	–	1.84	–
Debt Prepayment Cost	–	–	0.38
Less: Gain on Sale of ADESA Shares	–	–	0.41
Positive Resolution of Tax Audit Issues	–	0.13	–
State Tax Planning Initiatives	–	0.09	–
	$2.77	$2.26	$1.32

Critical Accounting Estimates

The preparation of financial statements and related disclosures in conformity with generally accepted accounting principles 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. Thus, actual results could differ from the amounts reported and disclosed herein. These policies are discussed with the Audit Committee of our Board of Directors on a regular basis. The following represent the policies we believe are most critical to our business and the understanding of our results of operations.

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

Critical Accounting Estimates (Continued)

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

We annually review the real estate carrying value for impairment. If circumstances indicate that the carrying value may not be recoverable, we record an impairment and adjust the related assets to their estimated fair value less costs to sell.

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

Pension and Postretirement Health and Life Actuarial Assumptions. We account for our pension and postretirement benefit obligations in accordance with the provisions of SFAS 158, "Employers' Accounting for Defined Benefit Pension and Other Postretirement Plans," SFAS 87, "Employers' Accounting for Pensions," and SFAS 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions." These standards require the use of assumptions in determining our obligations and annual cost of our pension and postretirement benefits. An important actuarial assumption for pension and other postretirement benefit plans is the expected long-term rate of return on plan assets. In establishing this assumption, we consider the diversification and allocation of plan assets, the actual long-term historical performance for the type of securities invested in, the actual long-term historical performance of plan assets and the impact of current economic conditions, if any, on long-term historical returns. Our pension asset allocation is approximately 65% equity, 30% fixed-rate and 5% other securities. Equity securities consist of a mix of market capitalization sizes and also include investments in real estate and venture capital funds. We currently use an expected long-term rate of return of 9% 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 1/2% decrease in the expected long-term rate of return would increase the annual expense for pension and other postretirement benefits by approximately $1 million after tax; conversely, a 1/2% increase in the expected long-term rate of return would decrease the annual expense by approximately $1 million after tax.

Currently for plan valuation purposes, we use a discount rate of 5.75%. The discount rate is determined considering high-quality long-term corporate bond rates at the valuation date. The discount rate is compared to the Citigroup Pension Discount Curve adjusted for ALLETE's specific cash flows. We believe the adjusted discount curve used in this comparison does not materially differ in duration and cash flows for our pension obligation. The Audit Committee of the Board of Directors annually reviews and approves the rate of return and discount rate used for pension valuation and accounting purposes. (See Note 16.)

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). 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 accounting principles generally accepted in the U.S. and the accounting principles imposed by the regulatory agencies. Regulatory assets generally represent incurred costs that have been deferred as they are probable of recovery in customer rates. Regulatory liabilities generally 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.)

Critical Accounting Estimates (Continued)

Valuation of Investments. As part of our emerging technology portfolio, we have several minority investments in venture capital funds and direct investments in privately-held, start-up companies. We account for our investment in venture capital funds under the equity method and account for our direct investments in privately-held companies under the cost method because of our ownership percentage. These investments are included in Investments on our consolidated balance sheet. Our policy is to review these investments for impairment on a quarterly basis by assessing such factors as continued commercial viability of products, cash flow and earnings. Any impairment would reduce the carrying value of the investment and be recognized as a loss. In 2006, we did not record an impairment loss on these investments ($5.1 million pretax in 2005).

Provision for Environmental Remediation. Our businesses are subject to regulation by various federal, state and local authorities concerning environmental matters. We review environmental matters on a quarterly basis. Accruals for environmental matters are recorded when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated, based on current law and existing technologies. These accruals are adjusted periodically as assessment and remediation efforts progress, or as additional technical or legal information becomes available. Accruals for environmental liabilities are included in the balance sheet at undiscounted amounts and exclude claims for recoveries from insurance or other third parties. Costs related to environmental contamination treatment and cleanup are charged to expense. We do not currently anticipate that potential expenditures for environmental remediation and cleanup will be material; however, if we become subject to more stringent remediation at known sites, if we discover additional contamination or previously unknown sites, or if we become subject to related personal or property damage, we could incur material costs in connection with our environmental remediation.

Taxation. We are required to make judgments regarding the potential tax effects of various financial transactions and our ongoing operations to estimate our obligations to taxing authorities. These tax obligations include income, real estate and use taxes. These judgments include reserves for potential adverse outcomes regarding tax positions that we have taken. We must also assess our ability to generate capital gains to realize tax benefits associated with capital losses expected to be generated in future periods. Capital losses may be deducted only to the extent of capital gains realized during the year of the loss or during the three prior or five succeeding years for federal purposes, and fifteen succeeding years for Minnesota purposes. As of December 31, 2006, we have, where appropriate, recorded a valuation allowance against our deferred tax assets associated with realized capital losses and impairments to reduce the deferred tax assets to the amount we estimate is more likely than not to be realized. While we believe the resulting tax reserve balances as of December 31, 2006, reflect the most likely outcome of these tax matters in accordance with SFAS 109, "Accounting for Income Taxes," the ultimate amount of capital losses resulting in tax benefits could differ from the net amount of deferred tax assets at December 31, 2006.

Outlook

ALLETE is committed to earning a financial return that rewards its shareholders, allows for reinvestment in its businesses and sustains growth. In the last 10 years, our average annual total shareholder return was 17%. By comparison, the Standard & Poor's 500 Index averaged 8% for the same period. We believe that, in order to enhance our ability to achieve our long-term annual earnings growth goals, we must pursue a strategy of further expansion of our energy and/or real estate businesses, and/or a new industry segment outside of these two businesses.

Earnings Guidance. In 2007, we expect ALLETE's diluted earnings per share from continuing operations to be in the range of $2.95 to $3.05. The growth in earnings per share is expected to come primarily from our larger full-year investment in ATC. We also expect increased sales at our Real Estate operations and continued strong sales at our Regulated Utility operations. This earnings projection does not include an impact from any investment we may make in new growth opportunities.

Energy. As part of our strategy, we will leverage the strengths of our Regulated Utility business to improve our strategic and financial outlook and seek growth opportunities in close geographic proximity to existing operations in the Midwest. In addition, we will evaluate growth opportunities through merger, acquisition or asset additions in our region. We believe our energy businesses are well positioned to successfully deal with the issues affecting the electric utility industry and to compete successfully. Our access to and ownership of low-cost power are our greatest strengths. We anticipate that we will have ready access to sufficient funds for capital investments. We believe electric industry deregulation is unlikely in Minnesota or Wisconsin in the next five years.

Rate Cases. Minnesota Power does not expect to file a request to increase rates for its retail utility operations during 2007. We will, however, continue to monitor the costs of serving our retail customers and evaluate the need for a rate filing in the future. Minnesota Power's retail rates are based on a 1994 MPUC retail rate order.

Outlook (Continued)

In May 2006, SWL&P filed an application with the PSCW for authority to increase retail utility rates on its electric, natural gas and water services an average of 5.2%, and requested an 11.7% return on common equity. An order was issued in December 2006 that allows for an 11.1% return on common equity. New rates became effective January 1, 2007, and reflect a 2.8% average increase in retail utility rates for SWL&P customers (a 2.8% increase in electric rates, a 1.4% increase in natural gas rates and an 8.6% increase in water rates). The rate case allowed for a $1.7 million increase in annual revenue requirements. The approved rates were lower than originally requested due to the subsequent removal of costs for a new water tower and electric substation from the original request. Both of these projects are now estimated to be in service in late 2008 because of delays in obtaining all the necessary construction approvals. SWL&P plans to file for another rate increase request in 2008.

Industrial Customers. Approximately 50% of our Regulated Utility kilowatthour sales are made to our Large Power Customers in the taconite, paper and pulp, and pipeline industries. Based on our research of the taconite industry, Minnesota taconite production for 2007 is anticipated to be about 40 million tons (production was 40 million tons in 2006; 41 million tons in 2005 and in 2004).

There was a slight slowdown for two of our customers in the paper industry in late December 2006 and early January 2007 due to slightly lower demand for their products and a need to balance orders with inventory. It is not known whether this trend will continue further into 2007. In addition, the wood products industry is operating at reduced levels reflecting a decrease in the number of new housing starts.

Our pipeline customers continued to operate at or above historic pumping levels during 2006 and forecast operating at record pumping levels in 2007. As Western Canadian oil sands reserves continue to develop and expand, pipeline operators served by the Company are executing expansion plans to transport additional crude oil supply to United States markets. We believe we are strategically positioned to serve these expanding pipeline facilities as Canadian supply continues to grow and displace domestic and imported Gulf Coast production.

Several natural resource-based companies have been making significant progress developing new projects in northeastern Minnesota. Minnesota Power has actively supported these projects which include paper, ferrous and non-ferrous developments. If some or all of these projects are completed, Minnesota Power could serve between 100 MW and 400 MW of new load. In 2006, a contract for approximately 70 MW was successfully negotiated with PolyMet Mining, a new customer planning to start a copper, nickel and precious metals (non-ferrous) mining operation in late 2008. If PolyMet's environmental permits are received and start-up is achieved, the contract with PolyMet Mining will run through at least 2018. The PolyMet Mining electric service agreement requires MPUC approval.

Additional Generation Needs. In 2006, the MPUC approved our Resource Plan, which detailed our forecasted retail energy needs and our projected demand along with our energy sourcing options to meet these projected requirements. We project an additional capacity need of approximately 150 MW by 2010, with another 200 MW of capacity needed by 2015. One of the key components in meeting our future needs was the redirection of our Taconite Harbor generating facility from Nonregulated Energy Operations to Regulated Utility operations effective January 1, 2006. We have also entered into a 50-MW long-term power purchase agreement with Manitoba Hydro which extends from May 2009 to April 2015 that is pending regulatory approval. We began purchasing the output from the 50-MW Oliver Wind I project in North Dakota under a 25-year power purchase agreement with an affiliate of FPL Energy in late December 2006. In January 2007, we announced plans for a second, 48-MW North Dakota wind project (Oliver Wind II) that is expected to be operational by the end of 2007, pending regulatory and other approvals. In addition, we are continuing to pursue the purchase of renewable energy from a new 25-MW to 30-MW wind facility that would be located in northeastern Minnesota, subject to a power purchase agreement and regulatory approvals.

We are also exploring construction and purchase options for our anticipated resource needs by 2015. Minnesota Power, Basin Electric Power Cooperative, Minnkota Power and Montana-Dakota Utilities Company are continuing a study that will evaluate the feasibility of a joint lignite-fueled generating resource in the vicinity of the existing Milton R. Young generating station (which includes Square Butte) near Center, North Dakota. We are also continuing to study the feasibility of the construction of a natural gas-fired electric generating facility which could be located in northwestern Wisconsin or northeastern Minnesota. Any final resource decision by Minnesota Power is subject to MPUC and other approvals.

We anticipate that our winter peak demand requirements by customers in our service territory will increase at an average annual growth rate of 1.5% through 2011. We continue to make investments to maintain and improve the integrity of our generating, transmission and distribution assets, and maintain environmental compliance.

Outlook (Continued)

AREA and Boswell Unit 3 Emission Reduction Plans. In May 2006, the MPUC approved our filing for cost recovery of planned expenditures to reduce emissions to meet pending federal requirements at Taconite Harbor and Laskin under the AREA Plan. The AREA Plan approval allows Minnesota Power to recover Minnesota jurisdictional costs for SO_2, NO_X and mercury emission reductions made at these facilities without a rate proceeding. Minnesota cost recovery from retail customers will include return on investment, depreciation, and incremental operations and maintenance expenses. Minnesota Power completed installation of new equipment at the first of two Laskin units at the end of November 2006, with the first of three Taconite Harbor unit installations anticipated to be completed by mid-2007. Work on all units at Taconite Harbor and Laskin is anticipated to be completed by the end of 2008. Cost recovery filings are required to be made 90 days prior to the anticipated in-service date for the equipment at each unit, with rate recovery beginning the month following the in-service date. We began cost recovery of AREA plan costs in December 2006 with the placement in service of Laskin Unit 2. We filed with the MPUC for cost recovery on Laskin Unit 1 in January 2007 and expect to begin cost recovery in May 2007. We anticipate beginning cost recovery on Taconite Harbor Unit 2 in mid-2007 and Taconite Harbor Units 1 and 3 in 2008. AREA plan expenditures as of December 31, 2006, were $11.4 million.

In May 2006, we announced plans to make emission reduction investments at our Boswell Unit 3 generating unit. Plans include reductions of particulate, SO_2, NO_X and mercury emissions to meet pending federal and state requirements. The estimated capital cost for these reductions is approximately $200 million, $14 million of which was spent in 2006 for design engineering and related costs. The balance is expected to be spent from 2007 through 2009 and is included in the $233 million the Company expects to spend for environmental upgrades from 2007 through 2011. (See Capital Requirements.) In October 2006, we submitted a filing to the MPCA for approval of the Boswell Unit 3 emission reduction plan. A filing with the MPUC for approval of Minnesota jurisdictional related expenditures on Boswell Unit 3 was made in January 2007 to allow cost recovery on these investments from retail customers without a rate proceeding. MPUC approval would authorize a cash return on construction work in progress during the construction phase and allow recovery for a return on investment, depreciation, and incremental operations and maintenance expenses once the unit is placed into service in late 2009. We expect to begin cost recovery on construction work in progress in 2008. In 2007, we will be filing with the MPUC a request to extend the asset life for depreciation purposes on Boswell Unit 3 from 8 years to 29 years. We anticipate approval of this filing in 2007. This extension will reduce 2007 depreciation expense by approximately $5 million.

CAIR and CAMR. In March 2005, the EPA issued its Clean Air Interstate Rule (CAIR) which would reduce emissions of SO_2 and NO_X. In November 2005, the EPA granted reconsideration of the CAIR. Minnesota Power filed comments for reconsideration arguing that the state of Minnesota did not belong in CAIR and that SO_2 allocations proposed under the CAIR were unfair. CAIR was finalized by the EPA in March 2006 when the EPA determined it would not make any changes to the CAIR as a result of the petitions for reconsideration. Petitions for Review, including Minnesota Power's, remain pending at the Court of Appeals, with resolution of the Petitions for Review anticipated in 2008. In March 2005, the EPA issued its Clean Air Mercury Rule (CAMR). The EPA granted reconsideration of the CAMR in October 2005 and finalized the rule in early 2006. Minnesota Power is not participating in the Petitions for Review of the CAMR. The final outcomes of these regulatory proceedings are expected to require significant capital investments in the 2008 to 2012 timeframe. (See Capital Requirements.)

MISO and Fuel Clause. As a result of MISO Day 2 implementation in April 2005, energy transactions to serve retail customers are sourced through wholesale transactions with MISO as the counterparty. We filed a petition with the MPUC in February 2005 to amend our fuel clause to accommodate costs and revenue related to MISO Day 2 market implementation. In April 2005, the MPUC approved interim ratemaking treatment of MISO Day 2 costs, which allowed these costs to be recovered through the fuel clause, subject to refund with interest.

In December 2005, the MPUC issued an order which denied recovery through the fuel clause of uplift charges, congestion revenue and expenses, and administrative costs related to Minnesota Power's MISO Day 2 market activities. This denial created a refund obligation. Minnesota Power requested rehearing of the order in a filing made with the MPUC in January 2006. Three other Minnesota utilities affected by the order also filed for rehearing, as did the DOC and MISO. In February 2006, the MPUC granted rehearing of the MISO Day 2 docket and suspended the refund obligation for charges recovered through the fuel clause denied in the December 2005 order. The MPUC also ordered a review of MISO Day 2 costs to determine which costs should be recovered on a current basis through the fuel clause and which costs were more appropriately deferred for potential recovery through base rates. The Company worked with other Minnesota utilities, the DOC and other stakeholders to review MISO Day 2 costs and to prepare a joint report and recommendations. The joint report and recommendations were filed with the MPUC in June 2006. A technical conference on the report was held with the MPUC on October 31, 2006. At a hearing November 9, 2006, the MPUC approved current recovery of nearly all MISO Day 2 charges.

Outlook (Continued)

On December 20, 2006, the MPUC issued an order allowing Minnesota Power and the other utilities involved in the MISO Day 2 proceeding to continue recovering MISO Day 2 charges through the Minnesota retail fuel clause except for MISO Day 2 administrative charges. On January 8, 2007, this order was challenged by the Minnesota OAG, which has sought reconsideration. The rehearing has been opposed by Minnesota Power and the other utilities, as well as MISO. The reconsideration request is currently pending before the MPUC. The MPUC has until March 9, 2007, to act on the Minnesota OAG's request. The order, if upheld, grants deferred accounting treatment for three MISO Day 2 charge types that were determined to be administrative charges. Under the order, Minnesota Power would refund through customer bills approximately $2 million of administrative charges previously collected through the fuel clause between April 1, 2005, and December 31, 2006, and record these administrative charges as a regulatory asset. Minnesota Power would be permitted to continue accumulating MISO Day 2 administrative charges after December 31, 2006, as a regulatory asset until it files its next rate case, at which time recovery for such charges will be determined. This order would remove the subject to refund requirement of the two interim orders, and include extensive fuel clause reporting requirements that would be reviewed in Minnesota Power's monthly and annual fuel clause filings with the MPUC. There would be no impact on earnings as a result of this ruling. The Company is unable to predict the outcome of this matter.

As a result of the MPUC's December 2006 order allowing recovery of nearly all MISO Day 2 charges through the fuel clause, on December 28, 2006, Minnesota Power rescinded its December 2005 Letter of Intent to Withdraw from MISO.

Investment in ATC. In December 2005, we entered into an agreement with Wisconsin Public Service Corporation and WPS Investments, LLC that provides for our Wisconsin subsidiary, Rainy River Energy Corporation - Wisconsin, to invest $60 million in ATC. In May 2006, the PSCW reviewed and approved the request that allows us to invest in ATC. During 2006, we invested $51.4 million in ATC. We plan to invest an additional $8.6 million in ATC in early 2007 to reach our $60 million investment commitment and estimated 8% ownership interest. As of December 31, 2006, our equity investment balance in ATC was $53.7 million, representing approximately a 7% ownership interest. (See Note 6.) We will have the opportunity to make additional investments in ATC through general capital calls based upon our pro-rata investment level in ATC.

Real Estate. We have a diversified mix of property under contract and available for sale—residential, commercial and industrial—in desirable Florida locations (see Item 1 – Real Estate). A large portion of our real estate inventory is located in Florida's Flagler and Volusia Counties, an area with one of the fastest growing populations in the United States. We expect this population growth to continue, which will increase the demand for real estate in the area. Rapid residential growth over the past few years in our markets has created a steady demand for our commercial properties. As of December 31, 2006, we had $113.8 million of pending contracts scheduled to close over the next several years. We believe the long-term growth indicators for Florida real estate remain strong.

Progress continues on our three major planned development projects in Florida—Town Center, which will be a new downtown for Palm Coast; Palm Coast Park, which is located in northwest Palm Coast; and Ormond Crossings, which is located in Ormond Beach along Interstate 95. Other ongoing land sales and rental income at the retail shopping center in Winter Haven provide us with additional revenue.

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

As of December 31, 2006, we had $4.1 million of deferred profit on sales of real estate, before taxes and minority interest, on our balance sheet. Most of the deferred profit relates to Town Center which will be recognized over the next several years as development obligations are completed.

Town Center. Throughout 2005 and 2006, our marketing program targeted a blend of office, retail commercial, residential and mixed-use project developers. In 2006, a Publix grocery store anchored retail center opened and construction started on an 84,000 square foot medical center. Twenty other projects are in the permitting stage, 11 of which are expected to break ground in 2007. Future marketing efforts will focus on attracting the following additional land uses to Town Center: residential apartments, assisted living facilities, business park uses and restaurants.

Pending land sales under contract for properties at Town Center totaled $40.1 million at December 31, 2006. We have the opportunity to receive participation revenue as part of one of these sales contracts. Among the pending Town Center sales contracts is a contract with Developers Realty Corporation (DRC) to develop projects in the downtown core area and a large retail shopping center on a 50-acre tract. DRC has entered into an agreement to form a joint venture with Weingarten Realty Investors (Weingarten). DRC/Weingarten has a commitment from a major national retail anchor for the retail shopping center.

Sites have also been set aside for a new city hall, an arts and entertainment center, and other public uses. At build-out, Town Center is expected to include over 2,900 residential units, including lodging facilities and 3.7 million square feet of various types of commercial space, including a movie theater. Future market conditions will determine how quickly Town Center is built out.

Outlook (Continued)

Palm Coast Park. We began selling property at Palm Coast Park in August 2006. Three developers who have purchased land at Palm Coast Park have started planning, engineering design and permitting of their respective projects. Since land is being sold before completion of the project infrastructure, revenue and cost of real estate sold are recorded using a percentage-of-completion method.

In 2006, the Palm Coast Park District issued $31.8 million of tax-exempt, 5.7% Special Assessment Bonds, the majority of which will be used to fund the construction of the major infrastructure improvements at Palm Coast Park, and to mitigate traffic and environmental impacts at Palm Coast Park. Major infrastructure construction began in December 2006 and is expected to be completed in 2007. Commercial and industrial lots will be offered for sale in 2007, with closings anticipated to begin in 2008. We anticipate that the Palm Coast Park District will need to issue additional bonds to pay for the development of residential and commercial properties.

At December 31, 2006, pending land sales under contract for properties at Palm Coast Park totaled $62.8 million. We have the opportunity to receive participation revenue as part of these sales contracts. One of the pending sales contracts, for the sale of five residential tracts and one commercial tract for a total of $52.5 million, provides for closings in 2007, 2008 and 2009. The project, which is named Sawmill Creek, will include up to 1,469 residential housing units, a championship golf course and neighborhood retail office space, along with a community park and an elementary and middle school. Other pending land sale contracts include a residential tract for an affordable condominium project and a 600-unit single-family residential project that will be connected to the existing Matanzas Woods golf course neighborhood.

Ormond Crossings. In December 2006, we received DRI approval from the city of Ormond Beach for our 6,000-acre Ormond Crossings project. This is a key approval necessary to develop up to 3,700 residential units and 5 million commercial square feet within Ormond Crossings. Most of Ormond Crossings is located in the city of Ormond Beach in Volusia County; the remainder of the development is an adjacent piece of unincorporated land in neighboring Flagler County. A development order from Flagler County is under review by the Flagler County Commission and, if approved, we will receive entitlements for up to 700 additional residential units. Actual build-out of Ormond Crossings, however, will consider market demand as well as infrastructure and mitigation costs.

After an agreement is finalized with the Florida Department of Transportation concerning traffic mitigation costs, we will determine the best economic build-out of the project. The agreement and economic analysis are expected to be completed in 2007.

Engineering design and permitting will be ongoing as the project is developed and sites are sold. We anticipate Ormond Crossings land sales closings starting in 2009.

Other. We have the potential to recognize gains or losses on the sale of investments in our emerging technology portfolio. We plan to sell investments in our emerging technology portfolio as shares are distributed to us. Some restrictions on sales may apply, including, but not limited to, underwriter lock-up periods that typically extend for 180 days following an initial public offering. We have committed to make additional investments in certain emerging technology holdings. The total future commitment was $2.5 million at December 31, 2006, and is expected to be invested in 2007. 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% for 2007. On an ongoing basis ALLETE, has certain tax credits and other tax adjustments that will reduce the expected effective tax rate to approximately 38% for 2007. These tax credits and adjustments historically have included items such as investment tax credits, depletion allowances, Medicare prescription reimbursement as well as other items. The effective rate will 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. Based upon our earnings per share guidance for 2007, we expect our effective tax rate for 2007 to approximate 38%.

Liquidity and Capital Resources

Cash Flow Activities

Our strategy includes growing our businesses both internally by expanding facilities, services and operations (see Capital Requirements), and externally through acquisitions.

We believe our financial condition is strong, as evidenced by cash and cash equivalents of $44.8 million, $104.5 million of short-term investments and a debt to total capital ratio of 37% at December 31, 2006.

Liquidity and Capital Resources (Continued)

Operating Activities. Cash from operating activities was $142.5 million for 2006 ($53.5 million for 2005; $175.0 million for 2004). Cash from operating activities was higher in 2006 than 2005, primarily due to the $77.9 million Kendall County Charge in 2005 and related $24.3 million federal tax refund received in 2006. Cash also increased $4.4 million in 2006 due to the collection of customer receivables which were up as a result of colder weather in December 2005. Other differences between 2006 and 2005 include an additional $9 million cash used for inventories in 2006 and the payment of approximately $13 million of 2005 accrued liabilities. Additional inventories primarily reflect coal purchases in anticipation of maintenance on coal handling equipment.

Cash from operating activities was lower in 2005 than 2004 due to the absence of cash from discontinued operations ($2.3 million in 2005; $108.8 million in 2004). In 2004, we spun off our Automotive Services business and essentially completed the exit from our Water Services businesses. The lower cash from operations was partially offset by the collection of a $6.7 million outstanding receivable at December 31, 2004, from ATC for work on the Duluth-to-Wausau transmission line and other receivables, and an additional $7.5 million of deferred profit on real estate activities.

Investing Activities. Cash used for investing activities was $154.7 million for 2006 (cash from investing activities of $3.9 million for 2005; cash used for investing activities of $126.5 million for 2004). Gross proceeds from the sale of available-for-sale securities were $608.8 million in 2006 ($376.0 million in 2005; $1.9 million in 2004) and purchases were $596.4 million ($343.7 million in 2005; $149.5 million in 2004). Cash used for investing activities was higher in 2006 than 2005, primarily due to $51.4 million invested in ATC and a $43.7 million increase in expenditures for property, plant and equipment due to major environmental construction projects.

Cash from investing activities was higher in 2005 than 2004, primarily due to a $179.9 million increase in net proceeds received from the sale of short-term investments and $35.5 million received from the sale of Enventis Telecom. These increases were partially offset by the absence of $66.0 million proceeds received in 2004 from the sale of our remaining Water Services businesses and $12.0 million received from Split Rock Energy in 2004 upon termination of the joint venture.

Financing Activities. Cash used for financing activities was $32.6 million for 2006 ($13.9 million for 2005; $228.7 million for 2004). Cash used for financing activities was higher in 2006 than 2005 primarily due to an additional $7.2 million in dividends paid as a result of more shares outstanding, a higher dividend rate and fewer shares of common stock issued under our long-term incentive compensation plan. In 2006, we refinanced $77.8 million of long-term debt at lower rates.

Cash used for financing activities was lower in 2005 than 2004 primarily due to significant debt repayment ($35.7 million in 2005; $241.1 million in 2004). In 2005, we refinanced $35 million of long-term debt at a lower rate. In 2004, we repaid $3.5 million of industrial development revenue bonds and $125 million of senior notes, and refinanced $111 million of pollution control refunding revenue bonds at a lower rate. In addition, $53 million from a previous credit agreement was paid off early in 2004. Proceeds from the sale of our Water Services assets in 2003 and 2004, and proceeds received from ADESA in 2004 were used to repay the debt in 2004. Cash used for financing activities was also lower in 2005 than 2004 due to lower dividends paid following the spin-off of Automotive Services.

In 2006, our Town Center development project was financed with tax-exempt bonds issued by the Town Center District and a revolving development loan. In March 2005, the Town Center District issued $26.4 million of tax-exempt, 6% Capital Improvement Revenue Bonds, Series 2005, which are payable over 31 years (by May 1, 2036). The bond proceeds (less capitalized interest, a debt service reserve fund and cost of issuance) were used to pay for the construction of a portion of the major infrastructure improvements at Town Center. The bonds are payable from and secured by the revenue derived from assessments imposed, levied and collected by the Town Center District. The assessments represent an allocation of the costs of the improvements, including bond financing costs, to the lands within the Town Center District benefiting from the improvements. The assessments were billed to Town Center landowners beginning in November 2006. To the extent that we still own land at the time of the assessment, we recognize the cost of our portion of these assessments, based upon our ownership of benefited property. At December 31, 2006, we owned approximately 73% of the assessable land in the Town Center District.

Our Palm Coast Park development project in Florida is being financed with tax-exempt bonds issued by the Palm Coast Park District. In May 2006, Palm Coast Park District issued $31.8 million of tax-exempt, 5.7% Special Assessment Bonds, Series 2006 which are payable over 31 years (by May 1, 2037). The bond proceeds (less capitalized interest, a debt service reserve fund and cost of issuance) are being used to fund the construction of the major infrastructure improvements at Palm Coast Park, and to mitigate traffic and environmental impacts. The bonds are payable from and secured by the revenue derived from assessments imposed, levied and collected by the Palm Coast Park District. The assessments represent an allocation of the costs of the improvements, including bond financing costs, to the lands within the Palm Coast Park District benefiting from the improvements. The assessments will be billed to Palm Coast Park landowners beginning in November 2007. To the extent that we still own land at the time of the assessment, we will recognize the cost of our portion of these assessments, based upon our ownership of benefited property. At December 31, 2006, we owned 97% of the assessable land in the Palm Coast Park District.

Liquidity and Capital Resources (Continued)

Working Capital. Additional working capital, if and when needed, generally is provided by the sale of commercial paper. We have 0.6 million original issue shares of our common stock available for issuance through *Invest Direct*, our direct stock purchase and dividend reinvestment plan. We have bank lines of credit aggregating $170.0 million, the majority of which expire in January 2012. In January 2006, we renewed, increased and extended a committed, syndicated, unsecured revolving credit facility with LaSalle Bank National Association, as Agent, for $150 million (Line) with a maturity date of January 11, 2011. The Line was subsequently extended for an additional year in December 2006 and currently matures on January 11, 2012. At our request and subject to certain conditions, the Line may be increased to $200 million and extended for two additional 12-month periods. We may prepay amounts outstanding under the Line in whole or in part at our discretion. Additionally, we may irrevocably terminate or reduce the size of the Line prior to maturity. The Line may be used for general corporate purposes, working capital and to provide liquidity in support of our commercial paper program. The amount and timing of future sales of our securities will depend upon market conditions and our specific needs. We may sell securities to meet capital requirements, to provide for the retirement or early redemption of issues of long-term debt, to reduce short-term debt and for other corporate purposes.

Securities

In March 2001, ALLETE, ALLETE Capital II and ALLETE Capital III, jointly filed a registration statement with the SEC, pursuant to Rule 415 under the Securities Act of 1933. The registration statement, which has been declared effective by the SEC, relates to the possible issuance of a remaining aggregate amount of $387 million of securities, which may include ALLETE common stock, first mortgage bonds and other debt securities, and ALLETE Capital II and ALLETE Capital III preferred trust securities. ALLETE also previously filed a registration statement, which has been declared effective by the SEC, relating to the possible issuance of $25 million of first mortgage bonds and other debt securities. We may sell all or a portion of the remaining 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 thereunder.

In March 2006, we issued $50 million in principal amount of First Mortgage Bonds, 5.69% Series due March 1, 2036, in the private placement market. Proceeds were used to redeem $50 million in principal amount of First Mortgage Bonds, 7% Series due March 1, 2008.

In July 2006, the Collier County Industrial Development Authority (Authority or Issuer) issued $27.8 million of Industrial Development Variable Rate Demand Refunding Revenue Bonds Series 2006 due 2025 (Refunding Bonds) on behalf of ALLETE. The interest rate on these bonds was 3.94% at December 31, 2006. Pursuant to a financing agreement between the Authority and ALLETE dated as of July 1, 2006, ALLETE is obligated to make payments to the Issuer sufficient to pay all principal and interest on the Refunding Bonds. ALLETE's obligations under the financing agreement are supported by a direct pay letter of credit. Proceeds from the Refunding Bonds and internally generated funds were used to redeem $29.1 million of outstanding Collier County Industrial Development Refunding Revenue Bonds 6.5% Series 1996 due 2025 on August 9, 2006. As a result of an early redemption premium, we recognized a $0.6 million pre-tax charge to other expense in the third quarter of 2006.

On February 1, 2007, we issued $60 million in principal amount of First Mortgage Bonds, 5.99% Series due February 1, 2027, in the private placement market. Proceeds were used to retire $60 million in principal amount of First Mortgage Bonds, 7% Series on February 15, 2007.

Financial Covenants

Our lines of credit and letters of credit supporting certain long-term debt arrangements contain financial covenants. The most restrictive covenant requires ALLETE to maintain a quarterly ratio of its funded debt to total capital of less than or equal to .65 to 1.00. Failure to meet this covenant could give rise to an event of default, if not corrected after notice from the lender, in which event ALLETE may need to pursue alternative sources of funding. Some of ALLETE's debt arrangements contain "cross-default" provisions that would result in an event of default if there is a failure under other financing arrangements to meet payment terms or to observe other covenants that would result in an acceleration of payments due. As of December 31, 2006, 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, 2006, remains constant through the remaining term.

Liquidity and Capital Resources (Continued)

Unconditional purchase obligations represent our Square Butte power purchase agreements, and minimum purchase commitments under coal and rail contracts.

Under our power purchase agreement with Square Butte that extends through 2026, we are obligated to pay our pro rata share of Square Butte's costs based on our entitlement to the output of Square Butte's 455 MW coal-fired generating unit near Center, North Dakota. Our payment obligation is suspended if Square Butte fails to deliver any power, whether produced or purchased, for a period of one year. Square Butte's fixed costs consist primarily of debt service. The following table reflects our share of future debt service based on our output entitlement of approximately 60% in 2007, 55% in 2008 and 50% thereafter. (See Note 8.)

Under an agreement with Wisconsin Public Service Corporation and WPS Investments, LLC, we have a commitment to invest $60 million in ATC. During 2006, we invested $51.4 million in ATC. We plan to invest an additional $8.6 million in ATC in early 2007 to reach our $60 million investment commitment. (See Notes 6 and 8.)

	Payments Due by Period				
Contractual Obligations As of December 31, 2006	**Total**	**Less than 1 Year**	**1 to 3 Years**	**4 to 5 Years**	**After 5 Years**
Millions					
Long-Term Debt *(a)*	$ 639.7	$ 46.7	$ 65.1	$31.2	$496.7
Operating Lease Obligations	86.5	8.2	21.1	11.4	45.8
Unconditional Purchase Obligations	321.2	53.7	58.0	26.2	183.3
Investment in ATC	8.6	8.6	–	–	–
	$1,056.0	$117.2	$ 144.2	$68.8	$725.8

(a) Includes interest and assumes variable interest rate in effect at December 31, 2006, remains constant through remaining term.

We expect to contribute approximately $6 million to our postretirement health and life plans in 2007. We are not required to make any contributions to our defined benefit pension plans in 2007. We are unable to predict contribution levels to our defined benefit pension plans after 2007.

Emerging Technology Portfolio. We have investments in emerging technologies through minority investments in venture capital funds and privately-held, start-up companies. We have committed to make additional investments in certain emerging technology holdings. The total future commitment was $2.5 million at December 31, 2006 ($3.1 million at December 31, 2005; $4.5 million at December 31, 2004) and is expected to be invested in 2007. We do not have plans to make any additional investments beyond this commitment.

Credit Ratings

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

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

Payout Ratio

In 2006, we paid out 53% (259% in 2005; 77% in 2004) of our per share earnings in dividends. The payout ratio in 2005 was impacted by a $1.84 per diluted share charge resulting from our assignment of the Kendall County power purchase agreement to Constellation Energy Commodities in April 2005. (See Note 10.)

On January 26, 2007, our Board of Directors increased the dividend on ALLETE common stock by 13%, declaring a dividend of $0.41 per share payable March 1, 2007, to shareholders of record at the close of business February 15, 2007.

Capital Requirements

Continuing Operations. Capital additions for 2006 totaled $109.4 million ($58.6 million in 2005; $57.8 million in 2004). Expenditures for 2006 included $107.5 million for Regulated Utility and $1.9 million for Nonregulated Energy Operations. Internally-generated funds were the source of funding for these expenditures.

Capital additions are expected to be $179 million in 2007 and estimated to total about $700 million for 2008 through 2011. The 2007 amount includes $88 million for federal or state required environmental compliance projects at generation facilities (primarily for our AREA and Boswell Unit 3 emission reduction plans), $86 million for other regulated system component replacements and upgrades and $5 million for upgrades within Nonregulated Energy Operations. Over the next five years, we expect to use internally-generated funds and new issue debt to fund our projected capital additions. Approximately $145 million of the estimated capital additions for 2008 through 2011 relate to federal or state required environmental upgrades at our generation facilities, $450 million is for other regulated system replacements and upgrades, while $95 million is for possible generation resource additions linked to potential load growth identified in our Resource Plan filing.

Real estate development expenditures are and will be funded with a revolving development loan and tax-exempt bonds issued by community development districts. The Palm Coast Park District issued $31.8 million of tax-exempt bonds in May 2006. Bond proceeds of $26.3 million will be used for environmental and traffic mitigation, and the construction of infrastructure improvements at Palm Coast Park, with the remaining funds to be used for capitalized interest, a debt service reserve fund and costs of issuance. We anticipate that the Palm Coast Park District will need to issue additional bonds to pay for the development of retail commercial, office and industrial lots at Palm Coast Park. Company expenditures related to our real estate developments in Florida increase the carrying value of our land assets, which are classified as Investments on our consolidated balance sheet.

Discontinued Operations. There were no capital additions for discontinued operations in 2006 ($4.5 million in 2005; $21.4 million in 2004).

Environmental and Other Matters

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

Market Risk

Securities Investments

Available-for-Sale Securities. At December 31, 2006, our available-for-sale securities portfolio consisted of securities in a grantor trust established to fund certain employee benefits included in Investments, and various auction rate bonds and variable rate demand notes included as Short-Term Investments. Our available-for-sale securities portfolio had a fair value of $130.1 million at December 31, 2006 ($139.5 million at December 31, 2005) and a total unrealized after-tax gain of $4.0 million at December 31, 2006 ($2.1 million at December 31, 2005).

We use the specific identification method as the basis for determining the cost of securities sold. Our policy is to review, on a quarterly basis, available-for-sale securities for other than temporary impairment by assessing such factors as the share price trends and the impact of overall market conditions. As a result of our periodic assessments, we did not record any impairments on our available-for-sale securities in 2006 or 2005.

Emerging Technology Portfolio. As part of our emerging technology portfolio, we have several minority investments in venture capital funds and direct investments in privately-held, start-up companies. We account for our investment in venture capital funds under the equity method and account for our direct investments in privately-held companies under the cost method because of our ownership percentage. The total carrying value of our emerging technology portfolio was $9.2 million at December 31, 2006, and December 31, 2005. Our policy is to review these investments quarterly for impairment by assessing such factors as continued commercial viability of products, cash flow and earnings. Any impairment would reduce the carrying value of the investment. Our basis in direct investments in privately-held companies included in the emerging technology portfolio was zero at December 31, 2006, and at December 31, 2005. In 2005, we recorded $5.1 million ($3.3 million after tax) of impairments related to our direct investments in certain privately-held, start-up companies whose future business prospects had significantly diminished. Developments at these companies indicated that future commercial viability was unlikely, as was new financing necessary to continue development. In 2004, we recorded $6.5 million ($4.1 million after tax) of impairments.

Market Risk (Continued)

Interest Rate Risk

We are exposed to risks resulting from changes in interest rates as a result of our issuance of variable rate debt. We manage our interest rate risk by varying the issuance and maturity dates of our fixed rate debt, limiting the amount of variable rate debt, and continually monitoring the effects of market changes in interest rates. The table below presents the long-term debt obligations and the corresponding weighted average interest rate at December 31, 2006.

	Principal Cash Flow by Expected Maturity Date							
Interest Rate Sensitive Financial Instruments	**2007**	**2008**	**2009**	**2010**	**2011**	**Thereafter**	**Total**	**Fair Value**
Dollars in Millions								
Long-Term Debt								
Fixed Rate	$21.3	$7.0	$2.0	$0.9	$0.9	$275.6	$307.7	$305.8
Average Interest Rate – %	6.7	7.1	5.4	6.5	6.5	5.7	5.8	
Variable Rate	$8.4	–	$8.2	$3.6	–	$61.6	$81.8	$81.8
Average Interest Rate – % *(a)*	5.9	–	3.9	3.6	–	3.9	4.1	

(a) Assumes rate in effect at December 31, 2006, remains constant through remaining term.

The interest rate on variable rate long-term debt is reset on a periodic basis reflecting current market conditions. Based on the variable rate debt outstanding at December 31, 2006, and assuming no other changes to our financial structure, an increase or decrease of 100 basis points would impact the amount of pretax interest expense by $0.8 million. This amount was determined by considering the impact of a hypothetical 100 basis point change to the average variable interest rate on the variable rate debt held as of December 31, 2006.

Commodity Price Risk

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

Power Marketing

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

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

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

New Accounting Standards

New accounting standards are discussed in Note 2.

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

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

Item 8. Financial Statements and Supplementary Data

See our consolidated financial statements as of December 31, 2006 and 2005, and for each of the three years in the period ended December 31, 2006, and supplementary data, also included, which are indexed in Item 15(a).

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

Not applicable.

Item 9A. Controls and Procedures

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of our disclosure controls and procedures, as such term is defined under Rule 13a-15(e) promulgated under the Securities Exchange Act of 1934, as amended (Exchange Act). Based on this evaluation, our principal executive officer and our principal financial officer concluded that our disclosure controls and procedures were effective as of the end of the period covered by this annual report.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the framework in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our evaluation under the framework in Internal Control—Integrated Framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2006.

Our management's assessment of the effectiveness of our internal control over financial reporting as of December 31, 2006, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

Item 9B. Other Information

None.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

Unless otherwise stated, the information required for this Item is incorporated by reference herein from our Proxy Statement for the 2007 Annual Meeting of Shareholders (2007 Proxy Statement) under the following headings:

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

Our 2007 Proxy Statement will be filed with the SEC within 120 days after the end of our 2006 fiscal year.

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

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

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

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

Item 11. Executive Compensation

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

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

The information required for this Item is incorporated by reference herein from the "Security Ownership of Certain Beneficial Owners," the "Security Ownership of Management" and the "Equity Compensation Plan Information" sections in our 2007 Proxy Statement.

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

The information required for this Item is incorporated by reference herein from the "Corporate Governance" section in our 2007 Proxy Statement.

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

Item 14. Principal Accountant Fees and Services

The information required by this Item is incorporated by reference herein from the "Report of the Audit Committee" section in our 2007 Proxy Statement.

Part IV

Item 15. Exhibits and Financial Statement Schedules

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

(1) Financial Statements

(2) Financial Statement Schedules

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

(3) Exhibits including those incorporated by reference.

Exhibit Number

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

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

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

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

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

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

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

4(a)3 - Twenty-Sixth Supplemental Indenture, dated as of October 1, 2006, between ALLETE and The Bank of New York and Douglas J. MacInnes, as Trustees.

Exhibit Number

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

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

*4(d)	-	Amended and Restated Rights Agreement, dated as of July 12, 2006, between ALLETE and the Corporate Secretary of ALLETE, as Rights Agent (filed as Exhibit 4 to the July 14, 2006, Form 8-K, File No. 1-3548).
*10(a)	-	Power Purchase and Sale Agreement, dated as of May 29, 1998, between Minnesota Power, Inc. (now ALLETE) and Square Butte Electric Cooperative (filed as Exhibit 10 to the June 30, 1998, Form 10-Q, File No. 1-3548).
*10(b)	-	Amended and Restated Withdrawal Agreement (without Exhibits and Schedules), dated January 30, 2004, by and between Great River Energy and Minnesota Power (now ALLETE) (filed as Exhibit 10(p) to the 2003 Form 10-K, File No. 1-3548).
*10(c)	-	Master Agreement (without Appendices and Exhibits), dated December 28, 2004, by and between Rainy River Energy Corporation and Constellation Energy Commodities Group, Inc. (filed as Exhibit 10(c) to the 2004 Form 10-K, File No. 1-3548).
*10(d)1	-	Fourth Amended and Restated Committed Facility Letter (without Exhibits), dated January 11, 2006, by and among ALLETE and LaSalle Bank National Association, as Agent (filed as Exhibit 10 to the January 17, 2006, Form 8-K, File No. 1-3548).
*10(d)2	-	First Amendment to Fourth Amended and Restated Committed Facility Letter dated June 19, 2006, by and among ALLETE and LaSalle Bank National Association, as Agent (filed as Exhibit 10(a) to the June 30, 2006, Form 10-Q, File No. 1-3548).
10(d)3	-	Second Amendment to Fourth Amended and Restated Committed Facility Letter dated December 14, 2006, by and among ALLETE and LaSalle Bank National Association, as Agent.
*10(e)1	-	Financing Agreement between Collier County Industrial Development Authority and ALLETE dated as of July 1, 2006 (filed as Exhibit 10(b)1 to the June 30, 2006, Form 10-Q, File No. 1-3548).
*10(e)2	-	Letter of Credit Agreement, dated as of July 5, 2006, among ALLETE, the Participating Banks and Wells Fargo Bank, National Association, as Administrative Agent and Issuing Bank (filed as Exhibit 10(b)2 to the June 30, 2006, Form 10-Q, File No. 1-3548).
*10(f)	-	Master Separation Agreement, dated June 4, 2004, between ALLETE, Inc. and ADESA, Inc. (filed as Exhibit 10.1 to ADESA, Inc.'s June 30, 2004, Form 10-Q, File No. 1-32198).
*10(g)	-	Agreement (without Exhibit) dated December 16, 2005, among ALLETE, Wisconsin Public Service Corporation and WPS Investments, LLC (filed as Exhibit 10 to the December 21, 2005 Form 8-K, File No. 1-3548).
+*10(h)1	-	Minnesota Power (now ALLETE) Executive Annual Incentive Plan, as amended, effective January 1, 1999 with amendments through January 2003 (filed as Exhibit 10 to the September 30, 2003, Form 10-Q, File No. 1-3548).
+*10(h)2	-	November 2003 Amendment to the ALLETE Executive Annual Incentive Plan (filed as Exhibit 10(t)2 to the 2003 Form 10-K, File No. 1-3548).
+*10(h)3	-	July 2004 Amendment to the ALLETE Executive Annual Incentive Plan (filed as Exhibit 10(a) to the June 30, 2004, Form 10-Q, File No. 1-3548).

Exhibit Number

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

Exhibit Number

+*10(n)3	-	July 2004 Amendment to the ALLETE Director Stock Plan (filed as Exhibit 10(e) to the June 30, 2004, Form 10-Q, File No. 1-3548).
+10(n)4	-	January 2007 Amendment to the ALLETE Director Stock Plan.
+*10(n)5	-	ALLETE Director Compensation Summary Effective May 1, 2005 (filed as Exhibit 10 to the June 30, 2005, Form 10-Q, File No. 1-3548).
+10(n)6	-	ALLETE Non-Management Director Compensation Summary Effective February 15, 2007.
+*10(o)1	-	Minnesota Power (now ALLETE) Director Compensation Deferral Plan Amended and Restated, effective January 1, 1990 (filed as Exhibit 10(ac) to the 2002 Form 10-K, File No. 1-3548).
+*10(o)2	-	October 2003 Amendment to the Minnesota Power (now ALLETE) Director Compensation Deferral Plan (filed as Exhibit 10(aa)2 to the 2003 Form 10-K, File No. 1-3548).
+*10(o)3	-	January 2005 Amendment to the ALLETE Director Compensation Deferral Plan (filed as Exhibit 10(c) to the March 31, 2005, Form 10-Q, File No. 1-3548).
+*10(o)4	-	August 2006 Amendment to the ALLETE Director Compensation Deferral Plan (filed as Exhibit 10(d) to the September 30, 2006, Form 10-Q, File No. 1-3548).
+*10(p)	-	ALLETE Director Compensation Trust Agreement, effective October 11, 2004 (filed as Exhibit 10(a) to the September 30, 2004, Form 10-Q, File No. 1-3548).
12	-	Computation of Ratios of Earnings to Fixed Charges.
21	-	Subsidiaries of the Registrant.
23(a)	-	Consent of Independent Registered Public Accounting Firm.
23(b)	-	Consent of General Counsel.
31(a)	-	Rule 13a-14(a)/15d-14(a) Certification by the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(b)	-	Rule 13a-14(a)/15d-14(a) Certification by the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32	-	Section 1350 Certification of Annual Report by the Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99	-	ALLETE News Release dated February 16, 2007, announcing 2006 earnings. **(This exhibit has been furnished and shall not be deemed "filed" for purposes of Section 18 of the Securities Exchange Act of 1934, nor shall it be deemed incorporated by reference in any filing under the Securities Act of 1933, except as shall be expressly set forth by specific reference in such filing.)**

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

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* *Incorporated herein by reference as indicated.*

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

Signatures

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

ALLETE, Inc.

Dated: February 16, 2007

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

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

Signature	Title	Date
/s/ Donald J. Shippar Donald J. Shippar	Chairman, President, Chief Executive Officer and Director	February 16, 2007
/s/ Mark A. Schober Mark A. Schober	Senior Vice President and Chief Financial Officer	February 16, 2007
/s/ Steven Q. DeVinck Steven Q. DeVinck	Controller	February 16, 2007
/s/ Kathleen A. Brekken Kathleen A. Brekken	Director	February 16, 2007
/s/ Heidi J. Eddins Heidi J. Eddins	Director	February 16, 2007
/s/ James J. Hoolihan James J. Hoolihan	Director	February 16, 2007
/s/ Peter J. Johnson Peter J. Johnson	Director	February 16, 2007
/s/ Madeleine W. Ludlow Madeleine W. Ludlow	Director	February 16, 2007
/s/ George L. Mayer George L. Mayer	Director	February 16, 2007
/s/ Roger D. Peirce Roger D. Peirce	Director	February 16, 2007
/s/ Jack I. Rajala Jack I. Rajala	Director	February 16, 2007
/s/ Nick Smith Nick Smith	Director	February 16, 2007
/s/ Bruce W. Stender Bruce W. Stender	Director	February 16, 2007

Report of Independent Registered Public Accounting Firm

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

We have completed integrated audits of ALLETE, Inc.'s consolidated financial statements and of its internal control over financial reporting as of December 31, 2006, in accordance with the standards of the Public Company Accounting Oversight Board (United States). Our opinions, based on our audits, are presented below.

Consolidated financial statements and financial statement schedule

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)(1) present fairly, in all material respects, the financial position of ALLETE, Inc. and its subsidiaries (the Company) at December 31, 2006 and 2005, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2006 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the accompanying index under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements and financial statement schedule based on our audits. We conducted our audits of these statements in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit of financial statements includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As discussed in Note 15 to the consolidated financial statements, in 2004 the Company changed its method of accounting for investments in limited liability companies in accordance with EITF 03-16, "Accounting for Investments in Limited Liability Companies." As discussed in Note 16 to the consolidated financial statements, in 2006 the Company adopted SFAS 158, "Employer's Accounting for Defined Benefit Pension and Other Postretirement Plans." As discussed in Note 17 to the consolidated financial statements, in 2006 the Company changed the manner in which it accounts for share-based compensation.

Internal control over financial reporting

Also, in our opinion, management's assessment, included in Management's Report on Internal Control Over Financial Reporting appearing under Item 9A, that the Company maintained effective internal control over financial reporting as of December 31, 2006 based on criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), is fairly stated, in all material respects, based on those criteria. Furthermore, in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2006, based on criteria established in Internal Control—Integrated Framework issued by the COSO. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting. Our responsibility is to express opinions on management's assessment and on the effectiveness of the Company's internal control over financial reporting based on our audit. We conducted our audit of internal control over financial reporting in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. An audit of internal control over financial reporting includes obtaining an understanding of internal control over financial reporting, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we consider necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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

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

/s/ PricewaterhouseCoopers LLP

PricewaterhouseCoopers LLP
Minneapolis, Minnesota
February 12, 2007, except as to Note 7 for which the date is February 15, 2007

Consolidated Financial Statements

ALLETE Consolidated Balance Sheet

December 31	2006	2005
Millions		
Assets		
Current Assets		
Cash and Cash Equivalents	$ 44.8	$ 89.6
Short-Term Investments	104.5	116.9
Accounts Receivable (Less Allowance of $1.1 and $1.0)	70.9	79.1
Inventories	43.4	33.1
Prepayments and Other	23.8	23.8
Deferred Income Taxes	0.3	31.0
Discontinued Operations	–	0.4
Total Current Assets	287.7	373.9
Property, Plant and Equipment – Net	921.6	860.4
Investments	189.1	117.7
Other Assets	135.0	44.6
Discontinued Operations	–	2.2
Total Assets	$1,533.4	$1,398.8
Liabilities and Shareholders' Equity		
Liabilities		
Current Liabilities		
Accounts Payable	$ 53.5	$ 44.7
Accrued Taxes	23.3	19.1
Accrued Interest	8.6	7.4
Long-Term Debt Due Within One Year	29.7	2.7
Deferred Profit on Sales of Real Estate	4.1	8.6
Other	24.3	24.2
Discontinued Operations	–	13.0
Total Current Liabilities	143.5	119.7
Long-Term Debt	359.8	387.8
Deferred Income Taxes	130.8	138.4
Other Liabilities	226.1	144.1
Minority Interest	7.4	6.0
Total Liabilities	867.6	796.0
Commitments and Contingencies		
Shareholders' Equity		
Common Stock Without Par Value, 43.3 Shares Authorized 30.4 and 30.1 Shares Outstanding	438.7	421.1
Unearned ESOP Shares	(71.9)	(77.6)
Accumulated Other Comprehensive Loss	(8.8)	(12.8)
Retained Earnings	307.8	272.1
Total Shareholders' Equity	665.8	602.8
Total Liabilities and Shareholders' Equity	$1,533.4	$1,398.8

The accompanying notes are an integral part of these statements.

ALLETE Consolidated Statement of Income

For the Year Ended December 31	2006	2005	2004
Millions Except Per Share Amounts			
Operating Revenue	$767.1	$737.4	$704.1
Operating Expenses			
Fuel and Purchased Power	281.7	273.1	286.2
Operating and Maintenance	296.0	293.5	270.1
Kendall County Charge	–	77.9	–
Depreciation	48.7	47.8	46.9
Total Operating Expenses	626.4	692.3	603.2
Operating Income from Continuing Operations	140.7	45.1	100.9
Other Income (Expense)			
Interest Expense	(27.4)	(26.4)	(31.7)
Other	14.9	1.1	(12.2)
Total Other Expense	(12.5)	(25.3)	(43.9)
Income from Continuing Operations Before Minority Interest and Income Taxes	128.2	19.8	57.0
Minority Interest	4.6	2.7	2.1
Income from Continuing Operations Before Income Taxes	123.6	17.1	54.9
Income Tax Expense (Benefit)	46.3	(0.5)	16.4
Income from Continuing Operations Before Change in Accounting Principle	77.3	17.6	38.5
Income (Loss) from Discontinued Operations – Net of Tax	(0.9)	(4.3)	73.7
Change in Accounting Principle – Net of Tax	–	–	(7.8)
Net Income	$ 76.4	$ 13.3	$104.4
Average Shares of Common Stock			
Basic	27.8	27.3	28.3
Diluted	27.9	27.4	28.4
Basic Earnings (Loss) Per Share of Common Stock			
Continuing Operations	$2.78	$0.65	$1.37
Discontinued Operations	(0.03)	(0.16)	2.60
Change in Accounting Principle	–	–	(0.28)
	$2.75	$0.49	$3.69
Diluted Earnings (Loss) Per Share of Common Stock			
Continuing Operations	$2.77	$0.64	$1.35
Discontinued Operations	(0.03)	(0.16)	2.59
Change in Accounting Principle	–	–	(0.27)
	$2.74	$0.48	$3.67
Dividends Per Share of Common Stock	$1.4500	$1.2450	$2.8425

The accompanying notes are an integral part of these statements.

ALLETE Consolidated Statement of Cash Flows

For the Year Ended December 31	2006	2005	2004
Millions			
Operating Activities			
Net Income	$ 76.4	$ 13.3	$104.4
(Income) Loss from Discontinued Operations	0.9	4.3	(73.7)
Income from Equity Investments	(1.8)	–	–
Change in Accounting Principle	–	–	7.8
Loss on Impairment of Investments	–	5.1	6.5
Depreciation	48.7	47.8	46.9
Deferred Income Taxes	27.8	(34.2)	(1.1)
Minority Interest	4.6	2.7	2.1
Stock Compensation Expense	1.8	1.5	1.0
Bad Debt Expense	0.7	1.1	0.9
Changes in Operating Assets and Liabilities			
Accounts Receivable	7.5	(1.4)	(22.9)
Inventories	(10.3)	(1.3)	(0.3)
Prepayments and Other	(2.3)	(2.5)	(3.6)
Accounts Payable	5.1	4.9	0.2
Other Current Liabilities	0.2	5.8	(4.8)
Other Assets	(4.3)	8.2	6.2
Other Liabilities	1.0	(4.1)	(3.4)
Net Operating Activities from Discontinued Operations	(13.5)	2.3	108.8
Cash from Operating Activities	142.5	53.5	175.0
Investing Activities			
Proceeds from Sale of Available-For-Sale Securities	608.8	376.0	1.9
Payments for Purchase of Available-For-Sale Securities	(596.4)	(343.7)	(149.5)
Changes to Investments	(52.0)	(1.1)	12.4
Expenditures for Property, Plant and Equipment	(102.3)	(58.6)	(57.8)
Other	(15.0)	0.6	2.0
Net Investing Activities from Discontinued Operations	2.2	30.7	64.5
Cash from (for) Investing Activities	(154.7)	3.9	(126.5)
Financing Activities			
Issuance of Common Stock	15.8	21.0	49.0
Issuance of Long-Term Debt	77.8	35.0	120.8
Reacquired Common Stock	–	–	(5.8)
Changes in Notes Payable – Net	–	–	(53.0)
Reductions of Long-Term Debt	(78.9)	(35.7)	(241.1)
Dividends on Common Stock and Distributions to Minority Shareholders	(43.9)	(36.7)	(79.7)
Net Increase (Decrease) in Book Overdrafts	(3.4)	3.4	–
Net Financing Activities for Discontinued Operations	–	(0.9)	(18.9)
Cash for Financing Activities	(32.6)	(13.9)	(228.7)
Change in Cash and Cash Equivalents	(44.8)	43.5	(180.2)
Cash and Cash Equivalents at Beginning of Period	89.6	46.1	226.3
Cash and Cash Equivalents at End of Period ***(a)***	$ 44.8	$ 89.6	$ 46.1

(a) Included $2.4 million of cash from Discontinued Operations at December 31, 2004.

The accompanying notes are an integral part of these statements.

ALLETE Consolidated Statement of Shareholders' Equity

	Total Shareholders' Equity	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Unearned ESOP Shares	Common Stock
Millions					
Balance at December 31, 2003	$ 1,460.2	$631.9	$14.5	$(45.4)	$859.2
Comprehensive Income					
Net Income	104.4	104.4			
Other Comprehensive Income – Net of Tax					
Unrealized Gains on Securities – Net	0.7		0.7		
Foreign Currency Translation Adjustments	(23.5)		(23.5)		
Additional Pension Liability	(3.1)		(3.1)		
Total Comprehensive Income	78.5				
Common Stock Issued – Net	43.2				43.2
ADESA IPO	70.1				70.1
Spin-Off of ADESA	(963.6)	(363.4)			(600.2)
Receipt of ADESA Stock by ESOP	54.3			26.5	27.8
Purchase of ALLETE Shares by ESOP	(35.6)			(35.6)	
Dividends Declared	(79.7)	(79.7)			
ESOP Shares Earned	3.1			3.1	
Balance at December 31, 2004	630.5	293.2	(11.4)	(51.4)	400.1
Comprehensive Income					
Net Income	13.3	13.3			
Other Comprehensive Income – Net of Tax					
Unrealized Gains on Securities – Net	0.6		0.6		
Additional Pension Liability	(2.0)		(2.0)		
Total Comprehensive Income	11.9				
Common Stock Issued – Net	21.0				21.0
Dividends Declared	(34.4)	(34.4)			
Purchase of ALLETE Shares by ESOP	(30.3)			(30.3)	
ESOP Shares Earned	4.1			4.1	
Balance at December 31, 2005	602.8	272.1	(12.8)	(77.6)	421.1
Comprehensive Income					
Net Income	76.4	76.4			
Other Comprehensive Income – Net of Tax					
Unrealized Gains on Securities – Net	1.9		1.9		
Additional Pension Liability	6.4		6.4		
Total Comprehensive Income	84.7				
Adjustment to initially apply SFAS 158 – Net of Tax	(4.3)		(4.3)		
Common Stock Issued – Net	17.6				17.6
Dividends Declared	(40.7)	(40.7)			
ESOP Shares Earned	5.7			5.7	
Balance at December 31, 2006	$ 665.8	$307.8	$ (8.8)	$(71.9)	$438.7

The accompanying notes are an integral part of these statements.

Notes to Consolidated Financial Statements

Note 1. Business Segments

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

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

Effective the third quarter of 2006, financial results for our equity investment in ATC have been reported as a separate segment. ATC is a Wisconsin-based public utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota and Illinois. ATC provides transmission service under rates regulated by the FERC that are set in accordance with the FERC's policy of establishing the independent operation and ownership of, and investment in, transmission facilities. (See Note 6.)

		Energy				
	Consolidated	Regulated Utility	Nonregulated Energy Operations	Investment in ATC	Real Estate	Other
Millions						
2006						
Operating Revenue	$767.1	$639.2	$65.0	–	$62.6	$0.3
Fuel and Purchased Power	281.7	281.7	–	–	–	–
Operating and Maintenance	296.0	217.9	57.1	–	18.2	2.8
Depreciation Expense	48.7	44.2	4.3	–	0.1	0.1
Operating Income (Loss) from Continuing Operations	140.7	95.4	3.6	–	44.3	(2.6)
Interest Expense	(27.4)	(20.2)	(3.3)	–	–	(3.9)
Other Income	14.9	0.9	2.2	$3.0	–	8.8
Income from Continuing Operations Before Minority Interest and Income Taxes	128.2	76.1	2.5	3.0	44.3	2.3
Minority Interest	4.6	–	–	–	4.6	–
Income from Continuing Operations Before Income Taxes	123.6	76.1	2.5	3.0	39.7	2.3
Income Tax Expense (Benefit)	46.3	29.3	(1.2)	1.1	16.9	0.2
Income from Continuing Operations	77.3	$ 46.8	$ 3.7	$1.9	$22.8	$2.1
Loss from Discontinued Operations – Net of Tax	(0.9)					
Net Income	$ 76.4					
Total Assets	$1,533.4	$1,143.3	$81.3	$53.7	$89.8	$165.3
Capital Additions	$109.4	$107.5	$1.9	–	–	–

Note 1. Business Segments (Continued)

		Energy				
Millions	Consolidated	Regulated Utility	Nonregulated Energy Operations	Investment in ATC	Real Estate	Other
2005						
Operating Revenue	$737.4	$ 575.6	$113.9	–	$47.5	$ 0.4
Fuel and Purchased Power	273.1	243.7	29.4	–	–	–
Operating and Maintenance	293.5	202.9	71.2	–	15.5	3.9
Kendall County Charge	77.9	–	77.9	–	–	–
Depreciation Expense	47.8	39.4	8.1	–	0.1	0.2
Operating Income (Loss) from Continuing Operations	45.1	89.6	(72.7)	–	31.9	(3.7)
Interest Expense	(26.4)	(17.4)	(6.6)	–	(0.1)	(2.3)
Other Income (Expense)	1.1	0.7	1.7	–	–	(1.3)
Income (Loss) from Continuing Operations Before Minority Interest and Income Taxes	19.8	72.9	(77.6)	–	31.8	(7.3)
Minority Interest	2.7	–	–	–	2.7	–
Income (Loss) from Continuing Operations Before Income Taxes	17.1	72.9	(77.6)	–	29.1	(7.3)
Income Tax Expense (Benefit)	(0.5)	27.2	(29.1)	–	11.6	(10.2)
Income (Loss) from Continuing Operations	17.6	$ 45.7	$ (48.5)	–	$17.5	$ 2.9
Loss from Discontinued Operations – Net of Tax	(4.3)					
Net Income	$ 13.3					
Total Assets	$1,398.8 *(a)*	$909.5	$185.2	–	$73.7	$227.8
Capital Additions	$63.1 *(a)*	$46.5	$12.1	–	–	–
2004						
Operating Revenue	$704.1	$555.0	$106.8	–	$41.9	$ 0.4
Fuel and Purchased Power	286.2	245.1	41.1	–	–	–
Operating and Maintenance	270.1	191.7	60.3	–	15.0	3.1
Depreciation Expense	46.9	39.5	7.2	–	0.1	0.1
Operating Income (Loss) from Continuing Operations	100.9	78.7	(1.8)	–	26.8	(2.8)
Interest Expense	(31.7)	(18.5)	(4.9)	–	(0.3)	(8.0)
Other Income (Expense)	(12.2)	0.1	0.6	–	–	(12.9)
Income (Loss) from Continuing Operations Before Minority Interest and Income Taxes	57.0	60.3	(6.1)	–	26.5	(23.7)
Minority Interest	2.1	–	–	–	2.1	–
Income (Loss) from Continuing Operations Before Income Taxes	54.9	60.3	(6.1)	–	24.4	(23.7)
Income Tax Expense (Benefit)	16.4	22.6	(3.2)	–	10.1	(13.1)
Income (Loss) from Continuing Operations	38.5	$ 37.7	$ (2.9)	–	$14.3	$ (10.6)
Income from Discontinued Operations – Net of Tax	73.7					
Change in Accounting Principle – Net of Tax	(7.8)					
Net Income	$104.4					
Total Assets	$1,431.4 *(a)*	$902.8	$161.4	–	$75.1	$242.6
Capital Additions	$79.2 *(a)*	$41.7	$15.7	–	–	$0.4

(a) Discontinued Operations represented $2.6 million of total assets in 2005 ($49.5 million in 2004) and $4.5 million of capital additions in 2005 ($21.4 million in 2004).

Note 2. Operations and Significant Accounting Policies

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

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

Business Segments. Our Regulated Utility, Nonregulated Energy Operations, Real Estate, Investment in ATC and Other segments were determined in accordance with SFAS 131, “Disclosures about Segments of an Enterprise and Related Information.” Segmentation is based on the manner in which we operate, assess, and allocate resources to the business. We measure performance of our operations through budgeting and monitoring of contributions to consolidated net income by each business segment. Discontinued Operations includes our telecommunications business, which we sold on December 30, 2005, our Automotive Services business that was spun off in September 2004, costs associated with the spin-off of ADESA incurred by ALLETE, and our Water Services businesses, the majority of which were sold in 2003.

Regulated Utility includes retail and wholesale rate-regulated electric, natural gas and water services in northeastern Minnesota and northwestern Wisconsin. Minnesota Power, an operating division of ALLETE, and SWL&P, a wholly-owned subsidiary, provide regulated utility electric service to 154,000 retail customers in northeastern Minnesota and northwestern Wisconsin. Approximately 39% of regulated utility electric revenue is from Large Power Customers (33% of consolidated revenue). Large Power Customers consist of five taconite producers, four paper and pulp mills, two pipeline companies and one manufacturer under all-requirements contracts with expiration dates extending from February 2008 through October 2013. Revenue of $89.0 million (11.6% of consolidated revenue) was received from one taconite producer in 2006 (11.3% in 2005; 12.6% in 2004). Regulated utility rates are under the jurisdiction of Minnesota and Wisconsin, and federal regulatory authorities. Billings are rendered on a cycle basis. Revenue is accrued for service provided but not billed. Regulated utility electric rates include adjustment clauses that: (1) bill or credit customers for fuel and purchased energy costs above or below the base levels in rate schedules; (2) bill retail customers for the recovery of conservation improvement program expenditures not collected in base rates; and (3) bill customers for the recovery of certain environmental expenditures. Fuel and purchased power expense is deferred to match the period in which the revenue for fuel and purchased power expense is collected from customers pursuant to the fuel adjustment clause.

Minnesota Power withdrew from Split Rock Energy, a joint venture with Great River Energy, in 2004. Upon withdrawal, we received a $12.0 million distribution in 2004. We accounted for our 50% ownership interest in Split Rock Energy under the equity method of accounting. For the year ended December 31, 2004, our pre-tax equity income from Split Rock Energy was less than $0.1 million. In 2004, prior to our withdrawal, we made power purchases from Split Rock Energy of $6.2 million and power sales to Split Rock Energy of $1.9 million.

Nonregulated Energy Operations includes our coal mining activities in North Dakota, approximately 50 MW of nonregulated generation and Minnesota land sales. BNI Coal, a wholly-owned subsidiary, mines and sells lignite coal to two North Dakota mine-mouth generating units, one of which is Square Butte. Square Butte supplies approximately 60% (323 MW) of its output to Minnesota Power under a long-term contract. (See Note 8.) Coal sales are recognized when delivered at the cost of production plus a specified profit per ton of coal delivered.

In 2004 and 2005, Nonregulated Energy Operations included nonregulated generation (non-rate base generation sold at market-based rates to the wholesale market) from our Taconite Harbor facility in northern Minnesota and generation secured through the Kendall County power purchase agreement. To help meet forecasted base load energy requirements effective January 1, 2006, Taconite Harbor was integrated into our Regulated Utility business in accordance with the terms of our Resource Plan, as approved by the MPUC. The Kendall County power purchase agreement was assigned to Constellation Energy Commodities in April 2005. (See Note 10.)

Investment in ATC includes our approximate 7% equity ownership interest in ATC, a Wisconsin-based public utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota and Illinois. ATC provides transmission service under rates regulated by the FERC that are set in accordance with the FERC’s policy of establishing the independent operation and ownership of, and investment in, transmission facilities. (See Note 6 and 8.)

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

Full profit recognition is recorded on sales upon closing, provided cash collections are at least 20% of the contract price and the other requirements of SFAS 66, “Accounting for Sales of Real Estate,” are met. In certain cases, where there are

Note 2. Operations and Significant Accounting Policies (Continued)

obligations to perform significant development activities after the date of sale, we recognize profit on a percentage-of-completion basis in accordance with SFAS 66. Pursuant to this method of accounting, gross profit is recognized based upon the relationship of development costs incurred as of that date to the total estimated costs to develop the parcels, including all related amenities or common costs of the entire project. Revenue and cost of real estate sold in excess of the amount recognized based on the percentage-of-completion method is deferred and recognized as revenue and cost of real estate sold during the period in which the related development costs are incurred. Revenue and cost of real estate sold are recorded net as Deferred Profit on Sales of Real Estate on our consolidated balance sheet. In addition to minimum base price contracts, certain contracts allow us to receive participation revenue from land sales to third parties if various formula-based criteria are achieved.

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

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

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

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

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

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

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

Accounts Receivable **December 31**	**2006**	**2005**
Millions		
Trade Accounts Receivable		
Billed	$58.5	$65.5
Unbilled	13.5	14.6
Less: Allowance for Doubtful Accounts	1.1	1.0
Total Accounts Receivable – Net	$70.9	$79.1

Note 2. Operations and Significant Accounting Policies (Continued)

Inventories. Inventories are stated at the lower of cost or market.

Inventories **December 31**	**2006**	**2005**
Millions		
Fuel	$18.9	$11.0
Materials and Supplies	24.5	22.1
Total Inventories	$43.4	$33.1

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

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

Supplemental Statement of Cash Flow Information. Amounts presented for 2005 and 2004 have been revised to eliminate intercompany interest payments from cash paid during the period for Interest – Net of Amounts Capitalized.

Consolidated Statement of Cash Flows **Supplemental Disclosure** **For the Year Ended December 31**	**2006**	**2005**	**2004**
Millions			
Cash Paid During the Period for			
Interest – Net of Amounts Capitalized	$25.3	$24.6	$41.2
Income Taxes	$34.5 *(a)*	$27.1	$75.7
Noncash Investing Activities			
Accounts Payable for Capital Additions to Property Plant and Equipment	$7.1	–	–

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

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

Accounting for Stock-Based Compensation. Effective January 1, 2006, we adopted the fair value recognition provisions of SFAS 123R, “Share-Based Payment,” using the modified prospective transition method. Under this method, we recognize compensation expense for all share-based payments granted after January 1, 2006, and those granted prior to but not yet vested as of January 1, 2006. Under the fair value recognition provisions of SFAS 123R, we recognize stock-based compensation net of an estimated forfeiture rate and only recognize compensation expense for those shares expected to vest over the required service period of the award. Prior to our adoption of SFAS 123R, we accounted for share-based payments under Accounting Principles Board Opinion No. 25, “Accounting for Stock Issued to Employees” and related interpretations. (See Note 17.)

Foreign Currency Translation. Results of operations for our Canadian and Mexican automotive subsidiaries prior to the spin-off of ADESA in 2004 were translated into United States dollars using the average exchange rates during the applicable periods. Assets and liabilities were translated into United States dollars using the exchange rate on the balance sheet date. Resulting translation adjustments were recorded in Accumulated Other Comprehensive Income (Loss) in Shareholders’ Equity.

Note 2. Operations and Significant Accounting Policies (Continued)

Prepayments and Other Current Assets December 31	2006	2005
Millions		
Deferred Fuel Adjustment Clause	$15.1	$13.5
Other	8.7	10.3
Total Prepayments and Other Current Assets	$23.8	$23.8

Other Assets December 31	2006	2005
Millions		
Future Benefit Obligations Under Defined Benefit Pension and Other Postretirement Plans	$ 86.1	–
Other	48.9	$44.6
Total Other Assets	$135.0	$44.6

Other Liabilities December 31	2006	2005
Millions		
Deferred Regulatory Credits (See Note 5)	$ 33.8	$ 31.8
Deferred Compensation	34.2	34.8
Future Benefit Obligation Under Defined Benefit Pension and Other Postretirement Plans	107.6	27.2
Asset Retirement Obligations (See Note 3)	27.2	25.3
Other	23.3	25.0
Total Other Liabilities	$226.1	$144.1

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

Income Taxes. We file a consolidated federal income tax return. We account for income taxes using the liability method as prescribed by SFAS 109, "Accounting for Income Taxes." Under the liability method, deferred income tax assets and liabilities are established for all temporary differences in the book and tax basis of assets and liabilities, based upon enacted tax laws and rates applicable to the periods in which the taxes become payable. Due to the effects of regulation on Minnesota Power, certain adjustments made to deferred income taxes are, in turn, recorded as regulatory assets or liabilities. Investment tax credits have been recorded as deferred credits and are being amortized to income tax expense over the service lives of the related property.

Excise Taxes. We collect excise taxes from our customers levied by government entities. These taxes are stated separately on the billing to the customer and recorded as a liability to be remitted to the government entity. We account for the collection and payment of these taxes on the net basis and neither the amounts collected or paid are reflected on our consolidated statement of income.

New Accounting Standards. *Interpretation No. 48.* In June 2006, the FASB issued Interpretation No. 48, "Accounting for Uncertainty in Income Taxes – an Interpretation of FASB Statement No. 109" (Interpretation No. 48). Interpretation No. 48 clarifies the accounting for uncertain tax positions in accordance with SFAS 109, "Accounting for Income Taxes." Pursuant to Interpretation No. 48, we will be required to recognize in our financial statements the largest tax benefit of a tax position that is "more-likely-than-not" to be sustained, on audit, based solely on the technical merits of the position as of the reporting date. Only tax positions that meet the "more-likely-than-not" threshold at that date may be recognized. The term "more-likely-than-not" means a likelihood of more than 50%. Interpretation No. 48 also provides guidance on new disclosure requirements, reporting and accrual of interest and penalties, accounting in interim periods and transition. The cumulative effect of initially applying Interpretation No. 48 will be recognized as a change in accounting principle as of the date of adoption. We are currently evaluating the impact of applying this interpretation as of January 1, 2007, the effective date of the interpretation. We do not expect Interpretation No. 48 to have a material impact on our financial position, results of operations or cash flows.

Note 2. Operations and Significant Accounting Policies (Continued)

SFAS 157. In September 2006, the FASB issued SFAS 157, "Fair Value Measurements" (SFAS 157), to increase consistency and comparability in fair value measurements by defining fair value, establishing a framework for measuring fair value in generally accepted accounting principles, and expanding disclosures about fair value measurements. SFAS 157 emphasizes that fair value is a market-based measurement, not an entity-specific measurement. It clarifies the extent to which fair value is used to measure recognized assets and liabilities, the inputs used to develop the measurements, and the effect of certain measurements on earnings for the period. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007, and will be applied on a prospective basis. We are currently evaluating the impact that the adoption of SFAS 157 will have on our financial position, results of operations and cash flows.

Note 3. Property, Plant and Equipment

Property, Plant and Equipment **December 31**	**2006** *(a)*	**2005**
Millions		
Regulated Utility	$1,575.8	$1,457.4
Construction Work in Progress	71.4	21.2
Accumulated Depreciation	(781.3)	(743.5)
Regulated Utility Plant – Net	865.9	735.1
Nonregulated Energy Operations	88.5	160.6
Construction Work in Progress	2.6	3.7
Accumulated Depreciation	(40.1)	(43.9)
Nonregulated Energy Operations Plant – Net	51.0	120.4
Other Plant – Net	4.7	4.9
Property, Plant and Equipment – Net	$ 921.6	$ 860.4

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

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

Estimated Useful Lives of Property, Plant and Equipment

Regulated Utility –	Generation	3 to 30 years	Nonregulated Energy Operations	5 to 35 years
	Transmission	40 to 60 years	Other Plant	5 to 30 years
	Distribution	30 to 70 years		

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

Asset Retirement Obligation	
Millions	
Obligation at December 31, 2004	$22.4
Accretion Expense	1.6
Additional Liabilities Incurred in 2005	1.3
Obligation at December 31, 2005	25.3
Accretion Expense	1.8
Additional Liabilities Incurred in 2006	0.1
Obligation at December 31, 2006	$27.2

Note 4. Jointly-Owned Electric Facility

We own 80% of the 536-MW Boswell Energy Center Unit 4 (Boswell Unit 4). While we operate the plant, certain decisions about the operations of Boswell Unit 4 are subject to the oversight of a committee on which we and Wisconsin Public Power, Inc., the owner of the other 20% of Boswell Unit 4, have equal representation and voting rights. Each of us must provide our own financing and is obligated to pay our ownership share of operating costs. Our share of direct operating expenses of Boswell Unit 4 is included in operating expense on our consolidated statement of income. Our 80% share of the original cost of Boswell Unit 4, which is included in property, plant and equipment at December 31, 2006, was $314 million ($310 million at December 31, 2005). The corresponding accumulated depreciation balance was $168 million at December 31, 2006 ($162 million at December 31, 2005).

Note 5. Regulatory Matters

Electric Rates. Entities within our Regulated Utility segment file for periodic rate revisions with the MPUC, the FERC or the PSCW. Minnesota Power's last retail rate filing with the MPUC was in 1994. SWL&P's current retail rates are based on a 2006 PSCW retail rate order, effective January 1, 2007. In 2006, 72% of our consolidated operating revenue was under regulatory authority (72% in 2005; 75% in 2004). The MPUC had regulatory authority over approximately 56% of our consolidated operating revenue in 2006 (56% in 2005; 60% in 2004).

Deferred Regulatory Charges and Credits. Our regulated utility operations are subject to the provisions of SFAS 71, "Accounting for the Effects of Certain Types of Regulation." We capitalize as deferred regulatory charges incurred costs which are probable of recovery in future utility rates. Deferred regulatory credits represent amounts expected to be credited to customers in rates. Deferred regulatory charges and credits are included in Other Assets and Other Liabilities on our consolidated balance sheet.

Deferred Regulatory Charges and Credits December 31	2006	2005
Millions		
Deferred Charges		
Income Taxes	$ 11.6	$ 12.0
Premium on Reacquired Debt	2.8	3.5
Future Benefit Obligations Under		
Defined Benefit Pension and Other Postretirement Plans (See Note 16)	86.1	–
Other	3.1	1.7
	103.6	17.2
Deferred Credits – Income Taxes	33.8	31.8
Net Deferred Regulatory Assets (Liabilities)	$ 69.8	$ (14.6)

Note 6. Investments

Available-for-Sale Investments. We account for our available-for-sale portfolio in accordance with SFAS 115, "Accounting for Certain Investments in Debt and Equity Securities." Our available-for-sale securities portfolio consisted of securities in a grantor trust established to fund certain employee benefits included in Investments and various auction rate municipal bonds and variable rate municipal demand notes included as Short-Term Investments (see below). Available-for-sale securities are recorded at fair value with unrealized gains and losses included in accumulated other comprehensive income (loss), net of tax. Unrealized losses that are other than temporary are recognized in earnings. Our short-term investments classified as available-for-sale securities, however, are recorded at cost. Their cost approximates fair market value as they typically reset every 7 to 35 days. Despite the long-term nature of their stated contractual maturities, we have the ability to quickly liquidate these securities. As a result, we had no cumulative gross unrealized holding gains (losses) or gross realized gains (losses) from our short-term investments. All income generated from these short-term investments was recorded as interest income. We use the specific identification method as the basis for determining the cost of securities sold. Our policy is to review, on a quarterly basis, available-for-sale securities for other than temporary impairment by assessing such factors as the share price trends and the impact of overall market conditions. As a result of our periodic assessments, we did not record any impairment of available-for-sale securities in 2006, 2005 or 2004.

During the fourth quarter of 2004, we sold 3.3 million shares of ADESA stock received by our ESOP plan (see Note 17) as a result of the September 2004 spin-off of ADESA. In total, the ESOP received total proceeds of $65.9 million, resulting in a gain of $11.5 million, which we recognized during the fourth quarter of 2004. We accounted for the ADESA stock as available-for-sale.

Note 6. Investments (Continued)

Available-For-Sale Securities

Millions At December 31	Cost	Gross Unrealized Gain	 (Loss)	Fair Value
2006	$123.2	$7.0	$(0.1)	$130.1
2005	$135.2	$4.4	$(0.1)	$139.5
2004	$176.4	$3.1	$(0.1)	$179.4

Year Ended December 31	Sales Proceeds	Gross Realized Gain	 (Loss)	Net Unrealized Gain (Loss) in Other Comprehensive Income
2006	$12.4	–	–	$2.7
2005	$32.3	–	–	$1.3
2004	$65.9	$11.5	–	$1.6

Short-Term Investments. At December 31, 2006, we held $104.5 million of short-term investments ($116.9 million at December 31, 2005) consisting of various auction rate municipal bonds and variable rate municipal demand notes.

Investments. At December 31, 2006, our long-term investment portfolio included the real estate assets of ALLETE Properties, our investment in ATC, debt and equity securities consisting primarily of securities held to fund employee benefits, and our emerging technology portfolio.

Investments December 31	2006	2005
Millions		
Real Estate Assets	$ 89.8	$ 73.7
Debt and Equity Securities	36.4	34.8
Investment in ATC	53.7	–
Emerging Technology Portfolio	9.2	9.2
Total Investments	$189.1	$117.7

Real Estate Assets	2006	2005
Millions		
Land Held for Sale Beginning Balance	$48.0	$47.2
Additions during period: Capitalized Improvements	18.8	9.4
Purchases	1.4	–
Deductions during period: Cost of Real Estate Sold	(10.2)	(8.6)
Land Held for Sale Ending Balance	58.0	48.0
Long-Term Finance Receivables	18.3	7.4
Other *(a)*	13.5	18.3
Total Real Estate Assets	$89.8	$73.7

(a) Consisted primarily of a shopping center.

Finance receivables, which are collateralized by land, have maturities ranging up to ten years, accrue interest at market-based rates and are net of an allowance for doubtful accounts of $0.2 million at December 31, 2006 ($0.6 million at December 31, 2005). Minority interest associated with real estate operations was $7.4 million at December 31, 2006 ($6.0 million at December 31, 2005).

Investment in ATC. We have an equity ownership interest in ATC, a Wisconsin-based public utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota and Illinois. ATC provides transmission service under rates regulated by the FERC that are set in accordance with the FERC's policy of establishing the independent operation and ownership of, and investment in, transmission facilities. 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."

Note 6. Investments (Continued)

ALLETE's Interest in ATC
For the Year Ended December 31, 2006

Millions	
Equity in Earnings	$3.0
Accumulated Equity in Undistributed Earnings	$2.3
Equity Investment Balance	$53.7
Equity Ownership	7%

Emerging Technology Portfolio. As part of our emerging technology portfolio, we have several minority investments in venture capital funds and direct investments in privately-held, start-up companies. We account for our investment in venture capital funds under the equity method and account for our direct investments in privately-held companies under the cost method because of our ownership percentage. The total carrying value of our emerging technology portfolio was $9.2 million at December 31, 2006, and December 31, 2005. Our policy is to review these investments quarterly for impairment by assessing such factors as continued commercial viability of products, cash flow and earnings. Any impairment would reduce the carrying value of the investment. Our basis in direct investments in privately-held companies included in the emerging technology portfolio was zero at both December 31, 2006, and December 31, 2005. We did not record any impairments in 2006. In 2005, we recorded $5.1 million ($3.3 million after tax) of impairments related to our direct investments in certain privately-held, start-up companies whose future business prospects had significantly diminished. Developments at these companies indicated that future commercial viability was unlikely, as was new financing necessary to continue development. In 2004, we recorded $6.5 million ($4.1 million after tax) of impairments.

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

Financial Instruments **December 31**	**Carrying Amount**	**Fair Value**
Millions		
Long-Term Debt		
2006	$389.5	$387.6
2005	$390.5	$392.5

Concentration of Credit Risk. Financial instruments that subject us to concentrations of credit risk consist primarily of accounts receivable. Minnesota Power sells electricity to 12 Large Power Customers. Receivables from these customers totaled approximately $9 million at December 31, 2006 ($10 million at December 31, 2005). Minnesota Power does not obtain collateral to support utility receivables, but monitors the credit standing of major customers. In addition, our taconite-producing Large Power Customers are on a weekly billing cycle, which allows us to closely manage collection of amounts due.

Note 7. Short-Term and Long-Term Debt

Short-Term Debt. Total short-term debt outstanding at December 31, 2006, was $29.7 million ($2.7 million at December 31, 2005) and consisted of Long-Term Debt Due Within One Year.

As of December 31, 2006, we had bank lines of credit aggregating $170.0 million ($120.0 million at December 31, 2005), the majority of which expire in January 2012. These bank lines of credit made financing available through short-term bank loans and provided credit support for commercial paper. At December 31, 2006, $2.9 million ($1.1 million at December 31, 2005) was drawn on our lines of credit leaving a $167.1 million balance available for use ($118.9 million at December 31, 2005). The drawn amounts at December 31, 2006 and 2005, related to an $8.5 million revolving development loan with CypressCoquina Bank that we entered into in March 2005. The revolving development loan has an interest rate equal to the prime rate, with an initial term of 36 months. The term of the loan may be extended 24 months if certain conditions are met. The loan is guaranteed by Lehigh Acquisition Corporation. There was no commercial paper issued as of December 31, 2006, or December 31, 2005.

In January 2006, we renewed, increased and extended a committed, syndicated, unsecured revolving credit facility (Line) with LaSalle Bank National Association, as Agent, for $150 million ($100 million at December 31, 2005). The Line was subsequently extended for an additional year in December 2006 and currently matures in January 2012. At our request and subject to certain conditions, the Line may be increased to $200 million and extended for two additional 12-month periods. The Line may be used for general corporate purposes and working capital, and to provide liquidity in support of our commercial paper program. We may prepay amounts outstanding under the Line in whole or in part at our discretion without premium or penalty. Additionally, we may irrevocably terminate or reduce the size of the Line prior to maturity without premium or penalty. No funds were drawn under this Line at December 31, 2006.

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

Long-Term Debt. The aggregate amount of long-term debt maturing during 2007 is $29.7 million ($7.0 million in 2008; $10.2 million in 2009; $4.5 million in 2010; $0.9 million in 2011; and $337.2 million thereafter). Substantially all of our electric plant is subject to the lien of the mortgages collateralizing various first mortgage bonds.

In March 2006, we issued $50 million in principal amount of First Mortgage Bonds, 5.69% Series due March 1, 2036, in the private placement market. Proceeds were used to redeem $50 million in principal amount of First Mortgage Bonds, 7% Series due March 1, 2008.

In July 2006, the Collier County Industrial Development Authority (Authority or Issuer) issued $27.8 million of Industrial Development Variable Rate Demand Refunding Revenue Bonds Series 2006 due 2025 (Refunding Bonds) on behalf of ALLETE. The interest rate on these bonds was 3.94% at December 31, 2006. Pursuant to a financing agreement between the Authority and ALLETE dated as of July 1, 2006, ALLETE is obligated to make payments to the Issuer sufficient to pay all principal and interest on the Refunding Bonds. ALLETE's obligations under the financing agreement are supported by a direct pay letter of credit. Proceeds from the Refunding Bonds and internally generated funds were used to redeem $29.1 million of outstanding Collier County Industrial Development Refunding Revenue Bonds 6.5% Series 1996 due 2025 on August 9, 2006. As a result of an early redemption premium, we recognized a $0.6 million pre-tax charge to other expense in the third quarter of 2006.

On February 1, 2007, we issued $60 million in principal amount of First Mortgage Bonds, 5.99% Series due February 1, 2027, in the private placement market. Proceeds were used to retire $60 million in principal amount of First Mortgage Bonds, 7% Series on February 15, 2007.

Long-Term Debt **December 31**	**2006**	**2005**
Millions		
First Mortgage Bonds		
6.68% Series Due 2007	$ 20.0	$ 20.0
7% Series Due 2007 *(a)*	60.0	60.0
7% Series Due 2008	–	50.0
5.28% Series Due 2020	35.0	35.0
4.95% Pollution Control Series F Due 2022	111.0	111.0
5.69% Series Due 2036	50.0	–
Variable Demand Revenue Refunding Bonds		
Series 1997 A, B, C and D Due 2007 – 2020	39.0	39.0
Industrial Development Revenue Bonds 6.5% Due 2025	6.0	35.1
Industrial Development Variable Rate Demand Refunding		
Revenue Bonds Series 2006 Due 2025	27.8	–
Other Long-Term Debt, 2.0% – 8.5% Due 2007 – 2025	40.7	40.4
Total Long-Term Debt	389.5	390.5
Less Due Within One Year	29.7	2.7
Net Long-Term Debt	$359.8	$387.8

(a) Retired on February 15, 2007.

The 6.68% Series Due 2007 cannot be redeemed prior to November 15, 2007. The remaining debt may be redeemed in whole or in part at our option, according to the terms of the obligations.

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

Note 8. Commitments, Guarantees and Contingencies

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

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

Minnesota Power is obligated to pay its pro rata share of Square Butte's costs based on Minnesota Power's entitlement to Unit output. Minnesota Power's payment obligation will be suspended if Square Butte fails to deliver any power, whether produced or purchased, for a period of one year. Square Butte's fixed costs consist primarily of debt service. At December 31, 2006, Square Butte had total debt outstanding of $303.7 million. Total annual debt service for Square Butte is expected to be approximately $26 million in each of the years 2007 through 2011. Variable operating costs include the price of coal purchased from BNI Coal, our subsidiary, under a long-term contract.

Minnesota Power's cost of power purchased from Square Butte during 2006 was $57.9 million ($56.4 million in 2005; $56.1 million in 2004). This reflects Minnesota Power's pro rata share of total Square Butte costs, based on the 66% output entitlement in 2006 and the 71% output entitlement in 2005 and 2004. Included in this amount was Minnesota Power's pro rata share of interest expense of $12.6 million in 2006 ($13.6 million in 2005; $12.6 million in 2004). Minnesota Power's payments to Square Butte are approved as a purchased power expense for ratemaking purposes by both the MPUC and the FERC.

Leasing Agreements. BNI Coal is obligated to make lease payments for a dragline totaling $2.8 million annually for the lease term which expires in 2027. BNI Coal has the option at the end of the lease term to renew the lease at a fair market rental, to purchase the dragline at fair market value, or to surrender the dragline and pay a $3.0 million termination fee. We lease other properties and equipment under operating lease agreements with terms expiring through 2013. The aggregate amount of minimum lease payments for all operating leases is $8.2 million in 2007, $7.6 million in 2008, $7.0 million in 2009, $6.5 million in 2010, $6.0 million in 2011 and $51.2 million thereafter. Total rent expense was $6.8 million in 2006 ($6.2 million in 2005; $3.8 million in 2004).

Coal, Rail and Shipping Contracts. We have three coal supply agreements with various expiration dates ranging from December 2008 to December 2009. We also have rail and shipping agreements for the transportation of all of our coal, with various expiration dates ranging from December 2007 to December 2011. Our minimum annual payment obligations under these coal, rail and shipping agreements are currently $37.8 million in 2007, $11.2 million in 2008, $5.8 million in 2009 and no specific commitments beyond 2009. Our minimum annual payment obligations will increase when annual nominations are made for coal deliveries in future years.

Fuel Clause Recovery of MISO Day 2 Costs. Minnesota Power filed a petition with the MPUC in February 2005 to amend its fuel clause to accommodate costs and revenue related to the MISO Day 2 energy market, the market through which Minnesota Power engages in wholesale energy transactions in MISO's day-ahead and real-time markets (MISO Day 2). In April 2005, the MPUC approved interim accounting treatment of MISO Day 2 costs to be accounted for on a net basis and recovered through the fuel clause, subject to refund with interest. This interim treatment has continued while the MPUC has addressed the cost recovery petitions from Xcel Energy Inc., Otter Tail Power Company, Alliant Energy Corporation and Minnesota Power.

In December 2005, the MPUC issued an order which denied recovery through the fuel clause of uplift charges, congestion revenue and expenses, and administrative costs related to Minnesota Power's MISO Day 2 market activities. This denial created a refund obligation. Minnesota Power requested rehearing of the order in a filing made with the MPUC in January 2006. The other three utilities affected by the order also filed for rehearing, as did the DOC and MISO. In February 2006, the MPUC granted rehearing of the MISO Day 2 docket and suspended the refund obligation for charges recovered through the fuel clause denied in the December 2005 order. The MPUC also ordered review of MISO Day 2 costs to determine which costs should be recovered on a current basis through the fuel clause and which costs are more appropriately deferred for potential recovery through base rates. The Company worked with other Minnesota utilities, the DOC and other stakeholders to review MISO Day 2 costs and to prepare a joint report and recommendations. The joint report and recommendations were filed with the MPUC in June 2006. A technical conference on the report was held with the MPUC on October 31, 2006. At a hearing November 9, 2006, the MPUC approved current recovery of nearly all MISO Day 2 charges.

Note 8. Commitments, Guarantees and Contingencies (Continued)

On December 20, 2006, the MPUC issued an order allowing Minnesota Power and the other utilities involved in the MISO Day 2 proceeding to continue recovering MISO Day 2 charges through the Minnesota retail fuel clause except for MISO Day 2 administrative charges. On January 8, 2007, this order was challenged by the Minnesota OAG, which has sought reconsideration. The rehearing has been opposed by Minnesota Power and the other utilities, as well as MISO. The reconsideration request is currently pending before the MPUC. The MPUC has until March 9, 2007, to act on the Minnesota OAG's request. The order, if upheld, grants deferred accounting treatment for three MISO Day 2 charge types that were determined to be administrative charges. Under the order, Minnesota Power would refund through customer bills approximately $2 million of administrative charges previously collected through the fuel clause between April 1, 2005, and December 31, 2006, and record these administrative charges as a regulatory asset. Minnesota Power would be permitted to continue accumulating MISO Day 2 administrative charges after December 31, 2006, as a regulatory asset until it files its next rate case, at which time recovery for such charges will be determined. This order would remove the subject to refund requirement of the two interim orders, and include extensive fuel clause reporting requirements that would be reviewed in Minnesota Power's monthly and annual fuel clause filings with the MPUC. There would be no impact on earnings as a result of this ruling. The Company is unable to predict the outcome of this matter.

Emerging Technology Portfolio. We have investments in emerging technologies through minority investments in venture capital funds structured as limited liability companies, and direct investments in privately-held, start-up companies. We have committed to make additional investments in certain emerging technology venture capital funds. The total future commitment was $2.5 million at December 31, 2006 ($3.1 million at December 31, 2005), and will be invested in 2007. We do not have plans to make any additional investments beyond this commitment.

Investment in ATC. In December 2005, we entered into an agreement with Wisconsin Public Service Corporation and WPS Investments, LLC that provides for our Wisconsin subsidiary, Rainy River Energy Corporation - Wisconsin, to invest $60 million in ATC. In May 2006, the PSCW reviewed and approved the request that allows us to invest in ATC. During 2006, we invested $51.4 million in ATC. We plan to invest an additional $8.6 million in ATC in early 2007 to reach our $60 million investment commitment and estimated 8% ownership interest. As of December 31, 2006, our equity investment balance in ATC was $53.7 million, representing approximately a 7% ownership interest. (See Note 6.)

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

SWL&P Manufactured Gas Plant. In May 2001, SWL&P received notice from the WDNR that the city of Superior had found soil contamination on property adjoining a former Manufactured Gas Plant (MGP) site owned and operated by SWL&P from 1889 to 1904. The WDNR requested SWL&P to initiate an environmental investigation. The WDNR also issued SWL&P a Responsible Party letter in February 2002. In February 2003, SWL&P submitted a Phase II environmental site investigation report to the WDNR. This report identified some MGP-like chemicals that were found in the soil near the former plant site. The investigation continued through the fall of 2006. It is anticipated that the final report for this portion of the investigation will be completed during the first quarter of 2007. Although it is not possible to quantify the total potential clean-up costs until the investigation is completed, a $0.5 million liability was recorded in December 2003 based on initial studies to address the known areas of contamination. The Company has recorded a corresponding amount as a regulatory asset. The PSCW has approved SWL&P's deferral of these MGP environmental investigation and potential clean-up costs for future recovery in rates, subject to a regulatory prudency review. In May 2005, the PSCW approved the collection through rates of $150,000 of site investigation costs that had been incurred at the time SWL&P filed its 2006 rate request. In December 2006, the PSCW approved the recovery of an additional $186,000 of site investigation costs that were incurred through 2005. ALLETE maintains pollution liability insurance coverage that includes coverage for SWL&P. A claim has been filed with respect to this matter. The insurance carrier has issued a reservation of rights letter and the Company continues to work with the insurer to determine the availability of insurance coverage.

Note 8. Commitments, Guarantees and Contingencies (Continued)

EPA Clean Air Interstate Rule and Clean Air Mercury Rule. In March 2005, the EPA announced the final Clean Air Interstate Rule (CAIR) that reduces and permanently caps emissions of SO_2 and NO_X in the eastern United States. The CAIR includes Minnesota as one of the 28 states it considers an “eastern” state. The EPA also announced the final Clean Air Mercury Rule (CAMR) that reduces and permanently caps electric utility mercury emissions nationwide. The CAIR and the CAMR regulations have been challenged in the federal court system, which may delay implementation or modify provisions. Minnesota Power is participating in a legal challenge to the CAIR, but is not participating in a challenge to the CAMR. However, if the CAMR and the CAIR do go into effect, Minnesota Power expects to be required to: (1) make emissions reductions; (2) purchase mercury, SO_2 and NO_X allowances through the EPA’s cap-and-trade system; or (3) use a combination of both.

Minnesota Power petitioned the EPA to review their CAIR determinations affecting Minnesota. In July 2005, Minnesota Power also filed a Petition for Review with the U.S. Court of Appeals for the District of Columbia Circuit (Court of Appeals). In November 2005, the EPA agreed to reconsider certain aspects of the CAIR, including the Minnesota Power petition addressing modeling used to determine Minnesota’s inclusion in the CAIR region and our claims about inequities in the SO_2 allowance methodology. In March 2006, the EPA announced that it would not make any changes to the CAIR as a result of the petitions for reconsideration. Petitions for Review, including Minnesota Power’s, remain pending at the Court of Appeals. If the Petitions for Review filed with the Court of Appeals are successful, we expect to incur lower compliance costs, consistent with the rules applicable to those states considered “western” states under the CAIR. Resolution of the CAIR Petition for Review with the Court of Appeals is anticipated in 2008.

Community Development District Obligations. *Town Center.* In March 2005, the Town Center District issued $26.4 million of tax-exempt, 6% Capital Improvement Revenue Bonds, Series 2005, which are payable over 31 years (by May 1, 2036). The bond proceeds (less capitalized interest, a debt service reserve fund and cost of issuance) were used to pay for the construction of a portion of the major infrastructure improvements at Town Center. The bonds are payable from and secured by the revenue derived from assessments imposed, levied and collected by the Town Center District. The assessments represent an allocation of the costs of the improvements, including bond financing costs, to the lands within the Town Center District benefiting from the improvements. The assessments were billed to Town Center landowners beginning in November 2006. To the extent that we still own land at the time of the assessment, in accordance with EITF 91-10, we recognize the cost of our portion of these assessments, based upon our ownership of benefited property. At December 31, 2006, we owned approximately 73% of the assessable land in the Town Center District.

Palm Coast Park. In May 2006, the Palm Coast Park District issued $31.8 million of tax-exempt, 5.7% Special Assessment Bonds, Series 2006, which are payable over 31 years (by May 1, 2037). The bond proceeds (less capitalized interest, a debt service reserve fund and cost of issuance) are being used to pay for the construction of the major infrastructure improvements at Palm Coast Park and to mitigate traffic and environmental impacts. The bonds are payable from and secured by the revenue derived from assessments imposed, levied and collected by the Palm Coast Park District. The assessments represent an allocation of the costs of the improvements, including bond financing costs, to the lands within the Palm Coast Park District benefiting from the improvements. The assessments will be billed to Palm Coast Park landowners beginning in November 2007. To the extent that we still own land at the time of the assessment, in accordance with EITF 91-10, we will recognize the cost of our portion of these assessments, based upon our ownership of benefited property. At December 31, 2006, we owned 97% of the assessable land in the Palm Coast Park District.

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

Note 9. Common Stock and Earnings Per Share

Our Articles of Incorporation and mortgages contain provisions that, under certain circumstances, would restrict the payment of common stock dividends. As of December 31, 2006, no retained earnings were restricted as a result of these provisions.

Reverse Common Stock Split. On September 20, 2004, our one-for-three reverse common stock split became effective. All common share and per share amounts have been adjusted for all periods to reflect the one-for-three reverse stock split.

Summary of Common Stock		Shares	Equity
		Thousands	Millions
Balance at December 31, 2003		29,099	$859.2
2004	Employee Stock Purchase Plan	14	1.0
	Invest Direct *(a)*	247	18.1
	ADESA IPO (See Note 13)	–	70.1
	Spin-Off of ADESA (See Note 13)	–	(600.2)
	Receipt of ADESA Stock by ESOP	–	27.8
	Reacquired	(70)	(5.8)
	Options and Stock Awards	361	29.9
Balance at December 31, 2004		29,651	400.1
2005	Employee Stock Purchase Plan	13	0.5
	Invest Direct *(a)*	238	10.5
	Options and Stock Awards	241	10.0
Balance at December 31, 2005		30,143	421.1
2006	Employee Stock Purchase Plan	12	0.5
	Invest Direct *(a)*	218	10.0
	Options and Stock Awards	63	7.1
Balance at December 31, 2006		30,436	$438.7

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

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

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

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

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

Earnings Per Share. The difference between basic and diluted earnings per share arises from outstanding stock options and performance share awards granted under our Executive and Director Long-Term Incentive Compensation Plans. For 2006 and 2005, no options to purchase shares of common stock were excluded from the computation of diluted earnings per share because they were anti-dilutive due to the option exercise prices being greater than the average market price of the common shares during the period (0.1 shares were excluded for 2004).

Reconciliation of Basic and Diluted Earnings Per Share For the Year Ended December 31	Basic	Dilutive Securities	Diluted
Millions Except Per Share Amounts			
2006			
Income from Continuing Operations	$77.3	–	$77.3
Common Shares	27.8	0.1	27.9
Per Share from Continuing Operations	$2.78	–	$2.77
2005			
Income from Continuing Operations	$17.6	–	$17.6
Common Shares	27.3	0.1	27.4
Per Share from Continuing Operations	$0.65	–	$0.64
2004			
Income from Continuing Operations Before Change in Accounting Principle	$38.5	–	$38.5
Common Shares	28.3	0.1	28.4
Per Share from Continuing Operations	$1.37	–	$1.35

Note 10. Kendall County Charge

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

Note 11. Other Income (Expense)

For the Year Ended December 31	2006	2005	2004
Millions			
Loss on Emerging Technology Investments	$ (0.9)	$(6.1)	$ (8.6)
Income from Investment in ATC (See Note 6)	3.0	–	–
Debt Prepayment Premium and Unamortized Debt Issuance Costs	(0.6)	–	(18.5)
Gain on ESOP's Sale of ADESA Stock (See Note 17)	–	–	11.5
Investments and Other Income	13.4	7.2	3.4
Total Other Income (Expense)	$ 14.9	$ 1.1	$ (12.2)

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

In July 2004, we repaid $125 million in principal amount of 7.80% Senior Notes due 2008. Proceeds from the sale of our water assets and proceeds received from ADESA were used to repay this debt. As a result of the redemption, we recognized an expense of $18.5 million in the third quarter of 2004 comprised of an early redemption premium and the write-off of unamortized debt issuance costs.

Note 12. Income Tax Expense

Income Tax Expense Year Ended December 31	2006	2005	2004
Millions			
Current Tax Expense			
Federal	$ 8.9 *(a)*	$27.2 *(b)*	$11.2
State	9.6	6.5 *(b)*	6.3
Total Current Tax Expense	18.5	33.7	17.5
Deferred Tax Expense (Benefit)			
Federal	28.0 *(a)*	(26.4) *(b)*	1.6
State	2.0	(9.5)	(2.3)
Total Deferred Tax Expense (Benefit)	30.0	(35.9)	(0.7)
Change in Valuation Allowance	(1.1)	3.0	0.9
Deferred Tax Credits	(1.1)	(1.3)	(1.3)
Income Tax Expense (Benefit) for Continuing Operations	46.3	(0.5)	16.4
Income Tax Expense (Benefit) for Discontinued Operations	(0.6)	3.4	57.6
Change in Accounting Principle	–	–	(5.5)
Total Income Tax Expense	$45.7	$ 2.9	$68.5

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

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

Note 12. Income Tax Expense (Continued)

Reconciliation of Taxes from Federal Statutory Rate to Total Income Tax Expense for Continuing Operations Year Ended December 31	2006	2005	2004
Millions			
Income from Continuing Operations Before Minority Interest and Income Taxes	$128.2	$19.8	$57.0
Statutory Federal Income Tax Rate	35%	35%	35%
Income Taxes Computed at 35% Statutory Federal Rate	44.9	6.9	20.0
Increase (Decrease) in Tax Due to:			
Amortization of Deferred Investment Tax Credits	(1.1)	(1.3)	(1.3)
State Income Taxes – Net of Federal Income Tax Benefit	6.5	1.1	3.6
Depletion	(1.1)	(1.0)	(0.6)
Employee Benefits	0.1	(0.5)	(0.4)
Domestic Manufacturing Deduction	(0.6)	(0.4)	–
Regulatory Differences for Utility Plant	(0.7)	(0.6)	(0.6)
Positive Resolution of Audit Issues	–	(3.7)	–
Sale of ADESA Stock by ESOP	–	–	(4.1)
Other	(1.7)	(1.0)	(0.2)
Total Income Tax Expense (Benefit) for Continuing Operations	$ 46.3	$ (0.5)	$16.4

The effective tax rate on income from continuing operations before minority interest was a 36.1% expense for 2006; (2.5% benefit for 2005; 28.8% expense for 2004). The 2006 effective rate was impacted by investment tax credits, deductions for Medicare health subsidies, depletion and the expected use of state capital loss carryforwards, of which a $1.1 million benefit was included in the state tax provision. The 2005 effective rate was impacted by three major items—a $2.5 million deferred tax adjustment to reflect comprehensive state tax planning initiatives, a $3.7 million current tax adjustment to reflect the receipt of a positive audit report and an increase in taxes due to the inability to recognize certain state benefits for capital loss carryforwards.

Deferred Tax Assets and Liabilities December 31	2006	2005
Millions		
Deferred Tax Assets		
Employee Benefits and Compensation *(a)*	$ 95.5	$ 58.0
Property Related	32.8	31.0
Kendall County Capital Loss	4.3	30.5
Investment Tax Credits	12.1	12.9
Excess of Tax Value Over Book Value *(b)*	4.7	5.6
Other	8.9	9.0
Gross Deferred Tax Assets	158.3	147.0
Deferred Tax Asset Valuation Allowance	(3.6)	(4.1)
Total Deferred Tax Assets	154.7	142.9
Deferred Tax Liabilities		
Property Related	204.7	210.8
Regulatory Asset for Benefit Obligations	34.8	–
Investment Tax Credits	17.2	18.3
Employee Benefits and Compensation	13.2	12.6
Fuel Clause Adjustment	6.0	5.4
Other	9.3	3.2
Total Deferred Tax Liabilities	285.2	250.3
Accumulated Deferred Income Taxes	$130.5	$107.4
Recorded as:		
Current Deferred Tax Assets	$ 0.3	$ 31.0
Long-Term Deferred Tax Liabilities	130.8	138.4
Net Deferred Tax Liabilities	$130.5	$107.4

(a) Included Unfunded Employee Benefits
(b) Included impairments related to the emerging technology portfolio.

Note 13. Discontinued Operations

Enventis Telecom. On December 30, 2005, we sold all the stock of our telecommunications subsidiary, Enventis Telecom, to Hickory Tech Corporation of Mankato, Minnesota, for $35.5 million. The transaction resulted in an after-tax loss of $3.6 million, which was included in our 2005 loss from discontinued operations. Net cash proceeds realized from the sale were approximately $29 million after transaction costs, repayment of debt and payment of income taxes. In accordance with SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," we have reported our telecommunications business in discontinued operations for all periods presented.

Automotive Services. On September 20, 2004, the spin-off of Automotive Services was completed by distributing to ALLETE shareholders all of ALLETE's shares of ADESA common stock. One share of ADESA common stock was distributed for each outstanding share of ALLETE common stock held at the close of business on September 13, 2004, the record date. The distribution was made from ALLETE's retained earnings to the extent of ADESA's undistributed earnings ($363.4 million), with the remainder made from common stock ($600.2 million).

In June 2004, ADESA issued 6.3 million shares of common stock through an IPO priced at $24.00 per share, which netted proceeds of $136.0 million after transaction costs, issued $125 million of senior notes and borrowed $275 million under a new $525 million credit facility. With these funds, ADESA repaid previously existing debt and all intercompany debt outstanding to ALLETE. The IPO represented 6.6% of ADESA's 94.9 million shares then outstanding. As a result of the IPO, ALLETE recorded a $70.1 million increase to Common Stock with no gain recognized pursuant to SEC Staff Accounting Bulletin Topic 5H, "Accounting for Sales of Stock by a Subsidiary." We accounted for the 6.6% public ownership of ADESA as a minority interest and continued to own and consolidate the remaining portion of ADESA until the spin-off was completed on September 20, 2004.

In accordance with SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," we have reported our Automotive Services business in Discontinued Operations.

Water Services. During 2003, we sold, under condemnation or imminent threat of condemnation, substantially all of our water assets in Florida for a total sales price of approximately $445 million. Income from discontinued operations for 2003 included a $71.6 million after-tax gain on the sale of substantially all our Water Services businesses. The gain was net of all selling, transaction and employee termination benefit expenses, as well as impairments on certain remaining assets.

In June 2004, we essentially concluded our strategy to exit our Water Services businesses when we completed the sale of our North Carolina water assets and the sale of the remaining 72 water and wastewater systems in Florida. Aqua Utilities Florida, Inc. (Aqua Utilities) purchased our North Carolina water assets for $48 million and assumed approximately $28 million in debt. Aqua Utilities also purchased 63 of our water and wastewater systems in Florida for $14 million. Seminole County purchased the remaining 9 Florida systems for a total of $4 million. The FPSC approved the Seminole County transaction in September 2004. On December 20, 2005, the FPSC ordered a $1.7 million reduction to plant investment, which the Company reserved for in 2005, and approved the transfer of the remaining 63 water and wastewater systems from Florida Water to Aqua Utilities. On March 15, 2006, the Company paid Aqua Utilities the adjustment refund amount of $1.7 million. Gains in 2004 from the sale of our North Carolina assets and the remaining systems in Florida were offset by an adjustment to gains reported in 2003, resulting in an overall net loss of $0.5 million in 2004. The adjustment to gains reported in 2003 resulted primarily from an arbitration award in December 2004 relating to a gain-sharing provision on a system sold in 2003; $5.1 million was recorded in 2004.

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

The net cash proceeds from the sale of all water assets in 2003 and 2004, after transaction costs, retirement of most Florida Water debt and payment of income taxes, were approximately $300 million. These net proceeds were used to retire debt at ALLETE.

In accordance with SFAS 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," we suspended depreciating our Water Services assets when they were classified as held-for-sale in 2001. If we had not suspended depreciation, depreciation expense at our Water Services businesses would have been $2.6 million in 2004.

Financial results for 2006 reflected additional legal and administrative expenses incurred by the Company to exit the Water Services businesses.

Note 13. Discontinued Operations (Continued)

Discontinued Operations Summary Income Statement For the Year Ended December 31	2006	2005	2004
Millions			
Operating Revenue			
Automotive Services	–	–	$681.7
Water Services	–	–	18.5
Enventis Telecom	–	$50.7	47.3
Total Operating Revenue	–	$50.7	$747.5
Pre-Tax Income (Loss) from Operations			
Automotive Services	–	–	$132.5
Water Services	–	–	(1.7)
Enventis Telecom	–	$ 3.0	1.0
	–	3.0	131.8
Income Tax Expense (Benefit)			
Automotive Services	–	–	54.0
Water Services	–	–	(0.9)
Enventis Telecom	–	1.2	0.4
	–	1.2	53.5
Total Income from Operations	–	1.8	78.3
Loss on Disposal			
Automotive Services	–	–	(6.7)
Water Services	$(1.5)	(4.5)	6.2
Enventis Telecom	–	0.6	–
	(1.5)	(3.9)	(0.5)
Income Tax Expense (Benefit)			
Automotive Services	–	–	(2.6)
Water Services	(0.6)	(2.0)	6.7
Enventis Telecom	–	4.2	–
	(0.6)	2.2	4.1
Net Loss on Disposal	(0.9)	(6.1)	(4.6)
Income (Loss) from Discontinued Operations	$(0.9)	$(4.3)	$ 73.7

Discontinued Operations Summary Balance Sheet Information December 31	2005
Millions	
Assets of Discontinued Operations	
Other Current Assets	$0.4
Property, Plant and Equipment	$2.2
Liabilities of Discontinued Operations	
Current Liabilities	$13.0

Note 14. Other Comprehensive Income (Loss)

Other Comprehensive Income (Loss) Year Ended December 31	Pre-Tax Amount	Tax Expense (Benefit)	Net-of-Tax Amount
Millions			
2006			
Unrealized Gain on Securities During the Year	$ 2.5	$0.6	$1.9
Additional Pension Liability	11.0	4.6	6.4
Other Comprehensive Income	$13.5	$5.2	$8.3
2005			
Unrealized Gain on Securities During the Year	$ 1.3	$ 0.7	$ 0.6
Additional Pension Liability	(3.4)	(1.4)	(2.0)
Other Comprehensive Loss	$(2.1)	$(0.7)	$(1.4)
2004			
Unrealized Gain on Securities			
Gain During the Year	$ 13.1	$ 0.9	$ 12.2
Less: Gain Included in Net Income	11.5	–	11.5
Net Unrealized Gain on Securities	1.6	0.9	0.7
Foreign Currency Translation Adjustments	(23.5)	–	(23.5)
Additional Pension Liability	(5.7)	(2.6)	(3.1)
Other Comprehensive Loss	$(27.6)	$(1.7)	$(25.9)

Accumulated Other Comprehensive Income (Loss) December 31	2006	2005
Millions		
Unrealized Gain on Securities	$ 4.0	$ 2.1
Defined Benefit Pension and Other Postretirement Plans	(12.8)	–
Additional Pension Liability	–	(14.9)
Total Accumulated Other Comprehensive Loss	$ (8.8)	$ (12.8)

Note 15. Change in Accounting Principle

In the third quarter of 2004 we adopted EITF 03-16, “Accounting for Investments in Limited Liability Companies,” which requires the use of the equity method of accounting for investments in all limited liability companies, including investments we have in venture capital funds within our emerging technology portfolio. We had previously accounted for these investments under the cost method of accounting. EITF 03-16 is effective for reporting periods beginning after June 15, 2004. Pursuant to EITF 03-16, the effect of adoption is reported as the cumulative effect of a change in accounting principle. The cumulative effect of this change on prior years was a loss of $13.3 million ($7.8 million after-tax), which was recorded as a change in accounting principle and reflected in income for the year ended December 31, 2004. During 2006, $0.2 million of current losses after-tax under the equity method were recognized ($0 in 2005; $1.6 million loss in 2004).

Note 16. Pension and Other Postretirement Benefit Plans

We have noncontributory defined benefit pension plans covering eligible employees. The plans provide defined benefits based on years of service and final average pay. We also have defined contribution pension plans covering substantially all employees; employer contributions are made through our employee stock ownership plan (see Note 17), except for BNI Coal, which made cash contributions of $0.7 million in 2006 ($0.7 million in 2005; $0.6 million in 2004). In July 2006, we made an $8.3 million contribution to ALLETE's defined benefit plan.

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

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

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

Incremental Effect of Applying SFAS 158 on Individual Line Items in the Balance Sheet Year Ended December 31, 2006	**Pre-SFAS 158**	**SFAS 158 Adoption Adjustments**	**Post-SFAS 158**
Millions			
Prepayments and Other Current Assets	$25.9	$(2.1)	$23.8
Other Assets	$48.9	$86.1	$135.0
Total Assets	$1,449.4	$84.0	$1,533.4
Other Current Liabilities	$24.3	–	$24.3
Deferred Income Tax Liabilities	$133.5	$(2.7)	$130.8
Other Liabilities	$135.4	$90.7	$226.1
Total Liabilities	$779.6	$88.0	$867.6
Accumulated Other Comprehensive Loss – Net of Tax	$(4.5)	$(4.3)	$(8.8)
Total Shareholders' Equity	$670.1	$(4.3)	$665.8

Approximately 84% of the defined benefit pension and 71% of the postretirement health and life benefit costs recognized annually by our regulated companies are recovered through rates filed with our regulatory jurisdictions. It is expected that these costs will continue to be recovered in future rates in accordance with the requirements of SFAS 71. As a result, these amounts that are required to otherwise be recognized in accumulated other comprehensive income under the provisions of SFAS 158 have been recognized as a long-term regulatory asset on our consolidated balance sheet. The remaining 16% of the defined benefit pension and 29% of the postretirement health and life benefit costs relate to costs associated with our nonregulated operations and, accordingly, have been recognized as a charge to accumulated other comprehensive income at December 31, 2006.

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

We use a September 30 measurement date for the pension and postretirement health and life plans. Pursuant to SFAS 158, we are required to change our measurement date to December 31 during the year ending December 31, 2008.

Pension Obligation and Funded Status **At September 30**	**2006**	**2005**
Millions		
Change in Benefit Obligation		
Obligation, Beginning of Year	$412.4	$380.0
Service Cost	9.1	8.7
Interest Cost	22.2	21.3
Actuarial Loss (Gain)	(12.2)	16.6
Benefits Paid	(19.8)	(18.9)
Other	6.0	4.7
Obligation, End of Year	417.7	412.4
Change in Plan Assets		
Fair Value, Beginning of Year	337.1	310.1
Actual Return on Assets	32.5	40.6
Employer Contribution	8.9	0.6
Benefits Paid	(19.8)	(18.9)
Other	6.0	4.7
Fair Value, End of Year	364.7	337.1
Funded Status	$ (53.0)	(75.3)
Amounts		
Net Loss		90.6
Prior Service Cost		4.5
Transition Obligation		(0.1)
Net Assets Recognized		$ 19.7
Amounts Recognized in Consolidated Balance Sheet Consist of:		
Prepaid Pension Cost		$33.8
Accrued Benefit Liability		(42.3)
Intangible Assets		2.3
Accumulated Other Comprehensive Income		25.9
Net Assets Recognized		$19.7

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

Pension Costs **Year Ended December 31**	**2006**
Millions	
Net Loss	$69.9
Prior Service Cost	3.9
Transition Obligation	(0.1)
	$73.7

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

Components of Net Periodic Pension Expense (Income) Year Ended December 31	2006	2005	2004
Millions			
Service Cost	$ 9.1	$ 8.7	$ 8.4
Interest Cost	22.2	21.3	20.7
Expected Return on Assets	(28.6)	(28.2)	(27.4)
Amortized Amounts			
Loss	4.6	3.1	1.4
Prior Service Cost	0.6	0.6	0.8
Transition Obligation	–	0.2	0.3
Net Pension Expense	$ 7.9	$ 5.7	$ 4.2

Information for Pension Plans with an Accumulated Benefit Obligation in Excess of Plan Assets At September 30	2006	2005
Millions		
Projected Benefit Obligation	$180.4	$177.5
Accumulated Benefit Obligation	$160.6	$157.7
Fair Value of Plan Assets	$130.9	$116.3

Additional Pension Information Year Ended December 31	2006	2005	2004
Millions			
Increase (Decrease) in Additional Pension Liability Included in Other Comprehensive Income	$11.0	$(3.4)	$(5.7)

The accumulated benefit obligation for all defined benefit pension plans was $376.1 million and $369.5 million at September 30, 2006 and 2005, respectively.

Postretirement Health and Life Obligation and Funded Status At September 30	2006	2005
Millions		
Change in Benefit Obligation		
Obligation, Beginning of Year	$136.9	$117.2
Service Cost	4.4	4.0
Interest Cost	7.4	6.6
Actuarial Loss (Gain)	(4.7)	13.1
Participation Contributions	1.4	1.3
Benefits Paid	(6.4)	(5.3)
Amendments	(0.1)	–
Obligation, End of Year	138.9	136.9
Change in Plan Assets		
Fair Value, Beginning of Year	60.9	54.1
Actual Return on Assets	5.8	7.1
Employer Contribution	17.2	3.6
Participation Contributions	1.4	1.4
Benefits Paid	(6.4)	(5.3)
Fair Value, End of Year	78.9	60.9
Funded Status	$ (60.0)	(76.0)
Amounts		
Net Loss		25.8
Transition Obligation		17.4
Net Liabilities Recognized		$ (32.8)

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

Under SFAS 106, "Employers' Accounting for Postretirement Benefits Other Than Pensions," only assets in the VEBAs are treated as plan assets in the previous table for the purpose of determining funded status. In addition to the postretirement health and life assets reported in the previous table, we had $25.6 million in an irrevocable grantor trust at December 31, 2006 ($22.6 million at December 31, 2005). We consolidate the irrevocable grantor trust and it is included in Investments on our consolidated balance sheet.

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

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

Components of Net Periodic Postretirement Health and Life Expense **Year Ended December 31**	**2006**	**2005**	**2004**
Millions			
Service Cost	$ 4.4	$4.0	$3.9
Interest Cost	7.4	6.7	6.6
Expected Return on Assets	(5.6)	(4.8)	(4.6)
Amortized Amounts			
Loss	1.7	0.7	0.4
Transition Obligation	2.4	2.4	2.4
Net Expense	$10.3	$9.0	$8.7

Estimated Future Benefit Payments	**Pension**	**Postretirement Health and Life**
Millions		
2007	$20	$5
2008	$21	$5
2009	$22	$6
2010	$22	$7
2011	$23	$7
Years 2012 – 2016	$138	$45

The pension and postretirement health and life costs recorded in other long-term assets and accumulated other comprehensive income expected to be recognized as a component of net pension and postretirement benefit costs for the year ending December 31, 2007, are as follows:

	Pension	**Postretirement Health and Life**
Millions		
Net Loss (Gain)	$3.4	$0.9
Prior Service Costs	$0.7	–
Transition Obligations	$(0.1)	$2.5

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

Weighted-Average Assumptions Used to Determine Benefit Obligation At September 30	2006	2005
Discount Rate	5.75%	5.50%
Rate of Compensation Increase	3.5 – 4.5%	3.5 – 4.5%
Health Care Trend Rates		
Trend Rate	10%	10%
Ultimate Trend Rate	5%	5%
Year Ultimate Trend Rate Effective	2011	2010

Weighted-Average Assumptions Used to Determine Net Periodic Benefit Costs Year Ended December 31	2006	2005	2004
Discount Rate	5.50%	5.75%	6.00%
Expected Long-Term Return on Plan Assets			
Pension	9.0%	9.0%	9.0%
Postretirement Health and Life	5.0 – 9.0%	5.0 – 9.0%	7.2 – 9.0%
Rate of Compensation Increase	3.5 – 4.5%	3.5 – 4.5%	3.5 – 4.5%

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

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

Sensitivity of a One-Percentage-Point Change in Health Care Trend Rates	One Percent Increase	One Percent Decrease
Millions		
Effect on Total of Postretirement Health and Life Service and Interest Cost	$1.9	$(1.5)
Effect on Postretirement Health and Life Obligation	$17.5	$(14.3)

	Pension		Postretirement Health and Life *(a)*	
Plan Asset Allocations	**2006**	**2005**	**2006**	**2005**
Equity Securities	65.1%	64.9%	68.9%	68.6%
Debt Securities	29.6	29.6	30.6	30.5
Real Estate	0.8	1.3	–	–
Venture Capital	4.2	2.9	–	–
Cash	0.3	1.3	0.5	0.9
	100.0%	100.0%	100.0%	100.0%

(a) Included VEBAs and irrevocable grantor trust.

Pension plan equity securities did not include ALLETE common stock at September 30, 2006, or September 30, 2005.

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

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

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

(a) Included VEBAs and irrevocable grantor trust.

We expect to contribute approximately $6 million to our postretirement health and life plans in 2007. We are not required to make any contributions to our defined benefit pension plans in 2007.

In May 2004, the FASB issued FSP 106-2, "Accounting and Disclosure Requirements Related to the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Act)," which provides accounting and disclosure guidance for employers that sponsor postretirement health care plans that provide prescription drug benefits. FSP 106-2 requires that the accumulated postretirement benefit obligation and postretirement benefit cost reflect the impact of the Act upon adoption. We provide postretirement health benefits that include prescription drug benefits and have concluded that our prescription drug benefits will qualify us for the federal subsidy to be provided for under the Act. We adopted FSP 106-2 in the third quarter of 2004. The deduction for Medicare health subsidies reduced our after-tax postretirement medical expense by $2.4 million for 2006 ($3.5 million in 2005; $1.6 million for 2004).

In 2005, we determined that our postretirement health care plans meet the requirements of the Centers for Medicare and Medicaid Services' (CMS) regulations, and enrolled with the CMS to begin recovering the subsidy. We expect to receive the first subsidy payment in mid-2007 for 2006 credits.

Note 17. Employee Stock and Incentive Plans

Employee Stock Ownership Plan. We sponsor a leveraged employee stock ownership plan (ESOP) within the Retirement Savings and Stock Ownership Plan (RSOP) that covers certain eligible employees. In 1989, the ESOP used the proceeds from a $16.5 million third-party loan, guaranteed by us, to purchase 0.6 million shares (0.4 million shares adjusted for stock splits) of our common stock on the open market. This loan was fully repaid in 2004, and all shares originally purchased with loan proceeds have been allocated to participants. In 1990, the ESOP issued a $75 million note (term not to exceed 25 years at 10.25%) to us as consideration for 2.8 million shares (1.9 million shares adjusted for stock splits) of our newly issued common stock. The note was refinanced in 2006 at 6%. The Company makes annual contributions to the ESOP equal to the ESOP's debt service less available dividends received by the ESOP. The majority of dividends received by the ESOP are used to pay debt service, with the balance distributed to participants. The ESOP shares were initially pledged as collateral for its debt. As the debt is repaid, shares are released from collateral and allocated to participants based on the proportion of debt service paid in the year. As shares are released from collateral, the Company reports compensation expense equal to the current market price of the shares less dividends on allocated shares. Dividends on allocated ESOP shares are recorded as a reduction of retained earnings; available dividends on unallocated ESOP shares are recorded as a reduction of debt and accrued interest. ESOP compensation expense was $4.6 million in 2006 ($5.5 million in 2005; $5.0 million in 2004).

As a result of the September 2004 spin-off of ADESA, the ESOP received 3.3 million shares of ADESA common stock related to unearned ESOP shares that had not been allocated to participants. The ESOP was required to sell the ADESA common stock and use the proceeds to purchase ALLETE common stock on the open market. At December 31, 2004, the ESOP had sold all of these ADESA shares. The 3.3 million ADESA shares sold by the ESOP in 2004 resulted in total proceeds of $65.9 million and an after-tax gain of $11.5 million, which we recognized in the fourth quarter of 2004. (See Note 11.) Under the direction of an independent trustee, the ESOP used the proceeds to purchase shares of ALLETE common stock in late 2004 and early 2005, which were recorded using the treasury method as Unearned ESOP Shares within Shareholders' Equity as presented on our consolidated balance sheet.

Summary of ALLETE Common Stock Purchases		Shares	Amount
Millions Except Shares			
2004	October	80,600	$ 2.7
	November	669,578	23.5
	December	262,600	9.4
2005	January	544,797	21.4
	February	214,928	8.9
		1,772,503	$65.9

Note 17. Employee Stock and Incentive Plans (Continued)

In September 2005, the ESOP's independent trustee directed the sale of approximately 1.4 million shares of ADESA common stock that remained invested in the RSOP participants' ADESA common stock funds at September 1, 2005. Proceeds from the sale of the ADESA common stock were $30.4 million, of which the majority was used to purchase ALLETE common stock as required by the terms of the RSOP. The process was completed on October 26, 2005. Proceeds totaling $28.5 million were used to purchase a total of 644,450 shares of ALLETE common stock (289,900 shares in September 2005; 354,550 shares in October 2005).

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

Year Ended December 31	**2006**	**2005**	**2004**
Millions			
ESOP Shares			
Allocated	1.7	1.9	1.4
Unallocated	2.5	2.6	2.0
Total	4.2	4.5	3.4
Fair Value of Unallocated Shares	$115.2	$115.0	$72.7

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

Stock Incentive Plan. Under our Executive Long-Term Incentive Compensation Plan (Executive Plan), share-based awards may be issued to key employees via a broad range of methods, including non-qualified and incentive stock options, performance shares, performance units, restricted stock, stock appreciation rights and other awards. There are 3.2 million shares of common stock reserved for issuance under the Executive Plan, with 1.5 million of these shares available for issuance as of December 31, 2006.

We had a Director Long-Term Stock Incentive Plan (Director Plan) which expired on January 1, 2006. No grants have been made since 2003 under the Director Plan. Approximately 9,000 options were outstanding under the Director Plan at December 31, 2006.

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

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

The following assumptions were used in determining the fair value of stock options granted during 2006, under the Black-Scholes option-pricing model:

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

Note 17. Employee Stock and Incentive Plans (Continued)

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

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

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

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

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

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

There were no capitalized stock-based compensation costs at December 31, 2006.

As of December 31, 2006, the total unrecognized compensation cost for performance share awards not yet recognized in our statements of income was $1.3 million. This amount is expected to be recognized over a weighted-average period of 1.31 years.

The following table presents the pro forma effect of stock-based compensation had we applied the provisions of SFAS 123 for the years ended December 31, 2005 and 2004.

Pro Forma Effect of SFAS 123 **Accounting for Stock-Based Compensation**	**2005**	**2004**
Millions Except Per Share Amounts		
Net Income		
As Reported	$13.3	$104.4
Less: Employee Stock Compensation Expense Determined Under SFAS 123 – Net of Tax	1.5	1.3
Plus: Employee Stock Compensation Expense Included in Net Income – Net of Tax	1.5	1.0
Pro Forma Net Income	$13.3	$104.1
Basic Earnings Per Share		
As Reported	$0.49	$3.69
Pro Forma	$0.49	$3.68
Diluted Earnings Per Share		
As Reported	$0.48	$3.67
Pro Forma	$0.48	$3.66

Note 17. Employee Stock and Incentive Plans (Continued)

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

	2005	2004
Risk-Free Interest Rate	3.7%	3.3%
Expected Life	5 Years	5 Years
Expected Volatility	20.0%	28.1%
Dividend Growth Rate	5%	2%

The following table presents information regarding our outstanding stock options for the year ended December 31, 2006.

	Number of Options	Weighted-Average Exercise Price	Aggregate Intrinsic Value	Weighted-Average Remaining Contractual Term
			Millions	
Outstanding at December 31, 2005	357,827	$34.29	$3.5	7.4 years
Granted	115,653	$44.15		
Exercised	(28,896)	$26.47		
Forfeited	(6,233)	$38.25		
Outstanding at December 31, 2006	438,351	$37.35	$4.0	7.2 years
Exercisable at December 31, 2006	238,640	$33.18	$3.2	6.2 years
Fair Value of Options Granted During the Year	$7.28			

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

At December 31, 2006, options outstanding consisted of less than 0.1 million with exercise prices ranging from $15.88 to $19.21, 0.1 million with exercise prices ranging from $23.79 to $27.40 and 0.3 million with exercise prices ranging from $35.78 to $41.35. The options with exercise prices ranging from $23.79 to $27.40 have an average remaining contractual life of 4.8 years, with 0.1 million exercisable on December 31, 2006, at a weighted average price of $25.32. The options with exercise prices ranging from $35.78 to $41.35 have an average remaining contractual life of 7.7 years, with 0.2 million exercisable on December 31, 2006, at a weighted average price of $39.29.

	2005	
Stock Option Activity	**Options**	**Weighted Average Exercise Price**
Outstanding, Beginning of Year	437,965	$28.94
Granted	119,077	$41.35
Exercised	(199,215)	$26.74
Forfeited	–	–
Outstanding, End of Year	357,827	$34.29
Exercisable, End of Year	178,332	$28.35
Fair Value of Options Granted During the Year	$6.51	

Note 17. Employee Stock and Incentive Plans (Continued)

Stock Option Activity *(a)*	2004 Options	2004 Weighted Average Exercise Price
Outstanding, Beginning of Period	760,026	$64.47
Granted	39,759	$97.65
Exercised	(295,359)	$67.14
Forfeited	(7,396)	$63.06
Outstanding, End of Period	497,030	$69.85
Exercisable, End of Period	–	–
Fair Value of Options Granted During the Period	$20.01	

(a) All amounts above are prior to the ADESA spin-off and the historical option and weighted average exercise prices have been adjusted for the one-for-three reverse stock split on September 20, 2004. The 2004 amounts are up to the September 20, 2004, spin-off of ADESA.

Stock Option Activity *(a)*	2004 Options	2004 Weighted Average Exercise Price
Outstanding as of September 20, 2004, after spin-off	478,054	$28.56
Granted	–	–
Exercised	(40,089)	$24.40
Forfeited	–	–
Outstanding, End of Year	437,965	$28.94
Exercisable, End of Year	287,711	$26.57

(a) Amounts subsequent to the ADESA spin-off.

The employee stock options outstanding at the date of the ADESA spin-off were converted to reflect the spin-off and one-for-three reverse stock split. This conversion was done to preserve the noncompensatory nature of the options under FASB Interpretation No. 44, "Accounting for Certain Transactions Involving Stock Compensation."

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

Performance Shares. The following table presents information regarding our nonvested performance shares for the year ended December 31, 2006.

	Number of Shares	Weighted-Average Grant Date Fair Value
Nonvested at December 31, 2005	97,884	$38.63
Granted	26,967	$43.87
Awarded	(49,076)	$37.76
Forfeited	(4,771)	$41.53
Nonvested at December 31, 2006	71,004	$41.03

Less than 0.1 million performance share grants were awarded in February 2006 for performance periods ending in 2008. The ultimate issuance is contingent upon the attainment of certain future performance goals of ALLETE during the performance periods. The grant date fair value of the performance share awards was $1.0 million.

Less than 0.1 million performance share grants were awarded in February 2005 for the performance periods ending in 2007. The grant date fair value of the share awards was $1.0 million. Performance share grants related to the 2006 period will be issued in early 2007.

Employee Stock Purchase Plan. We have an Employee Stock Purchase Plan that permits eligible employees to buy up to $23,750 per year of our common stock at 95% of the market price. At December 31, 2006, 0.5 million shares had been issued under the plan and 0.1 million shares were held in reserve for future issuance.

Note 18. Quarterly Financial Data (Unaudited)

Information for any one quarterly period is not necessarily indicative of the results which may be expected for the year. Financial results for the second quarter of 2005 included a $50.4 million, or $1.84 per share, charge related to the assignment of the Kendall County purchase power agreement. (See Note 10.) Financial results for the fourth quarter of 2005 included 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.

Quarter Ended		**Mar. 31**	**Jun. 30**	**Sept. 30**	**Dec. 31**
Millions Except Earnings Per Share					
2006					
Operating Revenue		$192.5	$178.3	$199.1	$197.2
Operating Income from Continuing Operations		$36.4	$26.3	$38.7	$39.3
Income (Loss)	Continuing Operations	$18.8	$13.6	$21.9	$23.0
	Discontinued Operations	–	(0.4)	(0.1)	(0.4)
Net Income		$18.8	$13.2	$21.8	$22.6
Earnings (Loss) Per Share of Common Stock					
Basic	Continuing Operations	$0.68	$0.50	$0.78	$0.82
	Discontinued Operations	–	(0.02)	–	(0.01)
		$0.68	$0.48	$0.78	$0.81
Diluted	Continuing Operations	$0.68	$0.49	$0.78	$0.82
	Discontinued Operations	–	(0.02)	–	(0.01)
		$0.68	$0.47	$0.78	$0.81
2005					
Operating Revenue		$193.3	$174.4	$177.4	$192.3
Operating Income (Loss) from Continuing Operations		$41.1	$(56.0)	$32.7	$27.3
Income (Loss)	Continuing Operations	$17.4	$(39.8)	$15.8	$24.2
	Discontinued Operations	–	(0.5)	(0.6)	(3.2)
Net Income (Loss)		$17.4	$(40.3)	$15.2	$21.0
Earnings (Loss) Per Share of Common Stock					
Basic	Continuing Operations	$0.64	$(1.46)	$0.58	$0.89
	Discontinued Operations	–	(0.02)	(0.02)	(0.12)
		$0.64	$(1.48)	$0.56	$0.77
Diluted	Continuing Operations	$0.64	$(1.46)	$0.58	$0.88
	Discontinued Operations	–	(0.02)	(0.02)	(0.12)
		$0.64	$(1.48)	$0.56	$0.76

ALLETE
Valuation and Qualifying Accounts and Reserves

For the Year Ended December 31		Balance at Beginning of Year	Additions Charged to Income	Additions Other Changes	Deductions from Reserves *(a)*	Balance at End of Period
Millions						
Reserve Deducted from Related Assets						
Reserve For Uncollectible Accounts						
2006	Trade Accounts Receivable	$1.0	$0.7	–	$0.6	$1.1
	Finance Receivables – Long-Term	0.6	–	–	0.4	0.2
2005	Trade Accounts Receivable	1.0	1.1	–	1.1	1.0
	Finance Receivables – Long-Term	0.7	–	–	0.1	0.6
2004	Trade Accounts Receivable	1.1	0.9	–	1.0	1.0
	Finance Receivables – Long-Term	1.2	–	–	0.5	0.7
Deferred Asset Valuation Allowance						
2006	Deferred Tax Assets	4.1	(1.1)	$0.6	–	3.6
2005	Deferred Tax Assets	1.1	3.8	–	0.8	4.1
2004	Deferred Tax Assets	0.2	0.9	–	–	1.1

(a) Included uncollectible accounts written off.

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

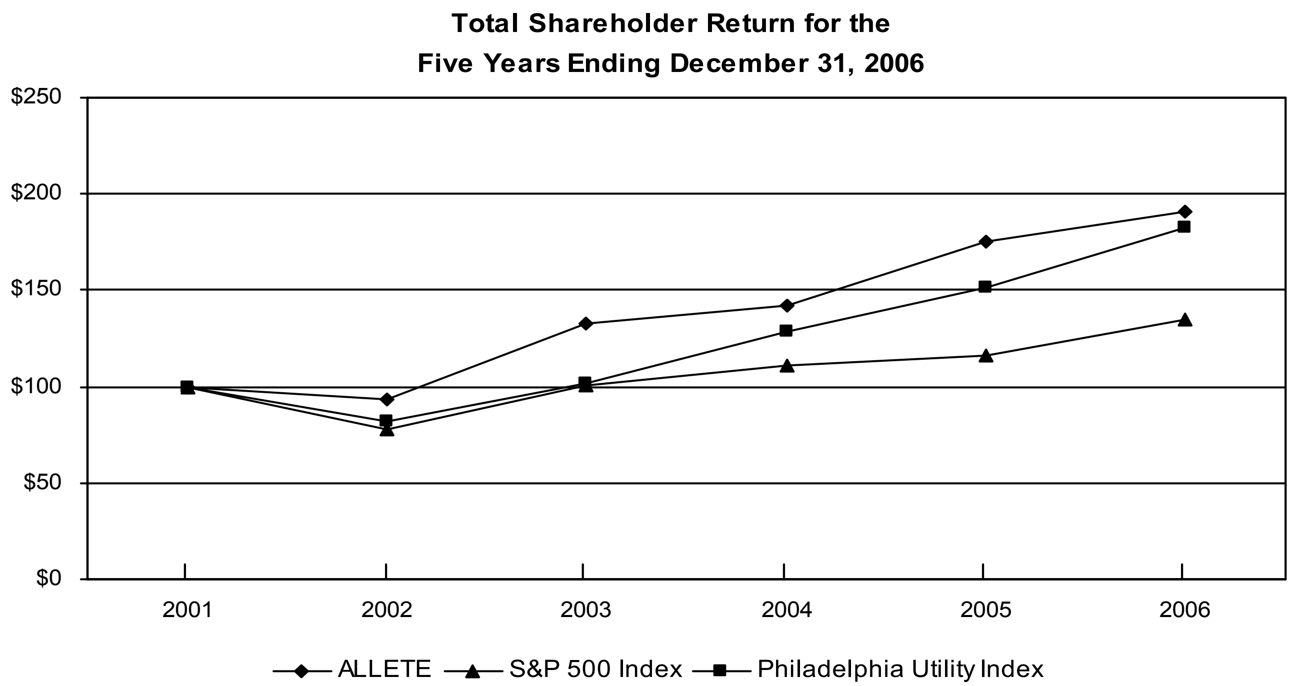
For the Year Ended December 31	2006	2005	2004	2003	2002
Millions Except Ratios					
Income from Continuing Operations					
Before Minority Interest and Income Taxes	$128.2	$19.8	$ 57.0	$ 49.5	$ 37.9
Less: Minority Interest *(a)*	–	–	2.1	2.6	1.0
Undistributed Income from Less than 50%					
Owned Equity Investment	2.3	–	–	2.9	4.7
	125.9	19.8	54.9	44.0	32.2
Fixed Charges					
Interest on Long-Term Debt	22.2	23.1	60.3	70.0	73.9
Capitalized Interest	0.6	0.3	0.7	1.2	0.8
Other Interest Charges	5.3	3.5	8.7	4.3	5.3
Interest Component of All Rentals	2.0	2.8	3.5	8.0	9.9
Total Fixed Charges	30.1	29.7	73.2	83.5	89.9
Earnings Before Income Taxes and Fixed Charges					
(Excluding Capitalized Interest)	$155.4	$49.2	$127.4	$126.3	$121.3
Ratio of Earnings to Fixed Charges	5.16	1.66	1.74	1.51	1.35

(a) Pre-tax income of subsidiaries that have not incurred fixed charges.

ALLETE Common Stock Performance

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

The calculations assume a $100 investment on December 31, 2001, and reinvestment of dividends. The calculations further assume that the shares of ADESA common stock received by ALLETE shareholders in connection with the September 20, 2004, spin-off of ADESA were immediately sold and the proceeds invested in additional ALLETE common stock.



	2001	2002	2003	2004	2005	2006
ALLETE	$100	$94	$132	$142	$175	$191
S&P 500 Index	$100	$78	$100	$111	$117	$135
Philadelphia Utility Index	$100	$82	$102	$128	$152	$182

ALLETE Executive Officers

Donald J. Shippar	Chairman, President and Chief Executive Officer
Deborah A. Amberg	Senior Vice President, General Counsel and Secretary
Steven Q. DeVinck	Controller
Laura A. Holquist	President – ALLETE Properties
Mark A. Schober	Senior Vice President and Chief Financial Officer
Donald W. Stellmaker	Treasurer
Timothy J. Thorp	Vice President – Investor Relations
Claudia Scott Welty	Senior Vice President and Chief Administrative Officer

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Investor Information

Shareholder Information and Assistance

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

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

Invest Direct

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

Analyst Inquiries

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

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

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

Annual Meeting

Our Annual Meeting of Shareholders is held the second Tuesday in May. Shareholders are invited to attend the 2007 Annual Meeting, beginning at 10:30 a.m., May 8, at the Duluth Entertainment and Convention Center, 350 Harbor Drive, Duluth, MN.

Corporate Website

www.allete.com

Stock Exchange Listings

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

Transfer Agents and Registrars for Common Stock

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

Common Stock Dividend Payment Dates

March 1, June 1, September 1 and December 1

Annual Report

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

We have included as Exhibit 31(a) and 31(b) to our 2006 Form 10-K, filed with the Securities and Exchange Commission, certificates of the Chief Executive Officer and Chief Financial Officer of ALLETE certifying the quality of ALLETE's public disclosure. We have also submitted to the New York Stock Exchange a certificate of the Chief Executive Officer of ALLETE certifying that he is not aware of any violation by ALLETE of New York Stock Exchange corporate governance listing standards.

Productolith Gloss paper manufactured by Stora Enso was used for the cover of the 2006 ALLETE Annual Report and Form 10-K. ALLETE is proud to use the high quality product of a valued customer in this report.

ALLETE BOARD OF directors

(standing, left to right) **Roger D. Peirce**, 69, retired Vice Chairman and CEO of Super Steel Products Corp., a manufacturer of fabricated metal products, Mequon, Wis.; **James J. Hoolihan**, 54, President and CEO of the Blandin Foundation and Chairman of Industrial Lubricant Co., a provider of industrial supplies and services to logging, railroad and mining companies, Grand Rapids, Minn.; **George L. Mayer**, 62, President of Manhattan Realty Group, Larchmont, N.Y.; **Kathleen A. Brekken**, 57, retired President and CEO of Midwest of Cannon Falls, a designer, wholesaler and distributor of giftware, Cannon Falls, Minn.; **Donald J. Shippar**, 57, Chairman, President and CEO of ALLETE, Duluth, Minn.; **Heidi J. Eddins**, 50, Executive Vice President, Secretary and General Counsel of Florida East Coast Industries, Inc., a transportation and real estate company, St. Augustine, Fla.; and **Jack J. Rajala**, 67, Chairman and CEO of Rajala Companies, lumber manufacturing and trading firms, Grand Rapids, Minn.

(seated, left to right) **Peter J. Johnson**, 70, retired Chairman and CEO of Hoover Construction, Virginia, Minn.; **Madeleine W. Ludlow**, 52, Principal in Ludlow Ward Capital Partners, Cincinnati, Ohio; **Bruce W. Stender**, 65, President and CEO of Labovitz Enterprises, which owns and manages commercial real estate, Duluth, Minn.; and **Nick Smith**, 70, Of Counsel, Fryberger, Buchanan, Smith & Frederick, P.A., Duluth, Minn.