ALLETE INC
Form 10-Q
August 02, 2012
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 June 30, 2012

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,
38,288,789 shares outstanding
as of June 30, 2012

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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 Clean Energy	ALLETE Clean Energy, Inc.
ALLETE Properties	ALLETE Properties, LLC, and its subsidiaries
ARS	Auction Rate Securities
ATC	American Transmission Company, LLC
Bison 1	Bison 1 Wind Facility
Bison 2	Bison 2 Wind Project
Bison 3	Bison 3 Wind Project
BNI Coal	BNI Coal, Ltd.
Boswell	Boswell Energy Center
CAIR	Clean Air Interstate Rule
CO_2	Carbon Dioxide
Company	ALLETE, Inc., and its subsidiaries
CSAPR	Cross-State Air Pollution Rule
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
Item ___	Item ___ of this Form 10-Q
kV	Kilovolt(s)
Laskin	Laskin Energy Center
LIBOR	London Interbank Offered Rate
MACT	Maximum Achievable Control Technology
Magnetation	Magnetation, Inc.
Manitoba Hydro	Manitoba Hydro-Electric Board
MATS	Mercury and Air Toxics Standards
Medicare Part D	Medicare Part D provision of The Patient Protection and Affordable Care Act of 2010
Mesabi Nugget	Mesabi Nugget Delaware, LLC
Minnesota Power	An operating division of ALLETE, Inc.
Minnkota Power	Minnkota Power Cooperative, Inc.
MISO	Midwest Independent Transmission System Operator, Inc.
MPCA	Minnesota Pollution Control Agency

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Definitions (Continued)

Abbreviation or Acronym	Term
MPUC	Minnesota Public Utilities Commission
MW / MWh	Megawatt(s) / Megawatt-hour(s)
NAAQS	National Ambient Air Quality Standards
NDPSC	North Dakota Public Service Commission
Non-residential	Retail commercial, non-retail commercial, office, industrial, warehouse, storage and institutional
NO_2	Nitrogen Dioxide
NO_X	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
SIP	State Implementation Plan
SO_2	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
U.S.	United States of America
USS Corporation	United States Steel Corporation
WDNR	Wisconsin Department of Natural Resources

Forward-Looking Statements

Statements in this report that are not statements of historical facts are 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," "likely," "will continue," "could," "may," "potential," "target," "outlook" or words of similar m 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 providing this cautionary statement to identify important factors that could cause our actual results to differ materially from those indicated in forward-looking statements made by or on behalf of ALLETE in this 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 that could cause our actual results to differ materially from those indicated in the forward-looking statements:

- our ability to successfully implement our strategic objectives;
- regulatory or legislative actions, including changes in governmental policies 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, capital structure, 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, acts of terrorism and cyber attacks;
- 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.

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 26 of our 2011 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

	June 30, 2012	December 31, 2011
Assets		
Current Assets		
Cash and Cash Equivalents	$8.6	$101.1
Accounts Receivable (Less Allowance of $1.1 and $0.9)	66.7	79.7
Inventories	69.3	69.1
Prepayments and Other	25.5	27.1
Total Current Assets	170.1	277.0
Property, Plant and Equipment - Net	2,177.5	1,982.7
Regulatory Assets	336.9	345.9
Investment in ATC	102.6	98.9
Other Investments	136.0	132.3
Other Non-Current Assets	39.1	39.2
Total Assets	$2,962.2	$2,876.0
Liabilities and Equity		
Liabilities		
Current Liabilities		
Accounts Payable	$78.3	$71.8
Accrued Taxes	22.6	26.4
Accrued Interest	12.8	12.8
Long-Term Debt Due Within One Year	67.4	5.4
Notes Payable	—	1.1
Other	51.3	45.6
Total Current Liabilities	232.4	163.1
Long-Term Debt	808.4	857.9
Deferred Income Taxes	388.0	373.6
Regulatory Liabilities	49.3	43.5
Defined Benefit Pension and Other Postretirement Benefit Plans	253.8	253.5
Other Non-Current Liabilities	110.6	105.1
Total Liabilities	1,842.5	1,796.7
Commitments, Guarantees and Contingencies (Note 13)		
Equity		
Common Stock Without Par Value, 80.0 Shares Authorized, 38.3 and 37.5 Shares Outstanding	737.3	705.6
Unearned ESOP Shares	(24.9)	(29.0)
Accumulated Other Comprehensive Loss	(27.6)	(28.9)
Retained Earnings	434.9	431.6
Total Equity	1,119.7	1,079.3
Total Liabilities and Equity	$2,962.2	$2,876.0

The accompanying notes are an integral part of these statements.

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

	Quarter Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Operating Revenue	$216.4	$219.9	$456.4	$462.1
Operating Expenses				
Fuel and Purchased Power	72.1	76.0	149.2	155.0
Operating and Maintenance	96.2	95.7	196.1	185.8
Depreciation	24.8	22.1	49.4	44.4
Total Operating Expenses	193.1	193.8	394.7	385.2
Operating Income	23.3	26.1	61.7	76.9
Other Income (Expense)				
Interest Expense	(10.1)	(11.0)	(21.1)	(21.7)
Equity Earnings in ATC	4.8	4.6	9.4	9.0
Other	1.2	1.0	1.9	1.8
Total Other Expense	(4.1)	(5.4)	(9.8)	(10.9)
Income Before Non-Controlling Interest and Income Taxes	19.2	20.7	51.9	66.0
Income Tax Expense	4.8	3.8	13.1	12.0
Net Income	14.4	16.9	38.8	54.0
Less: Non-Controlling Interest in Subsidiaries	—	(0.1)	—	(0.2)
Net Income Attributable to ALLETE	$14.4	$17.0	$38.8	$54.2
Average Shares of Common Stock				
Basic	37.3	35.0	37.0	34.8
Diluted	37.4	35.1	37.1	34.9
Basic Earnings Per Share of Common Stock	$0.39	$0.49	$1.05	$1.56
Diluted Earnings Per Share of Common Stock	$0.39	$0.48	$1.05	$1.55
Dividends Per Share of Common Stock	$0.46	$0.445	$0.92	$0.89

The accompanying notes are an integral part of these statements.

ALLETE
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME
Millions – Unaudited

	Quarter Ended June 30,		Six Months Ended June 30,	
Comprehensive Income (Loss)	2012	2011	2012	2011
Millions				
Net Income	$14.4	$16.9	$38.8	$54.0
Other Comprehensive Income (Loss)				
Unrealized Gain (Loss) on Securities				
Net of Income Taxes of $(0.5), $0.2, $0.2 and $0.8	(0.5)	0.2	0.5	1.1
Unrealized Loss on Derivatives				
Net of Income Taxes of $—, $—, $(0.1) and $—	(0.1)	—	(0.2)	—
Defined Benefit Pension and Other Postretirement Benefit Plans				
Net of Income Taxes of $0.4, $0.2, $0.7 and $0.5	0.5	0.4	1.0	0.8
Total Other Comprehensive Income (Loss)	(0.1)	0.6	1.3	1.9
Total Comprehensive Income	$14.3	$17.5	$40.1	$55.9
Less: Non-Controlling Interest in Subsidiaries	—	(0.1)	—	(0.2)
Comprehensive Income Attributable to ALLETE	$14.3	$17.6	$40.1	$56.1

The accompanying notes are an integral part of these statements.

ALLETE
CONSOLIDATED STATEMENT OF CASH FLOWS
Millions – Unaudited

	Six Months Ended June 30,	
	2012	2011
Operating Activities		
Net Income	$38.8	$54.0
Allowance for Funds Used During Construction	(1.9)	(1.1)
Income from Equity Investments, Net of Dividends	(1.7)	(0.9)
Gain on Sale of Assets	—	(0.7)
Depreciation Expense	49.4	44.4
Amortization of Debt Issuance Costs	0.5	0.5
Deferred Income Tax Expense	13.1	11.8
Share-Based Compensation Expense	1.2	1.1
ESOP Compensation Expense	3.7	3.6
Defined Benefit Pension and Postretirement Benefit Expense	13.8	12.3
Bad Debt Expense	0.5	0.5
Changes in Operating Assets and Liabilities		
Accounts Receivable	12.4	27.2
Inventories	(0.2)	(1.3)
Prepayments and Other	1.6	8.0
Accounts Payable	(8.2)	(17.7)
Other Current Liabilities	—	(10.1)
Cash Contributions to Defined Benefit Pension and Other Postretirement Benefit Plans	—	(10.9)
Changes in Regulatory and Other Non-Current Assets	(1.8)	(1.2)
Changes in Regulatory and Other Non-Current Liabilities	6.9	10.5
Cash from Operating Activities	128.1	130.0
Investing Activities		
Proceeds from Sale of Available-for-sale Securities	1.0	7.2
Payments for Purchase of Available-for-sale Securities	(1.0)	(1.2)
Investment in ATC	(2.0)	(1.4)
Changes to Other Investments	(3.2)	(1.4)
Additions to Property, Plant and Equipment	(221.8)	(91.6)
Proceeds from Sale of Assets	—	1.4
Cash for Investing Activities	(227.0)	(87.0)
Financing Activities		
Proceeds from Issuance of Common Stock	30.5	22.9
Proceeds from Issuance of Long-Term Debt	15.6	—
Proceeds (Payments) from (for) Notes Payable	(1.1)	1.5
Reductions of Long-Term Debt	(3.1)	(1.5)
Dividends on Common Stock	(35.5)	(31.4)
Cash from (for) Financing Activities	6.4	(8.5)
Change in Cash and Cash Equivalents	(92.5)	34.5
Cash and Cash Equivalents at Beginning of Period	101.1	44.9

Cash and Cash Equivalents at End of Period	$8.6	$79.4

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, 2011, 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 June 30, 2012, are not necessarily indicative of results that may be expected for any other interim period or for the year ending December 31, 2012. For further information, refer to the consolidated financial statements and notes included in our 2011 Form 10-K.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES

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

Inventories	June 30, 2012	December 31, 2011
Millions		
Fuel	$27.5	$28.6
Materials and Supplies	41.8	40.5
Total Inventories	$69.3	$69.1

Prepayments and Other Current Assets	June 30, 2012	December 31, 2011
Millions		
Deferred Fuel Adjustment Clause	$18.5	$17.5
Other	7.0	9.6
Total Prepayments and Other Current Assets	$25.5	$27.1

Other Current Liabilities	June 30, 2012	December 31, 2011
Millions		
Customer Deposits	$25.8	$16.3
Other	25.5	29.3
Total Other Current Liabilities	$51.3	$45.6

Other Non-Current Liabilities	June 30, 2012	December 31, 2011
Millions		
Asset Retirement Obligation	$61.0	$57.0
Other	49.6	48.1
Total Other Non-Current Liabilities	$110.6	$105.1

Supplemental Statement of Cash Flows Information.

For the Six Months Ended June 30,	2012	2011
Millions		
Cash Paid During the Period for Interest – Net of Amounts Capitalized	$21.7	$21.9

Cash Paid During the Period for Income Taxes	$0.2	$0.4
Noncash Investing and Financing Activities		
Increase (Decrease) in Accounts Payable for Capital Additions to Property, Plant and Equipment	$14.8	$(13.2)
AFUDC – Equity	$1.9	$1.1

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Accounts Receivable. Accounts receivable are reported on the Consolidated 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. In the third quarter of 2011, one of Minnesota Power's Large Power Customers, NewPage Corporation, filed for Chapter 11 bankruptcy protection. Minnesota Power had a pre-bankruptcy petition receivable of $3.2 million as of June 30, 2012. Based on our assessment of the facts and circumstances existing as of June 30, 2012, we have determined that it is not probable that the pre-petition receivable has been impaired at this time. We will continue to assess for impairment as the bankruptcy proceeds and as facts and circumstances change. This customer's operations have continued without interruption and we continue to provide electric and steam service to this customer. We have received payment of scheduled post-petition receivable balances and we expect continued payment of all other post-petition receivables.

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

New Accounting Standards.

Fair Value. In May 2011, the FASB issued an accounting standards update on fair value measurement. This update requires disclosure of a sensitivity analysis for fair value measurements within Level 3 and the valuation process used. No retrospective application of this guidance is required. If we utilize Level 3 fair value measurements in the future, this guidance would significantly increase our disclosures in this area. This guidance was effective beginning with the quarter ended March 31, 2012, and did not have a material impact on our consolidated financial position, results of operations or cash flows.

Statement of Comprehensive Income. In June 2011, the FASB issued an accounting standards update on the presentation of comprehensive income. This guidance was effective beginning with the quarter ended March 31, 2012, and modified our presentation of other comprehensive income, moving it from the footnotes to the face of the financial statements in a separate Consolidated Statement of Comprehensive Income immediately following the Consolidated Statement of Income. The components of net income and other comprehensive income are unchanged and earnings per share continues to be based on net income.

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, ALLETE Properties, our Florida real estate investment, and ALLETE Clean Energy, aimed at developing or acquiring capital projects that create energy solutions via wind, solar, biomass, hydro, natural gas/liquids, shale resources, clean coal and other clean energy innovations. The Investments and Other 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 investments.

Millions	Consolidated	Regulated Operations	Investments and Other
For the Quarter Ended June 30, 2012			
Operating Revenue	$216.4	$197.0	$19.4
Fuel and Purchased Power Expense	72.1	72.1	—
Operating and Maintenance Expense	96.2	76.1	20.1
Depreciation Expense	24.8	23.4	1.4
Operating Income (Loss)	23.3	25.4	(2.1)
Interest Expense	(10.1)	(9.9)	(0.2)
Equity Earnings in ATC	4.8	4.8	—
Other Income	1.2	1.2	—
Income (Loss) Before Non-Controlling Interest and Income Taxes	19.2	21.5	(2.3)
Income Tax Expense (Benefit)	4.8	7.1	(2.3)
Net Income	14.4	14.4	—
Less: Non-Controlling Interest in Subsidiaries	—	—	—
Net Income Attributable to ALLETE	$14.4	$14.4	—

Millions	Consolidated	Regulated Operations	Investments and Other
For the Quarter Ended June 30, 2011			
Operating Revenue	$219.9	$201.8	$18.1
Fuel and Purchased Power Expense	76.0	76.0	—
Operating and Maintenance Expense	95.7	77.2	18.5
Depreciation Expense	22.1	20.9	1.2
Operating Income (Loss)	26.1	27.7	(1.6)
Interest Expense	(11.0)	(9.1)	(1.9)
Equity Earnings in ATC	4.6	4.6	—
Other Income	1.0	0.6	0.4
Income (Loss) Before Non-Controlling Interest and Income Taxes	20.7	23.8	(3.1)
Income Tax Expense (Benefit)	3.8	5.5	(1.7)
Net Income (Loss)	16.9	18.3	(1.4)
Less: Non-Controlling Interest in Subsidiaries	(0.1)	—	(0.1)
Net Income (Loss) Attributable to ALLETE	$17.0	$18.3	$(1.3)

NOTE 2. BUSINESS SEGMENTS (Continued)

Millions	Consolidated	Regulated Operations	Investments and Other
For the Six Months Ended June 30, 2012			
Operating Revenue	$456.4	$415.6	$40.8
Fuel and Purchased Power Expense	149.2	149.2	—
Operating and Maintenance Expense	196.1	154.2	41.9
Depreciation Expense	49.4	46.6	2.8
Operating Income (Loss)	61.7	65.6	(3.9)
Interest Expense	(21.1)	(19.5)	(1.6)
Equity Earnings in ATC	9.4	9.4	—
Other Income (Expense)	1.9	2.0	(0.1)
Income (Loss) Before Non-Controlling Interest and Income Taxes	51.9	57.5	(5.6)
Income Tax Expense (Benefit)	13.1	18.7	(5.6)
Net Income	38.8	38.8	—
Less: Non-Controlling Interest in Subsidiaries	—	—	—
Net Income Attributable to ALLETE	$38.8	$38.8	—
As of June 30, 2012			
Total Assets	$2,962.2	$2,755.4	$206.8
Property, Plant and Equipment – Net	$2,177.5	$2,119.9	$57.6
Accumulated Depreciation	$1,124.5	$1,070.1	$54.4
Capital Additions	$235.1	$232.3	$2.8

Millions	Consolidated	Regulated Operations	Investments and Other
For the Six Months Ended June 30, 2011			
Operating Revenue	$462.1	$424.8	$37.3
Fuel and Purchased Power Expense	155.0	155.0	—
Operating and Maintenance Expense	185.8	148.4	37.4
Depreciation Expense	44.4	42.1	2.3
Operating Income (Loss)	76.9	79.3	(2.4)
Interest Expense	(21.7)	(17.7)	(4.0)
Equity Earnings in ATC	9.0	9.0	—
Other Income	1.8	1.2	0.6
Income (Loss) Before Non-Controlling Interest and Income Taxes	66.0	71.8	(5.8)
Income Tax Expense (Benefit)	12.0	15.1	(3.1)
Net Income (Loss)	54.0	56.7	(2.7)
Less: Non-Controlling Interest in Subsidiaries	(0.2)	—	(0.2)
Net Income (Loss) Attributable to ALLETE	$54.2	$56.7	$(2.5)
As of June 30, 2011			
Total Assets	$2,645.5	$2,381.6	$263.9
Property, Plant and Equipment – Net	$1,861.1	$1,808.9	$52.2
Accumulated Depreciation	$1,062.6	$1,011.3	$51.3
Capital Additions	$79.7	$69.3	$10.4

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 available-for-sale in Minnesota.

Investments	June 30, 2012	December 31, 2011
Millions		
ALLETE Properties	$91.2	$91.3
Available-for-sale Securities	26.7	24.7
Other	18.1	16.3
Total Investments	$136.0	$132.3

ALLETE Properties	June 30, 2012	December 31, 2011
Millions		
Land Inventory Beginning Balance (January 1, 2012 and 2011, respectively)	$86.0	$86.0
Deeds to Collateralized Property	0.5	1.8
Land Impairment	—	(1.7)
Capitalized Improvements and Other	0.1	0.2
Cost of Real Estate Sold	—	(0.3)
Land Inventory Ending Balance	86.6	86.0
Long-Term Finance Receivables (net of allowances of $0.6 and $0.6)	1.4	2.0
Other	3.2	3.3
Total Real Estate Assets	$91.2	$91.3

Land Inventory. Land inventory is accounted for as held for use and is recorded at cost, unless the carrying value is determined not to be recoverable in accordance with the accounting standards for property, plant and equipment, in which case the land inventory is written down to fair value. Land values are reviewed for impairment on a quarterly basis and no impairments were recorded for the six months ended June 30, 2012 ($1.7 million as of December 31, 2011). In the fourth quarter of 2011, an impairment analysis of estimated future undiscounted cash flows was conducted and indicated that the cash flows were not adequate to recover the carrying basis of certain properties not strategic to our three major development projects. Consequently, we reduced the cost basis to estimated fair value resulting in a pretax impairment charge of $1.7 million. Fair value was determined based on property tax assessed values, discounted cash flow analysis, or a combination thereof.

Long-Term Finance Receivables. As of June 30, 2012, long-term finance receivables were $1.4 million net of allowance ($2.0 million net of allowance as of December 31, 2011). 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 June 30, 2012, we had an allowance for doubtful accounts of $0.6 million ($0.6 million as of December 31, 2011).

NOTE 4. DERIVATIVES

During the third quarter of 2011, we entered into a variable-to-fixed interest rate swap (Swap), designated as a cash flow hedge, in order to manage the interest rate risk associated with a $75.0 million Term Loan. The Term Loan has a variable interest rate equal to the one-month LIBOR plus 1.00 percent, has a maturity of August 25, 2014, and represents approximately 9 percent of the Company's outstanding long-term debt as of June 30, 2012. (See Note 8. Short-Term and Long-Term Debt.) The Swap agreement has a notional amount equal to the underlying debt principal and matures on August 25, 2014. The Swap agreement involves the receipt of variable rate amounts in exchange for fixed rate interest payments over the life of the agreement without an exchange of the underlying notional amount. The variable rate of the Swap is equal to the one-month LIBOR and the fixed rate is equal to 0.825 percent. Cash flows from the interest rate swap are expected to be highly effective in offsetting the variable interest expense of the debt attributable to fluctuations in the one-month LIBOR interest rate over the life of the Swap. If it is determined that a derivative is not or has ceased to be effective as a hedge, the Company prospectively discontinues hedge accounting. The shortcut method is used to assess hedge effectiveness. At inception, all shortcut method requirements were satisfied; thus changes in value of the Swap designated as the hedging instrument will be deemed 100 percent effective. As a result, there was no ineffectiveness recorded for the quarter and six months ended June 30, 2012. The mark-to-market fluctuation on the cash flow hedge was recorded in accumulated other comprehensive income on the Consolidated Balance Sheet. As of June 30, 2012, a $0.7 million decrease (a $0.4 million decrease as of December 31, 2011) in fair value has been recorded and is included in other non-current liabilities on the Consolidated Balance Sheet. Cash flows from derivative activities are presented in the same category as the item being hedged on the Consolidated Statement of Cash Flows. Amounts recorded in other comprehensive income related to cash flow hedges will be recognized in earnings when the hedged transactions occur or when it is probable that the hedged transactions will not occur. Gains or losses on interest rate hedging transactions are reflected as a component of interest expense on the Consolidated Statement of Income.

NOTE 5. 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 9. Fair Value to the consolidated financial statements in our 2011 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 June 30, 2012 and December 31, 2011. 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 June 30, 2012			
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Total
Millions				
Assets:				

Equity Securities	$18.0	—	—	$18.0
Available-for-sale Securities – Corporate Debt Securities	—	$8.3	—	8.3
Money Market Funds	14.6	—	—	14.6
Total Fair Value of Assets	$32.6	$8.3	—	$40.9
Liabilities:				
Deferred Compensation	—	$14.3	—	$14.3
Derivatives – Interest Rate Swap	—	0.7	—	0.7
Total Fair Value of Liabilities	—	$15.0	—	$15.0
Total Net Fair Value of Assets (Liabilities)	$32.6	$(6.7)	—	$25.9

NOTE 5. FAIR VALUE (Continued)

Recurring Fair Value Measures	Fair Value as of December 31, 2011			
	Level 1	Level 2	Level 3	Total
Millions				
Assets:				
Equity Securities	$17.6	—	—	$17.6
Available-for-sale Securities – Corporate Debt Securities	—	$8.2	—	8.2
Money Market Funds	11.4	—	—	11.4
Total Fair Value of Assets	$29.0	$8.2	—	$37.2
Liabilities:				
Deferred Compensation	—	$12.8	—	$12.8
Derivatives – Interest Rate Swap	—	0.4	—	0.4
Total Fair Value of Liabilities	—	$13.2	—	$13.2
Total Net Fair Value of Assets (Liabilities)	$29.0	$(5.0)	—	$24.0

Recurring Fair Value Measures Activity in Level 3	Debt Securities Issued by States of the United States (ARS)	
Millions		
Balance as of December 31, 2011 and 2010, respectively	—	$6.7
Redeemed During the Period (a)	—	(6.7)
Balance as of June 30, 2012 and 2011, respectively	—	—

(a) The remaining ARS were redeemed at carrying value on January 5, 2011.

The Company's policy is to recognize transfers in and transfers out of a given hierarchy level as of the actual date of the event or of the change in circumstances that caused the transfer. For the six months ended June 30, 2012 and 2011, there were no transfers in or out of Levels 1, 2 or 3.

Fair Value of Financial Instruments. With the exception of the item listed below, the estimated fair value of all financial instruments approximates the carrying amount. The fair value for the item listed below was based on quoted market prices for the same or similar instruments (Level 2).

Financial Instruments	Carrying Amount	Fair Value
Millions		
Long-Term Debt, Including Current Portion		
June 30, 2012	$875.8	$984.3
December 31, 2011	$863.3	$966.4

NOTE 6. REGULATORY MATTERS

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

2010 Minnesota Rate Case. Minnesota Power's current retail rates are based on a 2011 MPUC retail rate order, effective June 1, 2011, that allowed for a 10.38 percent return on common equity and a 54.29 percent equity ratio.

NOTE 6. REGULATORY MATTERS (Continued)

In February 2011, Minnesota Power appealed the MPUC's interim rate decision in the Company's 2010 rate case with the Minnesota Court of Appeals. The Company appealed the MPUC's finding of exigent circumstances in the interim rate decision with the primary arguments 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. In December 2011, the Minnesota Court of Appeals concluded that the MPUC did not err in finding exigent circumstances and properly exercised its discretion in setting interim rates. On January 4, 2012, the Company filed a petition for review at the Minnesota Supreme Court. On February 14, 2012, the Minnesota Supreme Court granted the petition for review. We cannot predict the outcome 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. Minnesota Power's formula-based contract with the City of Nashwauk is effective April 1, 2013 through June 30, 2024, and the restated formula-based contracts with the remaining 15 Minnesota municipal customers and SWL&P are effective through June 30, 2019. The rates included in these contracts are calculated using a cost-based formula methodology that is set each July 1, using estimated costs and a rate of return that is equal to our authorized rate of return for Minnesota retail customers (currently 10.38 percent). The formula-based rate methodology also provides for a yearly true-up calculation for actual costs incurred. The contract terms include a termination clause requiring a three-year notice to terminate. Under the City of Nashwauk contract, no termination notice may be given prior to July 1, 2021. Under the restated contracts, no termination notices may be given prior to June 30, 2016. A two-year cancellation notice is required for the one private non-affiliated utility in Wisconsin, and on December 31, 2011, this customer submitted a cancellation notice with termination effective on December 31, 2013. The 17 MW of average monthly demand provided to this customer is expected to be used to supply energy to prospective additional load customers beginning in 2014.

2012 Wisconsin Rate Case. SWL&P's current retail rates are based on a 2010 PSCW retail rate order, effective January 1, 2011, that allowed for a 10.9 percent return on common equity. In May 2012, SWL&P filed a rate increase request with the PSCW seeking an average overall increase of 2.5 percent for retail customers (a 1.2 percent increase in electric rates, a 0.7 percent increase in natural gas rates, and a 13.4 percent increase in water rates). The rate filing seeks an overall return on equity of 10.9 percent, and a capital structure consisting of approximately 55 percent equity and 45 percent debt. On an annualized basis, the requested rate increase would generate approximately $1.8 million in additional revenue. Evidentiary and public hearings will be scheduled in late 2012. The Company anticipates new rates will take effect during the first quarter of 2013. We cannot predict the level of rates that may be approved by the PSCW.

ALLETE Clean Energy. In August 2011, the Company filed with the MPUC for approval of certain affiliated interest agreements between ALLETE and ALLETE Clean Energy. These agreements relate to various relationships between the parties, including the accounting for certain shared services, as well as the transfer of transmission and wind development rights in North Dakota to ALLETE Clean Energy. These transmission and wind development rights are separate and distinct from those needed by Minnesota Power to meet Minnesota's renewable energy standard requirements. On July 23, 2012, the MPUC issued an order approving certain administrative items related to accounting for shared services as well as the approval of the transfer of meteorological towers, while deferring decisions related to transmission and wind development rights pending the MPUC's further review of Minnesota Power's future retail electric service needs.

The Patient Protection and Affordable Care Act of 2010 (PPACA). In March 2010, PPACA was signed into law. One of the provisions changed the tax treatment for retiree prescription drug expenses by eliminating the tax deduction for expenses that are reimbursed under Medicare Part D, beginning January 1, 2013. Based on this provision, we are subject to additional taxes in the future and were required to reverse previously recorded tax benefits which resulted in a non-recurring charge to net income of $4.0 million in 2010. In October 2010, we submitted a filing with the MPUC requesting deferral of the retail portion of the tax charge taken in 2010 resulting from PPACA. On May 24, 2011, the MPUC approved our request for deferral until the next rate case and as a result we recorded an income tax benefit of $2.9 million and a related regulatory asset of $5.0 million in the second quarter of 2011.

Pension. In December 2011, the Company filed a petition with the MPUC requesting a mechanism to recover the cost of capital associated with the prepaid pension asset (or liability) created by the required contributions under the pension plan in excess of (or less than) annual pension expense. The Company further requested a mechanism to defer pension expenses in excess of (or less than) those currently being recovered in base rates. If our petition is successful, the impact would be deferred in a regulatory asset (or liability) for recovery (or refund) in the Company's next general rate case. We cannot predict the outcome at this time.

NOTE 6. REGULATORY MATTERS (Continued)

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

Regulatory Assets and Liabilities	June 30, 2012	December 31, 2011
Millions		
Current Regulatory Assets (a)		
Deferred Fuel	$18.5	$17.5
Total Current Regulatory Assets	18.5	17.5
Non-Current Regulatory Assets		
Future Benefit Obligations Under		
Defined Benefit Pension and Other Postretirement Benefit Plans	282.0	292.8
Income Taxes	28.3	28.6
Asset Retirement Obligation	10.9	9.8
Current Cost Recovery Riders	5.9	0.7
PPACA Income Tax Deferral	5.0	5.0
Conservation Improvement Program	0.5	4.6
Other	4.3	4.4
Total Non-Current Regulatory Assets	336.9	345.9
Total Regulatory Assets	$355.4	$363.4
Non-Current Regulatory Liabilities		
Income Taxes	$20.5	$21.9
Plant Removal Obligations	16.7	15.0
Wholesale and Retail Contra AFUDC	6.3	1.5
Other	5.8	5.1
Total Non-Current Regulatory Liabilities	$49.3	$43.5

(a) Current regulatory assets are included in prepayments and other on the Consolidated Balance Sheet.

NOTE 7. 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 June 30, 2012, our equity investment in ATC was $102.6 million ($98.9 million at December 31, 2011). In the first six months of 2012, we invested $2.0 million in ATC, and on July 31, 2012, we invested an additional $1.9 million. In total, we expect to invest $4.7 million in 2012.

ALLETE's Investment in ATC	
Millions	
Equity Investment Balance as of December 31, 2011	$98.9
Cash Investments	2.0

Equity in ATC Earnings	9.4
Distributed ATC Earnings	(7.7)
Equity Investment Balance as of June 30, 2012	$102.6

NOTE 7. INVESTMENT IN ATC (Continued)

ATC’s summarized financial data for the quarters and six months ended June 30, 2012 and 2011, is as follows:

	Quarter Ended		Six Months Ended	
ATC Summarized Financial Data	June 30,		June 30,	
Income Statement Data	2012	2011	2012	2011
Millions				
Revenue	$152.2	$138.2	$299.8	$277.8
Operating Expense	71.8	63.0	141.3	126.1
Other Expense	21.1	19.6	41.1	41.9
Net Income	$59.3	$55.6	$117.4	$109.8
ALLETE’s Equity in Net Income	$4.8	$4.6	$9.4	$9.0

NOTE 8. SHORT-TERM AND LONG-TERM DEBT

Short-Term Debt. As of June 30, 2012, total short-term debt outstanding was $67.4 million ($6.5 million as of December 31, 2011) and consisted of long-term debt due within one year and notes payable. Short-term debt increased from year end primarily due to $60 million of long-term debt maturing in April 2013, which we intend to refinance prior to its maturity.

Long-Term Debt. As of June 30, 2012, total long-term debt outstanding was $808.4 million ($857.9 million as of December 31, 2011). As of June 30, 2012, we had borrowed $14.0 million under our $150.0 million line of credit due in January 2014.

On July 2, 2012, we issued $160.0 million of the Company’s First Mortgage Bonds (Bonds) in the private placement market in two series as follows:

Issue Date	Maturity Date	Principal Amount	Interest Rate
July 2, 2012	July 15, 2026	$75 Million	3.20%
July 2, 2012	July 15, 2042	$85 Million	4.08%

We have the option to prepay all or a portion of the 3.20 percent Bonds at our discretion at any time prior to January 15, 2026, subject to a make-whole provision, and at any time on or after January 15, 2026, at par, including, in each case, accrued and unpaid interest. We also have the option to prepay all or a portion of the 4.08 percent Bonds at our discretion at any time prior to January 15, 2042, subject to a make-whole provision, and at any time on or after January 15, 2042, at par, including, in each case, accrued and unpaid interest. The Bonds are subject to the additional terms and conditions of our utility mortgage. In July 2012, we used a portion of the proceeds from the sale of the Bonds to redeem $6.0 million of our 6.50 percent Industrial Development Revenue Bonds and to repay the outstanding borrowings on our $150.0 million line of credit. The remaining proceeds will be used to fund utility capital expenditures and/or for general corporate purposes. The Bonds were sold in reliance on an exemption from registration under Section 4(a)(2) of the Securities Act of 1933, as amended, to certain institutional accredited investors.

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 financial covenant requires ALLETE to maintain a ratio of Indebtedness to Total Capitalization (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 June 30, 2012, our ratio was approximately 0.43 to 1.00. Failure to meet this covenant would give rise to an event of default if not cured after notice from a 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 June 30, 2012, ALLETE was in compliance with its financial covenants.

NOTE 9. OTHER INCOME (EXPENSE)

	Quarter Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Millions				
AFUDC – Equity	$1.2	$0.5	$1.9	$1.1
Investment and Other Income	—	0.5	—	0.7
Total Other Income	$1.2	$1.0	$1.9	$1.8

NOTE 10. INCOME TAX EXPENSE

	Quarter Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
Millions				
Current Tax Expense				
Federal (a)	—	—	—	—
State (a)	—	$0.1	—	$0.2
Total Current Tax Expense	—	0.1	—	0.2
Deferred Tax Expense (Benefit)				
Federal (b)	$5.0	4.0	$13.7	10.8
State (b)	(0.4)	—	(1.2)	1.5
Change in Valuation Allowance (c)	0.4	—	1.0	—
Investment Tax Credit Amortization	(0.2)	(0.3)	(0.4)	(0.5)
Total Deferred Tax Expense	4.8	3.7	13.1	11.8
Total Income Tax Expense	$4.8	$3.8	$13.1	$12.0

(a) For the quarter and six months ended June 30, 2012, the federal and state current tax expense of zero and zero, respectively, ($0.1 million and $0.2 million for the quarter and six months ended June 30, 2011) is due to a net operating loss (NOL) which resulted primarily from the bonus depreciation provision of the Tax Relief, Unemployment Insurance Reauthorization, and Job Creation Act of 2010. The 2011 and 2012 federal and state NOLs will be carried forward to offset future taxable income.

(b) For the quarter and six months ended June 30, 2012, the state deferred tax benefit of $0.4 million and $1.2 million, respectively, is due to state renewable tax credits earned which will be carried forward to offset future state tax. The quarter ended June 30, 2011, includes a $2.9 million income tax benefit related to the MPUC approval of our request to defer the retail portion of the tax charge taken in 2010 resulting from PPACA. The six months ended June 30, 2011, includes the second quarter item above and the reversal in the first quarter 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.

(c) The increase in valuation allowance in 2012 is due to state renewable tax credits earned in 2012 which are not expected to be utilized within their allowable tax carryforward period.

For the six months ended June 30, 2012, the effective tax rate was 25.2 percent (18.2 percent for the six months ended June 30, 2011; the effective tax rate for the six months ended June 30, 2011, was lowered by 4.4 percentage points due to the non-recurring income tax benefit related to the MPUC approval of our request to defer the retail portion of the tax charge taken in 2010 resulting from PPACA and by 9.4 percentage points due to the non-recurring reversal of the 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). The increase in the effective tax rate from June 30, 2011, was primarily due to the 2011 non-recurring items above, partially offset by increased renewable tax credits in 2012. The effective tax rate deviated from the statutory rate of approximately 41 percent primarily due to deductions for AFUDC – Equity, investment tax credits, renewable tax credits and depletion, and in 2011, for the non-recurring items discussed above.

Uncertain Tax Positions. As of June 30, 2012, we had gross unrecognized tax benefits of $2.9 million ($11.4 million as of December 31, 2011). The $8.5 million decrease in the unrecognized tax benefits balance for the six months ended June 30, 2012, was due to the resolution of a federal audit matter for prior years' activity. Of this total, $0.5 million represents the amount of unrecognized tax benefits included in the Consolidated Balance Sheet, that, if recognized, would favorably impact the effective income tax rate.

NOTE 10. INCOME TAX EXPENSE (Continued)

ALLETE's IRS exam for tax years 2005 through 2009 is currently awaiting review at the IRS appeals office. If the IRS appeals process is completed during the next twelve months, substantially all of the unrecognized tax benefits as of June 30, 2012, could be reversed. The unrecognized tax benefits are primarily due to tax positions which are timing in nature and therefore would have an immaterial impact on our effective tax rate if recognized.

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 and six months ended June 30, 2012 and 2011, 0.3 million and 0.3 million options, respectively, 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.

Reconciliation of Basic and Diluted Earnings Per Share	Basic	2012 Dilutive Securities	Diluted	Basic	2011 Dilutive Securities	Diluted
Millions Except Per Share Amounts						
For the Quarter Ended June 30,						
Net Income Attributable to ALLETE	$14.4		$14.4	$17.0		$17.0
Common Shares	37.3	0.1	37.4	35.0	0.1	35.1
Earnings Per Share	$0.39		$0.39	$0.49		$0.48
For the Six Months Ended June 30,						
Net Income Attributable to ALLETE	$38.8		$38.8	$54.2		$54.2
Common Shares	37.0	0.1	37.1	34.8	0.1	34.9
Earnings Per Share	$1.05		$1.05	$1.56		$1.55

NOTE 12. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS

	Pension		Other Postretirement	
Components of Net Periodic Benefit Expense	2012	2011	2012	2011
Millions				
For the Quarter Ended June 30,				
Service Cost	$2.3	$1.9	$1.1	$0.9
Interest Cost	6.6	6.8	2.3	2.7
Expected Return on Plan Assets	(8.9)	(8.6)	(2.5)	(2.5)
Amortization of Prior Service Costs	0.1	0.1	(0.5)	(0.5)
Amortization of Net Loss	4.4	3.0	1.9	2.2
Amortization of Transition Obligation	—	—	0.1	0.1
Net Periodic Benefit Expense	$4.5	$3.2	$2.4	$2.9
For the Six Months Ended June 30,				
Service Cost	$4.6	$3.8	$2.1	$1.9
Interest Cost	13.2	13.7	4.7	5.4

Expected Return on Plan Assets	(17.7)	(17.3)	(5.0)	(4.9)
Amortization of Prior Service Costs	0.2	0.2	(0.9)	(0.9)
Amortization of Net Loss	8.7	6.0	3.8	4.3
Amortization of Transition Obligation	—	—	0.1	0.1
Net Periodic Benefit Expense	$9.0	$6.4	$4.8	$5.9

NOTE 12. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (Continued)

Employer Contributions. For the six months ended June 30, 2012, no contributions were made to our defined benefit pension plan (no contributions for the six months ended June 30, 2011). For the six months ended June 30, 2012, no contributions were made to our other postretirement benefit plan ($10.9 million for the six months ended June 30, 2011). We do not expect to make any contributions to our defined benefit pension plan in 2012, and we expect to contribute $8.7 million to our other postretirement benefit plan in 2012. In July 2012, Congress passed new legislation which included a pension funding stabilization provision. The provision, which is designed to stabilize the discount rate used to determine funding requirements from the effects of interest rate volatility, will not have a material impact on our contributions in 2012.

Accounting and disclosure requirements for the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Act) provide 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 for the federal subsidy under the Act. For the six months ended June 30, 2012, we received $0.3 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 PPAs, 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 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 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. As of June 30, 2012, Square Butte had total debt outstanding of $419.2 million. Annual debt service for Square Butte is expected to be approximately $44 million in each of the five years, 2012 through 2016, 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, under a long-term contract.

Minnkota Power Sales Agreement. 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 late 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 the ability to transmit additional wind generation on the existing 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 Oliver Wind I (50 MW) and Oliver Wind II (48 MW)—wind facilities 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 PPAs. Minnesota Power has a PPA with Manitoba Hydro that expires in April 2015. Under this agreement Minnesota Power is 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.

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

Minnesota Power has a separate PPA with Manitoba Hydro to purchase surplus energy 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, Minnesota Power will purchase at least one million MWh of energy over the contract term. In March 2011, the MPUC approved this PPA with Manitoba Hydro.

In May 2011, Minnesota Power and Manitoba Hydro signed a long-term PPA. The PPA calls for Manitoba Hydro to sell 250 MW of capacity and energy to Minnesota Power for 15 years beginning in 2020 and requires construction of additional transmission capacity between Manitoba and the U.S. The capacity price is adjusted annually until 2020 by a change in a governmental inflationary index. The energy price is based on a formula that includes an annual fixed price component adjusted for a change in a governmental inflationary index and a natural gas index, as well as market prices. On January 26, 2012, the MPUC approved this PPA with Manitoba Hydro. In February 2012, Minnesota Power and Manitoba Hydro proposed construction of a 500 kV transmission line between Manitoba and Minnesota's Iron Range in order to strengthen the electric grid, enhance regional reliability and promote a greater exchange of sustainable energy, which is expected to be in service in 2020. Total project cost and cost allocations are still to be determined.

North Dakota Wind Development. Minnesota Power uses the 465-mile, 250 kV DC transmission line that runs from Center, North Dakota, to Duluth, Minnesota to transport increasing amounts of wind energy from North Dakota while gradually phasing out coal-based electricity delivered to our system over this transmission line from Square Butte's lignite coal-fired generating unit.

Bison 1 is an 82 MW wind facility in North Dakota, which was completed in two phases. The first phase was completed in 2010, and the second phase was completed in January 2012. The project also included construction of a 22-mile, 230 kV transmission line. Bison 1 had a total project cost of $173.8 million. We expect to incur additional costs of $3.6 million through 2013, related to land restoration and completion of remaining associated upgrades for the 250 kV DC transmission line, of which $2.6 million was spent through June 30, 2012. The MPUC has approved current cost recovery for Bison 1 investments and expenses, and current customer billing rates for Bison 1 are based on a November 2011 MPUC order.

Bison 2 and Bison 3 are both 105 MW wind projects in North Dakota which are expected to be completed by the end of 2012. Construction is currently underway for both projects and the total project costs for Bison 2 and Bison 3 are estimated to be approximately $160 million each, of which $123.5 million and $100.7 million, respectively, was spent through June 30, 2012. In September 2011 and November 2011, the MPUC approved Minnesota Power's petitions seeking current cost recovery for investments and expenses related to Bison 2 and Bison 3, respectively. In August 2011 and October 2011, the NDPSC issued a Certificate of Site Compatibility for Bison 2 and Bison 3, respectively. We anticipate filing a petition with the MPUC in the second half of 2012 to establish customer billing rates for the approved cost recovery.

Coal, Rail and Shipping Contracts. We have coal supply agreements providing for the purchase of a significant portion of our coal requirements which expire in 2013. We also have coal transportation agreements in place for the delivery of a significant portion of our coal requirements with expiration dates through 2015. Our minimum annual payment obligation under these supply and transportation agreements for 2012 is $29.9 million, and for 2013 is $24.5 million. 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 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 $10.9 million in 2012, $11.1 million in 2013, $11.4 million in 2014, $11.2 million in 2015, $9.2 million in 2016 and $43.0 million thereafter.

Transmission. We are making investments in Upper Midwest transmission opportunities that strengthen or enhance the regional transmission grid. This includes the CapX2020 initiative, investments in our own transmission assets, investments in other regional transmission assets (individually or in combination with others), and our investment in ATC.

NOTE 13. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Transmission (Continued)

Transmission Investments. We have an approved cost recovery rider in place for certain transmission expenditures and the continued use of our 2009 billing factor was approved by the MPUC in May 2011. 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. In June 2011, we filed an updated billing factor that includes additional transmission projects and expenses, which we expect to be approved in 2012.

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, North Dakota to St. Cloud, Minnesota project, the Monticello, Minnesota to St. Cloud, Minnesota project, which together total a 238-mile, 345 kV line from Fargo, North Dakota to Monticello, Minnesota, and the 70-mile, 230 kV line between Bemidji, Minnesota and Minnesota Power’s Boswell Energy Center near Grand Rapids, Minnesota. Based on projected costs of the three transmission lines and the allocation agreements among participating utilities, Minnesota Power plans to invest between $100 million and $125 million in the CapX2020 initiative through 2015, of which $39.6 million was spent through June 30, 2012 ($27.8 million as of December 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 approved a route permit for the 28-mile 345 kV line between Monticello and St. Cloud. The project was completed and placed into service in December 2011. In June 2011, the MPUC approved the route permit for the Minnesota portion of the Fargo to St. Cloud project. The North Dakota permitting process is underway. The entire 238-mile, 345 kV line from Fargo to Monticello is expected to be in service by 2015.

In November 2010, the MPUC approved a route permit for the Bemidji to Grand Rapids, Minnesota line and construction for the 230 kV line project commenced in January 2011. The Leech Lake Band of Ojibwe (LLBO) subsequently petitioned the MPUC to suspend or revoke the route permit and also served the CapX2020 owners with a complaint filed in Leech Lake Tribal Court asserting adjudicatory and regulatory authority over the project. The CapX2020 owners filed a request for declaratory judgment in the United States District Court for the District of Minnesota (District Court) that the project does not require LLBO consent to cross non-tribal land within the reservation. The MPUC has taken no action in the matter in light of ongoing litigation in federal and tribal courts. In June 2011, the federal judge issued a preliminary injunction directing the LLBO to cease and desist its claims of tribal court jurisdiction or from taking other actions to interfere with regulatory review, approval or project construction. The LLBO abandoned its motion to dismiss the declaratory action because the District Court’s injunction order had already dismissed the basis for the motion, namely, that the District Court did not have jurisdiction to hear the CapX2020 owners’ action. On June 28, 2012, in a letter to the MPUC, the LLBO withdrew its petition to suspend or revoke the route permit issued to the CapX2020 owners. A consent decree dismissing the federal court action was also approved and executed by the LLBO and will be filed with the District Court in August once the LLBO revocation rights with respect to the consent decree have expired.

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.

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. Minnesota Power has evaluated various environmental compliance scenarios using possible ranges of future environmental regulations to determine prominent power supply trends and impacts on customers. All coal-fired generating facilities could potentially be impacted, with the possibility that additional environmental control installations will be needed. At Laskin and Taconite Harbor, we will also be considering options such as remissioning, repowering and retirement.

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

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. Accruals are adjusted as assessment and remediation efforts progress or as additional technical or legal information becomes 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 coal-fired generating facilities are equipped with pollution control equipment such as scrubbers, bag houses and low NO_X technologies. At this time, under currently applicable environmental regulations, these facilities are substantially compliant with applicable emission requirements.

New Source Review (NSR). In August 2008, Minnesota Power received a Notice of Violation (NOV) from the EPA asserting violations of the NSR requirements of the Clean Air Act at Boswell Units 1, 2, 3 and 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 2004 and 2005 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 specified in the 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.

Resolution of the NOVs could result in civil penalties and the installation of control technology, some of which is already planned or which has been completed to comply with 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.

Cross-State Air Pollution Rule (CSAPR). In July 2011, the EPA issued the CSAPR, which went into effect in October 2011. The final rule replaced the EPA's 2005 Clean Air Interstate Rule (CAIR). However, on December 30, 2011, the United States Court of Appeals for the District of Columbia Circuit issued a ruling staying implementation of the CSAPR, pending judicial review, and ordered that the CAIR remain in place while the CSAPR is stayed.

If the CSAPR is reinstated after judicial review, it will require states in the CSAPR region to significantly improve air quality by reducing power plant emissions that contribute to ozone and/or fine particle pollution in other states. These regulations do not directly require the installation of controls. Instead, they require facilities to have sufficient emission allowances to cover their emissions on an annual basis. These allowances would be allocated to facilities annually by the EPA and would also be able to be bought and sold.

The CAIR regulations similarly require certain states to improve air quality by reducing power plant emissions that contribute to ozone and/or fine particle pollution in other states. Minnesota participation in the CAIR was stayed by EPA administrative action while the EPA completed a review of air quality modeling issues in conjunction with the development of a final replacement rule. In its final determination, the EPA listed Minnesota as a CSAPR-affected state based on new 24-hour fine particulate NAAQS analysis. While the CAIR remains in effect, Minnesota participation in the CAIR will continue to be stayed. It is uncertain if the CSAPR-related emission restrictions will become effective for Minnesota utilities.

Since 2006, we have significantly reduced emissions at our Laskin, Taconite Harbor and Boswell generating units. Our analysis, based on our expected generation rates, indicates that these emission reductions would satisfy Minnesota Power's SO_2 and NO_X emission compliance obligations with respect to the EPA-allocated CSAPR allowances for 2012. We will continue to evaluate our compliance strategy under the CSAPR and, if any capital investments or allowance purchases are required, we would likely seek recovery of those costs. We are unable to predict any additional CSAPR compliance costs we might incur if CSAPR is reinstated.

Minnesota Regional Haze. The federal regional haze rule requires states to submit 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.

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

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 the 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 the 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.

In December 2011, the EPA published in the Federal Register a proposal to approve the trading program in the CSAPR as an alternative to determining BART. On May 30, 2012, the EPA finalized this rule allowing states participating in the CSAPR trading programs to use those programs in place of source-specific BART for SO_2 and NO_X emissions from power plants.

On January 2, 2012, the MPCA submitted to the EPA a draft supplemental Minnesota regional haze SIP stating that it would rely on the CSAPR to satisfy BART requirements for SO_2 and NO_x for electric generating units. On January 25, 2012, the EPA published in the Federal Register a proposal to approve the Minnesota SIP, including the supplemental Minnesota SIP. The MPCA submitted the final supplemental SIP to the EPA on May 8, 2012. The EPA approved the portion of the Minnesota SIP pertaining to elimination of BART requirements for those power plants which are required to comply with the CSAPR in a final rule published in the Federal Register on June 12, 2012. If the CSAPR is reinstated, Minnesota Power does not foresee a need to make significant additional expenditures at Taconite Harbor Unit 3 to comply with the regional haze rule.

If additional regional haze related controls are ultimately required, Minnesota Power will have up to five years from the final promulgation deadline to bring Taconite Harbor Unit 3 into compliance with the regional haze rule requirements. It is uncertain what controls would ultimately be required at Taconite Harbor Unit 3 under this scenario.

Mercury and Air Toxics Standards (MATS) Rule (formerly known as the Electric Generating Unit Maximum Achievable Control Technology (MACT) Rule). Under Section 112 of the Clean Air Act, the EPA is required to set emission standards for hazardous air pollutants (HAPs) for certain source categories. The EPA published the final MATS rule in the Federal Register on February 16, 2012, addressing such emissions from coal-fired utility units greater than 25 MW. There are currently 188 listed HAPs that the EPA is required to evaluate for establishment of MACT standards. In the final MATS rule, the EPA established categories of HAPs, including mercury, trace metals other than mercury, acid gases, dioxin/furans, and organics other than dioxin/furans. The EPA also established emission limits for the first three categories of HAPs, and work practice standards for the remaining categories. Affected sources must be in compliance with the rule by February 2015. States have the authority to grant sources a one-year extension and the EPA is assessing other means for granting additional extensions when justified. Compliance at our Boswell Unit 4 to address the final MATS rule is expected to result in capital expenditures totaling between $350 million to $400 million through 2016. Some additional controls for complying with the rule at our remaining coal-fired generating units may be required, the costs of which 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 March 2011, a final rule was published in the Federal Register for industrial boiler maximum achievable control technology (Industrial Boiler MACT). The rule was stayed by the EPA in May 2011, to allow the EPA time to consider additional comments received. The EPA re-proposed the rule in

December 2011. On January 9, 2012, the United States District Court for the District of Columbia ruled that the EPA stay of the Industrial Boiler MACT was unlawful, effectively reinstating the March 2011 rule and associated compliance deadlines. A final rule based on the December 2011 proposal, which will supersede the final March 2011 rule, is expected in 2012. Major sources are expected to have three years to achieve compliance with the final rule expected in 2012. It is not known yet whether the final rule will establish new compliance deadlines. Costs for complying with the final rule 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 applicable 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. Until Minnesota Power files its mercury emission reduction plan for Boswell Unit 4, it must file an annual report updating the MPUC and other stakeholders on the status of emission reduction planning for Boswell Unit 4. This annual report was filed on July 2, 2012.

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

Mercury emission limits have also been included in the recently finalized MATS rule. We anticipate that the emission reduction plan implemented to comply with the MATS rule will satisfy the mercury emission limits under Minnesota law. Costs for the Boswell Unit 4 emission reduction plan are included in the estimated capital expenditures required for compliance with the MATS rule discussed above.

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

Ozone NAAQS. The EPA has proposed to more stringently control emissions that result in ground level ozone. In January 2010, the EPA proposed to revise the 2008 eight-hour ozone standard and to adopt a secondary standard for the protection of sensitive vegetation from ozone-related damage. The EPA was scheduled to decide upon the 2008 eight-hour ozone standard in July 2011, but has announced that it is deferring revision of this standard until 2013.

Particulate Matter NAAQS. The EPA finalized the NAAQS Particulate Matter standards in September 2006. Since then, the EPA established a more stringent 24-hour average fine particulate matter ($PM_{2.5}$) standard and kept the annual average fine particulate matter standard and the 24-hour coarse particulate matter standard unchanged. The United States Court of Appeals for the District of Columbia Circuit has remanded the $PM_{2.5}$ standard to the EPA, requiring consideration of lower annual average standard values. The EPA proposed a new $PM_{2.5}$ standard on June 14, 2012, with a goal of finalizing the standard by December 14, 2012. The EPA has proposed a decrease to the current annual average fine particulate standard, which has been in place since 1997. The EPA's proposal also includes a separate fine particulate standard to improve visibility (see Minnesota Regional Haze). State attainment status determination with these new NAAQS will occur after the rule is finalized. It is not known when affected sources would have to take additional control measures if modeling demonstrates non-compliance.

SO_2 and NO_2 NAAQS. During 2010, the EPA finalized new one-hour NAAQS for SO_2 and NO_2. Ambient monitoring data indicates that Minnesota will likely be in compliance with these new standards; however, the one-hour SO_2 NAAQS also require the EPA to evaluate modeling data to determine attainment. The EPA notified states that their SIPs for attainment of the standard will be required to be submitted to the EPA for approval by June 2013. One-hour NAAQS attainment will be required by 2017.

The MPCA initiated modeling activities that included 65 sources within Minnesota that emit greater than 100 tons of SO_2 per year. However, on April 12, 2012, the MPCA notified Minnesota Power that such modeling had been suspended as a result of the EPA's announcement that the June 2013 SIP submittals would no longer require modeling demonstrations for states, such as Minnesota, in which ambient monitors indicate compliance with the new standard. The MPCA is awaiting updated EPA guidance and will communicate with affected sources once the MPCA has more information on how the state will meet the EPA's SIP requirements. The costs for complying with the final standard cannot be estimated at this time.

Climate Change. The scientific community generally accepts that emissions of GHGs are linked to global climate change. Climate change creates physical and financial risk. 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. We are 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; and
- Support research of technologies to reduce carbon emissions from generation facilities and support carbon sequestration efforts.

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

EPA Regulation of GHG Emissions. In May 2010, the EPA issued the final Prevention of Significant Deterioration (PSD) and Title V Greenhouse Gas Tailoring Rule (Tailoring Rule). The 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. However, GHG requirements are likely to be added to our existing Title V operating permits by the MPCA as these permits are renewed or amended.

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 that these control technologies could be determined to be BACT on a project-by-project basis.

On March 28, 2012, the EPA announced its proposed rule to apply CO_2 emission New Source Performance Standards (NSPS) to new fossil fuel-fired electric generating units. The proposed NSPS applies only to new or re-powered units and was open for public comment through June 25, 2012. It is anticipated that the EPA will issue NSPS for existing fossil fuel-fired generating units in the future. We cannot predict what CO_2 control measures, if any, may be required by such NSPS.

Legal challenges were filed with respect to the EPA's regulation of GHG emissions, including the Tailoring Rule. On June 26, 2012, the United States District Court for the District of Columbia upheld most of the EPA's proposed regulations, including the Tailoring Rule criteria, citing how the Clean Air Act compels the EPA to regulate in the manner the EPA proposed. 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 are unable to predict the GHG emission compliance costs we might incur; however, the costs could be material. We would seek recovery of any additional costs through cost recovery riders or in a general rate case.

Water. The Clean Water Act requires NPDES permits 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.

Clean Water Act – Aquatic Organisms. In April 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 and have a design intake flow of greater than 2 million gallons per day 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. The Section 316(b) proposed rule comment period ended in August 2011. The EPA is obligated to finalize the rule by June 27, 2013. We are currently reviewing the rule and are unable to predict the compliance costs we might incur; however, the costs could be material. We would seek recovery of any additional costs through cost recovery riders or in a general rate case.

EPA Steam Electric Power Generating Effluent Guidelines. In late 2009, the EPA announced that it will be reviewing and reissuing the federal effluent guidelines for steam electric stations. These are the underlying federal water discharge rules that apply to all steam electric stations. The EPA has indicated that the new rule promulgating these guidelines will be proposed in late 2012 and finalized in 2014. As part of the review phase for this new rule, the EPA issued an Information Collection Request (ICR) in June 2010, to most thermal electric generating stations in the country, including all five of Minnesota Power's generating stations. The ICR was completed and submitted to the EPA in September 2010, for Boswell, Laskin, Taconite Harbor, Hibbard, and Rapids Energy Center. The ICR was designed to gather extensive information on the nature and extent of all water discharge and related wastewater handling at power plants. The information gathered through the ICR will form a basis for development of the eventual new rule, which could include more restrictive requirements on wastewater discharge, flue gas desulfurization, and wet ash handling operations. We are unable to predict the costs we might incur to comply with potential future water discharge regulations at this time.

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

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

Coal Ash Management Facilities. Minnesota Power generates coal ash at all five of its coal-fired 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 proposed rule were due in November 2010. It is estimated that the final rule will be published in late 2012 or early 2013. We are unable to predict the compliance cost we might incur; however, the costs could be material. We would seek recovery of any additional costs through cost recovery riders or in a general rate case.

Manufactured Gas Plant Site. We are reviewing and addressing environmental conditions at a former manufactured gas plant site in 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. As of June 30, 2012, we had 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.

Other Matters

BNI Coal. As of June 30, 2012, BNI Coal had surety bonds outstanding of $29.8 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 $2.6 million to provide for BNI Coal’s total reclamation liability, which is currently estimated at $32.4 million. BNI Coal does not believe it is likely that any of these outstanding surety bonds or letters of credit will be drawn upon.

ALLETE Properties. As of June 30, 2012, ALLETE Properties, through its subsidiaries, had surety bonds outstanding and letters of credit to governmental entities totaling $10.2 million primarily related to development and maintenance obligations in various projects. The estimated cost of the remaining development work is approximately $7.4 million, of which $0.5 million is the contractual obligation of land purchasers. ALLETE Properties does not believe it is likely that any of these outstanding bonds or letters of credit will be drawn upon.

Community Development District Obligations. In March 2005, the Town Center District issued $26.4 million of tax-exempt, 6 percent capital improvement revenue bonds and in May 2006, the Palm Coast Park District issued $31.8 million of tax-exempt, 5.7 percent special assessment bonds. The capital improvement revenue bonds and the special assessment bonds are payable over 31 years (by May 1, 2036 and 2037, respectively) and secured by special assessments on the benefited land. The bond proceeds were used to pay for the construction of a portion of the major infrastructure improvements in each district and to mitigate traffic and environmental impacts. The assessments were billed to the landowners beginning in November 2006 for Town Center and November 2007 for Palm Coast Park. To the extent that we still own land at the time of the assessment, we will incur the cost of our portion of these assessments, based upon our ownership of benefited property. At June 30, 2012, we owned 73 percent of the assessable land in the Town Center District (73 percent at December 31, 2011) and 93 percent of the assessable land in the Palm Coast Park District (93 percent at December 31, 2011). At these ownership levels, our annual assessments are approximately $1.5 million for Town Center and $2.2 million for Palm Coast Park. As we sell property, the obligation to pay special assessments will pass to the new landowners. Under accounting guidance, these bonds are not reflected as debt on our Consolidated Balance Sheet.

Legal Proceedings. In January 2011, the Company was named as a defendant in a lawsuit in the Sixth Judicial District for the State of Minnesota by one of our customer's (United Taconite, LLC) property and business interruption insurers. In October 2006, United Taconite experienced a fire as a result of the failure of certain electrical protective equipment. The equipment at issue in the incident was not owned, designed, or installed by Minnesota Power, but Minnesota Power had provided testing and calibration services related to the equipment. The lawsuit alleges approximately $20.0 million in damages related to the fire. The Company believes that it has strong defenses to the lawsuit and intends to vigorously assert such defenses. An accrual related to any damages that may result from the lawsuit has not been recorded as of June 30, 2012, because a potential loss is not currently probable or reasonable estimable; however, the Company believes it has adequate insurance coverage for any potential loss.

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

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, and 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.

ITEM 2. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

OVERVIEW

The following discussion should be read in conjunction with our consolidated financial statements, notes to those statements, Management's Discussion and Analysis of Financial Condition and Results of Operations from the 2011 Form 10-K and the other financial information appearing elsewhere in this report. In addition to historical information, the following discussion and other parts of this Form 10-Q 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-Q under the heading "Forward-Looking Statements" located on page 5 and "Risk Factors" located in Part I, Item 1A, page 26 of our 2011 Form 10-K. The risks and uncertainties described in this Form 10-Q and our 2011 Form 10-K are not the only risks 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 risks set forth are realized.

Regulated Operations includes our regulated utilities, Minnesota Power and SWL&P, as well as our investment in ATC, a Wisconsin-based regulated utility that owns and maintains electric transmission assets in parts of Wisconsin, Michigan, Minnesota and Illinois. Minnesota Power provides regulated utility electric service in northeastern Minnesota to approximately 143,000 retail customers. Minnesota Power's non-affiliated municipal customers consist of 16 municipalities in Minnesota and 1 private utility in Wisconsin. SWL&P is also a private utility in Wisconsin and a customer of Minnesota Power. SWL&P provides regulated electric, natural gas and water service in northwestern Wisconsin to approximately 15,000 electric customers, 12,000 natural gas customers and 10,000 water customers. Our regulated utility operations include retail and wholesale activities under the jurisdiction of state and federal regulatory authorities.

Investments and Other is comprised primarily of BNI Coal, our coal mining operations in North Dakota, ALLETE Properties, our Florida real estate investment, and ALLETE Clean Energy, aimed at developing or acquiring capital projects that create energy solutions via wind, solar, biomass, hydro, natural gas/liquids, shale resources, clean coal and other clean energy innovations. 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 investments.

ALLETE is incorporated under the laws of Minnesota. Our corporate headquarters are in Duluth, Minnesota. Statistical information is presented as of June 30, 2012, 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.

Financial Overview

The following net income discussion summarizes a comparison of the six months ended June 30, 2012, to the six months ended June 30, 2011.

Net income attributable to ALLETE for the six months ended June 30, 2012, was $38.8 million, or $1.05 per diluted share, compared to $54.2 million, or $1.55 per diluted share, for the same period of 2011. Net income for 2011 included the reversal of a $6.2 million, or $0.18 per share, deferred tax liability related to a revenue receivable Minnesota Power agreed to forgo as part of a stipulation and settlement agreement in its 2010 rate case. Net income for 2011 also included the recognition of a $2.9 million, or $0.08 per share, income tax benefit related to the MPUC approval of our request to defer the retail portion of the tax charge taken in 2010 resulting from the PPACA. The remaining decrease resulted from a 1.8 percent reduction in kilowatt-hour sales, higher costs under our Square Butte PPA, increased operating and maintenance expense, and higher depreciation expense. The decrease in net income was partially offset by higher current cost recovery rider revenue.

OVERVIEW (Continued)

Regulated Operations net income attributable to ALLETE was $38.8 million for the first six months of 2012, compared to $56.7 million for the same period of 2011. Net income for 2011 included the reversal of a $6.2 million deferred tax liability related to a revenue receivable Minnesota Power agreed to forgo as part of a stipulation and settlement agreement in its 2010 rate case. Net income for 2011 also included the recognition of a $2.9 million income tax benefit related to the MPUC approval of our request to defer the retail portion of the tax charge taken in 2010 resulting from the PPACA. The remaining decrease resulted from a 1.8 percent reduction in kilowatt-hour sales, higher costs under our Square Butte PPA, increased operating and maintenance expense, and higher depreciation and interest expense. The decrease in net income was partially offset by higher current cost recovery rider revenue.

Investments and Other reflected no net income attributable to ALLETE for the first six months of 2012, compared to a net loss of $2.5 million in 2011. The increase in 2012 was primarily due to lower state income tax and interest expenses.

COMPARISON OF THE QUARTERS ENDED JUNE 30, 2012 AND 2011

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

Regulated Operations

Operating revenue decreased $4.8 million, or 2 percent, from 2011 primarily due to lower fuel adjustment clause recoveries and a 2.3 percent decrease in kilowatt-hours sold, lower revenue from our municipal customers and lower gas sales. These decreases were partially offset by higher current cost recovery rider revenue and transmission revenue.

Fuel adjustment clause recoveries decreased $3.5 million, or 18 percent, from 2011 due to lower fuel and purchased power costs attributable to our retail and municipal customers. (See Operating Expenses - Fuel and Purchased Power Expense.)

Revenue decreased $5.0 million due to a 2.3 percent reduction in kilowatt-hour sales. The decrease in kilowatt-hour sales was primarily due to lower sales to residential customers and other power suppliers. Residential sales were down primarily due to unseasonably warm weather during April 2012. Sales to our industrial customers remained strong, increasing 3.4 percent over last year.

Revenue from our municipal customers decreased $3.4 million due to period-over-period fluctuations in the true-up for actual costs provisions of the contracts. The rates included in these contracts are calculated using a cost-based formula methodology that is set at July 1 each year using estimated costs and a true-up for actual costs the following year.

Gas sales at SWL&P decreased $1.2 million from last year, also due to the unseasonably warm weather during April 2012 (see Operating Expenses - Operating and Maintenance Expense).

Current cost recovery rider revenue increased $6.1 million primarily due to higher capital expenditures related to our Bison projects.

Transmission revenue increased $1.9 million primarily due to higher MISO Regional Expansion Criteria and Benefits (RECB) revenue related to our investment in CapX2020.

Kilowatt-hours Sold Quarter Ended June 30, Millions	2012	2011	Quantity Variance	% Variance
Regulated Utility				
Retail and Municipals				
Residential	226	238	(12)	(5.0)%
Commercial	326	328	(2)	(0.6)%
Industrial	1,842	1,782	60	3.4%
Municipals	234	230	4	1.7%
Total Retail and Municipals	2,628	2,578	50	1.9%
Other Power Suppliers	492	614	(122)	(19.9)%
Total Regulated Utility Kilowatt-hours Sold	3,120	3,192	(72)	(2.3)%

COMPARISON OF THE QUARTERS ENDED JUNE 30, 2012 AND 2011 (Continued)
Regulated Operations (Continued)

Industrial Revenue. Revenue from electric sales to taconite customers accounted for 28 percent of consolidated operating revenue in 2012 (27 percent in 2011). Revenue from electric sales to paper and pulp mills accounted for 9 percent of consolidated operating revenue in 2012 (9 percent in 2011). Revenue from electric sales to pipelines and other industrials accounted for 7 percent of consolidated operating revenue in 2012 (8 percent in 2011).

Operating expenses decreased $2.5 million, or 1 percent, from 2011.

Fuel and Purchased Power Expense decreased $3.9 million, or 5 percent, from 2011 as lower wholesale power prices and a decrease in company generation were partially offset by higher coal prices and increased costs under our Square Butte PPA. (See Operating Revenue.)

Operating and Maintenance Expense decreased $1.1 million, or 1 percent, from 2011 primarily due to lower purchased gas costs at SWL&P related to the reduction in gas sales that resulted from unseasonably warm weather during April 2012; purchased gas costs are recovered through a purchased gas adjustment clause from customers (see Operating Revenue).

Depreciation Expense increased $2.5 million, or 12 percent, from 2011 reflecting additional property, plant and equipment in service.

Interest expense increased $0.8 million, or 9 percent, from 2011 primarily due to higher average long-term debt balances, partially offset by higher AFUDC - Debt.

Despite lower earnings, income tax expense increased $1.6 million, or 29 percent, from 2011, primarily due to the recognition of a $2.9 million income tax benefit related to the MPUC approval of our request to defer the retail portion of the tax charge taken in 2010 resulting from PPACA, which was partially offset by higher renewable tax credits in 2012.

Investments and Other

Operating revenue increased $1.3 million, or 7 percent, from 2011 primarily due to a $1.8 million increase in revenue at BNI Coal, which operates under a cost-plus contract and recorded higher sales revenue primarily as a result of higher expenses in 2012 (see Operating Expense).

Operating expenses increased $1.8 million, or 9 percent, from 2011 reflecting higher expenses at BNI Coal of $1.7 million primarily due to higher fuel costs and new equipment leases; these costs are recovered through the cost-plus contract (see Operating Revenue).

Interest expense decreased $1.7 million from 2011 primarily due to an increase in the proportion of ALLETE interest expense allocated to Minnesota Power. We record interest expense for Regulated Operations based on Minnesota Power's rate base and authorized capital structure, and allocate the balance to Investments and Other. Interest expense also decreased due to the reversal of interest accrued in previous years related to our uncertain tax positions.

Income tax benefits increased $0.6 million primarily due to lower state tax expense in 2012.

Income Taxes – Consolidated

For the quarter ended June 30, 2012, the effective tax rate was 25.0 percent (18.4 percent for the quarter ended June 30, 2011; the effective tax rate for the quarter ended June 30, 2011, was lowered by 14.0 percentage points due to the non-recurring income tax benefit related to the MPUC approval of our request to defer the retail portion of the tax charge taken in 2010 resulting from the PPACA). The increase in the effective tax rate from June 30, 2011, was primarily due to the 2011 non-recurring item above, partially offset by increased renewable tax credits in 2012. The effective tax rate deviated from the statutory rate of approximately 41 percent primarily due to deductions for AFUDC - Equity, investment tax credits, renewable tax credits and depletion, and in 2011, for the non-recurring item discussed above. (See Note 10. Income Tax Expense.)

COMPARISON OF THE SIX MONTHS ENDED JUNE 30, 2012 AND 2011

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

Regulated Operations

Operating revenue decreased $9.2 million, or 2 percent, from 2011 primarily due to lower fuel adjustment clause recoveries, a 1.8 percent decrease in kilowatt-hours sold, lower revenue from our municipal customers and lower gas sales. These decreases were partially offset by higher current cost recovery rider revenue and transmission revenue.

Fuel adjustment clause recoveries decreased $8.9 million, or 19 percent, from 2011 due to lower fuel and purchased power costs attributable to our retail and municipal customers. (See Operating Expenses - Fuel and Purchased Power Expense.)

Revenue decreased $6.7 million due to a 1.8 percent reduction in kilowatt-hour sales. The decrease in kilowatt-hour sales was primarily due to lower sales to residential customers and other power suppliers. Residential sales were down primarily due to unseasonably warm weather during the first four months of 2012; heating degree days in Duluth, Minnesota were approximately 22 percent lower than the first four months of 2011. Sales to our industrial customers remained strong, increasing 2.5 percent over the last year.

Revenue from our municipal customers decreased $3.4 million due to period-over-period fluctuations in the true-up for actual costs provisions of the contracts. The rates included in these contracts are calculated using a cost-based formula methodology that is set at July 1 each year using estimated costs and a true-up for actual costs the following year.

Gas sales at SWL&P decreased $2.9 million from last year, also due to the unseasonably warm weather during the first four months of 2012 (see Operating Expenses - Operating and Maintenance Expense).

Current cost recovery rider revenue increased by $8.8 million primarily due to higher capital expenditures related to our Bison projects.

Transmission revenue increased $3.5 million primarily due to higher MISO Regional Expansion Criteria and Benefits (RECB) revenue related to our investment in CapX2020.

Kilowatt-hours Sold			Quantity		%	
Six Months Ended June 30,	2012	2011	Variance		Variance	
Millions						
Regulated Utility						
Retail and Municipals						
Residential	552	600	(48	)	(8.0	)%
Commercial	690	704	(14	)	(2.0	)%
Industrial	3,710	3,620	90		2.5	%
Municipals	498	499	(1	)	(0.2	)%
Total Retail and Municipals	5,450	5,423	27		0.5	%
Other Power Suppliers	1,009	1,154	(145	)	(12.6	)%
Total Regulated Utility Kilowatt-hours Sold	6,459	6,577	(118	)	(1.8	)%

Industrial Revenue. Revenue from electric sales to taconite customers accounted for 27 percent of consolidated operating revenue in 2012 (26 percent in 2011). Revenue from electric sales to paper and pulp mills accounted for 9 percent of consolidated operating revenue in 2012 (9 percent in 2011). Revenue from electric sales to pipelines and other industrials accounted for 7 percent of consolidated operating revenue in 2012 (7 percent in 2011).

Operating expenses increased $4.5 million, or 1 percent, from 2011.

COMPARISON OF THE SIX MONTHS ENDED JUNE 30, 2012 AND 2011 (Continued)
Regulated Operations (Continued)

Fuel and Purchased Power Expense decreased $5.8 million, or 4 percent, from 2011 as lower wholesale power prices and a decrease in company generation were partially offset by higher coal prices and increased costs under our Square Butte PPA. (See Operating Revenue.)

Operating and Maintenance Expense increased $5.8 million or 4 percent, from 2011 due to increased salary, benefit, and transmission expenses, partially offset by lower purchased gas costs. Benefit expenses increased primarily due to higher pension expense resulting from lower discount rates. Transmission expense increased primarily due to higher MISO RECB expenses. Purchased gas costs at SWL&P decreased due to a reduction in gas sales due to unseasonably warm weather during the first four months of 2012; purchased gas costs are recovered from customers through a purchased gas adjustment clause(see Operating Revenue).

Depreciation Expense increased $4.5 million, or 11 percent, from 2011 reflecting additional property, plant and equipment in service.

Interest expense increased $1.8 million, or 10 percent, from 2011 primarily due to higher average long-term debt balances, partially offset by higher AFUDC - Debt.

Despite lower earnings, income tax expense increased $3.6 million, or 24 percent, from 2011, primarily due to the 2011 reversal of a $6.2 million deferred tax liability related to a revenue receivable Minnesota Power agreed to forgo as part of a stipulation and settlement agreement in its 2010 rate case and the recognition of a $2.9 million income tax benefit related to the MPUC approval of our request to defer the retail portion of the tax charge taken in 2010 resulting from PPACA. These increases were partially offset by increased renewable tax credits in 2012.

Investments and Other

Operating revenue increased $3.5 million, or 9 percent, from 2011 primarily due to a $4.9 million increase in revenue at BNI Coal, which operates under a cost-plus contract and recorded higher sales revenue primarily as a result of higher expenses in 2012 (see Operating Expense). Revenue at ALLETE Properties decreased $0.8 million from 2011 primarily due to a land sale in March 2011.

ALLETE Properties	2012		2011	
Revenue and Sales Activity	Quantity	Amount	Quantity	Amount
Dollars in Millions				
Revenue from Land Sales				
Acres (a)	—	—	3	$0.4
Revenue from Land Sales		—		0.4
Other Revenue (b)		$0.3		0.7
Total ALLETE Properties Revenue		$0.3		$1.1

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

(b) For the six months ended June 30, 2011, Other Revenue included a $0.4 million forfeited deposit due to the transfer of property back to ALLETE Properties by deed-in-lieu of foreclosure, in satisfaction of amounts previously owed under long-term financing receivables.

Operating expenses increased $5.0 million, or 13 percent, from 2011 reflecting higher expenses at BNI Coal of $4.4 million primarily due to higher fuel costs and new equipment leases; these costs are recovered through the cost-plus contract (see Operating Revenue).

Interest expense decreased $2.4 million from 2011 primarily due to an increase in the proportion of ALLETE interest expense allocated to Minnesota Power. We record interest expense for Regulated Operations based on Minnesota Power's rate base and authorized capital structure, and allocate the balance to Investments and Other. Interest expense also decreased due to the reversal of interest accrued in previous years related to our uncertain tax positions.

Income tax benefits increased $2.5 million primarily due to lower state tax expenses in 2012.

COMPARISON OF THE SIX MONTHS ENDED JUNE 30, 2012 AND 2011 (Continued)

Income Taxes – Consolidated

For the six months ended June 30, 2012, the effective tax rate was 25.2 percent (18.2 percent for the six months ended June 30, 2011; the effective tax rate for the six months ended June 30, 2011, was lowered by 4.4 percentage points due to the income tax benefit related to the MPUC approval of our request to defer the retail portion of the tax charge taken in 2010 resulting from the PPACA and by 9.4 percentage points due to the reversal of the 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). The increase in the effective tax rate from June 30, 2011, was primarily due to the 2011 non-recurring items above, partially offset by increased renewable tax credits in 2012. The effective tax rate deviated from the statutory rate of approximately 41 percent primarily due to deductions for AFUDC - Equity, investment tax credits, renewable tax credits and depletion, and in 2011, for the non-recurring items discussed above. (See Note 10. Income Tax Expense.)

CRITICAL ACCOUNTING POLICIES

Certain accounting measurements under GAAP involve management's judgment about subjective factors and estimates, the effects of which are inherently uncertain. Accounting measurements that we believe are most critical to our reported results of operations and financial condition include: regulatory accounting, pension and postretirement health and life actuarial assumptions, impairment of long-lived assets and taxation. These policies are reviewed with the Audit Committee of our Board of Directors on a regular basis and summarized in Part II, Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations of our 2011 Form 10-K.

OUTLOOK

For additional information see our 2011 Form 10-K.

ALLETE is an energy company committed to earning a financial return that rewards our shareholders, allows for reinvestment in our businesses and sustains growth. The Company has a key long-term objective of achieving minimum average earnings per share growth of 5 percent per year (using 2010 as a base year) and maintaining a competitive dividend payout. To accomplish this, Minnesota Power will continue to pursue customer growth opportunities and current cost recovery rider approval for environmental, renewable and transmission investments, as well as work with legislators and regulators to earn a fair rate of return. In addition, ALLETE will pursue new energy-centric initiatives that provide long-term earnings growth potential, while at the same time reduce our exposure to industrial electricity sales. The new energy-centric pursuits will be in renewable energy, transmission and other energy-related infrastructure or infrastructure services.

We believe that, over the long-term, less carbon intensive and more sustainable renewable energy sources will play an increasingly important role in our nation's energy mix. Minnesota Power is developing additional renewable resources which will be used to meet regulated renewable supply requirements. In addition, in June 2011, we established ALLETE Clean Energy, a wholly-owned subsidiary of ALLETE. ALLETE Clean Energy operates independently of Minnesota Power to develop or acquire capital projects aimed at creating energy solutions via wind, solar, biomass, hydro, natural gas/liquids, shale resources, clean coal and other clean energy innovations. ALLETE Clean Energy intends to market to electric utilities, cooperatives, municipalities, independent power marketers and large end-users across North America through long-term PPAs, and will be subject to applicable state and federal regulatory approvals. For wind development, we intend to capitalize on our existing presence in North Dakota through BNI Coal, our DC transmission line and our Bison 1, 2 and 3 wind projects. We have a long-term business presence and established landowner relationships in North Dakota.

We plan to make investments in Upper Midwest transmission opportunities that strengthen or enhance the regional transmission grid or take advantage of our geographical location between sources of renewable energy and end users. This includes the CapX2020 initiative, investments in our own transmission assets, investments in other regional transmission assets (individually or in combination with others), and our investment in ATC. Transmission investments could be made by Minnesota Power or a subsidiary of ALLETE. (See Transmission.)

OUTLOOK (Continued)

North American energy trends continue to evolve, and may be impacted by emerging technological, environmental, and demand changes. We believe this may create opportunity, and we are exploring investing in other energy-centric businesses related to energy infrastructure and infrastructure services. Our investment criteria focuses on investments with recurring or contractual revenues, differentiated offerings and reasonable barriers to entry. In addition, investments would typically support ALLETE's investment grade credit metrics and dividend policy.

Regulated Operations. Minnesota Power's long-term strategy is to be the leading electric energy provider in northeastern Minnesota by providing safe, reliable and cost-competitive electric energy, while complying with environmental permit conditions and renewable requirements. Keeping the cost of energy production competitive enables Minnesota Power to effectively compete in the wholesale power markets and minimizes retail rate increases to help maintain the viability of its customers. As part of maintaining cost competitiveness, Minnesota Power intends to reduce its exposure to possible future carbon and GHG legislation by reshaping its generation portfolio, over time, to reduce its reliance on coal. We will monitor and review proposed environmental regulations and may challenge those that add considerable cost with limited environmental benefit. Minnesota Power will continue to pursue customer growth opportunities and current cost recovery rider approval for environmental, renewable and transmission investments, as well as work with legislators and regulators to earn a fair rate of return. We project that our Regulated Operations will not earn its allowed rate of return in 2012.

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

Rates. Minnesota Power's current retail rates are based on a 2011 MPUC retail rate order, effective June 1, 2011, that allowed for a 10.38 percent return on common equity and a 54.29 percent equity ratio.

Interim Rate Appeal. In February 2011, Minnesota Power appealed the MPUC's interim rate decision in the Company's 2010 rate case with the Minnesota Court of Appeals. The Company appealed the MPUC's finding of exigent circumstances in the interim rate decision with the primary arguments 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. In December 2011, the Minnesota Court of Appeals concluded that the MPUC did not err in finding exigent circumstances and properly exercised its discretion in setting interim rates.

On January 4, 2012, the Company filed a petition for review at the Minnesota Supreme Court. On February 14, 2012, the Minnesota Supreme Court granted the petition for review. We cannot predict the outcome at this time.

Pension. In December 2011, the Company filed a petition with the MPUC requesting a mechanism to recover the cost of capital associated with the prepaid pension asset (or liability) created by the required contributions under the pension plan in excess of (or less than) annual pension expense. The Company further requested a mechanism to defer pension expenses in excess of (or less than) those currently being recovered in base rates. If our petition is successful, the impact would be deferred in a regulatory asset (or liability) for recovery (or refund) in the Company's next general rate case. We cannot predict the outcome at this time.

ALLETE Clean Energy. In August 2011, the Company filed with the MPUC for approval of certain affiliated interest agreements between ALLETE and ALLETE Clean Energy. These agreements relate to various relationships between the parties, including the accounting for certain shared services, as well as the transfer of transmission and wind development rights in North Dakota to ALLETE Clean Energy. These transmission and wind development rights are separate and distinct from those needed by Minnesota Power to meet Minnesota's renewable energy standard requirements. On July 23, 2012, the MPUC issued an order approving certain administrative items related to accounting for shared services as well as the approval of the transfer of meteorological towers, while deferring decisions related to transmission and wind development rights pending the MPUC's further review of Minnesota Power's future retail electric service needs.

OUTLOOK (Continued)
Regulatory Matters (Continued)

Federal Energy Regulatory Commission. 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. Minnesota Power’s formula-based contract with the City of Nashwauk is effective April 1, 2013 through June 30, 2024, and the restated formula-based contracts with the remaining 15 Minnesota municipal customers and SWL&P are effective through June 30, 2019. The rates included in these contracts are calculated using a cost-based formula methodology that is set each July 1, using estimated costs and a rate of return that is equal to our authorized rate of return for Minnesota retail customers (currently 10.38 percent). The formula-based rate methodology also provides for a yearly true-up calculation for actual costs incurred. The contract terms include a termination clause requiring a three-year notice to terminate. Under the City of Nashwauk contract, no termination notice may be given prior to July 1, 2021. Under the restated contracts, no termination notices may be given prior to June 30, 2016. A two-year cancellation notice is required for the one private non-affiliated utility in Wisconsin, and on December 31, 2011, this customer submitted a cancellation notice with termination effective on December 31, 2013. The 17 MW of average monthly demand provided to this customer is expected to be used to supply energy to prospective additional load customers beginning in 2014.

Public Service Commission of Wisconsin. SWL&P’s current retail rates are based on a 2010 PSCW retail rate order, effective January 1, 2011, that allowed for a 10.9 percent return on common equity. In May 2012, SWL&P filed a rate increase request with the PSCW seeking an average overall increase of 2.5 percent for retail customers (a 1.2 percent increase in electric rates, a 0.7 percent increase in natural gas rates, and a 13.4 percent increase in water rates). The rate filing seeks an overall return on equity of 10.9 percent, and a capital structure consisting of approximately 55 percent equity and 45 percent debt. On an annualized basis, the requested rate increase would generate approximately $1.8 million in additional revenue. Evidentiary and public hearings will be scheduled in late 2012. The Company anticipates new rates will take effect during the first quarter of 2013. We cannot predict the level of rates that may be approved by the PSCW.

Industrial Customers. Electric power is one of several key inputs in the taconite mining, paper production and pipeline industries. Approximately 57 percent of our Regulated Utility kilowatt-hour sales in the six months ended June 30, 2012 (55 percent in the six months ended June 30, 2011) were made to our industrial customers, which include the taconite, paper, pulp and wood products, and pipeline industries.

According to the American Iron and Steel Institute (AISI), an association of North American steel producers, U.S. raw steel production operated at approximately 75 percent of capacity in 2011. Annual taconite production in Minnesota was approximately 40 million tons in 2011, near full capacity.

The AISI and the World Steel Association, an association of approximately 170 steel producers, national and regional steel industry associations and steel research institutes representing around 85 percent of world steel production, project U.S. steel consumption will be similar in 2012 compared to 2011 (for the six months ended June 30, 2012, U.S. steel production was 78 percent of capacity).

Steelworkers Union. Union contracts between the United Steelworkers union and three of our taconite mining customers operating five union taconite mining plants in Minnesota will expire at the end of August 2012. We continue to monitor the ongoing discussions. At this time we do not believe that any potential work stoppage would have a material impact on our financial position or results of operations for 2012, due to committed demand nominations through December 2012.

Prospective Additional Load. Minnesota Power is pursuing new wholesale and retail loads in and around its service territory. Currently, several companies in northeastern Minnesota continue to progress in the development of natural resource based projects that represent long-term growth potential and load diversity for Minnesota Power. These potential projects are in the ferrous and non-ferrous mining and steel industries and include PolyMet, Mesabi Nugget, USS Corporation’s expansion at its Keewatin taconite facility, Essar Steel Limited Minnesota (Essar), Magnetation, and Mining Resources, LLC (Mining Resources). We cannot predict the outcome of these projects, but if these projects are constructed, Minnesota Power could serve up to approximately 600 MW of new retail or wholesale load.

OUTLOOK (Continued)

Renewable Energy. In February 2007, Minnesota enacted a law requiring 25 percent of Minnesota Power's total retail energy sales in Minnesota be from renewable energy sources by 2025. The law also requires Minnesota Power to meet interim milestones of 12 percent by 2012, 17 percent by 2016 and 20 percent by 2020. Minnesota Power has developed a plan to meet the renewable goals set by Minnesota and has included this plan in its 2010 Integrated Resource Plan. The MPUC approved our Integrated Resource Plan in its final order issued on May 6, 2011. The law allows the MPUC to modify or delay meeting a milestone if implementation will cause significant ratepayer cost or technical reliability issues. If a utility is not in compliance with a milestone, the MPUC may order the utility to construct facilities, purchase renewable energy or purchase renewable energy credits. By the end of 2012, we expect 20 percent of the Company's generation to come from renewable energy.

Minnesota Power has taken several steps to begin executing its renewable energy strategy through key renewable projects that will ensure we meet the identified state mandate. We have executed two long-term PPAs with an affiliate of NextEra Energy, Inc., for wind energy in North Dakota (Oliver Wind I and II). Other steps include Taconite Ridge, our wind facility located in northeastern Minnesota, and our Bison 1, 2 and 3 wind projects.

North Dakota Wind Development. Minnesota Power uses the 465-mile, 250 kV DC transmission line that runs from Center, North Dakota, to Duluth, Minnesota to transport increasing amounts of wind energy from North Dakota while gradually phasing out coal-based electricity delivered to our system over this transmission line from Square Butte's lignite coal-fired generating unit.

Bison 1 is an 82 MW wind facility in North Dakota, which was completed in two phases. The first phase was completed in 2010, and the second phase was completed in January 2012. The project also included construction of a 22-mile, 230 kV transmission line. Bison 1 had a total project cost of $173.8 million. We expect to incur additional costs of $3.6 million through 2013, related to land restoration and completion of remaining associated upgrades for the 250 kV DC transmission line, of which $2.6 million was spent through June 30, 2012. The MPUC has approved current cost recovery for Bison 1 investments and expenses, and current customer billing rates for Bison 1 are based on a November 2011 MPUC order.

Bison 2 and Bison 3 are both 105 MW wind projects in North Dakota which are expected to be completed by the end of 2012. Construction is currently underway for both projects and the total project costs for Bison 2 and Bison 3 are estimated to be approximately $160 million each, of which $123.5 million and $100.7 million, respectively, was spent through June 30, 2012. In September 2011 and November 2011, the MPUC approved Minnesota Power's petition seeking current cost recovery for investments and expenses related to Bison 2 and Bison 3, respectively. In August 2011 and October 2011, the NDPSC issued a Certificate of Site Compatibility for Bison 2 and Bison 3, respectively. We anticipate filing a petition with the MPUC in the second half of 2012 to establish customer billing rates for the approved cost recovery.

Manitoba Hydro. Minnesota Power has a long-term PPA with Manitoba Hydro for the purchase of 50 MW of capacity and energy associated with that capacity, which expires in April 2015. In addition, Minnesota Power signed a separate PPA with Manitoba Hydro to purchase surplus energy 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. The MPUC approved this PPA with Manitoba Hydro in March 2011.

In May 2011, Minnesota Power and Manitoba Hydro signed an additional long-term PPA. The PPA calls for Manitoba Hydro to sell 250 MW of capacity and energy to Minnesota Power for 15 years beginning in 2020. The capacity price is adjusted annually until 2020 by a change in a governmental inflationary index. The energy price is based on a formula that includes an annual fixed price component adjusted for a change in a governmental inflationary index and a natural gas index, as well as market prices. On January 26, 2012, the MPUC approved this PPA with Manitoba Hydro. The agreement requires construction of additional transmission capacity between Manitoba and Minnesota's Iron Range. Total project cost and cost allocations are still to be determined. In addition, we are exploring other regional grid enhancements that would allow for the movement of more renewable energy in the Upper Midwest while at the same time strengthening electric reliability in the region. (See Transmission.)

Hibbard Biomass Upgrade Project. Hibbard is a 51 MW biomass/coal/natural gas facility located in Duluth, Minnesota. The biomass optimization project is designed to leverage existing assets to increase biomass renewable energy production at the facility for Minnesota Power customers. As a result of Minnesota Power's progress in meeting the State of Minnesota's renewable portfolio standard and current market conditions, the biomass optimization project has been deferred to post-2020.

OUTLOOK (Continued)

Integrated Resource Plan. The MPUC approved our Integrated Resource Plan in its final order issued in May 2011. A required baseload diversification study evaluating the impact of additional environmental regulations over the next two decades was filed on February 6, 2012. Through this study, Minnesota Power evaluated various environmental compliance scenarios using possible ranges of future environmental regulations to determine prominent power supply trends and impacts on customers. The report identified that all of our coal-fired Energy Centers will be impacted with the possibility that additional environmental control installations will be needed. At Laskin and Taconite Harbor, we will also be considering options such as remissioning, repowering and retirement for these facilities in our upcoming resource planning processes. An MPUC hearing regarding our baseload diversification study is expected to be held during the third quarter of 2012.

Transmission. We plan to make investments in Upper Midwest transmission opportunities that strengthen or enhance the regional transmission grid or take advantage of our geographical location between sources of renewable energy and end users. This includes the CapX2020 initiative, investments in our own transmission assets, investments in other regional transmission assets (individually or in combination with others), and our investment in ATC.

Transmission Investments. We have an approved cost recovery rider in place for certain transmission expenditures and the continued use of our 2009 billing factor was approved by the MPUC in May 2011. 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. In June 2011, we filed an updated billing factor that includes additional transmission projects and expenses, which we expect to be approved in 2012.

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, North Dakota to St. Cloud, Minnesota project, the Monticello, Minnesota to St. Cloud, Minnesota project, which together total a 238-mile, 345 kV line from Fargo, North Dakota to Monticello, Minnesota, and the 70-mile, 230 kV line between Bemidji, Minnesota and Minnesota Power’s Boswell Energy Center near Grand Rapids, Minnesota. Based on projected costs of the three transmission lines and the allocation agreements among participating utilities, Minnesota Power plans to invest between $100 million and $125 million in the CapX2020 initiative through 2015, of which $39.6 million was spent through June 30, 2012. 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 line between Monticello and St. Cloud. The project was completed and placed into service in December 2011. In June 2011, the MPUC approved the route permit for the Minnesota portion of the Fargo to St. Cloud project. The North Dakota permitting process is underway. The entire 238-mile, 345 kV line from Fargo to Monticello is expected to be in service by 2015.

In November 2010, the MPUC approved a route permit for the Bemidji to Grand Rapids, Minnesota line and construction for the 230 kV line project commenced in January 2011. The Leech Lake Band of Ojibwe (LLBO) subsequently petitioned the MPUC to suspend or revoke the route permit and also served the CapX2020 owners with a complaint filed in Leech Lake Tribal Court asserting adjudicatory and regulatory authority over the project. The CapX2020 owners filed a request for declaratory judgment in the United States District Court for the District of

Minnesota (District Court) that the project does not require LLBO consent to cross non-tribal land within the reservation. The MPUC has taken no action in the matter in light of ongoing litigation in federal and tribal courts. In June 2011, the federal judge issued a preliminary injunction directing the LLBO to cease and desist its claims of tribal court jurisdiction or from taking other actions to interfere with regulatory review, approval or project construction. The LLBO abandoned its motion to dismiss the declaratory action because the District Court's injunction order had already dismissed the basis for the motion, namely, that the District Court did not have jurisdiction to hear the CapX2020 owners' action. On June 28, 2012, in a letter to the MPUC, the LLBO withdrew its petition to suspend or revoke the route permit issued to the CapX2020 owners. A consent decree dismissing the federal court action was also approved and executed by the LLBO and will be filed with the District Court in August once the LLBO revocation rights with respect to the consent decree have expired.

OUTLOOK (Continued)
Transmission (Continued)

Manitoba Hydro PPA - Future Transmission Requirements. As a condition of the long-term PPA signed in May 2011 with Manitoba Hydro, construction of additional transmission capacity is required. (See Renewable Energy). In February 2012, Minnesota Power and Manitoba Hydro proposed construction of a 500 kV transmission line between Manitoba and Minnesota's Iron Range in order to strengthen the electric grid, enhance regional reliability and promote a greater exchange of sustainable energy which is expected to be in service in 2020. Total project cost and cost allocations are still to be determined.

ATC Joint Development. In addition to the Manitoba to Minnesota's Iron Range transmission line, Minnesota Power and ATC are evaluating the joint development of a 345 kV transmission line from Hibbing to Duluth, Minnesota for service in approximately 2020. This is in addition to assessing transmission alternatives in Wisconsin that would allow for the movement of more renewable energy in the Upper Midwest while at the same time strengthening electric reliability in the region. Total project costs, ownership shares and cost allocation are still to be determined.

Investment in ATC. As of June 30, 2012, our equity investment in ATC was $102.6 million, representing an approximate 8 percent ownership interest. ATC rates are based on a FERC approved 12.2 percent return on common equity dedicated to utility plant. In September 2011, ATC updated its 10-year transmission assessment covering the years 2011 through 2020 which identifies between $3.8 and $4.4 billion in transmission system improvements. This investment is expected to be funded by ATC through a combination of internally generated cash, debt and investor contributions. As opportunities arise, we plan to make additional investments in ATC through general capital calls based upon our pro rata ownership interest in ATC. In the first six months of 2012, we invested $2.0 million in ATC, and on July 31, 2012, we invested an additional $1.9 million. In total, we expect to invest approximately $4.7 million in 2012. (See Note 7. Investment in ATC.)

In April 2011, ATC and Duke Energy Corporation announced the creation of a joint venture, Duke-American Transmission Co. (DATC) that intends to build, own and operate new electric transmission infrastructure in the U.S. and Canada. DATC is subject to the rules and regulations of FERC, MISO, PJM Interconnection LLC and various other independent system operators and state regulatory authorities. In September 2011, DATC announced its first set of proposed transmission projects, which include seven new transmission line projects in five Midwestern states. The individual projects have a total cost of approximately $4 billion. We intend to maintain our approximate 8 percent ownership interest in ATC.

Hydro Operations. On June 19 and 20, 2012, record rainfall and flooding occurred near Duluth, Minnesota and surrounding areas. The flooding impacted Minnesota Power's hydro system, particularly the Thomson Energy Center, which is currently off-line due to damage to the forebay canal and flooding at the facility.

The Company has property insurance coverage of $100 million per occurrence and a deductible of $500,000 per location, providing coverage for water damage, equipment damage, and other structural damage at the facilities. The policy does not cover damage to land and earthen structures, which may include damage to the forebay canal at the Thomson Energy Center. Any expenditures to remediate the forebay canal would be capitalized.

Minnesota Power continues to assess the impacts of the flooding on our operations and is in close contact with the appropriate regulatory bodies which oversee the hydro system operations, including dams and reservoirs. Until that assessment is complete we are not able to estimate the capital costs and schedule for repairing and restoring our facilities for future operations. The Thomson facility represents approximately 5 percent of total company electric generation capability. Additional purchased power expense required due to the Thomson facility outage would be recovered through our fuel adjustment clause. We do not believe that this event will have a material impact on our financial position or results of operations.

Investments and Other

BNI Coal. BNI Coal anticipates selling approximately 4 million tons of coal in 2012 (approximately 4 million tons were sold in 2011) and has sold 2.2 million tons through June 30, 2012 (2.1 million tons were sold as of June 30, 2011).

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

OUTLOOK (Continued)
Investments and Other (Continued)

Our two major development projects are Town Center and Palm Coast Park. Another major project, Ormond Crossings, is currently in the planning stage. The City of Ormond Beach, Florida, approved a Development Agreement for Ormond Crossings which will facilitate development of the project as currently planned. Separately, the Lake Swamp wetland mitigation bank was permitted on land that was previously part of Ormond Crossings.

Summary of Development Projects (100% Owned)		Residential	Non-residential
Land Available-for-Sale	Acres (a)	Units (b)	Sq. Ft. (b, c)
Current Development Projects			
Town Center	965	2,485	2,246,200
Palm Coast Park	3,888	3,554	3,096,800
Total Current Development Projects	4,853	6,039	5,343,000
Planned Development Project			
Ormond Crossings	2,914	2,950	3,215,000
Other			
Lake Swamp Wetland Mitigation Project	3,044	(d)	(d)
Total of Development Projects	10,811	8,989	8,558,000

(a) Acreage amounts are approximate and shown on a gross basis, including wetlands.
(b) Units and square footage are estimated. Density at build out may differ from these estimates.
(c) Depending on the project, non-residential includes retail commercial, non-retail commercial, office, industrial, warehouse, storage and institutional.
(d) The Lake Swamp wetland mitigation bank is a permitted, regionally significant wetlands mitigation bank. Wetland mitigation credits will be used at Ormond Crossings and are available-for-sale to developers of other projects that are located in the bank’s service area.

In addition to the three development projects and the mitigation bank, ALLETE Properties has 1,962 acres of other land available-for-sale.

ALLETE intends to sell its Florida land assets when opportunities arise. However, if weak market conditions continue for an extended period of time, the impact on our future operations would be the continuation of little or no sales while still incurring operating expenses and carrying costs such as community development district assessments and property taxes.

Income Taxes. ALLETE’s aggregate federal and multi-state statutory tax rate is approximately 41 percent for 2012. On an ongoing basis, ALLETE has certain tax credits and other tax adjustments that reduce the statutory rate to the effective tax rate. These tax credits and adjustments historically have included items such as investment tax credits, renewable tax credits, AFUDC-Equity, depletion, as well as other items. The annual effective rate can also be impacted by such items as changes in income from operations before non-controlling interest and income taxes, state and federal tax law changes that become effective during the year, business combinations and configuration changes, tax planning initiatives and resolution of prior years’ tax matters. Due primarily to increased renewable tax credits as a result of additional wind generation, we expect our effective tax rate to be approximately 25 percent for 2012. (See Note 10. Income Tax Expense.)

LIQUIDITY AND CAPITAL RESOURCES

Liquidity Position. ALLETE is well-positioned to meet the Company’s cash flow needs. As of June 30, 2012, we had cash and cash equivalents of $8.6 million, $392.4 million in available consolidated lines of credit and a debt-to-capital ratio of 44 percent. As planned, in June 2012, we had borrowed $14.0 million under our $150.0 million line of credit. On July 2, 2012, we issued $160.0 million of the Company’s First Mortgage Bonds in the private placement market in two series (see Note 8. Shorter-Term and Long-Term Debt), of which we used a portion of the proceeds to repay the borrowing under our $150.0 million line of credit.

LIQUIDITY AND CAPITAL RESOURCES (Continued)

Capital Structure. ALLETE's capital structure is as follows:

Millions	June 30, 2012	%	December 31, 2011	%
ALLETE Equity	$1,119.7	56	$1,079.3	56
Long-Term Debt (Including Current Maturities)	875.8	44	863.3	44
Short-Term Debt	—	—	1.1	—
	$1,995.5	100	$1,943.7	100

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

For the Six Months Ended June 30, Millions	2012	2011
Cash and Cash Equivalents at Beginning of Period	$101.1	$44.9
Cash Flows from (used for)		
Operating Activities	128.1	130.0
Investing Activities	(227.0)	(87.0)
Financing Activities	6.4	(8.5)
Change in Cash and Cash Equivalents	(92.5)	34.5
Cash and Cash Equivalents at End of Period	$8.6	$79.4

Operating Activities. Cash from operating activities was $128.1 million for the six months ended June 30, 2012 ($130.0 million for the six months ended June 30, 2011). Cash from operating activities was similar to 2011 due to decreased accounts receivable collections as a result of higher income tax refunds in 2011 and lower net income, offset by increases due to the timing of contributions to other postretirement employee benefit plans, increased other current liabilities due to receipt of customer security deposits for capital expenditures relating to a transmission project, and increased accounts payable due to timing of payments for the true-up related to our municipal customer contracts.

Investing Activities. Cash used for investing activities was $227.0 million for the six months ended June 30, 2012 ($87.0 million for the six months ended June 30, 2011). The increase in cash used for investing activities was primarily due to higher capital expenditures in 2012 primarily related to our Bison projects.

Financing Activities. Cash from financing activities was $6.4 million for the six months ended June 30, 2012 (cash used for financing activities was $8.5 million for the six months ended June 30, 2011). The increase in cash from financing activities in 2012 was primarily due to proceeds of $14 million from draws on our $150.0 million line of credit. There were no long-term debt issuances in the first six months of 2011.

Working Capital. Additional working capital, if and when needed, generally is provided by consolidated bank lines of credit or the sale of securities or commercial paper. As of June 30, 2012, we had available consolidated bank lines of credit aggregating $392.4 million, the majority of which expire in June 2015. In addition, we have 1.2 million original issue shares of our common stock available for issuance through Invest Direct, our direct stock purchase and dividend reinvestment plan, and 2.3 million original issue shares of common stock available for issuance through a Distribution Agreement with KCCI, Inc. The amount and timing of future sales of our securities will depend upon market conditions and our specific needs.

Securities. We entered into a distribution agreement with KCCI, Inc. in February 2008, as amended, with respect to the issuance and sale of up to an aggregate of 6.6 million shares of our common stock, without par value. For the six months ended June 30, 2012, 0.4 million shares of common stock were issued under this agreement, for net proceeds of $18.7 million (0.4 million shares were issued for the six months ended June 30, 2011, for net proceeds of $14.7 million). The shares issued in 2012 were, and the remaining shares may be, offered for sale, from time to time, in accordance with the terms of the amended distribution agreement pursuant to Registration Statement No. 333-170289.

In 2012, we issued 0.3 million shares of common stock through Invest Direct, the Employee Stock Purchase Plan, and the Retirement Savings and Stock Ownership Plan, resulting in net proceeds of $11.8 million (0.3 million shares were issued for net proceeds of $8.2 million in 2011). These shares of common stock were registered under Registration Statement Nos. 333-166515, 333-105225 and 333-162890, respectively.

LIQUIDITY AND CAPITAL RESOURCES (Continued)
Securities (Continued)

On July 2, 2012, we issued $160.0 million of the Company's First Mortgage Bonds (Bonds) in the private placement market in two series. (See Note 8. Short-Term and Long-Term Debt.) On July 16, 2012, we used a portion of the proceeds from the sale of the Bonds to redeem $6.0 million of 6.50 percent Industrial Development Revenue Bonds and to repay the outstanding borrowings on our $150.0 million line of credit. The remaining proceeds will be used to fund utility capital expenditures and/or for general corporate purposes.

Financial Covenants. See Note 8. Short-Term and Long-Term Debt for information regarding our financial covenants.

Pension and Other Postretirement Benefit Plans. Management considers various factors when making funding decisions, such as regulatory requirements, actuarially determined minimum contribution requirements and contributions required to avoid benefit restrictions for the defined benefit pension plans. We do not expect to contribute to our defined benefit pension plan in 2012. We expect to contribute $8.7 million to our other postretirement benefit plan in 2012. (See Note 12. Pension and Other Postretirement Benefit Plans.)

Off-Balance Sheet Arrangements

Off-balance sheet arrangements are summarized in our 2011 Form 10-K, with additional disclosure in Note 13. Commitments, Guarantees and Contingencies of this Form 10-Q.

Capital Requirements

Our capital expenditures for 2012 are expected to be approximately $440 million. For the six months ended June 30, 2012, capital expenditures totaled $235.1 million ($79.7 million for the six months ended June 30, 2011). The expenditures were primarily made in the Regulated Operations segment.

OTHER

Environmental Matters

Our businesses are subject to regulation of environmental matters by various federal, state and local authorities. Due to future environmental requirements through legislation and/or rulemaking in the future, we anticipate that potential expenditures for environmental matters will be material and will require significant capital investments. Environmental Matters are summarized in our 2011 Form 10-K, with additional disclosure in Note 13. Commitments, Guarantees and Contingencies of this Form 10-Q.
We are unable to predict the outcome of the matters discussed.

NEW ACCOUNTING STANDARDS

New accounting standards are discussed in Note 1. Operations and Significant Accounting Policies of this Form 10-Q.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

SECURITIES INVESTMENTS

Available-for-sale Securities. As of June 30, 2012, our available-for-sale securities portfolio consisted of securities held to fund certain employee benefits. (See Note 3. Investments.)

COMMODITY PRICE RISK

Our regulated utility operations incur costs for power and fuel (primarily coal and related transportation) in Minnesota and power and natural gas purchased for resale in our regulated service territory in Wisconsin. Our Minnesota regulated utility's exposure to price risk for these commodities is significantly mitigated by the current ratemaking process and regulatory framework, which allows recovery of fuel costs in excess of those included in base rates. Conversely, costs below those in base rates result in a credit to our ratepayers. We seek to prudently manage our customers' exposure to price risk by entering into contracts of various durations and terms for the purchase of power and coal and related transportation costs (Minnesota Power) and natural gas (SWL&P).

POWER MARKETING

Our power marketing activities consist of: (1) purchasing energy in the wholesale market to serve our regulated service territory when retail energy requirements exceed generation output; and (2) selling excess available energy and purchased power. From time to time, our utility operations may have excess energy that is temporarily not required by retail and municipal customers in our regulated service territory. We actively sell any excess energy to the wholesale market to optimize the value of our generating facilities.

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

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. We may also enter into derivative financial instruments, such as interest rate swaps, to mitigate interest rate exposure. Interest rates on variable rate long-term debt are reset on a periodic basis reflecting prevailing market conditions. Based on the variable rate debt outstanding at June 30, 2012, and assuming no other changes to our financial structure, an increase of 100 basis points in interest rates would impact the amount of pretax interest expense by $0.7 million. This amount was determined by considering the impact of a hypothetical 100 basis point increase to the average variable interest rate on the variable rate debt outstanding as of June 30, 2012.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures. As of June 30, 2012, evaluations were performed, under the supervision and with the participation of management, including our principal executive officer and principal financial officer, of the effectiveness of the design and operation of ALLETE's disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934 (Exchange Act)). Based upon those evaluations, our principal executive officer and principal financial officer have concluded that such disclosure controls and procedures are effective to provide assurance that information required to be disclosed in ALLETE's reports filed or submitted under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and such information is accumulated and communicated to our management, including our principal executive officer and principal financial officer, to allow timely decisions regarding required disclosure.

Changes in Internal Controls. There has been no change in our internal control over financial reporting that occurred during our most recent fiscal quarter that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting. In January 2012, the Company completed and installed new information systems designed to enhance certain supply-chain, financial and asset management applications. These changes were not the result of any identified deficiencies in our internal control over financial reporting.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

CapX2020 Bemidji to Grand Rapids Line. In November 2010, the MPUC approved a route permit for the Bemidji to Grand Rapids, Minnesota line and construction for the 230 kV line project commenced in January 2011. The Leech Lake Band of Ojibwe (LLBO) subsequently petitioned the MPUC to suspend or revoke the route permit and also served the CapX2020 owners with a complaint filed in Leech Lake Tribal Court asserting adjudicatory and regulatory authority over the project. The CapX2020 owners filed a request for declaratory judgment in the United States District Court for the District of Minnesota (District Court) that the project does not require LLBO consent to cross non-tribal land within the reservation. The MPUC has taken no action in the matter in light of ongoing litigation in federal and tribal courts. In June 2011, the federal judge issued a preliminary injunction directing the LLBO to cease and desist its claims of tribal court jurisdiction or from taking other actions to interfere with regulatory review, approval or project construction. The LLBO abandoned its motion to dismiss the declaratory action because the District Court's injunction order had already dismissed the basis for the motion, namely, that the District Court did not have jurisdiction to hear the CapX2020 owners' action. On June 28, 2012, in a letter to the MPUC, the LLBO withdrew its petition to suspend or revoke the route permit issued to the CapX2020 owners. A consent decree dismissing the federal court action was also approved and executed by the LLBO and will be filed with the District Court in August once the LLBO revocation rights with respect to the consent decree have expired.

ITEM 1A. RISK FACTORS

There have been no material changes from the risk factors disclosed in Part 1, Item 1A Risk Factors of our 2011 Form 10-K.

ITEM 2. UNREGISTERED SALES OF EQUITY SECURITIES AND USE OF PROCEEDS

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. MINE SAFETY DISCLOSURES

The Dodd-Frank Wall Street Reform and Consumer Protection Act (Dodd-Frank Act) requires issuers to include in periodic reports filed with the SEC certain information relating to citations or orders for violations of standards under the Federal Mine Safety and Health Act of 1977 (Mine Safety Act). Information concerning mine safety violations or other regulatory matters required by Section 1503(a) of the Dodd-Frank Act and this Item are included in Exhibit 95 to this Form 10-Q.

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

Exhibit Number	
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 Periodic Report by the Chief Executive Officer and the Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
95	Mine Safety
99	ALLETE News Release dated August 2, 2012, announcing 2012 second quarter 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.)
101.INS	XBRL Instance
101.SCH	XBRL Schema
101.CAL	XBRL Calculation
101.DEF	XBRL Definition
101.LAB	XBRL Label
101.PRE	XBRL Presentation

SIGNATURES

Pursuant to the requirements 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.

August 2, 2012	/s/ Mark A. Schober Mark A. Schober Senior Vice President and Chief Financial Officer
August 2, 2012	/s/ Steven Q. DeVinck Steven Q. DeVinck Controller and Vice President – Business Support