ALLETE INC
Form 10-Q
April 29, 2011

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

(Mark One)

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

For the quarterly period ended March 31, 2011

or

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

For the transition period from ______________ to ______________

Commission File Number 1-3548

ALLETE, Inc.
(Exact name of registrant as specified in its charter)

| Minnesota | 41-0418150 |
|---|---|
| (State or other jurisdiction of incorporation or organization) | (IRS Employer Identification No.) |

30 West Superior Street
Duluth, Minnesota 55802-2093
(Address of principal executive offices)
(Zip Code)

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

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. T Yes £ No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). T Yes £ No

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act. (Check one):

| | |
|---|---|
| Large Accelerated Filer T | Accelerated Filer £ |
| Non-Accelerated Filer £ | Smaller Reporting Company £ |

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

Common Stock, no par value,
35,910,576 shares outstanding
as of March 31, 2011

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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 |
|---|---|
| AC | Alternating Current |
| AFUDC | Allowance for Funds Used During Construction – consisting of the cost of both the debt and equity funds used to finance utility plant additions during construction periods |
| ALLETE | ALLETE, Inc. |
| ALLETE Properties | ALLETE Properties, LLC and its subsidiaries |
| ARS | Auction Rate Securities |
| ATC | American Transmission Company LLC |
| Bison 1 | Bison 1 Wind Project |
| Bison 2 | Bison 2 Wind Project |
| BNI Coal | BNI Coal, Ltd. |
| Boswell | Boswell Energy Center |
| CO2 | Carbon Dioxide |
| Company | ALLETE, Inc. and its subsidiaries |
| DC | Direct Current |
| EPA | Environmental Protection Agency |
| ESOP | Employee Stock Ownership Plan |
| FASB | Financial Accounting Standards Board |
| FERC | Federal Energy Regulatory Commission |
| Form 10-K | ALLETE Annual Report on Form 10-K |
| Form 10-Q | ALLETE Quarterly Report on Form 10-Q |
| GAAP | United States Generally Accepted Accounting Principles |
| GHG | Greenhouse Gases |
| Hibbard | Hibbard Renewable Energy Center |
| Invest Direct | ALLETE's Direct Stock Purchase and Dividend Reinvestment Plan |
| kV | Kilovolt(s) |
| Laskin | Laskin Energy Center |
| Manitoba Hydro | Manitoba Hydro-Electric Board |
| Medicare Part D | Medicare Part D provision of the Patient Protection and Affordable Care Act of 2010 |
| Minnesota Power | An operating division of ALLETE, Inc. |
| Minnkota Power | Minnkota Power Cooperative, Inc. |
| MISO | Midwest Independent Transmission System Operator, Inc. |
| MPCA | Minnesota Pollution Control Agency |
| MPUC | Minnesota Public Utilities Commission |
| MW / MWh | Megawatt(s) / Megawatt-hour(s) |

Definitions (Continued)

| Abbreviation or Acronym | Term |
|---|---|
| NDPSC | North Dakota Public Service Commission |
| Non-residential | Retail commercial, non-retail commercial, office, industrial, warehouse, storage and institutional |
| NO2 | Nitrogen Dioxide |
| NOX | Nitrogen Oxide |
| Note ___ | Note ___ to the consolidated financial statements in this Form 10-Q |
| NPDES | National Pollutant Discharge Elimination System |
| 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 |
| PPA | Power Purchase Agreement |
| PPACA | The Patient Protection and Affordable Care Act of 2010 |
| PSCW | Public Service Commission of Wisconsin |
| Rainy River Energy | Rainy River Energy Corporation - Wisconsin |
| SEC | Securities and Exchange Commission |
| SO2 | Sulfur Dioxide |
| Square Butte | Square Butte Electric Cooperative |
| SWL&P | Superior Water, Light and Power Company |
| Taconite Harbor | Taconite Harbor Energy Center |
| Taconite Ridge | Taconite Ridge Energy Center |
| Town Center | Town Center at Palm Coast development project in Florida |
| Town Center District | Town Center at Palm Coast Community Development District |
| WDNR | Wisconsin Department of Natural Resources |

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

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

In connection with the safe harbor provisions of the Private Securities Litigation Reform Act of 1995, we are hereby filing cautionary statements identifying important factors that could cause our actual results to differ materially from those projected, or expectations suggested, in forward-looking statements made by or on behalf of ALLETE in this Quarterly Report on Form 10-Q, in presentations, on our website, in response to questions or otherwise. These statements are qualified in their entirety by reference to, and are accompanied by, the following important factors, in addition to any assumptions and other factors referred to specifically in connection with such forward-looking statements:

- our ability to successfully implement our strategic objectives;
- prevailing governmental policies, regulatory actions, and legislation, including those of the United States Congress, state legislatures, the FERC, the MPUC, the PSCW, the NDPSC, the EPA and various state, local and county regulators, and city administrators, about allowed rates of return, financings, industry and rate structure, acquisition and disposal of assets and facilities, real estate development, operation and construction of plant facilities, recovery of purchased power, capital investments and other expenses, present or prospective wholesale and retail competition (including but not limited to transmission costs), zoning and permitting of land held for resale and environmental matters;
- our ability to manage expansion and integrate acquisitions;
- the potential impacts of climate change and future regulation to restrict the emissions of GHG on our Regulated Operations;
- effects of restructuring initiatives in the electric industry;
- economic and geographic factors, including political and economic risks;
- changes in and compliance with laws and regulations;
- weather conditions;
- natural disasters and pandemic diseases;
- war and acts of terrorism;
- wholesale power market conditions;
- population growth rates and demographic patterns;
- effects of competition, including competition for retail and wholesale customers;
- changes in the real estate market;
- pricing and transportation of commodities;
- changes in tax rates or policies or in rates of inflation;
- project delays or changes in project costs;
- availability and management of construction materials and skilled construction labor for capital projects;
- changes in operating expenses and capital expenditures;
- global and domestic economic conditions affecting us or our customers;
- our ability to access capital markets and bank financing;
- changes in interest rates and the performance of the financial markets;

- our ability to replace a mature workforce and retain qualified, skilled and experienced personnel; and
- the outcome of legal and administrative proceedings (whether civil or criminal) and settlements that affect the business and profitability of ALLETE.

Additional disclosures regarding factors that could cause our results and performance to differ from results or performance anticipated by this report are discussed in Item 1A under the heading “Risk Factors” beginning on page 22 of our 2010 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-Q 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. FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS

ALLETE
CONSOLIDATED BALANCE SHEET
Millions – Unaudited

| | March 31, 2011 | December 31, 2010 |
|---|---|---|
| Assets | | |
| Current Assets | | |
| Cash and Cash Equivalents | $52.7 | $44.9 |
| Short-Term Investments | – | 6.7 |
| Accounts Receivable (Less Allowance of $1.0 and $0.9) | 91.5 | 99.5 |
| Inventories | 56.1 | 60.0 |
| Prepayments and Other | 24.5 | 28.6 |
| Total Current Assets | 224.8 | 239.7 |
| Property, Plant and Equipment - Net | 1,841.3 | 1,805.6 |
| Regulatory Assets | 288.5 | 310.2 |
| Investment in ATC | 94.8 | 93.3 |
| Other Investments | 128.1 | 126.0 |
| Other Non-Current Assets | 35.9 | 34.3 |
| Total Assets | $2,613.4 | $2,609.1 |
| | | |
| Liabilities and Equity | | |
| Liabilities | | |
| Current Liabilities | | |
| Accounts Payable | $48.2 | $75.4 |
| Accrued Taxes | 27.8 | 22.0 |
| Accrued Interest | 13.6 | 13.4 |
| Long-Term Debt Due Within One Year | 13.0 | 13.4 |
| Notes Payable | 0.5 | 1.0 |
| Other | 22.6 | 33.7 |
| Total Current Liabilities | 125.7 | 158.9 |
| Long-Term Debt | 771.0 | 771.6 |
| Deferred Income Taxes | 341.9 | 325.2 |
| Regulatory Liabilities | 45.4 | 43.6 |
| Other Non-Current Liabilities | 317.3 | 324.8 |
| Total Liabilities | 1,601.3 | 1,624.1 |
| | | |
| Commitments and Contingencies (Note 13) | | |
| | | |
| Equity | | |
| ALLETE's Equity | | |
| Common Stock Without Par Value, 80.0 Shares Authorized, 35.9 and 35.8 Shares Outstanding | 638.8 | 636.1 |

| | | |
|---|---|---|
| Unearned ESOP Shares | (34.6) | (36.8) |
| Accumulated Other Comprehensive Loss | (21.9) | (23.2) |
| Retained Earnings | 420.9 | 399.9 |
| Total ALLETE Equity | 1,003.2 | 976.0 |
| Non-Controlling Interest in Subsidiaries | 8.9 | 9.0 |
| Total Equity | 1,012.1 | 985.0 |
| Total Liabilities and Equity | $2,613.4 | $2,609.1 |

The accompanying notes are an integral part of these statements.

ALLETE
CONSOLIDATED STATEMENT OF INCOME
Millions Except Per Share Amounts – Unaudited

| | Quarter Ended March 31, 2011 | 2010 |
|---|---|---|
| Operating Revenue | $242.2 | $233.6 |
| Operating Expenses | | |
| Fuel and Purchased Power | 79.0 | 79.8 |
| Operating and Maintenance | 90.1 | 87.7 |
| Depreciation | 22.3 | 20.0 |
| Total Operating Expenses | 191.4 | 187.5 |
| Operating Income | 50.8 | 46.1 |
| Other Income (Expense) | | |
| Interest Expense | (10.7) | (8.9) |
| Equity Earnings in ATC | 4.4 | 4.5 |
| Other | 0.8 | 1.0 |
| Total Other Expense | (5.5) | (3.4) |
| Income Before Non-Controlling Interest and Income Taxes | 45.3 | 42.7 |
| Income Tax Expense | 8.2 | 19.9 |
| Net Income | 37.1 | 22.8 |
| Less: Non-Controlling Interest in Subsidiaries | (0.1) | (0.2) |
| Net Income Attributable to ALLETE | $37.2 | $23.0 |
| Average Shares of Common Stock | | |
| Basic | 34.6 | 33.8 |
| Diluted | 34.7 | 33.8 |
| Basic Earnings Per Share of Common Stock | $1.07 | $0.68 |
| Diluted Earnings Per Share of Common Stock | $1.07 | $0.68 |
| Dividends Per Share of Common Stock | $0.445 | $0.44 |

The accompanying notes are an integral part of these statements.

ALLETE
CONSOLIDATED STATEMENT OF CASH FLOWS
Millions – Unaudited

| | Quarter Ended March 31, | |
|---|---|---|
| | 2011 | 2010 |
| Operating Activities | | |
| Net Income | $37.1 | $22.8 |
| Allowance for Funds Used During Construction | (0.6) | (1.2) |
| Income from Equity Investments, Net of Dividends | – | (0.4) |
| Gain on Sale of Assets | (0.7) | – |
| Depreciation Expense | 22.3 | 20.0 |
| Amortization of Debt Issuance Costs | 0.2 | 0.2 |
| Deferred Income Tax Expense | 8.1 | 11.8 |
| Share-Based Compensation Expense | 0.6 | 0.5 |
| ESOP Compensation Expense | 1.9 | 1.8 |
| Bad Debt Expense | 0.2 | 0.2 |
| Changes in Operating Assets and Liabilities | | |
| Accounts Receivable | 7.8 | (0.6) |
| Inventories | 3.9 | 5.4 |
| Prepayments and Other | 4.1 | 4.9 |
| Accounts Payable | (12.7) | (20.0) |
| Other Current Liabilities | (5.1) | 5.0 |
| Regulatory and Other Assets | (0.7) | 5.1 |
| Regulatory and Other Liabilities | 2.7 | 1.2 |
| Cash from Operating Activities | 69.1 | 56.7 |
| | | |
| Investing Activities | | |
| Proceeds from Sale of Available-for-sale Securities | 7.0 | 0.6 |
| Payments for Purchase of Available-for-sale Securities | (0.9) | (1.2) |
| Investment in ATC | (0.8) | (1.2) |
| Changes to Other Investments | (0.9) | (1.8) |
| Additions to Property, Plant and Equipment | (51.5) | (48.1) |
| Proceeds from Sale of Assets | 1.4 | – |
| Cash for Investing Activities | (45.7) | (51.7) |
| | | |
| Financing Activities | | |
| Proceeds from Issuance of Common Stock | 2.1 | 7.3 |
| Proceeds from Issuance of Long-Term Debt | – | 80.0 |
| Payments on Long-Term Debt | (1.0) | (69.4) |
| Debt Issuance Costs | – | (0.7) |
| Dividends on Common Stock | (16.2) | (15.2) |
| Changes in Notes Payable | (0.5) | (0.2) |
| Cash from (for) Financing Activities | (15.6) | 1.8 |
| | | |
| Change in Cash and Cash Equivalents | 7.8 | 6.8 |
| Cash and Cash Equivalents at Beginning of Period | 44.9 | 25.7 |

| | | |
|---|---|---|
| Cash and Cash Equivalents at End of Period | $52.7 | $32.5 |

The accompanying notes are an integral part of these statements.

## NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

The accompanying unaudited consolidated financial statements have been prepared in accordance with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X and do not include all of the information and notes required by GAAP for complete financial statements. Similarly, the December 31, 2010, consolidated balance sheet was derived from audited financial statements but does not include all disclosures required by GAAP. All adjustments are of a normal, recurring nature, except as otherwise disclosed. Operating results for the period ended March 31, 2011, are not necessarily indicative of results that may be expected for any other interim period or for the year ending December 31, 2011. For further information, refer to the consolidated financial statements and notes included in our 2010 Form 10-K.

### NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES

Subsequent Events. The Company performed an evaluation of subsequent events for potential recognition and disclosure through the time of the financial statements issuance.

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

| | March 31, | December 31, |
|---|---|---|
| Inventories | 2011 | 2010 |
| Millions | | |
| Fuel | $18.4 | $22.9 |
| Materials and Supplies | 37.7 | 37.1 |
| Total Inventories | $56.1 | $60.0 |

| | March 31, | December 31, |
|---|---|---|
| Prepayments and Other Current Assets | 2011 | 2010 |
| Millions | | |
| Deferred Fuel Adjustment Clause | $19.1 | $20.6 |
| Other | 5.4 | 8.0 |
| Total Prepayments and Other Current Assets | $24.5 | $28.6 |

| | March 31, | December 31, |
|---|---|---|
| Other Non-Current Liabilities | 2011 | 2010 |
| Millions | | |
| Future Benefit Obligation Under Defined Benefit Pension and Other Postretirement Benefit Plans | $220.4 | $231.4 |
| Asset Retirement Obligation | 51.3 | 50.3 |
| Other | 45.6 | 43.1 |
| Total Other Non-Current Liabilities | $317.3 | $324.8 |

Supplemental Statement of Cash Flows Information.

| For the Quarter Ended March 31, | 2011 | 2010 |
|---|---|---|
| Millions | | |
| Cash Paid During the Period for | | |
| Interest – Net of Amounts Capitalized | $10.4 | $10.0 |
| Income Taxes | $0.2 | $1.0 |
| | | |
| Noncash Investing and Financing Activities | | |
| Decrease in Accounts Payable for Capital Additions to Property, Plant and Equipment | $(14.4) | $(5.7) |
| AFUDC – Equity | $0.6 | $1.2 |

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

New Accounting Standards.

Receivables. In July 2010, the FASB issued an accounting standards update on allowances for credit losses and the credit quality of the financing receivables of an entity. This guidance required expanded disclosures in addition to a roll forward schedule of the allowance for credit losses for each reporting period. The guidance requiring expanded disclosures was adopted December 31, 2010, and did not have an impact on our consolidated financial position, results of operations or cash flows. The guidance requiring a roll forward schedule, which is included in Note 3. Investments, was effective January 1, 2011, and did not have an impact on our consolidated financial position, results of operations or cash flows.

NOTE 2. BUSINESS SEGMENTS

Regulated Operations includes our regulated utilities, Minnesota Power and SWL&P, as well as our investment in ATC, a Wisconsin-based utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota, and Illinois. Investments and Other is comprised primarily of BNI Coal, our coal mining operations in North Dakota, and ALLETE Properties, our Florida real estate investment. This segment also includes a small amount of non-rate base generation, approximately 5,500 acres of land available-for-sale in Minnesota and earnings on cash and short-term investments.

| | Consolidated | Regulated Operations | Investments and Other |
|---|---|---|---|
| Millions | | | |
| For the Quarter Ended March 31, 2011 | | | |
| Operating Revenue | $242.2 | $223.0 | $19.2 |
| Fuel and Purchased Power Expense | 79.0 | 79.0 | – |
| Operating and Maintenance Expense | 90.1 | 71.2 | 18.9 |
| Depreciation Expense | 22.3 | 21.2 | 1.1 |
| Operating Income (Loss) | 50.8 | 51.6 | (0.8) |
| Interest Expense | (10.7) | (8.6) | (2.1) |
| Equity Earnings in ATC | 4.4 | 4.4 | – |
| Other Income | 0.8 | 0.6 | 0.2 |
| Income (Loss) Before Non-Controlling Interest and Income Taxes | 45.3 | 48.0 | (2.7) |
| Income Tax Expense (Benefit) | 8.2 | 9.6 | (1.4) |
| Net Income (Loss) | 37.1 | 38.4 | (1.3) |
| Less: Non-Controlling Interest in Subsidiaries | (0.1) | – | (0.1) |
| Net Income (Loss) Attributable to ALLETE | $37.2 | $38.4 | $(1.2) |
| | | | |
| As of March 31, 2011 | | | |
| Total Assets | $2,613.4 | $2,381.8 | $231.6 |
| Property, Plant and Equipment – Net | $1,841.3 | $1,794.6 | $46.7 |
| Accumulated Depreciation | $1,043.4 | $993.1 | $50.3 |
| Capital Additions | $35.9 | $33.0 | $2.9 |

NOTE 2. BUSINESS SEGMENTS (Continued)

| Millions | Consolidated | Regulated Operations | Investments and Other |
|---|---|---|---|
| For the Quarter Ended March 31, 2010 | | | |
| Operating Revenue | $233.6 | $216.1 | $17.5 |
| Fuel and Purchased Power Expense | 79.8 | 79.8 | – |
| Operating and Maintenance Expense | 87.7 | 69.8 | 17.9 |
| Depreciation Expense | 20.0 | 19.0 | 1.0 |
| Operating Income (Loss) | 46.1 | 47.5 | (1.4) |
| Interest Expense | (8.9) | (7.6) | (1.3) |
| Equity Earnings in ATC | 4.5 | 4.5 | – |
| Other Income (Expense) | 1.0 | 1.2 | (0.2) |
| Income (Loss) Before Non-Controlling Interest and Income Taxes | 42.7 | 45.6 | (2.9) |
| Income Tax Expense (Benefit) | 19.9 | 20.7 | (0.8) |
| Net Income (Loss) | 22.8 | 24.9 | (2.1) |
| Less: Non-Controlling Interest in Subsidiaries | (0.2) | – | (0.2) |
| Net Income (Loss) Attributable to ALLETE | $23.0 | $24.9 | $(1.9) |
| | | | |
| As of March 31, 2010 | | | |
| Total Assets | $2,416.0 | $2,196.4 | $219.6 |
| Property, Plant and Equipment – Net | $1,649.1 | $1,604.0 | $45.1 |
| Accumulated Depreciation | $990.3 | $942.8 | $47.5 |
| Capital Additions | $43.6 | $43.4 | $0.2 |

NOTE 3. INVESTMENTS

Investments. Our long-term investment portfolio includes the real estate assets of ALLETE Properties, debt and equity securities consisting primarily of securities held to fund employee benefits and land held-for-sale in Minnesota.

| Investments | March 31, 2011 | December 31, 2010 |
|---|---|---|
| Millions | | |
| ALLETE Properties | $93.7 | $94.0 |
| Available-for-sale Securities | 28.5 | 25.2 |
| Other | 5.9 | 6.8 |
| Total Investments | $128.1 | $126.0 |

| ALLETE Properties | March 31, 2011 | December 31, 2010 |
|---|---|---|
| Millions | | |
| Land Held-for-sale Beginning Balance (January 1, 2011 and 2010, respectively) | $86.0 | $74.9 |

| | | |
|---|---|---|
| Additions during period: | | |
| Deeds to Collateralized Property (a) | – | 9.9 |
| Capitalized Improvements and Other | 0.1 | 1.2 |
| Deductions during period: Cost of Real Estate Sold | (0.3) | – |
| Land Held-for-sale Ending Balance | 85.8 | 86.0 |
| Long-Term Finance Receivables (net of allowances of $0.9 and $0.8) | 3.6 | 3.7 |
| Other | 4.3 | 4.3 |
| Total Real Estate Assets | $93.7 | $94.0 |

(a) The deeds to collateralized property resulted primarily from an entity which filed for voluntary Chapter 11 bankruptcy in 2010 and were recorded at fair value net of estimated selling costs.

Land Held-for-sale. Land held-for-sale is recorded at the lower of cost or fair value as determined by the evaluation of individual land parcels. Land values are reviewed for impairment on a quarterly basis, and no impairments were recorded for the quarter ended March 31, 2011 (none in 2010).

NOTE 3. INVESTMENTS (Continued)

Long-Term Finance Receivables. As of March 31, 2011, long-term finance receivables were $3.6 million net of allowance ($3.7 million net of allowance as of December 31, 2010). Long-term finance receivables are collateralized by property sold, accrue interest at market-based rates and are net of an allowance for doubtful accounts. As of March 31, 2011, $0.9 million was reserved for delinquent note receivables where the fair value of the collateralized property was less than the note balance ($0.8 million of impairments as of December 31, 2010).

| Long-Term Finance Receivables | |
|---|---|
| Allowance Roll-Forward | |
| As of March 31, 2011 | Real Estate |
| Millions | |
| Beginning Balance as of December 31, 2010 | $0.8 |
| Additional Reserve | 0.1 |
| Ending Balance as of March 31, 2011 | $0.9 |

NOTE 4. FAIR VALUE

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. These inputs, which are used to measure fair value, are prioritized through the fair value hierarchy. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Descriptions of the three levels of the fair value hierarchy are discussed in Note 8. Fair Value to the consolidated financial statements in our 2010 Form 10-K.

The following tables set forth by level within the fair value hierarchy our assets and liabilities that were accounted for at fair value on a recurring basis as of March 31, 2011, and December 31, 2010. Each asset and liability is classified based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

| | Fair Value as of March 31, 2011 | | | |
|---|---|---|---|---|
| Recurring Fair Value Measures | Level 1 | Level 2 | Level 3 | Total |
| Millions | | | | |
| Assets: | | | | |
| Equity Securities | $21.1 | – | – | $21.1 |
| Available-for-sale Securities – Corporate Debt Securities | – | $7.8 | – | 7.8 |
| Money Market Funds | 2.1 | – | – | 2.1 |
| Total Fair Value of Assets | $23.2 | $7.8 | – | $31.0 |
| | | | | |
| Liabilities: | | | | |

| | | | | |
|---|---|---|---|---|
| Deferred Compensation | – | $13.7 | – | $13.7 |
| Total Fair Value of Liabilities | – | $13.7 | – | $13.7 |
| | | | | |
| Total Net Fair Value of Assets (Liabilities) | $23.2 | $(5.9) | – | $17.3 |

NOTE 4. FAIR VALUE (Continued)

| | Fair Value as of December 31, 2010 | | | |
|---|---|---|---|---|
| Recurring Fair Value Measures | Level 1 | Level 2 | Level 3 | Total |
| Millions | | | | |
| Assets: | | | | |
| Equity Securities | $19.4 | – | – | $19.4 |
| Available-for-sale Securities | | | | |
| Corporate Debt Securities | – | $7.5 | – | 7.5 |
| Debt Securities Issued by States of the United States (ARS) | – | – | $6.7 | 6.7 |
| Total Available-for-sale Securities | – | 7.5 | 6.7 | 14.2 |
| Money Market Funds | 0.8 | – | – | 0.8 |
| Total Fair Value of Assets | $20.2 | $7.5 | $6.7 | $34.4 |
| | | | | |
| Liabilities: | | | | |
| Deferred Compensation | – | $13.3 | – | $13.3 |
| Total Fair Value of Liabilities | – | $13.3 | – | $13.3 |
| | | | | |
| Total Net Fair Value of Assets (Liabilities) | $20.2 | $(5.8) | $6.7 | $21.1 |

| Recurring Fair Value Measures Activity in Level 3 | Derivatives | | Debt Securities Issued by States of the United States (ARS) | |
|---|---|---|---|---|
| Millions | | | | |
| Balance as of December 31, 2010 and December 31, 2009, respectively | – | $0.7 | $6.7 | $6.7 |
| Redeemed During the Period | – | – | (6.7) | – |
| Balance as of March 31, 2011 and March 31, 2010, respectively | – | $0.7 | – | $6.7 |

On January 5, 2011, the remaining $6.7 million of ARS were redeemed at carrying value.

The Company's policy is to recognize transfers in and transfers out as of the actual date of the event or of the change in circumstances that caused the transfer. For the quarters ended March 31, 2011, and March 31, 2010, there were no transfers in or out of Levels 1, 2 or 3.

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 listed below was based on quoted market prices for the same or similar instruments.

| Financial Instruments | Carrying Amount | Fair Value |
|---|---|---|
| Millions | | |

| | | |
|---|---|---|
| Long-Term Debt, Including Current Portion | | |
| March 31, 2011 | $784.0 | $779.0 |
| December 31, 2010 | $785.0 | $796.7 |

NOTE 5. REGULATORY MATTERS

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

2010 Rate Case. On November 2, 2009, Minnesota Power filed an $81 million retail rate increase request to recover the costs of significant investments to ensure current and future system reliability, enhance environmental performance, and bring new renewable energy to northeastern Minnesota. Interim rates were put into effect on January 1, 2010, and were originally estimated to increase revenues by $48.5 million in 2010. In April 2010, we adjusted our initial filing for events that had occurred since November 2009 – primarily increased sales to our industrial customers – resulting in a retail rate increase request of $72 million, a return on equity request of 11.25 percent, and a capital structure consisting of 54.29 percent equity and 45.71 percent debt.

NOTE 5. REGULATORY MATTERS (Continued)

On November 2, 2010, Minnesota Power received a written order from the MPUC approving a retail rate increase of approximately $54 million, a 10.38 percent return on common equity and a 54.29 percent equity ratio, subject to reconsideration. In an order dated January 20, 2011, the MPUC denied all reconsideration requests. Compliance filings were submitted in March 2011. Comments on the Company's proposed rate implementation were received from the Minnesota Office of the Attorney General and the Office of Energy Security, and final action by the MPUC is expected in the second quarter of 2011. Minnesota Power will continue to collect interim rates from its customers until the new rates go into effect, currently estimated to be in June or July 2011. We expect no interim rate refunds will be issued.

Under the terms of a stipulation and settlement agreement approved by the MPUC as part of this rate case, Minnesota Power agreed to forgo collection of $20.5 million in revenue receivable that it was entitled to under a prior rider for the Boswell Unit 3 environmental retrofit. The agreement required the Company to capitalize, as part of rate base, the $20.5 million to property, plant and equipment representing AFUDC. In conjunction with the settlement agreement, and upon receipt of the final rate order in February 2011, the Company reversed a $6.2 million deferred tax liability related to the revenue receivable Minnesota Power agreed to forgo. The $20.5 million revenue receivable was previously included in Regulatory Assets on the Company's consolidated balance sheet.

On February 22, 2011, Minnesota Power timely filed an appeal of the MPUC's interim rate decision in the Company's 2010 rate case with the Minnesota Court of Appeals. The Company is appealing the MPUC's interim rate decision finding of exigent circumstances in the interim rate decision with the primary argument that the MPUC exceeded its statutory authority, made its decision without the support of a body of record evidence, and that the decision violated public policy. The Company desires to resolve whether the MPUC's finding of exigent circumstances was lawful for application in future rate cases. The Company's initial brief was filed on April 25, 2011. If the appeal is successful, the Minnesota Court of Appeals will remand the case to the MPUC for further action consistent with its decision. The Company cannot predict the outcome of the matter at this time.

FERC-Approved Wholesale Rates. Minnesota Power's non-affiliated municipal customers consist of 16 municipalities in Minnesota and 1 private utility in Wisconsin. SWL&P, a wholly-owned subsidiary of ALLETE, is also a private utility in Wisconsin and a customer of Minnesota Power. In 2008, Minnesota Power entered into formula-based rate contracts with these customers. The rates included in these contracts are calculated using a cost-based formula methodology that is set at the beginning of the year using estimated costs, and provides for a true-up calculation for actual costs. The estimated true-up is recorded in the current year, then finalized and billed or paid to customers in the following year. The contracts include a termination clause requiring a three year notice to terminate. To date, no termination notices have been received.

2010 Wisconsin Rate Increase. SWL&P's 2011 retail rates are based on a 2010 PSCW retail rate order, effective January 1, 2011, that allows for a 10.9 percent return on common equity. The new rates reflect a 2.4 percent average increase in retail utility rates for SWL&P customers (a 12.8 percent increase in water rates, a 2.5 percent increase in natural gas rates and a 0.7 percent increase in electric rates). On an annualized basis, the rate increase will generate approximately $2 million in additional revenue.

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

NOTE 5. REGULATORY MATTERS (Continued)

| Regulatory Assets and Liabilities | March 31, 2011 | December 31, 2010 |
|---|---|---|
| Millions | | |
| Current Regulatory Assets (a) | | |
| Deferred Fuel | $19.1 | $20.6 |
| Total Current Regulatory Assets | 19.1 | 20.6 |
| Non-Current Regulatory Assets | | |
| Future Benefit Obligations Under | | |
| Defined Benefit Pension and Other Postretirement Benefit Plans | 253.7 | 257.9 |
| Boswell Unit 3 Environmental Rider | – | 20.5 |
| Income Taxes | 19.7 | 17.3 |
| Asset Retirement Obligation | 8.2 | 7.8 |
| Rate Case Expenses | 1.2 | 1.4 |
| Premium on Reacquired Debt | 1.8 | 1.8 |
| Other | 3.9 | 3.5 |
| Total Non-Current Regulatory Assets | 288.5 | 310.2 |
| Total Regulatory Assets | $307.6 | $330.8 |
| | | |
| Non-Current Regulatory Liabilities | | |
| Income Taxes | $22.8 | $23.4 |
| Plant Removal Obligations | 17.0 | 16.9 |
| Other | 5.6 | 3.3 |
| Total Non-Current Regulatory Liabilities | $45.4 | $43.6 |

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

NOTE 6. INVESTMENT IN ATC

Our wholly-owned subsidiary, Rainy River Energy, owns approximately 8 percent of ATC, a Wisconsin-based utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota, and Illinois. ATC rates are FERC approved and are based on a 12.2 percent return on common equity dedicated to utility plant. We account for our investment in ATC under the equity method of accounting. As of March 31, 2011, our equity investment balance in ATC was $94.8 million ($93.3 million as of December 31, 2010). In the first quarter of 2011, we invested $0.8 million in ATC, and on April 29, 2011, we invested an additional $0.6 million. We expect to invest an additional $0.6 million in 2011 in ATC.

| ALLETE's Investment in ATC | |
|---|---|
| Millions | |
| Equity Investment Balance as of December 31, 2010 | $93.3 |
| Cash Investments | 0.8 |
| Equity in ATC Earnings | 4.4 |
| Distributed ATC Earnings | (3.7) |
| Equity Investment Balance as of March 31, 2011 | $94.8 |

ATC's summarized financial data for the quarter ended March 31, 2011 and 2010, is as follows:

| | Quarter Ended March 31, | |
|---|---|---|
| ATC Summarized Financial Data | | |
| Income Statement Data | 2011 | 2010 |
| Millions | | |
| Revenue | $139.6 | $138.5 |
| Operating Expense | 63.1 | 62.8 |
| Other Expense | 22.3 | 20.6 |
| Net Income | $54.2 | $55.1 |
| | | |
| ALLETE’s Equity in Net Income | $4.4 | $4.5 |

NOTE 7. SHORT-TERM AND LONG-TERM DEBT

Short-Term Debt. Total short-term debt outstanding as of March 31, 2011, was $13.5 million ($14.4 million as of December 31, 2010) and consisted of long-term debt due within one year and notes payable.

Long-Term Debt. No long-term debt was issued in the first three months of 2011. As of March 31, 2011, long-term debt outstanding was $771.0 million ($771.6 million as of December 31, 2011).

Financial Covenants. Our long-term debt arrangements contain customary covenants. In addition, our lines of credit and letters of credit supporting certain long-term debt arrangements contain financial covenants. Our compliance with financial covenants is not dependent on debt ratings. The most restrictive covenant requires ALLETE to maintain a ratio of its Funded Debt to Total Capital (as the amounts are calculated in accordance with the respective long-term debt arrangements) of less than or equal to 0.65 to 1.00 measured quarterly. As of March 31, 2011, our ratio was approximately 0.42 to 1.00. Failure to meet this covenant would give rise to an event of default if not cured after notice from the lender, in which event ALLETE may need to pursue alternative sources of funding. Some of ALLETE's debt arrangements contain "cross-default" provisions that would result in an event of default if there is a failure under other financing arrangements to meet payment terms or to observe other covenants that would result in an acceleration of payments due. As of March 31, 2011, ALLETE was in compliance with its financial covenants.

NOTE 8. OTHER INCOME (EXPENSE)

| | Quarter Ended March 31, | |
|---|---|---|
| | 2011 | 2010 |
| Millions | | |
| AFUDC – Equity | $0.6 | $1.2 |
| Investment and Other Income (Expense) | 0.2 | (0.2) |
| Total Other Income | $0.8 | $1.0 |

NOTE 9. INCOME TAX EXPENSE

| | Quarter Ended March 31, | |
|---|---|---|
| | 2011 | 2010 |
| Millions | | |
| Current Tax Expense (Benefit) | | |
| Federal (a) | – | $7.2 |
| State (a) | $0.1 | 0.9 |
| Total Current Tax Expense | 0.1 | 8.1 |
| Deferred Tax Expense | | |
| Federal (b) | 6.8 | 9.8 |
| State (b) | 1.5 | 2.2 |
| Deferred Tax Credits | (0.2) | (0.2) |
| Total Deferred Tax Expense | 8.1 | 11.8 |
| Total Income Tax Expense | $8.2 | $19.9 |

(a) The federal and state current tax expense of zero and $0.1 million, respectively, for the quarter ended March 31, 2011, is due to a net operating loss (NOL) which resulted primarily from the bonus depreciation provision in the Tax Relief, Unemployment Insurance Reauthorization and Job Creation Act of 2010. The 2011 federal and state NOL will be carried forward to offset future taxable income. For the quarter ended March 31, 2010, we recorded a current tax expense, as the Small Business Jobs Act of 2010 was passed into law in the third quarter of 2010. The bonus depreciation provision of this legislation and tax planning initiatives resulted in a NOL and overall current tax benefit for the year ended December 31, 2010.

(b) The quarter ended March 31, 2011, includes a reversal of a $6.2 million deferred tax liability related to a revenue receivable that Minnesota Power agreed to forgo as part of a stipulation and settlement agreement in its 2010 rate case. Included in 2010 is a charge of $4.0 million as a result of PPACA eliminating the tax deduction for expenses that are reimbursed under Medicare Part D beginning January 1, 2013.

NOTE 9. INCOME TAX EXPENSE (Continued)

For the quarter ended March 31, 2011, the effective tax rate was 18.1 percent (46.6 percent for the quarter ended March 31, 2010). Excluding the non-recurring tax items recorded in the first quarters of 2011 and 2010, as described above, the effective tax rates were 31.8 percent and 37.2 percent, respectively. The effective tax rate for both years, excluding their respective non-recurring items, deviated from the statutory rate of approximately 41 percent primarily due to deductions for AFUDC-Equity, investment tax credits, renewable tax credits, and depletion.

Uncertain Tax Positions. As of March 31, 2011, we had gross unrecognized tax benefits of $11.3 million. Of this total, $0.6 million represents the amount of unrecognized tax benefits that, if recognized, would favorably impact the effective income tax rate.

We expect that the total amount of unrecognized tax benefits as of March 31, 2011, will change by an immaterial amount in the next 12 months.

NOTE 10. OTHER COMPREHENSIVE INCOME

The components of total comprehensive income were as follows:

| | Quarter Ended March 31, | |
|---|---|---|
| Other Comprehensive Income | 2011 | 2010 |
| Millions | | |
| Net Income | $37.1 | $22.8 |
| Other Comprehensive Income | | |
| Unrealized Gain on Securities | | |
| Net of income taxes of $0.6 and $– | 0.9 | 0.1 |
| Defined Benefit Pension and Other Postretirement Plans | | |
| Net of income taxes of $0.3 and $0.2 | 0.4 | 0.3 |
| Total Other Comprehensive Income | 1.3 | 0.4 |
| Total Comprehensive Income | $38.4 | $23.2 |
| Less: Non-Controlling Interest in Subsidiaries | (0.1) | (0.2) |
| Comprehensive Income Attributable to ALLETE | $38.5 | $23.4 |

NOTE 11. EARNINGS PER SHARE AND COMMON STOCK

The difference between basic and diluted earnings per share, if any, arises from outstanding stock options and performance share awards granted under our Executive and Director Long-Term Incentive Compensation Plans. For the quarter ended March 31, 2011, 0.4 million options to purchase shares of common stock were excluded from the computation of diluted earnings per share because the option exercise prices were greater than the average market prices; therefore, their effect would have been anti-dilutive. For the quarter ended March 31, 2010, 0.6 million options to purchase shares of common stock were excluded from the computation of diluted earnings per share.

| | 2011 | | | 2010 | | |
|---|---|---|---|---|---|---|
| Reconciliation of Basic and Diluted | | Dilutive | | | Dilutive | |
| Earnings Per Share | Basic | Securities | Diluted | Basic | Securities | Diluted |

| Millions Except Per Share Amounts | | | | | | |
|---|---|---|---|---|---|---|
| For the Quarter Ended March 31, | | | | | | |
| Net Income Attributable to ALLETE | $37.2 | – | $37.2 | $23.0 | – | $23.0 |
| Common Shares | 34.6 | 0.1 | 34.7 | 33.8 | – | 33.8 |
| Earnings Per Share | $1.07 | – | $1.07 | $0.68 | – | $0.68 |

NOTE 12. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS

| | Pension | | Other Postretirement | |
|---|---|---|---|---|
| Components of Net Periodic Benefit Expense | 2011 | 2010 | 2011 | 2010 |
| Millions | | | | |
| For the Quarter Ended March 31, | | | | |
| Service Cost | $1.9 | $1.5 | $1.0 | $1.2 |
| Interest Cost | 6.9 | 6.6 | 2.7 | 2.7 |
| Expected Return on Plan Assets | (8.7) | (8.4) | (2.4) | (2.4) |
| Amortization of Prior Service Costs | 0.1 | 0.1 | (0.4) | – |
| Amortization of Net Loss | 3.0 | 1.6 | 2.1 | 1.2 |
| Amortization of Transition Obligation | – | – | – | 0.6 |
| Net Periodic Benefit Expense | $3.2 | $1.4 | $3.0 | $3.3 |

Employer Contributions. For the quarter ended March 31, 2011, no contributions were made to our defined benefit pension plan (no contributions for the quarter ended March 31, 2010) and $10.9 million was contributed to our other postretirement benefit plan ($2.6 million for the quarter ended March 31, 2010). We expect to make approximately $2 million in contributions to our defined benefit pension plan and an additional $1 million to our other postretirement benefit plan in 2011.

Accounting and disclosure requirements for the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Act) provides guidance for employers that sponsor postretirement health care plans that provide prescription drug benefits. We provide postretirement health benefits that include prescription drug benefits, which qualify us for the federal subsidy under the Act. For the quarter ended March 31, 2011, we received $0.2 million in prescription drug reimbursements.

NOTE 13. COMMITMENTS, GUARANTEES AND CONTINGENCIES

Power Purchase Agreements. Our long-term PPAs have been evaluated under the accounting guidance for variable interest entities. We have determined that either we have no variable interest in the PPA or where we do have variable interests, we are not the primary beneficiary; therefore, consolidation is not required. These conclusions are based on the fact that we do not have both control over activities that are most significant to the entity and an obligation to absorb losses or receive benefits from the entity's performance. Our financial exposure relating to these PPAs is limited to our fixed capacity and energy payments.

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

Minnesota Power is obligated to pay its pro rata share of Square Butte's costs based on Minnesota Power's entitlement to Unit output. Our output entitlement under the Agreement is 50 percent for the remainder of the contract, subject to the provisions of the Minnkota Power sales agreement described below. 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 costs consist primarily of debt service, operating and maintenance, depreciation and fuel expenses. We expect debt service, operating and maintenance, and depreciation expenses for Square Butte to increase in 2011 due to environmental compliance obligations. As of March 31, 2011, Square Butte had total debt outstanding of $369.4 million. Annual debt service for Square Butte is expected to be approximately $39 million in each of the five years, 2011 through 2015, of which Minnesota Power's obligation is 50 percent. Fuel expenses are recoverable through our fuel adjustment clause and include the cost of coal purchased from BNI Coal, our subsidiary, under a long-term contract.

NOTE 13. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Power Purchase Agreements (Continued)

Minnkota Power Sales Agreement. In conjunction with the purchase of the existing 250 kV DC transmission line from Square Butte in December 2009, Minnesota Power entered into a power sales agreement with Minnkota Power. Under the power sales agreement, Minnesota Power will sell a portion of its output from Square Butte to Minnkota Power, resulting in Minnkota Power's net entitlement increasing and Minnesota Power's net entitlement decreasing until Minnesota Power's share is eliminated at the end of 2025.

No power will be sold under this agreement until Minnkota Power has placed in service a new AC transmission line, which is anticipated to occur in 2013. This new AC transmission line will allow Minnkota Power to transmit its entitlement from Square Butte directly to its customers, which, in turn, will enable Minnesota Power to transmit new wind generation on the DC transmission line.

Wind PPAs. In 2006 and 2007, Minnesota Power entered into two long-term wind PPAs with an affiliate of NextEra Energy, Inc. to purchase the output from two wind facilities, Oliver Wind I (50 MW) and Oliver Wind II (48 MW), located near Center, North Dakota. Each agreement is for 25 years and provides for the purchase of all output from the facilities at fixed prices. There are no fixed capacity charges and we only pay for energy as it is delivered to us.

Hydro PPA. Minnesota Power has a PPA with Manitoba Hydro that began in May 2009 and expires in April 2015. Under the agreement with Manitoba Hydro, Minnesota Power is currently purchasing 50 MW of capacity and the energy associated with that capacity. Both the capacity price and the energy price are adjusted annually by the change in a governmental inflationary index.

In April 2010, Minnesota Power signed a definitive agreement with Manitoba Hydro to purchase surplus energy beginning in May 2011 through April 2022. This energy-only transaction primarily consists of surplus hydro energy on Manitoba Hydro's system that is delivered to Minnesota Power on a non-firm basis. The pricing is based on forward market prices. Under this agreement with Manitoba Hydro, Minnesota Power will be purchasing at least one million MWh of energy over the contract term. On March 11, 2011, the MPUC approved our PPA with Manitoba Hydro.

North Dakota Wind Development. On December 31, 2009, we purchased an existing 250 kV DC transmission line from Square Butte for $69.7 million. The 465-mile transmission line runs from Center, North Dakota to Duluth, Minnesota. We use this line to transport increasing amounts of wind energy from North Dakota while gradually phasing out coal-based electricity currently being delivered to our system over this transmission line from Square Butte's lignite coal-fired generating unit.

Bison 1 is a two phase, 82 MW wind project in North Dakota. All permitting has been received and the first phase was completed in 2010. Phase one included the construction of a 22-mile, 230 kV transmission line and the installation of sixteen 2.3-MW wind turbines, all of which were in-service at the end of 2010. Phase two is expected to be completed in late 2011 and consists of the installation of fifteen 3.0-MW wind turbines. Bison 1 is expected to have a total capital cost of approximately $177 million, of which $132.9 million was spent through March 31, 2011. In 2009, the MPUC approved Minnesota Power's petition seeking current cost recovery for investments and expenditures related to Bison 1, and in July 2010, the MPUC approved our petition establishing rates effective August 1, 2010. On March 31, 2011, Minnesota Power petitioned the MPUC to update the rates for additional investments and expenditures related to Bison 1.

Bison 2 is a 105 MW wind project in North Dakota which, if approved by the MPUC, is expected to be completed by the end of 2012. Total project cost is estimated to be approximately $160 million. Construction would begin upon the receipt of all regulatory and permitting approvals. Request for approval of the project was filed with the MPUC on

March 24, 2011. On April 6, 2011, the request for site permit approval was submitted to the NDPSC. We will file for current cost recovery for Bison 2 from the MPUC once the project and related permitting have been approved.

NOTE 13. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)

Coal, Rail and Shipping Contracts. We have coal supply agreements and transportation agreements providing for the purchase and delivery of a significant portion of our coal requirements. These coal and transportation agreements, including option terms, expire in various years between late 2011 and 2015. Our minimum annual payment obligation is $46.4 million in 2011, $16.6 million in 2012, and 16.2 million in 2013. Our minimum annual payment obligations will increase when annual nominations are made for coal deliveries in future years. The delivered costs of fuel for Minnesota Power’s generation are recoverable from Minnesota Power’s utility customers through the fuel adjustment clause.

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 fair market value, to purchase the dragline at fair market value, or to surrender the dragline and pay a $3.0 million termination fee. We lease other properties and equipment under operating lease agreements with terms expiring through 2016. The aggregate amount of minimum lease payments for all operating leases is $8.1 million in 2011, $8.4 million in 2012, $8.5 million in 2013, $8.7 million in 2014, $8.4 million in 2015 and $44.7 million thereafter.

Transmission. We are making investments in Upper Midwest transmission opportunities that strengthen or enhance the regional transmission grid. These investments include the CapX2020 initiative, investments in our transmission assets and our investment in ATC.

CapX2020. Minnesota Power is a participant in the CapX2020 initiative which represents an effort to ensure electric transmission and distribution reliability in Minnesota and the surrounding region for the future. CapX2020, which consists of electric cooperatives, municipals and investor-owned utilities, including Minnesota’s largest transmission owners, has assessed the transmission system and projected growth in customer demand for electricity through 2020. Studies show that the region's transmission system will require major upgrades and expansion to accommodate increased electricity demand as well as support renewable energy expansion through 2020.

Minnesota Power is currently participating in three CapX2020 projects: the Fargo to St. Cloud project, the Monticello to St. Cloud project, which together total a 238-mile, 345 kV line from Fargo to Monticello, and the 70-mile, 230 kV line between Bemidji and Minnesota Power’s Boswell Energy Center near Grand Rapids, Minnesota. Based on projected costs of the three transmission lines and the percentage agreements among participating utilities, Minnesota Power plans to invest between $100 million and $125 million in the CapX2020 initiative through 2015, of which $15.4 million was spent through March 31, 2011. As future CapX2020 projects are identified, Minnesota Power may elect to participate on a project-by-project basis.

In July 2010, the MPUC granted a route permit for the 28-mile, 345 kV transmission line between Monticello and St. Cloud. Construction of the project is expected to be completed in late 2011. The 210-mile, 345 kV transmission line from St. Cloud to Fargo is expected to be completed by 2015. Construction for the Bemidji to Grand Rapids 230 kV line project commenced in January 2011.

We have an approved cost recovery rider in place for certain transmission expenditures, and our current billing factor was approved by the MPUC in June 2009. The billing factor allows us to charge our retail customers on a current basis for the costs of constructing certain transmission facilities plus a return on the capital invested.

Environmental Matters

Our businesses are subject to regulation of environmental matters by various federal, state, and local authorities. Currently, a number of regulatory changes to the Clean Air Act, the Clean Water Act, and various waste management requirements are under consideration by both Congress and the EPA. Minnesota Power's fossil fuel facilities will likely be subject to regulation under these proposals. Our intention is to reduce our exposure to these requirements by reshaping our generation portfolio over time to reduce our reliance on coal.

NOTE 13. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

We consider our businesses to be in substantial compliance with currently applicable environmental regulations and believe all necessary permits to conduct such operations have been obtained. Due to future restrictive environmental requirements through legislation and/or rulemaking, we anticipate that potential expenditures for environmental matters will be material and will require significant capital investments.

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

Air. The electric utility industry is heavily regulated both at the federal and state level to address air emissions. Minnesota Power’s generating facilities mainly burn low-sulfur western sub-bituminous coal. Square Butte, located in North Dakota, burns lignite coal. All of Minnesota Power’s generating facilities are equipped with pollution control equipment such as scrubbers, bag houses and low NOx technologies. At this time, these facilities are substantially compliant with applicable emission requirements.

New Source Review. In August 2008, Minnesota Power received a Notice of Violation (NOV) from the United States EPA asserting violations of the New Source Review (NSR) requirements of the Clean Air Act at Boswell Units 1-4 and Laskin Unit 2. The NOV asserts that seven projects undertaken at these coal-fired plants between the years 1981 and 2000 should have been reviewed under the NSR requirements, and that the Boswell Unit 4 Title V permit was violated. In April 2011, Minnesota Power received a NOV alleging that two projects undertaken at Rapids Energy Center in 2005 and 2006 should have been reviewed under the NSR requirements and that the Rapids Energy Center’s Title V permit was violated. Minnesota Power believes the projects in both NOVs were in full compliance with the Clean Air Act, NSR requirements and applicable permits. We are engaged in discussions with the EPA regarding resolution of these matters, but we are unable to predict the outcome of these discussions.

The resolution could result in civil penalties and the installation of control technology, some of which is already planned or completed for other regulatory requirements. Any costs of installing pollution control technology would likely be eligible for recovery in rates over time subject to MPUC and FERC approval in a rate proceeding. Since 2006, Minnesota Power has significantly reduced emissions at Laskin and Boswell, and continues to reduce emissions at Boswell.

EPA Transport Rule. On July 6, 2010, the EPA proposed a rule known as the Transport Rule (TR) requiring 31 states, including Minnesota as well as the District of Columbia, to reduce power plant SO2 and NOx emissions that can significantly contribute to ozone and fine particle pollution problems in other states. If adopted, the TR will replace the Clean Air Interstate Rule (CAIR) that was issued by the EPA in March 2005. Minnesota was included as one of the original 28 CAIR states but, following Minnesota Power’s successful challenge to CAIR, the EPA granted an administrative stay of the CAIR requirements in Minnesota while it prepared the TR. The proposed TR responds to the United States Court of Appeals for the District of Columbia Circuit’s remand of CAIR by replacing and reforming provisions to address updated air quality standards, improved emissions data and reformed emissions transport modeling.

The EPA took public comments on the proposed rule through October 1, 2010, and plans to finalize the rule in July 2011. Emissions reductions are proposed to take effect in 2012, within one year of projected finalization of the rule.

The EPA has not yet determined whether trading of emission allowances between regulated generating units or states may be implemented. Since 2006, we have made substantial investments in pollution control equipment at our Laskin, Taconite Harbor and Boswell generating units which have significantly reduced emissions. These reductions may satisfy Minnesota Power's obligations with respect to these requirements. We are unable to predict any additional compliance costs we might incur at this time.

NOTE 13. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

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

Pursuant to the regional haze rule, Minnesota was required to develop its SIP by December 2007. As a mechanism for demonstrating progress towards meeting the long-term regional haze goal, in April 2007 the MPCA advanced a draft conceptual SIP which relied on the implementation of CAIR. However, a formal SIP was not filed at that time due to the United States Court of Appeals for the District of Columbia Circuit’s remand of CAIR. Subsequently, the MPCA requested that companies with BART eligible units complete and submit a BART emissions control retrofit study, which was completed for Taconite Harbor Unit 3 in November 2008. The retrofit work completed in 2009 at Boswell Unit 3 meets the BART requirements for that unit. In December 2009, the MPCA approved the Minnesota SIP for submittal to the EPA for its review and approval. The Minnesota SIP incorporates information from the BART emissions control retrofit studies that were completed as requested by the MPCA. A decision by the EPA is pending on whether to approve the Minnesota SIP. If approved, Minnesota Power will have five years to bring Taconite Harbor Unit 3 into compliance. It is uncertain what controls will ultimately be required at Taconite Harbor Unit 3 in connection with the regional haze rule.

EPA National Emission Standards for Hazardous Air Pollutants (NESHAPs) for Coal- and Oil-fired Electric Utility Steam Generating Units (EUSGU). Under Section 112 of the Clean Air Act, the EPA is required to set emission standards for hazardous air pollutants for certain source categories. In December 2009, Minnesota Power and other utilities received an Information Collection Request from the EPA requiring that emissions data be provided and stack testing be performed in order to develop a database upon which to base future regulations. In March 2010, Minnesota Power responded to the Information Collection Request. Stack testing was completed during the third quarter of 2010 and the results were submitted to the EPA. The EPA released their proposed EUSGU NESHAPs rule on March 16, 2011. As part of the NESHAPs rulemaking, the EPA will develop Maximum Achievable Control Technology standards for utilities. Minnesota Power is still in the process of reviewing the proposed rule. Costs for complying with potential future mercury and other hazardous air pollutant regulations under the Clean Air Act cannot be estimated at this time.

EPA National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial, and Institutional Boilers and Process Heaters. In June 2010, the EPA proposed four rules addressing hazardous air pollutant emissions from industrial boilers and solid waste incinerators and redefining solid waste. Comments on these proposed rules were due in August 2010, with final rules expected in early 2011. On March 21, 2011, the final rules were published in the Federal Register. Major sources have three years to achieve compliance with the final rules. Minnesota Power is in the process of reviewing the rules to determine the potential impact on our facilities. These rules may result in additional control measures being required at Rapids Energy Center and Hibbard. Costs for complying with these proposed rules cannot be estimated at this time.

Minnesota Mercury Emission Reduction Act. Under Minnesota law, a mercury emissions reduction plan for Boswell Unit 4 is required to be submitted by July 1, 2015, with implementation no later than December 31, 2018. The statute also calls for an evaluation of a mercury control alternative which provides for environmental and public health benefits without imposing excessive costs on the utility’s customers. Costs for the Boswell Unit 4 emission reduction plan cannot be estimated at this time.

Proposed and Finalized National Ambient Air Quality Standards. The EPA is required to review the National Ambient Air Quality Standards (NAAQS) every five years. Each state is required to adopt plans describing how they will reduce emissions to attain these NAAQS if the state's air quality is not in compliance with a NAAQS. These state plans often include more stringent air emission limitations on sources of air pollutants. Four NAAQS have either recently been revised or are currently proposed for revision, as described below.

NOTE 13. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

Ozone NAAQS. The EPA is proposing to more stringently control emissions that result in ground level ozone. In January 2010, the EPA proposed to reduce the eight-hour ozone standard and to adopt a secondary standard for the protection of sensitive vegetation from ozone-related damage. The EPA expects to issue final standards by July 2011. As proposed, states have until early 2014 to submit plans outlining how they will meet the standards.

Particulate Matter NAAQS. The EPA finalized the NAAQS Particulate Matter standards in September 2006. The EPA established a more stringent 24-hour average fine particulate (PM2.5) standard and kept the annual average fine particulate matter standard and the 24-hour coarse particulate matter standard unchanged. The District of Columbia Circuit Court of Appeals has remanded the PM2.5 standard to the EPA, requiring consideration of lower annual average standard values. The EPA plans to finalize the new PM2.5 standards in 2011 and state attainment status determination will likely not occur prior to 2013. As early as late 2014, affected sources would have to take additional control measures if modeling demonstrates non-compliance at the property boundary. The EPA has indicated that ambient air quality monitoring for 2008 through 2010 will be used as a basis for states to characterize their attainment status.

SO2 and NO2 NAAQS. The EPA recently finalized a new one-hour NAAQS for SO2 and NO2. Monitoring data indicates that Minnesota will likely be in compliance with these new standards; however, the SO2 NAAQS also requires the EPA to evaluate modeling data to determine attainment. It is unclear what the outcome of this evaluation will be. These NAAQS could also result in more stringent emission limits on our steam generating facilities, possibly resulting in additional control measures on some of our units.

We are unable to predict the nature or timing of any additional NAAQS regulation or compliance costs we might incur at this time.

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

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

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

EPA Regulation of GHG Emissions. On May 13, 2010, the EPA issued the final Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas Tailoring Rule (Tailoring Rule). The PSD/Tailoring Rule establishes permitting thresholds required to address GHG emissions for new facilities, at existing facilities that undergo major modifications, and at other facilities characterized as major sources under the Clean Air Act's Title V program.

For our existing facilities, the rule does not require amending our existing Title V Operating Permits to include GHG requirements. Implementation of the requirement to add GHG provisions to permits will be completed at the state level in Minnesota by the MPCA when the Title V permits are renewed. However, installation of new units or modification of existing units resulting in a significant increase in GHG emissions will require obtaining PSD permits and amending our operating permits to demonstrate that Best Available Control Technology (BACT) is being used at the facility to control GHG emissions. The EPA has defined significant emissions increase for existing sources as a GHG increase of 75,000 tons or more per year of total GHG on a CO2 equivalent basis.

NOTE 13. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

In late 2010, the EPA issued guidance to permitting authorities and affected sources to facilitate incorporation of the Tailoring Rule permitting requirements into the Title V and PSD permitting programs. The guidance stated that the project-specific top-down BACT determination process used for other pollutants will also be used to determine BACT for GHG emissions. Through sector-specific white papers, the EPA also provided examples and technical summaries of GHG emission control technologies and techniques the EPA considers available or likely to be available to sources. It is possible these control technologies could be determined to be BACT on a project-by-project basis. In the near term, one option appears to be energy efficiency maximization.

Legal challenges to the EPA's regulation of GHG emissions, including the Tailoring Rule, have been filed by others and are awaiting judicial determination. Comments to the permitting guidance were also submitted by Minnesota Power and others and may be addressed by the EPA in the form of revised guidance documents.

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

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

Clean Water Act - Aquatic Organisms. On April 20, 2011, the EPA published in the Federal Register proposed regulations under section 316(b) of the Clean Water Act that set standards applicable to cooling water intake structures for the protection of aquatic organisms. The proposed regulations would require existing large power plants and manufacturing facilities that withdraw greater than 25 percent of water from adjacent water bodies for cooling purposes to limit the number of aquatic organisms that are killed when they are pinned against the facility's intake structure or that are drawn into the facility's cooling system. The section 316(b) standards would be implemented through NPDES permits issued to the covered facilities. Comments on the proposed rule are due 90 days after publication in the Federal Register. The EPA is obligated to finalize the rule by July 27, 2012. Minnesota Power is in the process of evaluating the potential impacts the proposed rule may have on its facilities. We are unable to predict the compliance costs we might incur; however, there is the possibility they could have a material impact on our financial results.

Solid and Hazardous Waste. The Resource Conservation and Recovery Act of 1976 regulates the management and disposal of solid and hazardous wastes. We are required to notify the EPA of hazardous waste activity and, consequently, routinely submit the necessary reports to the EPA.

Coal Ash Management Facilities. Minnesota Power generates coal ash at all five of its steam electric generating facilities. Two facilities store ash in onsite impoundments (ash ponds) with engineered liners and containment dikes. Another facility stores dry ash in a landfill with an engineered liner and leachate collection system. Two facilities generate a combined wood and coal ash that is either land applied as an approved beneficial use, or trucked to state permitted landfills. In June 2010, the EPA proposed regulations for coal combustion residuals generated by the electric utility sector. The proposal sought comments on three general regulatory schemes for coal ash. Comments on the purposed rule were due in November 2010. It is estimated that the final rule will be published in mid-2012. We are unable to predict the compliance costs we might incur; however, there is the possibility they could have a material impact on our financial results.

Manufactured Gas Plant Site. We are reviewing and addressing environmental conditions at a former manufactured gas plant site within the City of Superior, Wisconsin, and formerly operated by SWL&P. We have been working with the WDNR to determine the extent of contamination and the remediation of contaminated locations. At March 31, 2011, we have a $0.5 million liability for this site, and a corresponding regulatory asset as we expect recovery of remediation costs to be allowed by the PSCW.

NOTE 13. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)

BNI Coal. As of March 31, 2011, BNI Coal had surety bonds outstanding of $18.4 million related to the reclamation liability for closing costs associated with its mine and mine facilities. Although the coal supply agreements obligate the customers to provide for the closing costs, additional assurance is required by federal and state regulations. In addition to the surety bonds, BNI Coal has secured a letter of credit with CoBANK ACB for an additional $10.0 million, of which $6.7 million is needed to meet the requirements for BNI Coal's total reclamation liability currently estimated at $25.1 million. BNI Coal does not believe it is likely that any of these outstanding bonds will be drawn upon.

ALLETE Properties. As of March 31, 2011, ALLETE Properties, through its subsidiaries, had surety bonds outstanding of $11.2 million primarily related to performance and maintenance obligations to governmental entities to construct improvements in the Company's various projects. The cost of the remaining work to be completed on these improvements is estimated to be approximately $9.0 million, and ALLETE Properties does not believe it is likely that any of these outstanding bonds will be drawn upon.

Community Development District Obligations. In March of 2005, the Town Center District issued $26.4 million of tax-exempt, 6 percent capital improvement revenu