ALLETE INC
Form 10-Q
August 01, 2013
UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-Q

(Mark One)
x Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended June 30, 2013

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. x 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). x 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 x	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 x No

Common Stock, no par value,
40,127,405 shares outstanding
as of June 30, 2013

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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 – the cost of both 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
ArcelorMittal	ArcelorMittal USA, Inc.
ATC	American Transmission Company LLC
Bison	Bison Wind Energy Center
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
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
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
Minnesota Power	An operating division of ALLETE, Inc.
Minnkota Power	Minnkota Power Cooperative, Inc.

Definitions (Continued)

Abbreviation or Acronym	Term
MISO	Midcontinent Independent System Operator, Inc.
MPCA	Minnesota Pollution Control Agency
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 Oxides
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
PolyMet	PolyMet Mining Corporation
PPA	Power Purchase Agreement
PPACA	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 can be 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 those of the United States Congress, state legislatures, the FERC, the MPUC, the PSCW, the NDPSC, the EPA and various state, local and county regulators, and city administrators, that impact our allowed rates of return, capital structure, ability to secure financing, industry and rate structure, acquisition and disposal of assets and facilities, operation and construction of plant facilities, recovery of purchased power, capital investments and other expenses, including present or prospective wholesale and retail competition and environmental matters;
- our ability to manage expansion and integrate acquisitions;
- our current and potential industrial and municipal customers’ ability to execute announced expansion plans;
- the impacts on our Regulated Operations of climate change and future regulation to restrict the emissions of GHG;
- 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;
- zoning and permitting of land held for resale, real estate development or changes in the real estate market;
- pricing, availability and transportation of fuel and other commodities and the ability to recover the costs of such 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 or performance to differ from those anticipated by this report are discussed in Item 1A under the heading “Risk Factors” beginning on page 27 of our 2012 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 we assess the impact of each of these factors on our businesses 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 identify the risks and uncertainties that may affect our business.

PART I. FINANCIAL INFORMATION
ITEM 1. FINANCIAL STATEMENTS
ALLETE
CONSOLIDATED BALANCE SHEET
Millions – Unaudited

	June 30, 2013	December 31, 2012
Assets		
Current Assets		
Cash and Cash Equivalents	$145.0	$80.8
Accounts Receivable (Less Allowance of $1.1 and $1.0)	78.7	89.0
Inventories	71.0	69.8
Prepayments and Other	26.2	33.6
Total Current Assets	320.9	273.2
Property, Plant and Equipment - Net	2,397.2	2,347.6
Regulatory Assets	337.5	340.3
Investment in ATC	111.2	107.3
Other Investments	140.2	143.5
Other Non-Current Assets	43.9	41.5
Total Assets	$3,350.9	$3,253.4
Liabilities and Equity		
Liabilities		
Current Liabilities		
Accounts Payable	$52.1	$90.5
Accrued Taxes	26.4	30.2
Accrued Interest	15.9	15.6
Long-Term Debt Due Within One Year	37.9	84.5
Other	60.8	62.6
Total Current Liabilities	193.1	283.4
Long-Term Debt	1,064.7	933.6
Deferred Income Taxes	435.5	423.8
Regulatory Liabilities	63.1	60.1
Defined Benefit Pension and Other Postretirement Benefit Plans	216.2	228.2
Other Non-Current Liabilities	129.3	123.3
Total Liabilities	2,101.9	2,052.4
Commitments, Guarantees and Contingencies (Note 14)		
Equity		
Common Stock Without Par Value, 80.0 Shares Authorized, 40.1 and 39.4 Shares Outstanding	819.3	784.7
Unearned ESOP Shares	(17.2)	(21.3)
Accumulated Other Comprehensive Loss	(21.0)	(22.0)
Retained Earnings	467.9	459.6
Total Equity	1,249.0	1,201.0
Total Liabilities and Equity	$3,350.9	$3,253.4

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,	
	2013	2012	2013	2012
Operating Revenue	$235.6	$216.4	$499.4	$456.4
Operating Expenses				
Fuel and Purchased Power	78.7	72.1	165.2	149.2
Operating and Maintenance	103.8	96.2	208.5	196.1
Depreciation	28.7	24.8	56.9	49.4
Total Operating Expenses	211.2	193.1	430.6	394.7
Operating Income	24.4	23.3	68.8	61.7
Other Income (Expense)				
Interest Expense	(12.8)	(10.1)	(25.1)	(21.1)
Equity Earnings in ATC	5.0	4.8	10.2	9.4
Other	1.5	1.2	4.2	1.9
Total Other Expense	(6.3)	(4.1)	(10.7)	(9.8)
Income Before Income Taxes	18.1	19.2	58.1	51.9
Income Tax Expense	4.1	4.8	11.6	13.1
Net Income	$14.0	$14.4	$46.5	$38.8
Average Shares of Common Stock				
Basic	39.4	37.3	39.2	37.0
Diluted	39.6	37.4	39.3	37.1
Basic Earnings Per Share of Common Stock	$0.36	$0.39	$1.19	$1.05
Diluted Earnings Per Share of Common Stock	$0.35	$0.39	$1.18	$1.05
Dividends Per Share of Common Stock	$0.475	$0.46	$0.95	$0.92

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)	2013	2012	2013	2012
Millions				
Net Income	$14.0	$14.4	$46.5	$38.8
Other Comprehensive Income (Loss)				
Unrealized Gain (Loss) on Securities				
Net of Income Taxes of $0.1, $(0.5), $0.1 and $0.2	0.1	(0.5)	0.1	0.5
Unrealized Gain (Loss) on Derivatives				
Net of Income Taxes of $0.1, $–, $0.1 and $(0.1)	—	(0.1)	0.1	(0.2)
Defined Benefit Pension and Other Postretirement Benefit Plans				
Net of Income Taxes of $0.3, $0.4, $0.5 and $0.7	0.5	0.5	0.8	1.0
Total Other Comprehensive Income (Loss)	0.6	(0.1)	1.0	1.3
Comprehensive Income	$14.6	$14.3	$47.5	$40.1

The accompanying notes are an integral part of these statements.

ALLETE
CONSOLIDATED STATEMENT OF CASH FLOWS
Millions – Unaudited

	Six Months Ended June 30, 2013	2012
Operating Activities		
Net Income	$46.5	$38.8
Allowance for Funds Used During Construction – Equity	(2.1)	(1.9)
Income from Equity Investments, Net of Dividends	(2.3)	(1.7)
Gain on Sale of Assets	(0.1)	—
Gain on Sale of Investments	(0.8)	—
Depreciation Expense	56.9	49.4
Amortization of Debt Issuance Costs	0.5	0.5
Deferred Income Tax Expense	11.6	13.1
Share-Based Compensation Expense	1.3	1.2
ESOP Compensation Expense	4.0	3.7
Defined Benefit Pension and Postretirement Benefit Expense	11.2	13.8
Bad Debt Expense	0.4	0.5
Changes in Operating Assets and Liabilities		
Accounts Receivable	9.9	12.4
Inventories	(1.2)	(0.2)
Prepayments and Other	7.4	1.6
Accounts Payable	(10.1)	(8.2)
Other Current Liabilities	(5.8)	—
Cash Contributions to Defined Benefit Pension and Other Postretirement Benefit Plans	(10.8)	—
Changes in Regulatory and Other Non-Current Assets	(8.0)	(1.8)
Changes in Regulatory and Other Non-Current Liabilities	2.6	6.9
Cash from Operating Activities	111.1	128.1
Investing Activities		
Proceeds from Sale of Available-for-sale Securities	8.1	1.0
Payments for Purchase of Available-for-sale Securities	(1.4)	(1.0)
Investment in ATC	(1.6)	(2.0)
Changes to Other Investments	(2.6)	(3.2)
Additions to Property, Plant and Equipment	(128.6)	(221.8)
Proceeds from Sale of Assets	0.9	—
Cash for Investing Activities	(125.2)	(227.0)
Financing Activities		
Proceeds from Issuance of Common Stock	33.3	30.5
Proceeds from Issuance of Long-Term Debt	150.0	15.6
Payments for Notes Payable	—	(1.1)
Payments for Long-Term Debt	(65.5)	(3.1)
Debt Issuance Costs	(1.3)	—
Dividends on Common Stock	(38.2)	(35.5)
Cash from Financing Activities	78.3	6.4
Change in Cash and Cash Equivalents	64.2	(92.5)
Cash and Cash Equivalents at Beginning of Period	80.8	101.1
Cash and Cash Equivalents at End of Period	$145.0	$8.6

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, 2012, 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, 2013, are not necessarily indicative of results that may be expected for any other interim period or for the year ending December 31, 2013. For further information, refer to the consolidated financial statements and notes included in our 2012 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, 2013	December 31, 2012
Millions		
Fuel	$25.3	$28.0
Materials and Supplies	45.7	41.8
Total Inventories	$71.0	$69.8

Prepayments and Other Current Assets	June 30, 2013	December 31, 2012
Millions		
Deferred Fuel Adjustment Clause	$18.3	$22.5
Other	7.9	11.1
Total Prepayments and Other Current Assets	$26.2	$33.6

Other Current Liabilities	June 30, 2013	December 31, 2012
Millions		
Customer Deposits	$29.1	$28.8
Other	31.7	33.8
Total Other Current Liabilities	$60.8	$62.6

Other Non-Current Liabilities	June 30, 2013	December 31, 2012
Millions		
Asset Retirement Obligation	$81.6	$77.9
Other	47.7	45.4
Total Other Non-Current Liabilities	$129.3	$123.3

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Supplemental Statement of Cash Flows Information.

For the Six Months Ended June 30,	2013	2012
Millions		
Cash Paid During the Period for Interest – Net of Amounts Capitalized	$22.8	$21.7
Cash Paid During the Period for Income Taxes	$0.6	$0.2
Noncash Investing and Financing Activities		
Decrease in Accounts Payable for Capital Additions to Property, Plant and Equipment	$28.2	$14.8
Capitalized Asset Retirement Costs	$1.9	$2.4
AFUDC – Equity	$2.1	$1.9

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.

Amounts Reclassified Out of Accumulated Other Comprehensive Income. In February 2013, the FASB issued an accounting standard update on disclosure of amounts reclassified out of accumulated other comprehensive income. This update requires entities to provide information about amounts reclassified out of accumulated other comprehensive income by component. In addition, entities are required to present, either on the face of the statement where net income is presented or in the notes, significant amounts reclassified out of accumulated other comprehensive income by the respective line items of net income but only if the amount reclassified is required under GAAP to be reclassified to net income in its entirety in the same reporting period. For other amounts that are not required under GAAP to be reclassified in their entirety to net income, entities are required to cross-reference to other disclosures required under GAAP that provide additional detail on these amounts. This guidance was adopted beginning with the quarter ended March 31, 2013, and required additional disclosures but did not have an impact on our consolidated financial position, results of operations, or cash flows. (See Note 11. Reclassifications Out of Accumulated Other Comprehensive Income (Loss).)

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 regulated 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, our business aimed at developing or acquiring capital projects that create energy solutions via wind, solar, biomass, midstream gas and oil infrastructure, among other energy-related projects. This segment also includes other business development and corporate expenditures, a small amount of non-rate base generation, approximately 6,000 acres of land in Minnesota, and earnings on cash and investments.

Millions	Consolidated	Regulated Operations	Investments and Other
For the Quarter Ended June 30, 2013			
Operating Revenue	$235.6	$215.8	$19.8
Fuel and Purchased Power Expense	78.7	78.7	—
Operating and Maintenance Expense	103.8	82.8	21.0
Depreciation Expense	28.7	27.1	1.6
Operating Income (Loss)	24.4	27.2	(2.8)
Interest Expense	(12.8)	(10.4)	(2.4)
Equity Earnings in ATC	5.0	5.0	—
Other Income	1.5	1.1	0.4
Income (Loss) Before Income Taxes	18.1	22.9	(4.8)
Income Tax Expense (Benefit)	4.1	6.6	(2.5)
Net Income (Loss)	$14.0	$16.3	$(2.3)

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 Income Taxes	19.2	21.5	(2.3)
Income Tax Expense (Benefit)	4.8	7.1	(2.3)
Net Income	$14.4	$14.4	—

NOTE 2. BUSINESS SEGMENTS (Continued)

Millions	Consolidated	Regulated Operations	Investments and Other
For the Six Months Ended June 30, 2013			
Operating Revenue	$499.4	$457.2	$42.2
Fuel and Purchased Power Expense	165.2	165.2	—
Operating and Maintenance Expense	208.5	165.0	43.5
Depreciation Expense	56.9	53.9	3.0
Operating Income (Loss)	68.8	73.1	(4.3)
Interest Expense	(25.1)	(21.1)	(4.0)
Equity Earnings in ATC	10.2	10.2	—
Other Income	4.2	2.2	2.0
Income (Loss) Before Income Taxes	58.1	64.4	(6.3)
Income Tax Expense (Benefit)	11.6	16.0	(4.4)
Net Income (Loss)	$46.5	$48.4	$(1.9)
As of June 30, 2013			
Total Assets	$3,350.9	$2,997.0	$353.9
Property, Plant and Equipment – Net	$2,397.2	$2,329.6	$67.6
Accumulated Depreciation	$1,202.8	$1,143.2	$59.6
Capital Additions	$100.2	$97.2	$3.0

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 Income Taxes	51.9	57.5	(5.6)
Income Tax Expense (Benefit)	13.1	18.7	(5.6)
Net Income	$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

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 in other postretirement plans to fund employee benefits, the cash equivalents within these plans, and other assets consisting primarily of land in Minnesota.

Other Investments	June 30, 2013	December 31, 2012
Millions		
ALLETE Properties	$91.1	$91.1
Available-for-sale Securities (a)	20.4	26.8
Cash Equivalents	24.4	20.7
Other	4.3	4.9
Total Other Investments	$140.2	$143.5

(a) As of June 30, 2013, the aggregate amount of available-for-sale corporate debt securities maturing in one year or less was $1.2 million, in one year to less than three years was $5.1 million, in three years to less than five years was $1.3 million, and in five or more years was $0.9 million.

ALLETE Properties	June 30, 2013	December 31, 2012
Millions		
Land Inventory Beginning Balance	$86.5	$86.0
Deeds to Collateralized Property	—	0.5
Cost of Sales	—	(0.2)
Capitalized Improvements and Other	0.1	0.2
Land Inventory Ending Balance	86.6	86.5
Long-Term Finance Receivables (net of allowances of $0.6 and $0.6)	1.4	1.4
Other	3.1	3.2
Total Real Estate Assets	$91.1	$91.1

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, 2013 (none for the year ended December 31, 2012).

Long-Term Finance Receivables. As of June 30, 2013, long-term finance receivables were $1.4 million net of allowance ($1.4 million net of allowance as of December 31, 2012). 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, 2013, we had an allowance for doubtful accounts of $0.6 million ($0.6 million as of December 31, 2012).

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 7 percent of the Company's outstanding long-term debt as of June 30, 2013. (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 with respect to that derivative. The shortcut method is used to assess hedge effectiveness. At inception, all shortcut method requirements were satisfied; thus changes in the value of the Swap are deemed 100 percent effective. As a result, there was no ineffectiveness recorded for the quarter and six months ended June 30, 2013. 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, 2013, the fair value of the Swap was a $0.5 million liability (a $0.7 million liability as of December 31, 2012) 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 2012 Form 10-K.

NOTE 5. FAIR VALUE (Continued)

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, 2013 and December 31, 2012. 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 these assets and liabilities and their placement within the fair value hierarchy levels. The estimated fair value of cash and cash equivalents listed on the Consolidated Balance Sheet approximates the carrying amount and therefore are excluded from the recurring fair value measures in the tables below.

	Fair Value as of June 30, 2013			
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Total
Millions				
Assets:				
Investments				
Available-for-sale – Equity Securities	$11.9	—	—	$11.9
Available-for-sale – Corporate Debt Securities	—	$8.5	—	8.5
Cash Equivalents	24.4	—	—	24.4
Total Fair Value of Assets	$36.3	$8.5	—	$44.8
Liabilities:				
Deferred Compensation	—	$15.7	—	$15.7
Derivatives – Interest Rate Swap	—	0.5	—	0.5
Total Fair Value of Liabilities	—	$16.2	—	$16.2
Total Net Fair Value of Assets (Liabilities)	$36.3	$(7.7)	—	$28.6

	Fair Value as of December 31, 2012			
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Total
Millions				
Assets:				
Investments				
Available-for-sale – Equity Securities	$18.0	—	—	$18.0
Available-for-sale – Corporate Debt Securities	—	$8.8	—	8.8
Cash Equivalents	20.7	—	—	20.7
Total Fair Value of Assets	$38.7	$8.8	—	$47.5
Liabilities:				
Deferred Compensation	—	$14.0	—	$14.0
Derivatives – Interest Rate Swap	—	0.7	—	0.7
Total Fair Value of Liabilities	—	$14.7	—	$14.7
Total Net Fair Value of Assets (Liabilities)	$38.7	$(5.9)	—	$32.8

There was no activity in Level 3 during the six months ended June 30, 2013 and 2012.

The Company’s policy is to recognize transfers in and transfers out of a given 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, 2013 and 2012 , there were no transfers in or out of Levels 1, 2 or 3.

NOTE 5. FAIR VALUE (Continued)

Fair Value of Financial Instruments. With the exception of the item listed in the table 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, 2013	$1,102.6	$1,160.2
December 31, 2012	$1,018.1	$1,143.7

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 allows for a 10.38 percent return on common equity and a 54.29 percent equity ratio.

In February 2011, Minnesota Power appealed the MPUC's interim rate decision in the Company's 2010 rate case to the Minnesota Court of Appeals. The Company appealed the MPUC's finding of exigent circumstances in the interim rate decision with the primary arguments being 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. In January 2012, the Company filed a petition for review at the Minnesota Supreme Court (Court). In February 2012, the Court granted the petition for review and oral arguments were held before the Court in October 2012. A decision is expected in the third quarter of 2013. 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 set each July 1 based on a cost-based formula methodology, 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 cost-based formula 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 wholesale customer submitted a cancellation notice with termination effective on December 31, 2013. The 17MW of average monthly demand currently provided to this wholesale customer is expected to be used, upon termination, to supply power for prospective additional retail and municipal load.

2012 Wisconsin Rate Case. SWL&P's 2013 retail rates are based on a 2012 PSCW retail rate order, effective January 1, 2013, that allows for a 10.9 percent return on common equity. The new rates reflect an average overall increase of

2.4 percent for retail customers (a 13.8 percent increase in water rates, a 1.2 percent increase in electric rates, and a 0.2 percent decrease in natural gas rates). On an annualized basis, the rate increase will generate approximately $1.7 million in additional revenue.

Transmission Cost Recovery Riders. Minnesota Power has an approved cost recovery rider in place for certain transmission investments and expenditures. The continued use of the 2009 billing factor was approved by the MPUC in May 2011, which allows Minnesota Power to charge retail customers on a current basis for the costs of constructing certain transmission facilities plus a return on the capital invested. In June 2011, Minnesota Power filed an updated billing factor that includes additional transmission expenditures, which is expected to be approved in the second half of 2013.

NOTE 6. REGULATORY MATTERS (Continued)

Renewable Cost Recovery Riders. The Bison Wind Energy Center in North Dakota consists of 292 MW of nameplate capacity and was completed in various phases through 2012. Customer billing rates for Bison were approved by the MPUC in a November 2011 order and are based on investments and expenditures through that period. Minnesota Power filed a cost recovery petition with the MPUC on May 31, 2013, to update customer billing rates for subsequent investments and expenditures since 2011, which is expected to be approved in the second half of 2013.

Rapids Energy Center. In December 2012, Minnesota Power filed with the MPUC for approval to transfer the assets of Rapids Energy Center from non-rate base generation to Minnesota Power's Regulated Operations. Rapids Energy Center is a generation facility that is located at the UPM, Blandin Paper Mill (Blandin). Minnesota Power and Blandin entered into a new electric service agreement in September 2012 which is also subject to MPUC approval. We expect a decision from the MPUC on these filings in late 2013.

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 with ALLETE, 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. In July 2012, the MPUC issued an order approving certain administrative items related to accounting for shared services and 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.

Integrated Resource Plan. In May 2011, the MPUC issued its final order approving our 2010 Integrated Resource Plan. As a condition of the final order, a required baseload diversification study evaluating the impact of additional environmental regulations over the next two decades was filed in February 2012. Minnesota Power's 2013 Integrated Resource Plan, filed on March 1, 2013, details our "EnergyForward" strategic plan and includes an analysis of a variety of existing and future energy resource alternatives and a projection of customer cost impact by class. A decision by the MPUC on this plan is expected in late 2013.

Boswell Mercury Emissions Reduction Plan. Minnesota Power is required to implement a mercury emissions reduction project for Boswell Unit 4 under the Minnesota Mercury Emissions Reduction Act and the Federal MATS rule. In August 2012, Minnesota Power filed its mercury emissions reduction plan for Boswell Unit 4 with the MPUC and the MPCA. The plan proposes that Minnesota Power install pollution controls by early 2016 to address both the Minnesota mercury emissions reduction requirements and the Federal MATS rule. Costs to implement the Boswell Unit 4 mercury emissions reduction plan are included in the estimated capital expenditures required for compliance with the MATS rule and are estimated to be between $350 million and $400 million. The MPCA issued its report on March 1, 2013, in support of the Boswell Unit 4 mercury emissions reduction plan stating that the plan is appropriate for accomplishing the objectives of reducing emissions of mercury and other pollutants under the Minnesota Statutes and recommended that the MPUC accept the report's findings. We expect a decision by the MPUC on the plan in the third quarter of 2013. Upon approval by the MPUC, we anticipate filing a petition to include investments and expenditures in customer billing rates.

The Patient Protection and Affordable Care Act of 2010 (PPACA). In March 2010, the 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 the PPACA. In May 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.

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.

NOTE 6. REGULATORY MATTERS (Continued)

Regulatory Assets and Liabilities	June 30, 2013	December 31, 2012
Millions		
Current Regulatory Assets (a)		
Deferred Fuel	$18.3	$22.5
Total Current Regulatory Assets	18.3	22.5
Non-Current Regulatory Assets		
Future Benefit Obligations Under		
Defined Benefit Pension and Other Postretirement Benefit Plans	251.5	260.7
Income Taxes	34.3	36.0
Asset Retirement Obligation	13.9	12.1
Cost Recovery Riders (b)	29.2	18.5
PPACA Income Tax Deferral	5.0	5.0
Conservation Improvement Program	—	4.3
Other	3.6	3.7
Total Non-Current Regulatory Assets	337.5	340.3
Total Regulatory Assets	$355.8	$362.8
Non-Current Regulatory Liabilities		
Income Taxes	$17.7	$19.5
Plant Removal Obligations	19.3	18.1
Wholesale and Retail Contra AFUDC	16.7	15.5
Conservation Improvement Program	2.7	—
Other	6.7	7.0
Total Non-Current Regulatory Liabilities	$63.1	$60.1

(a) Current regulatory assets are included in prepayments and other on the Consolidated Balance Sheet.
(b) The cost recovery rider regulatory asset is primarily due to capital expenditures related to Bison.

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, 2013, our equity investment in ATC was $111.2 million ($107.3 million at December 31, 2012). In the first six months of 2013, we invested $1.6 million in ATC, and on July 30, 2013, we invested an additional $0.8 million. We expect to make additional investments of approximately $0.7 million in 2013.

ALLETE’s Investment in ATC	
Millions	
Equity Investment Balance as of December 31, 2012	$107.3
Cash Investments	1.6
Equity in ATC Earnings	10.2
Distributed ATC Earnings	(7.9)
Equity Investment Balance as of June 30, 2013	$111.2

NOTE 7. INVESTMENT IN ATC (Continued)

ATC's summarized financial data for the quarters and six months ended June 30, 2013 and 2012, is as follows:

	Quarter Ended		Six Months Ended	
ATC Summarized Financial Data	June 30,		June 30,	
Income Statement Data	2013	2012	2013	2012
Millions				
Revenue	$152.1	$152.2	$303.9	$299.8
Operating Expense	69.9	71.8	139.7	141.3
Other Expense	20.9	21.1	42.4	41.1
Net Income	$61.3	$59.3	$121.8	$117.4
ALLETE's Equity in Net Income	$5.0	$4.8	$10.2	$9.4

NOTE 8. SHORT-TERM AND LONG-TERM DEBT

Short-Term Debt. As of June 30, 2013, total short-term debt outstanding was $37.9 million ($84.5 million as of December 31, 2012) and consisted of long-term debt due within one year. Short-term debt as of December 31, 2012 included $60.0 million of long-term debt that matured in April 2013.

Long-Term Debt. As of June 30, 2013, total long-term debt outstanding was $1,064.7 million ($933.6 million as of December 31, 2012).

On April 2, 2013, we issued $150.0 million of the Company's First Mortgage Bonds (Bonds) in the private placement market in three series as follows:

Maturity Date	Principal Amount	Interest Rate
April 15, 2018	$50 Million	1.83%
October 15, 2028	$40 Million	3.30%
October 15, 2043	$60 Million	4.21%

We have the option to prepay all or a portion of the 1.83 percent Bonds at our discretion at any time, subject to a make-whole provision. We have the option to prepay all or a portion of the 3.30 percent Bonds at our discretion at any time prior to April 15, 2028, subject to a make-whole provision, and at any time on or after April 15, 2028, at par, including, in each case, accrued and unpaid interest. We also have the option to prepay all or a portion of the 4.21 percent Bonds at our discretion at any time prior to April 15, 2043, subject to a make-whole provision, and at any time on or after April 15, 2043, at par, including, in each case, accrued and unpaid interest. The Bonds are subject to additional terms and conditions of our utility mortgage. Proceeds from the sale of the Bonds will be used to fund utility capital investments, repay debt, 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 in a private placement.

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, 2013, our ratio was approximately 0.47 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, 2013, ALLETE was in compliance with its financial covenants.

NOTE 9. OTHER INCOME (EXPENSE)

	Quarter Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Millions				
AFUDC – Equity	$1.0	$1.2	$2.1	$1.9
Gain on Sale of Available-for-sale Securities	—	—	0.8	—
Investments and Other Income	0.5	—	1.3	—
Total Other Income	$1.5	$1.2	$4.2	$1.9

NOTE 10. INCOME TAX EXPENSE

	Quarter Ended June 30,		Six Months Ended June 30,	
	2013	2012	2013	2012
Millions				
Current Tax Expense (Benefit)				
Federal (a)	$(0.2)	—	—	—
State (a)	—	—	—	—
Total Current Tax Expense (Benefit)	(0.2)	—	—	—
Deferred Tax Expense (Benefit)				
Federal	3.6	$4.8	$8.2	$13.2
State (b)	0.9	0.2	3.8	0.3
Investment Tax Credit Amortization	(0.2)	(0.2)	(0.4)	(0.4)
Total Deferred Tax Expense	4.3	4.8	11.6	13.1
Total Income Tax Expense	$4.1	$4.8	$11.6	$13.1

(a) We incurred net operating losses (NOLs) due to the bonus depreciation provisions of the American Taxpayer Relief Act of 2012 and the Tax Relief Unemployment Insurance Reauthorization and Job Creation Act of 2010 for the quarter and six months ended June 30, 2013 and 2012. The 2013 and 2012 federal and state NOLs will be carried forward to offset future taxable income.

(b) The quarter and six months ended June 30, 2012, reflected increased state tax benefit from state renewable tax credits compared to the quarter and six months ended June 30, 2013.

For the six months ended June 30, 2013, the effective tax rate was 20.0 percent (25.2 percent for the six months ended June 30, 2012). The decrease from the effective tax rate for the six months ended June 30, 2012, was primarily due to increased federal production tax credits. The effective tax rate deviated from the statutory rate of approximately 41 percent primarily due to deductions for AFUDC Equity, investment tax credits, federal production tax credits, state income tax credits and depletion.

Uncertain Tax Positions. As of June 30, 2013, we had gross unrecognized tax benefits of $2.6 million ($2.7 million as of December 31, 2012). Of the total gross unrecognized tax benefits, $0.7 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.

ALLETE's IRS exam for tax years 2005 through 2009 is currently under review at the IRS appeals office. We expect the IRS appeals process to be completed during the next twelve months, resulting in the reversal of substantially all of the unrecognized tax benefits as of June 30, 2013. 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. RECLASSIFICATIONS OUT OF ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

Changes in Accumulated Other Comprehensive Loss by Component

Millions	Unrealized Gains and Losses on Available-for-sale Securities (a)	Defined Benefit Pension, Other Postretirement Items (a)	Gains and Losses on Cash Flow Hedge (a)	Total (a)
For the Quarter Ended June 30, 2013				
Beginning Balance	$(0.1)	$(21.2)	$(0.3)	$(21.6)
Other Comprehensive Income (Loss) Before Reclassifications	0.1	(2.6)	—	(2.5)
Amounts Reclassified From Accumulated Other Comprehensive Loss	—	3.1	—	3.1
Net Other Comprehensive Income	0.1	0.5	—	0.6
Ending Balance	—	$(20.7)	$(0.3)	$(21.0)
For the Six Months Ended June 30, 2013				
Beginning Balance	$(0.1)	$(21.5)	$(0.4)	$(22.0)
Other Comprehensive Income (Loss) Before Reclassifications	0.6	(5.5)	0.1	(4.8)
Amounts Reclassified From Accumulated Other Comprehensive Loss	(0.5)	6.3	—	5.8
Net Other Comprehensive Income	0.1	0.8	0.1	1.0
Ending Balance	—	$(20.7)	$(0.3)	$(21.0)

(a) Amounts shown are net of tax.

NOTE 11. RECLASSIFICATIONS OUT OF ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS) (Continued)

Reclassifications Out of Accumulated Other Comprehensive Loss

Details About Accumulated Other Comprehensive Loss Components	Amount Reclassified from Accumulated Other Comprehensive Loss (a)		Affected Income Statement Line Item
Millions			
For the Quarter Ended June 30, 2013			
Amortization of Defined Benefit Pension and Other Postretirement Items			
Prior Service Costs	$0.7		(b)
Actuarial Gains and Losses	(5.8	)	(b)
	(5.1	)	
	2.0		Income Tax Expense
	$(3.1)		
Total Reclassifications	$(3.1)		
For the Six Months Ended June 30, 2013			
Unrealized Gains on Available-for-sale Securities	$0.8		Other Income (Expense) - Other
	(0.3	)	Income Tax Expense
	$0.5		
Amortization of Defined Benefit Pension and Other Postretirement Items			
Prior Service Costs	$1.2		(b)
Actuarial Gains and Losses	(11.5	)	(b)
	(10.3	)	
	4.0		Income Tax Expense
	$(6.3)		
Total Reclassifications	$(5.8)		

(a) Amounts in parentheses indicate charges to net income.

(b) These components of accumulated other comprehensive loss are included in the computation of net pension and other postretirement benefit expense. (See Note 13. Pension and Other Postretirement Benefit Plans.)

NOTE 12. EARNINGS PER SHARE AND COMMON STOCK

The difference between basic and diluted earnings per share, if any, arises from outstanding stock options, non-vested restricted stock units, and performance share awards granted under our Executive Long-Term Incentive Compensation Plan. For the quarters and six months ended June 30, 2013 and 2012, zero and 0.3 million options to purchase shares of common stock, respectively, 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	2013 Dilutive Securities	Diluted	Basic	2012 Dilutive Securities	Diluted
Millions Except Per Share Amounts						
For the Quarter Ended June 30,						
Net Income	$14.0		$14.0	$14.4		$14.4
Average Common Shares	39.4	0.2	39.6	37.3	0.1	37.4
Earnings Per Share	$0.36		$0.35	$0.39		$0.39
For the Six Months Ended June 30,						
Net Income	$46.5		$46.5	$38.8		$38.8
Average Common Shares	39.2	0.1	39.3	37.0	0.1	37.1
Earnings Per Share	$1.19		$1.18	$1.05		$1.05

NOTE 13. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS

	Pension		Other Postretirement	
Components of Net Periodic Benefit Expense	2013	2012	2013	2012
Millions				
For the Quarter Ended June 30,				
Service Cost	$2.5	$2.3	$1.0	$1.1
Interest Cost	6.5	6.6	1.7	2.3
Expected Return on Plan Assets	(8.8)	(8.9)	(2.4)	(2.5)
Amortization of Prior Service Costs	—	0.1	(0.7)	(0.5)
Amortization of Net Loss	5.4	4.4	0.4	1.9
Amortization of Transition Obligation	—	—	—	0.1
Net Periodic Benefit Expense	$5.6	$4.5	—	$2.4
For the Six Months Ended June 30,				
Service Cost	$5.0	$4.6	$2.0	$2.1
Interest Cost	13.0	13.2	3.4	4.7
Expected Return on Plan Assets	(17.6)	(17.7)	(4.9)	(5.0)
Amortization of Prior Service Costs	0.1	0.2	(1.3)	(0.9)
Amortization of Net Loss	10.7	8.7	0.8	3.8
Amortization of Transition Obligation	—	—	—	0.1
Net Periodic Benefit Expense	$11.2	$9.0	—	$4.8

Employer Contributions. For the six months ended June 30, 2013, no contributions were made to our defined benefit pension plan (none for the six months ended June 30, 2012). For the six months ended June 30, 2013, we contributed $10.8 million to our other postretirement benefit plan (none for the six months ended June 30, 2012). We do not expect to contribute to our defined benefit pension plan in 2013, and we do not expect to make any additional contributions to our other postretirement benefit plan in 2013.

NOTE 14. 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, 2013, Square Butte had total debt outstanding of $404.9 million. Annual debt service for Square Butte is expected to be approximately $44 million in each of the years 2013 through 2017, 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.

Minnesota Power's cost of power purchased from Square Butte during the six months ended June 30, 2013 was $33.0 million ($33.0 million for the six months ended June 30, 2012). This reflects Minnesota Power's pro rata share of total Square Butte costs based on the 50 percent output entitlement. Included in this amount was Minnesota Power's pro rata share of interest expense of $5.3 million during the six months ended June 30, 2013 ($5.6 million for the six months ended June 30, 2012). Minnesota Power's payments to Square Butte are approved as a purchased power expense for ratemaking purposes by both the MPUC and the FERC.

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 the 2009 agreement until Minnkota Power has placed in service a new AC transmission line, which is expected to occur by the end of the first quarter of 2014. This new AC transmission line will allow Minnkota Power to transmit its entitlement from Square Butte directly to its customers, which in turn will enable Minnesota Power to transmit additional wind generation on the existing DC transmission line.

Minnkota Power PPA. In December 2012, Minnesota Power entered into a long-term PPA with Minnkota Power. Under this agreement, Minnesota Power will purchase 50 MW of capacity and the energy associated with that capacity over the term June 1, 2016 through May 31, 2020. The agreement includes a fixed capacity charge and energy pricing that escalates at a fixed rate annually over the term.

Oliver Wind I and II 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 energy prices. There are no fixed capacity charges and we only pay for energy as it is delivered to us.

Manitoba Hydro PPAs. Minnesota Power has a long-term 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.

Minnesota Power has a separate long-term PPA with Manitoba Hydro to purchase surplus energy through April 2022. This energy-only agreement 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.

NOTE 14. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Power Purchase Agreements (Continued)

In May 2011, Minnesota Power and Manitoba Hydro signed an additional long-term PPA. The PPA provides for Manitoba Hydro to sell 250 MW of capacity and energy to Minnesota Power for 15 years beginning in 2020 and is subject to construction of additional transmission capacity between Manitoba and Minnesota's Iron Range, along with construction of new hydroelectric generating capacity in Manitoba. 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 changes in a governmental inflationary index, a natural gas index, and market prices.

In February 2012, Minnesota Power and Manitoba Hydro proposed construction of the Great Northern Transmission Line, 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 targeted to be in service in 2020. Total project cost and cost allocations are still to be determined; however, at this time we expect our capital expenditures to range between $200 million and $400 million. The Great Northern Transmission Line is subject to various federal and state regulatory approvals. In addition, Manitoba Hydro must obtain regulatory and governmental approvals related to new transmission lines and hydroelectric generation development in Canada.

Coal, Rail and Shipping Contracts. We have coal supply agreements providing for the purchase of a significant portion of our coal requirements with expiration dates through 2014. 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 is $22.4 million for the remainder of 2013 and $1.0 million for 2014. Our minimum annual payment obligation will increase when annual nominations are made for coal deliveries in future years. The delivered costs of fuel for Minnesota Power's generation are recoverable from Minnesota Power's utility customers through the fuel adjustment clause.

Leasing Agreements. BNI Coal is obligated to make lease payments for a dragline totaling $2.8 million annually for the lease term, which expires in 2027. BNI Coal has the option at the end of the lease term to renew the lease at fair market value, to purchase the dragline at fair market value, or to surrender the dragline and pay a $3.0 million termination fee. We also 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 $11.5 million in 2013, $11.7 million in 2014, $11.4 million in 2015, $9.3 million in 2016, $8.5 million in 2017 and $35.0 million thereafter.

Transmission. We continue to make 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.

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, municipal 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 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. The 28-mile 345 kV line between Monticello and St. Cloud was placed into service in December 2011 and the 70-mile 230 kV line between Bemidji, Minnesota and Minnesota Power's Boswell Energy Center near Grand Rapids, Minnesota was placed into service in September 2012. 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 was completed in August 2012. The entire 238-mile, 345 kV line from Fargo to Monticello is expected to be in service by 2015.

NOTE 14. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Transmission (Continued)

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 $110 million in the CapX2020 initiative through 2015. A total of $59.8 million was spent through June 30, 2013, of which $48.9 million related to the Fargo, North Dakota to Monticello, Minnesota projects and $10.9 million related to the Bemidji, Minnesota to Minnesota Power's Boswell Energy Center project ($48.2 million as of December 31, 2012 of which $37.3 million related to the Fargo, North Dakota to Monticello, Minnesota projects and $10.9 million related to the Bemidji, Minnesota to Minnesota Power's Boswell Energy Center project). As future CapX2020 projects are identified, Minnesota Power may elect to participate on a project-by-project basis.

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 expected future restrictive environmental requirements imposed 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 project power supply trends and impacts on customers.

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 become available. Accruals for environmental liabilities are included in the Consolidated Balance Sheet at undiscounted amounts and exclude claims for recoveries from insurance or other third parties. Costs related to environmental contamination treatment and cleanup are charged to expense unless recoverable in rates from customers.

Air. The electric utility industry is 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. 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. 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. Resolution of the NOVs could result in civil penalties, which we do not believe will be material to our results of operations, and the installation of additional pollution control equipment, some of which is already planned or which has been completed to comply with other regulatory requirements. We are engaged in discussions with the EPA regarding resolution of these matters, but we are unable to estimate the expenditures, or range of expenditures that may be required upon resolution. Any costs of installing additional pollution control equipment would likely be eligible for recovery in rates over time subject to regulatory approval in a rate proceeding.

NOTE 14. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

Cross-State Air Pollution Rule (CSAPR). In July 2011, the EPA issued the CSAPR, which replaced the EPA's 2005 CAIR. However, in August 2012, a three-judge panel of the District of Columbia Circuit Court of Appeals vacated the CSAPR, ordering that the CAIR remain in effect while a CSAPR replacement rule is promulgated. On March 29, 2013, the EPA petitioned the Supreme Court to review the District of Columbia Circuit Court of Appeals ruling. The Supreme Court decided to grant review on June 24, 2013, and is likely to issue its decision by June 2014. If reinstated after Supreme Court review, the CSAPR would require states in the CSAPR region, including Minnesota, to significantly improve air quality by reducing power plant emissions that contribute to ozone and/or fine particle pollution in other states. The CSAPR would not directly require the installation of controls. Instead, the rule would require facilities to have sufficient emission allowances to cover their emissions on an annual basis. These allowances would be allocated to facilities from each state's annual budget and could 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. The CAIR also created an allowance allocation and trading program rather than specifying pollution controls. 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. While the CAIR remains in effect, Minnesota participation in the CAIR will continue to be stayed. It remains uncertain if emission restrictions similar to those contained in the CSAPR will become effective for Minnesota utilities due to the August 2012 District of Columbia Circuit Court of Appeals decision.

Since 2006, we have significantly reduced emissions at our Laskin, Taconite Harbor and Boswell generating units. Based on our expected generation, these emission reductions would have satisfied Minnesota Power's SO_2 and NO_X emission compliance obligations with respect to the EPA-allocated CSAPR allowances for 2013. We are unable to predict any additional compliance costs we might incur if the CSAPR is reinstated or if a CSAPR replacement rule is promulgated.

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 first phase of 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, subject to BART requirements.

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 a trading program in the CSAPR as an alternative to determining BART. However, as a result of the August 2012 District of Columbia Circuit Court of Appeals decision to vacate the CSAPR (See Cross-State Air Pollution Rule), Minnesota Power is now evaluating whether significant additional expenditures at Taconite Harbor Unit 3 will be required to comply with BART requirements under the Regional Haze Rule. If additional regional haze related controls are ultimately required, Minnesota Power will have up to five years from the final rule promulgation date 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. On January 30, 2013, Minnesota Power announced its "EnergyForward" strategic plan, which includes retiring Taconite Harbor Unit 3 in 2015, subject to MPUC approval.

NOTE 14. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

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 in February 2012, addressing such emissions from coal-fired utility units greater than 25 MW. There are currently 187 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 April 2015. States have the authority to grant sources a one-year extension. Minnesota Power was notified by the MPCA that it has approved Minnesota Power's request for an additional year extending the date of compliance for the Boswell Unit 4 retrofit to April 1, 2016. Compliance at Boswell Unit 4 to address the final MATS rule is expected to result in capital expenditures totaling between $350 million and $400 million through 2016. Our "EnergyForward" plan also includes the conversion of Laskin Units 1 and 2 to natural gas in 2015, to position the Company for MATS compliance.

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. In January 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 supersedes the March 2011 rule, was released in December 2012. Major existing sources have until January 31, 2016 to achieve compliance with the final rule. Minnesota Power is in the process of assessing the impact of this rule on our affected units, Hibbard Renewable Energy Center and Rapids Energy Center. Costs for complying with the final rule cannot be estimated at this time.

Minnesota Mercury Emissions Reduction Act. Under the 2006 Minnesota Mercury Emissions Reduction Act, Minnesota Power is required to implement a mercury emissions reduction project for Boswell Unit 4 by December 31, 2018. In August 2012, Minnesota Power filed its mercury emissions reduction plan for Boswell Unit 4 with the MPUC and the MPCA. The plan proposes that Minnesota Power install pollution controls to address both the Minnesota mercury emissions reduction requirements and the MATS rule, which also regulates mercury emissions. Minnesota Power's request of an additional year extending the date of compliance for the Boswell Unit 4 retrofit to April 1, 2016, was approved by the MPCA. Costs to implement the Boswell Unit 4 mercury emissions 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 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. 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 since announced that it is deferring revision of this standard until 2014 or later.

Particulate Matter NAAQS. The EPA finalized the NAAQS Particulate Matter standards in September 2006. Since then, the EPA has established a more stringent 24-hour average fine particulate matter ($PM_{2.5}$) standard; the annual $PM_{2.5}$ standard and the 24-hour coarse particulate matter standard have remained unchanged. The United States Court of Appeals for the District of Columbia Circuit remanded the annual $PM_{2.5}$ standard to the EPA, requiring consideration of lower annual standard values. The EPA proposed new $PM_{2.5}$ standards in June 2012.

In December 2012, the EPA issued a final rule implementing a more stringent annual $PM_{2.5}$ standard, while retaining the current 24-hour $PM_{2.5}$ standard. To implement the new more stringent annual $PM_{2.5}$ standard, the EPA is also revising aspects of relevant monitoring, designations and permitting requirements. New projects and permits must comply with the new more stringent standard, and compliance with the NAAQS at the facility level is generally demonstrated by modeling.

NOTE 14. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

Under the final rule, states will be responsible for additional $PM_{2.5}$ monitoring, which will likely be accomplished by relocating or repurposing existing monitors. States are expected to propose attainment designations by December 2013, based on already available monitoring data. The EPA believes that most U.S. counties currently already meet the new standard and plans to finalize designations of attainment by December 2014. For those counties that the EPA does not designate as having already met the requirements of the new standard, specific dates for required attainment will depend on technology availability, state permitting goals, potential legal challenges and other factors.

SO_2 and NO_2 NAAQS. During 2010, the EPA finalized 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 were required to be submitted to the EPA for approval by June 2013, but the evaluation of modeling data will not be required until 2017.

In late 2011, the MPCA initiated modeling activities that included approximately 65 sources within Minnesota that emit greater than 100 tons of SO_2 per year. However, in April 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, where 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. Currently, compliance with these new NAAQS is expected to be required as early as 2017. The costs for complying with the final standards 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 risks. Physical risks could include, but are not limited to: increased or decreased precipitation and water levels in lakes and rivers; increased temperatures; and changes in 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:

- Expanding our renewable energy supply;
- Providing energy conservation initiatives for our customers and engaging in other demand side efforts;
- Supporting research of technologies to reduce carbon emissions from generation facilities and carbon sequestration efforts; and
- Evaluating and developing less carbon intensive future generating assets such as efficient and flexible natural gas generating facilities.

President Obama's Climate Action Plan. On June 25, 2013, President Obama announced a Climate Action Plan (CAP) that calls for implementation of measures that reduce GHG emissions in the U.S., emphasizing means such as expanded deployment of renewable energy resources, energy and resource conservation, energy efficiency improvements and a shift to fuel sources that have lower emissions. Certain portions of the CAP directly address electric utility GHG emissions, as further described below.

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, existing facilities that undergo major modifications and 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 Best Available Control Technology (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.

NOTE 14. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

In March 2012, the EPA announced a proposed rule to apply CO_2 emission New Source Performance Standards (NSPS) to new fossil fuel-fired electric generating units. The proposed NSPS apply only to new or re-powered units and were open for public comment through June 25, 2012. Based on the volume of comments received, the EPA announced its intent to re-propose the rule. The CAP described above directs the EPA to re-propose the rule by September 20, 2013. The CAP also directs the EPA to propose NSPS or regulatory guidelines for existing fossil fuel-fired electric generating units by June 1, 2014, and to finalize such rules by June 1, 2015. Under the CAP, the EPA will issue regulatory guidelines and objectives to the states, which in turn will submit SIPs for EPA approval that demonstrate how the state will meet or surpass achievement of the EPA targeted objectives. The CAP directs the EPA to require states to submit such SIPs by June 30, 2016.

Minnesota has already initiated several measures consistent with those called for under the CAP. Minnesota Power has also announced its “EnergyForward” strategy that provides for significant emission reductions and diversifying our electricity generation mix to include more renewable and natural gas energy.

Legal challenges have been filed with respect to the EPA’s regulation of GHG emissions, including the Tailoring Rule. In June 2012, the United States District Court for the District of Columbia upheld most of the EPA’s proposed regulations, including the Tailoring Rule criteria, finding that the Clean Air Act compels the EPA to regulate in the manner the EPA proposed. Comments on the permitting guidance were 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 announced 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, and the EPA is now expected to issue a final rule in November 2013. We are unable to predict the compliance costs we might incur under the final rule; however, the costs could be material. We would seek recovery of any additional costs through cost recovery riders or in a general rate case.

Steam Electric Power Generating Effluent Guidelines. On April 19, 2013, the EPA announced proposed revisions to the federal effluent guidelines for steam electric power generating stations under the Clean Water Act. Instead of proposing a single rule, the EPA proposed eight “options,” of which four are “preferred”. The proposed revisions would set limits on the level of toxic materials in wastewater discharged from seven waste streams: flue gas desulfurization wastewater, fly ash transport water, bottom ash transport water, combustion residual leachate, non-chemical metal cleaning wastes, coal gasification wastewater, and wastewater from flue gas mercury control systems. As part of this proposed rulemaking, the EPA is considering imposing rules to address “legacy” wastewater currently residing in ponds as well as rules to impose stringent best management practices for discharges from active coal combustion residual surface impoundments. The EPA’s proposed rulemaking would base effluent limitations on what can be achieved by available technologies. The proposed rule was published in the Federal Register on June 7, 2013, with public comments due September 20, 2013. It is expected that the EPA will issue a final rule in 2014. Compliance with the final rule would be required no later than July 1, 2022. We are reviewing the proposed rule and evaluating its potential impacts on our operations. We are unable to predict the compliance costs we might incur related to these or other potential future water discharge regulations; however, the costs could be material, including costs associated with retrofits for bottom ash handling, pond dewatering, pond closure, and wastewater treatment and/or reuse. We would seek recovery of any additional costs through cost recovery riders or in a general rate case.

NOTE 14. 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. It is expected that the final rule will be published in 2014. We 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.

Other Matters

BNI Coal. As of June 30, 2013, BNI Coal had surety bonds outstanding of $29.7 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 $32.3 million. BNI Coal does not believe it is likely that any of these outstanding surety bonds or the letter of credit will be drawn upon.

ALLETE Properties. As of June 30, 2013, 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 for various projects. The estimated cost of the remaining development work is approximately $7.4 million. ALLETE Properties does not believe it is likely that any of these outstanding surety 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 are 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, 2013, we owned 73 percent of the assessable land in the Town Center District (73 percent at December 31, 2012) and 93 percent of the assessable land in the Palm Coast Park District (93 percent at December 31, 2012). At these ownership levels, our annual assessments are approximately $1.4 million for Town Center and $2.1 million for Palm Coast Park. As we sell property, the obligation to pay special assessments will pass to the new landowners. In accordance with accounting guidance, these bonds are not reflected as debt on our Consolidated Balance Sheet.

Legal Proceedings.

United Taconite Lawsuit. 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, 2013, because a potential loss is not currently probable or reasonably estimable; however, the Company believes it has adequate insurance limits for any potential loss. Our insurance carrier is providing a defense subject to a reservation of rights as to certain claims.

NOTE 14. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Other Matters (Continued)

Notice of Potential Clean Air Act Citizen Lawsuit. In July 2013, the Sierra Club submitted to Minnesota Power a notice of intent to file a citizen suit under the Clean Air Act. This notice of intent alleged violations of opacity and other permit requirements at our Boswell, Laskin, and Taconite Harbor energy centers. Minnesota Power intends to vigorously defend any lawsuit that may be filed by the Sierra Club. We are unable to predict the outcome of this matter. Accordingly, an accrual related to any damages that may result from the notice of intent has not been recorded as of June 30, 2013, because a potential loss is not currently probable or reasonably estimable.

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 our results of operations 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 2012 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, beginning on page 27 of our 2012 Form 10 K. The risks and uncertainties described in this Form 10-Q and our 2012 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, our business aimed at developing or acquiring capital projects that create energy solutions via wind, solar, biomass, midstream gas and oil infrastructure, among other energy-related projects. This segment also includes other business development and corporate expenditures, a small amount of non-rate base generation, approximately 6,000 acres of land 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, 2013, 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.

OVERVIEW (Continued)

Financial Overview

The following net income discussion summarizes a comparison of the six months ended June 30, 2013, to the six months ended June 30, 2012.

Net income for the six months ended June 30, 2013, was $46.5 million, or $1.18 per diluted share, compared to $38.8 million, or $1.05 per diluted share, for the same period of 2012. Net income for 2013 reflected higher kilowatt-hour sales, cost recovery rider revenue and federal production tax credits, and higher FERC wholesale rates. These increases were partially offset by increased operating and maintenance, depreciation and interest expenses. Earnings per share dilution was $0.07 as a result of additional shares of common stock outstanding as of June 30, 2013.

Regulated Operations net income was $48.4 million for the six months ended June 30, 2013, compared to $38.8 million for the same period of 2012. Net income for 2013 reflected higher kilowatt-hour sales, cost recovery rider revenue and federal production tax credits, and FERC wholesale rates. These increases were partially offset by increased operating and maintenance, depreciation, and interest expenses.

Investments and Other net loss was $1.9 million for the six months ended June 30, 2013, compared to no net income for the same period of 2012. The decrease in 2013 was primarily due to higher interest and state income tax expense, partially offset by a gain on sale of available-for-sale securities.

COMPARISON OF THE QUARTERS ENDED JUNE 30, 2013 AND 2012

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

Regulated Operations

Operating revenue increased $18.8 million, or 10 percent, from 2012 primarily due to higher fuel adjustment clause recoveries, a 2.2 percent increase in kilowatt-hour sales, and higher municipal rates, gas sales, transmission revenue, and cost recovery rider revenue.

Fuel adjustment clause recoveries increased $5.2 million from 2012 due to higher fuel and purchased power costs attributable to our retail and municipal customers. (See Operating Expenses - Fuel and Purchased Power Expense.)

Revenue from Regulated Operations increased $4.2 million from 2012 due to a 2.2 percent increase in total kilowatt-hour sales. Kilowatt-hour sales to Other Power Suppliers increased 24.0 percent from 2012. Sales to Other Power Suppliers are sold at market-based prices into the MISO market on a daily basis or through bilateral agreements of various durations. The increase in kilowatt-hour sales was also due to higher sales to residential and commercial customers. In April 2012, heating degree days in Duluth, Minnesota were approximately 35 percent lower than the same period in 2013. Kilowatt-hour sales to industrial customers decreased 4.0 percent from 2012 primarily due to 65.5 million kilowatt-hours sold in the second quarter of 2012 through a short-term, fixed price contract.

Revenue from our municipal customers increased $3.1 million from 2012 due to higher rates under the cost-based formula primarily due to higher capital expenditures and 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.

COMPARISON OF THE QUARTERS ENDED JUNE 30, 2013 AND 2012 (Continued)
Regulated Operations (Continued)

Kilowatt-hours Sold Quarter Ended June 30, Millions	2013	2012	Quantity Variance	% Variance
Regulated Utility				
Retail and Municipals				
Residential	251	226	25	11.1 %
Commercial	335	326	9	2.8 %
Industrial	1,769	1,842	(73)	(4.0)%
Municipals	225	234	(9)	(3.8)%
Total Retail and Municipals	2,580	2,628	(48)	(1.8)%
Other Power Suppliers	610	492	118	24.0 %
Total Regulated Utility Kilowatt-hours Sold	3,190	3,120	70	2.2 %

Revenue from electric sales to taconite customers accounted for 26 percent of consolidated operating revenue in 2013 (28 percent in 2012). Revenue from electric sales to paper and pulp mills accounted for 8 percent of consolidated operating revenue in 2013 (9 percent in 2012). Revenue from electric sales to pipelines and other industrials accounted for 7 percent of consolidated operating revenue in 2013 (7 percent in 2012).

Revenue from gas sales at SWL&P increased $2.4 million from 2012 due to unseasonably warm weather in April 2012 and higher purchased gas expenses. (See Operating Expenses - Operating and Maintenance Expense).

Transmission revenue increased $2.2 million from 2012 primarily due to the commencement of recovery of our transmission investment related to the 230 kV transmission system upgrade that was placed into service in March 2013 (see Outlook – Industrial Customers – City of Nashwauk) and higher MISO Regional Expansion Criteria and Benefits (RECB) revenue related to our investment in CapX2020.

Cost recovery rider revenue increased $1.1 million from 2012 as our Bison Wind Energy Center was completed in various phases through December 2012 and in service in 2013.

Operating expenses increased $17.0 million, or 10 percent, from 2012.

Fuel and Purchased Power Expense increased $6.6 million, or 9 percent, from 2012 due to an increase in kilowatt-hour sales and higher purchased power prices. Fuel and purchased power expense related to our retail and municipal customers is recovered through the fuel adjustment clause. (See Operating Revenue.)

Operating and Maintenance Expense increased $6.7 million, or 9 percent, from 2012 primarily due to higher purchased gas expenses, higher operating and maintenance expenses related to our Bison Wind Energy Center, which was in service in 2013, and higher property tax expenses. Purchased gas expenses increased due to higher gas sales in 2013 as a result of the unseasonably warm weather in April 2012 and higher cost of gas in 2013; purchased gas costs are recovered through a purchased gas adjustment clause from customers (see Operating Revenue). Property tax expenses increased primarily due to higher taxable plant and rates.

Depreciation Expense increased $3.7 million, or 16 percent, from 2012 reflecting additional property, plant and equipment in service.

Interest expense increased $0.5 million, or 5 percent, from 2012 primarily due to higher average long-term debt balances.

Income tax expense decreased $0.5 million, or 7 percent, from 2012, primarily due to higher federal production tax credits in 2013 as our Bison Wind Energy Center was completed in various phases through December 2012 and in service in 2013.

COMPARISON OF THE QUARTERS ENDED JUNE 30, 2013 AND 2012 (Continued)

Investments and Other

Operating revenue increased $0.4 million, or 2 percent, from 2012 primarily due to a $0.6 million increase in revenue at BNI Coal. BNI Coal, which operates under a cost plus fixed fee contract, recorded higher revenue as a result of higher expenses in 2013. (See Operating Expense.)

Operating expenses increased $1.1 million, or 5 percent, from 2012 reflecting higher expenses at BNI Coal of $0.7 million primarily due to higher fuel costs and labor, which are recovered through the cost-plus contract. (See Operating Revenue.)

Interest expense increased $2.2 million from 2012 primarily due to a decrease 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.

Income tax benefits increased $0.2 million from 2012 primarily due to increased pretax losses offset by higher state tax expense. State income tax expense was higher in 2013 as more North Dakota income tax credits attributable to our North Dakota capital investments were recognized in 2012.

Income Taxes – Consolidated

For the quarter ended June 30, 2013, the effective tax rate was 22.7 percent (25.0 percent for the quarter ended June 30, 2012). The decrease from the effective tax rate for the quarter ended June 30, 2012, was primarily due to increased federal production tax credits in 2013. The effective tax rate deviated from the statutory rate of approximately 41 percent primarily due to deductions for AFUDC - Equity, investment tax credits, federal production tax credits, state income tax credits and depletion. (See Note 10. Income Tax Expense.)

COMPARISON OF THE SIX MONTHS ENDED JUNE 30, 2013 AND 2012

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

Regulated Operations

Operating revenue increased $41.6 million, or 10 percent, from 2012 primarily due to higher fuel adjustment clause recoveries, a 2.7 percent increase in kilowatt-hour sales, and higher municipal rates, cost recovery rider revenue, gas sales, and transmission revenue.

Fuel adjustment clause recoveries increased $12.3 million from 2012 due to higher fuel and purchased power costs attributable to our retail and municipal customers. (See Operating Expenses - Fuel and Purchased Power Expense.)

Revenue from Regulated Operations increased $9.6 million from 2012 due to a 2.7 percent increase in total kilowatt-hour sales. The increase was due primarily to a 19.0 percent increase in kilowatt-hour sales to Other Power Suppliers. Sales to Other Power Suppliers are sold at market-based prices into the MISO market on a daily basis or through bilateral agreements of various durations. Also contributing to the increase was higher sales to residential and commercial customers. In the first four months of 2012, heating degree days in Duluth, Minnesota were approximately 29 percent lower than the same period in 2013. Kilowatt-hour sales to industrial customers decreased 2.6 percent from 2012 primarily due to 65.5 million kilowatt-hours sold in the second quarter of 2012 through a short-term, fixed price contract.

Revenue from our municipal customers increased $4.9 million from 2012 due to higher rates under the cost-based formula primarily due to higher capital expenditures and 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.

COMPARISON OF THE SIX MONTHS ENDED JUNE 30, 2013 AND 2012 (Continued)
Regulated Operations (Continued)

Kilowatt-hours Sold Six Months Ended June 30, Millions	2013	2012	Quantity Variance	% Variance
Regulated Utility				
Retail and Municipals				
Residential	605	552	53	9.6 %
Commercial	712	690	22	3.2 %
Industrial	3,614	3,710	(96)	(2.6)%
Municipals	499	498	1	0.2 %
Total Retail and Municipals	5,430	5,450	(20)	(0.4)%
Other Power Suppliers	1,201	1,009	192	19.0 %
Total Regulated Utility Kilowatt-hours Sold	6,631	6,459	172	2.7 %

Revenue from electric sales to taconite customers accounted for 25 percent of consolidated operating revenue in 2013 (27 percent in 2012). Revenue from electric sales to paper and pulp mills accounted for 8 percent of consolidated operating revenue in 2013 (9 percent in 2012). Revenue from electric sales to pipelines and other industrials accounted for 6 percent of consolidated operating revenue in 2013 (7 percent in 2012).

Cost recovery rider revenue increased $6.0 million from 2012 as our Bison Wind Energy Center was completed in various phases through December 2012 and in service in 2013. Also contributing to the increase were higher capital expenditures related to our CapX2020 projects.

Revenue from gas sales at SWL&P increased $4.3 million from 2012 as a result of the unseasonably warm weather during the first four months of 2012 and higher purchased gas expenses. (See Operating Expenses - Operating and Maintenance Expense.)

Transmission revenue increased $3.1 million from 2012 primarily due to the commencement of recovery of our transmission investment related to the 230 kV transmission system upgrade that was placed into service in March 2013 (see Outlook – Industrial Customers – City of Nashwauk) and higher MISO RECB revenue related to our investment in CapX2020.

Operating expenses increased $34.1 million, or 10 percent, from 2012.

Fuel and Purchased Power Expense increased $16.0 million, or 11 percent, from 2012 due to an increase in kilowatt-hour sales and higher purchased power prices. Fuel and purchased power expense related to our retail and municipal customers is recovered through the fuel adjustment clause. (See Operating Revenue.)

Operating and Maintenance Expense increased $10.8 million, or 7 percent, from 2012 primarily due to higher purchased gas expenses, higher operating and maintenance expenses related to our Bison Wind Energy Center, which was in service in 2013, and higher property tax expenses. Purchased gas expenses increased due to higher gas sales in 2013 as a result of the unseasonably warm weather during the first four months of 2012 and higher cost of gas in 2013; purchased gas costs are recovered through a purchased gas adjustment clause from customers (see Operating Revenue). Property tax expenses increased primarily due to higher taxable plant and rates.

Depreciation Expense increased $7.3 million, or 16 percent, from 2012 reflecting additional property, plant and equipment in service.

Interest expense increased $1.6 million, or 8 percent, from 2012 primarily due to higher average long-term debt balances.

Income tax expense decreased $2.7 million, or 14 percent, from 2012, primarily due to higher federal production tax credits in 2013 as our Bison Wind Energy Center was completed in various phases through December 2012 and in service in 2013.

COMPARISON OF THE SIX MONTHS ENDED JUNE 30, 2013 AND 2012 (Continued)

Investments and Other

Operating revenue increased $1.4 million, or 3 percent, from 2012 primarily due to a $1.5 million increase in revenue at BNI Coal. BNI Coal, which operates under a cost plus fixed fee contract, recorded higher revenue as a result of higher expenses in 2013. (See Operating Expense.)

ALLETE Properties	2013		2012	
Revenue and Sales Activity	Acres (a)	Amount	Acres (a)	Amount
Dollars in Millions				
Revenue from Land Sales	19	$0.1	—	—
Other Revenue		0.3		$0.3
Total ALLETE Properties Revenue		$0.4		$0.3

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

Operating expenses increased $1.8 million, or 4 percent, from 2012 reflecting higher expenses at BNI Coal of $1.7 million primarily due to higher labor and fuel costs, which are recovered through the cost-plus contract. (See Operating Revenue.)

Interest expense increased $2.4 million from 2012 primarily due to a decrease 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.

Other income increased $2.1 million from 2012 primarily due to a gain on sale of available-for-sale securities.

Income tax benefits decreased $1.2 million from 2012 primarily due to higher state tax expense. State income tax expense was higher in 2013 as more North Dakota income tax credits attributable to our North Dakota capital investments were recognized in 2012.

Income Taxes – Consolidated

For the six months ended June 30, 2013, the effective tax rate was 20.0 percent (25.2 percent for the six months ended June 30, 2012). The decrease from the effective tax rate for the six months ended June 30, 2012, was primarily due to increased federal production tax credits in 2013. The effective tax rate deviated from the statutory rate of approximately 41 percent primarily due to deductions for AFUDC - Equity, investment tax credits, federal production tax credits, state income tax credits and depletion. (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 2012 Form 10-K.

OUTLOOK

For additional information see our 2012 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 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 expects to 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 energy sources will play an increasingly important role in our nation’s energy mix. Minnesota Power has developed renewable resources which will be used to meet regulated renewable supply requirements and is considering additional investments. 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, midstream gas and oil infrastructure, among other energy-related projects. ALLETE Clean Energy intends to market to electric utilities, cooperatives, municipalities, independent power marketers and large end-users across North America through long-term contracts or other sale arrangements, 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 Wind Energy Center. We have a long-term business presence and established landowner relationships in North Dakota.

We plan to make investments in transmission opportunities that strengthen or enhance the transmission grid or take advantage of our geographical location between sources of renewable energy and end users. This includes the Great Northern Transmission Line and the CapX2020 initiative, as well as investments to enhance our own transmission facilities, investments in other 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 Regulated Operations – Transmission.)

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 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 2013.

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.

OUTLOOK (Continued)
Regulated Operations (Continued)

Interim Rate Appeal. In February 2011, Minnesota Power appealed the MPUC's interim rate decision in the Company's 2010 rate case to the Minnesota Court of Appeals. The Company appealed the MPUC's finding of exigent circumstances in the interim rate decision with the primary arguments being 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. In January 2012, the Company filed a petition for review at the Minnesota Supreme Court (Court). In February 2012, the Court granted the petition for review and oral arguments were held before the Court in October 2012. A decision is expected in the third quarter of 2013. We cannot predict the outcome at this time.

Rapids Energy Center. In December 2012, Minnesota Power filed with the MPUC for approval to transfer the assets of Rapids Energy Center from non-rate base generation to Minnesota Power's Regulated Operations. Rapids Energy Center is a generation facility that is located at the UPM, Blandin Paper Mill (Blandin). Minnesota Power and Blandin entered into a new electric service agreement in September 2012 which is also subject to MPUC approval. We expect a decision from the MPUC on these filings in late 2013.

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 with ALLETE, 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. In July 2012, the MPUC issued an order approving certain administrative items related to accounting for shared services and 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.

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 set each July 1 based on a cost-based formula methodology, 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 cost-based formula 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 wholesale customer submitted a cancellation notice with termination effective on December 31, 2013. The 17 MW of average monthly demand currently provided to this wholesale customer is expected to be used, upon termination, to supply power for prospective additional retail and municipal load.

Industrial Customers. Electric power is one of several key inputs in the taconite mining, iron concentrate, paper, pulp and wood products, and pipeline industries. Approximately 54 percent of our Regulated Utility kilowatt-hour sales in the six months ended June 30, 2013 (57 percent in the six months ended June 30, 2012) were made to our industrial customers in these industries.

Minnesota Power provides electric service to five taconite customers capable of producing up to approximately 41 million tons of taconite pellets annually. Taconite pellets produced in Minnesota are primarily shipped to North American steel making facilities that are part of the integrated steel industry. Steel produced from these North American facilities is used primarily in the manufacture of automobiles, appliances, pipe and tube products for the gas and oil industry, and in the construction industry. Historically, less than five percent of Minnesota taconite production is exported outside of North America.

There has been a general historical correlation between U.S. steel production and Minnesota taconite production. 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, projected U.S. steel consumption in 2013 will be similar to 2012. The American Iron and Steel Institute (AISI), an association of North American steel producers, reported that U.S. raw steel production operated at approximately 77 percent of capacity during the first six months of 2013, compared to 78 percent in 2012. Based on this information, 2013 taconite production levels in Minnesota are expected to be similar to 2012.

OUTLOOK (Continued)
Regulated Operations (Continued)

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 projects are in the ferrous and non-ferrous mining and steel industries and include PolyMet, Mesabi Nugget Delaware, LLC, USS Corporation's Keewatin taconite expansion, Magnetation, Inc. and additional Essar Steel Minnesota LLC (Essar) load growth (see City of Nashwauk). 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.

City of Nashwauk. In May 2012, the Company entered into a new formula-based wholesale electric sales agreement with the City of Nashwauk, Minnesota for all of the City's electric service requirements, effective April 1, 2013 through June 30, 2024. A new Essar taconite facility is currently under construction in the City of Nashwauk. This facility will result in up to approximately 110 MW of additional load for Minnesota Power. Under the terms of a facilities construction agreement, Minnesota Power constructed a 230 kV transmission system upgrade to serve the Essar load which was placed into service in March 2013, with a total cost of approximately $35 million. This upgrade will allow the City of Nashwauk to provide electric service for Essar's new taconite facility. Billings to Essar to recover our transmission investments began in April 2013. Currently, Essar expects to begin blasting, mining and commissioning equipment in 2014. These activities will require an insignificant amount of electric power and as a result, we expect minimal impact from electric sales on our results of operations through 2014. Essar is expected to begin increasing its electric power requirements as it ramps up production in late 2014, into 2015 and beyond. Expansions for additional pellet production, production of direct reduced iron and production of steel slabs are also being considered by Essar for future years. In addition, on February 11, 2013, Essar announced a ten-year iron ore pellet off-take agreement with ArcelorMittal. Under the terms of the agreement, Essar will supply approximately 3 million to 4 million metric tons of pellets annually to ArcelorMittal through 2024.

EnergyForward. On January 30, 2013, Minnesota Power announced "EnergyForward", a strategic plan for assuring reliability, protecting affordability and further improving environmental performance. The plan includes completed and planned investments in wind and hydroelectric power, the addition of natural gas as a generation fuel source, and the installation of emissions control technology. Significant elements of the "EnergyForward" plan include:

- Major wind investments in North Dakota. Including the 210 MW of wind generation commissioned in December 2012, our Bison Wind Energy Center has 292 MW of nameplate capacity (see Renewable Energy).
- Planned installation of approximately $350 to $400 million in emissions control technology at our Boswell Unit 4 to further reduce emissions of SO_2, particulates and mercury (see Boswell Mercury Emission Reduction Plan).
- Planning for the proposed Great Northern Transmission Line to deliver hydroelectric power from northern Manitoba by 2020 (see Renewable Energy and Transmission).
- The conversion of Laskin from coal to cleaner-burning natural gas in 2015.
- Retiring Taconite Harbor Unit 3, one of three coal units at Taconite Harbor, in 2015.

Our "EnergyForward" initiatives are subject to regulatory approval, and were included in Minnesota Power's 2013 Integrated Resource Plan filed with the MPUC on March 1, 2013 (see Integrated Resource Plan).

Boswell Mercury Emissions Reduction Plan. Minnesota Power is required to implement a mercury emissions reduction project for Boswell Unit 4 under the Minnesota Mercury Emissions Reduction Act and the Federal MATS rule. In August 2012, Minnesota Power filed its mercury emissions reduction plan for Boswell Unit 4 with the MPUC and the MPCA. The plan proposes that Minnesota Power install pollution controls by early 2016 to address both the Minnesota mercury emissions reduction requirements and the Federal MATS rule. Costs to implement the Boswell Unit 4 mercury emissions reduction plan are included in the estimated capital expenditures required for compliance with the MATS rule and are estimated to be between $350 million and $400 million. The MPCA issued its report on March 1, 2013 in support of the Boswell Unit 4 mercury emissions reduction plan stating that the plan is appropriate for accomplishing the objectives of reducing emissions of mercury and other pollutants under the Minnesota Statutes and recommended that the MPUC accept the report’s findings. We expect a decision by the MPUC on the plan in the third quarter of 2013. Upon approval by the MPUC, we anticipate filing a petition to include investments and expenditures in customer billing rates. (See EnergyForward.)

OUTLOOK (Continued)
Regulated Operations (Continued)

Renewable Energy. In February 2007, Minnesota enacted a law requiring 25 percent of Minnesota Power's total retail and municipal 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. 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. Minnesota Power met the 2012 milestone and has developed a plan to meet the future renewable milestones which is included in its 2010 and 2013 Integrated Resource Plans. The MPUC approved the 2010 Integrated Resource Plan in its final order issued in May 2011. Minnesota Power submitted its 2013 Integrated Resource Plan on March 1, 2013, which included an update on its plans and progress in meeting the Minnesota renewable energy milestones through 2025. (See EnergyForward.)

Minnesota Power has taken several steps in executing its renewable energy strategy through key renewable projects that will ensure we meet the identified state mandate at the lowest cost for customers (see Wind Energy). We expect 17 percent of the Company's total retail and municipal energy sales will be supplied by renewable energy sources in 2013.

Wind Energy. Our wind energy facilities consist of our 292 MW Bison Wind Energy Center located in North Dakota completed in various phases through 2012, and our 25 MW Taconite Ridge Energy Center located in northeastern Minnesota completed in 2008. We also have 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) located in North Dakota.

Customer billing rates for our Bison Wind Energy Center were approved by the MPUC in a November 2011 order and are based on investments and expenditures through that period. We filed a cost recovery petition with the MPUC on May 31, 2013, to update customer billing rates for subsequent investments and expenditures since 2011, which is expected to be approved in the second half of 2013.

Our capital expenditures plan includes additional wind energy investments in North Dakota to meet Minnesota's 25 percent renewable energy mandate by 2025. On January 2, 2013, The American Taxpayer Relief Act of 2012 (ATRA) extended the availability of the production tax credit for renewable energy facilities that commence construction by December 31, 2013, among other ATRA requirements.

On May 3, 2013, we filed for NDPSC site permit approval for construction of Bison 4, an approximately 200 MW wind project in North Dakota. If approved by the NDPSC, construction would commence in the second half of 2013 and would be expected to be completed by the end of 2014. The total project investment is estimated to be approximately $345 million (see Liquidity and Capital Resources – Capital Requirements). We also expect to file for MPUC approval of the project in the third quarter of 2013. Upon approval by the MPUC, we will seek current cost recovery eligibility for our investment.

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. The DC transmission line capacity can be increased if renewable energy or transmission needs justify investments to upgrade the line.

Manitoba Hydro. Minnesota Power has a long-term 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.

Minnesota Power has a separate long-term PPA with Manitoba Hydro to purchase surplus energy through April 2022. This energy-only agreement 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.

OUTLOOK (Continued)
Regulated Operations (Continued)

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 changes in a governmental inflationary index, a natural gas index, and market prices. The agreement is subject to construction of additional transmission capacity between Manitoba and Minnesota's Iron Range. 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.)

Hydro Operations. In June 2012, record rainfall and flooding occurred near Duluth, Minnesota and surrounding areas. The flooding impacted Minnesota Power's St. Louis River hydro system, particularly the Thomson Energy Center, which is currently off-line due to damage to the forebay canal and flooding at the facility. Minnesota Power continues to work on restoring the Thomson facility and to assess options for rebuilding the forebay canal. We are 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 fully estimate the capital cost and schedule for rebuilding the forebay canal and resuming generation; however, based on a preliminary evaluation, the capital rebuild cost is estimated to be approximately $25 million. In addition to the forebay work, Minnesota Power is performing restoration and upgrade work on electrical, mechanical and flow line systems at the Thomson facility, which is estimated to cost a total of approximately $35 million (net of anticipated insurance recoveries). Any expenditures to restore and upgrade systems and rebuild the forebay canal will be capitalized. Minnesota Power is working towards returning to partial generation from the Thomson Energy Center by the end of 2013 and to full generation by the end of 2014. In addition to the work at the Thomson facility, additional work on the Thomson Dam and other facilities in the St. Louis River hydro system are necessary to meet high flow events like that experienced in June 2012, which is estimated to cost approximately $10 million dollars through 2015. We expect to file a request with the MPUC in the third quarter of 2013 for cost recovery of capital expenditures related to the restoration and repair of the Thomson facility and other related St. Louis River hydro system projects through a renewable resources rider.

Minnesota Solar Mandate. In May 2013, legislation was enacted by the state of Minnesota requiring at least 1.5 percent of total retail electric sales, excluding sales to certain industrial customers, to be generated by solar energy by the end of 2020. At least ten percent of the 1.5 percent mandate must be met by solar energy generated by or procured from solar photovoltaic devices with a nameplate capacity of 20 kilowatts or less. Minnesota Power is in the process of evaluating the potential impact of this legislation on our operations.

Integrated Resource Plan. In May 2011, the MPUC issued its final order approving our 2010 Integrated Resource Plan. As a condition of the final order, a required baseload diversification study evaluating the impact of additional environmental regulations over the next two decades was filed in February 2012. Minnesota Power's 2013 Integrated Resource Plan, filed on March 1, 2013, details our "EnergyForward" strategic plan (see EnergyForward), and includes an analysis of a variety of existing and future energy resource alternatives and a projection of customer cost impact by class. A decision by the MPUC on this plan is expected in late 2013.

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

Transmission Investments. Minnesota Power has an approved cost recovery rider in place for certain transmission investments and expenditures. The continued use of the 2009 billing factor was approved by the MPUC in May 2011, which allows Minnesota Power to charge retail customers on a current basis for the costs of constructing certain transmission facilities plus a return on the capital invested. In June 2011, Minnesota Power filed an updated billing factor that includes additional transmission expenditures, which is expected to be approved in the second half of 2013.

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, municipal 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.

OUTLOOK (Continued)
Regulated Operations (Continued)

Minnesota Power is 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. The 28-mile 345 kV line between Monticello and St. Cloud was placed into service in December 2011 and the 70-mile 230 kV line between Bemidji, Minnesota and Minnesota Power’s Boswell Energy Center near Grand Rapids, Minnesota was placed into service in September 2012. 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 was completed in August 2012. The entire 238-mile, 345 kV line from Fargo to Monticello is expected to be in service by 2015.

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 $110 million in the CapX2020 initiative through 2015. A total of $59.8 million was spent through June 30, 2013, of which $48.9 million related to the Fargo, North Dakota to Monticello, Minnesota projects and $10.9 million related to the Bemidji, Minnesota to Minnesota Power’s Boswell Energy Center project ($48.2 million as of December 31, 2012 of which $37.3 million related to the Fargo, North Dakota to Monticello, Minnesota projects and $10.9 million related to the Bemidji, Minnesota to Minnesota Power’s Boswell Energy Center project). As future CapX2020 projects are identified, Minnesota Power may elect to participate on a project-by-project basis.

Great Northern Transmission Line. As a condition of the long-term PPA signed in May 2011 with Manitoba Hydro, construction of additional transmission capacity is required. In February 2012, Minnesota Power and Manitoba Hydro proposed construction of the Great Northern Transmission Line, 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 targeted to be in service in 2020. Total project cost and cost allocations are still to be determined; however, at this time we expect our capital expenditures to range between $200 million and $400 million. The Great Northern Transmission Line is subject to various federal and state regulatory approvals. In addition, Manitoba Hydro must obtain regulatory and governmental approvals related to new transmission lines and hydroelectric generation development in Canada.

ATC Joint Development. Minnesota Power and ATC are evaluating the joint development of a 345 kV transmission line from Minnesota’s Iron Range to Duluth, Minnesota, for service after 2020, as a potential second phase of the Great Northern Transmission Line. 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 allocations are still to be determined.

Investment in ATC. As of June 30, 2013, our equity investment in ATC was $111.2 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 2012, ATC updated its 10-year transmission assessment covering the years 2012 through 2021 which identifies a need for between $3.9 and $4.8 billion in transmission system investments. These investments by ATC are expected to be funded 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 2013, we invested $1.6 million in ATC, and on July 30, 2013, we invested an additional $0.8 million. We expect to make additional investments of approximately $0.7 million in 2013. (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 the 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.

OUTLOOK (Continued)

Investments and Other

BNI Coal. BNI Coal anticipates selling approximately 4 million tons of coal in 2013 (4.4 million tons were sold in 2012) and has sold 2.0 million tons through June 30, 2013 (2.2 million tons were sold as of June 30, 2012).

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, sell the portfolio when opportunities arise and reinvest the proceeds in our growth initiatives. If weak market conditions continue, 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, or impairments. ALLETE does not intend to acquire additional Florida real estate.

Our two major development projects are Town Center and Palm Coast Park. Another major project, Ormond Crossings, is in the permitting 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 1,941 acres of other land available-for-sale.

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 with ALLETE, 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. In July 2012, the MPUC issued an order approving certain administrative items related to accounting for shared services and 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)

Income Taxes. ALLETE’s aggregate federal and multi-state statutory tax rate is approximately 41 percent for 2013. 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, domestic manufacturer’s deduction, depletion, as well as other items. The annual effective rate can also be impacted by such items as changes in income from operations before 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 production tax credits as a result of additional wind generation, we expect our effective tax rate to be approximately 20 percent for 2013. We also expect that our effective tax rate will be lower than the statutory rate over the next ten years due to production tax credits attributable to our wind generation. (See Note 10. Income Tax Expense.)

LIQUIDITY AND CAPITAL RESOURCES

Liquidity Position. ALLETE is well-positioned to meet the Company’s liquidity needs. As of June 30, 2013, we had cash and cash equivalents of $145.0 million, $400.7 million in available consolidated lines of credit and a debt-to-capital ratio of 47 percent.

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

Millions	June 30, 2013	%	December 31, 2012	%
ALLETE Equity	$1,249.0	53	$1,201.0	54
Long-Term Debt (Including Current Maturities)	1,102.6	47	1,018.1	46
	$2,351.6	100	$2,219.1	100

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

For the Six Months Ended June 30, Millions	2013	2012
Cash and Cash Equivalents at Beginning of Period	$80.8	$101.1
Cash Flows from (used for)		
Operating Activities	111.1	128.1
Investing Activities	(125.2)	(227.0)
Financing Activities	78.3	6.4
Change in Cash and Cash Equivalents	64.2	(92.5)
Cash and Cash Equivalents at End of Period	$145.0	$8.6

Operating Activities. Cash from operating activities was $111.1 million for the six months ended June 30, 2013 ($128.1 million for the six months ended June 30, 2012). Cash from operating activities was lower than 2012 primarily due to cash contributions to other postretirement benefit plans ($10.8 million in 2013 and none in 2012), decreased other current liabilities due to receipt of customer security deposits in 2012, and increased cost recovery rider receivable, offset by higher net income.

Investing Activities. Cash used for investing activities was $125.2 million for the six months ended June 30, 2013 ($227.0 million for the six months ended June 30, 2012). The decrease in cash used for investing activities was primarily due to lower payments for capital expenditures in 2013 as we completed our Bison project in late 2012.

Financing Activities. Cash from financing activities was $78.3 million for the six months ended June 30, 2013 ($6.4 million for the six months ended June 30, 2012). The increase in cash from financing activities was primarily due to proceeds of $150.0 million from long-term debt issuances in 2013 partially offset by $60.0 million of long-term debt maturing in April 2013.

LIQUIDITY AND CAPITAL RESOURCES (Continued)

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, 2013, we had available consolidated bank lines of credit aggregating $400.7 million, of which $150.0 million expires in January 2014, and $250.0 million expires in June 2015. In addition, we have 2.7 million original issue shares of our common stock available for issuance through Invest Direct, our direct stock purchase and dividend reinvestment plan, and 4.2 million original issue shares of common stock available for issuance through a Distribution Agreement with KCCI, Ltd. 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, Ltd. in February 2008, as amended most recently in August 2012, with respect to the issuance and sale of up to an aggregate of 9.6 million shares of our common stock, without par value, of which 4.2 million remain available for issuance. For the six months ended June 30, 2013, 0.3 million shares of common stock were issued under this agreement, resulting in net proceeds of $11.7 million (0.4 million shares were issued for the six months ended June 30, 2012, resulting in net proceeds of $18.7 million). The shares issued in 2013 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.

During the six months ended June 30, 2013, we issued 0.4 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 $21.6 million (0.3 million shares were issued for net proceeds of $11.8 million during the six months ended June 30, 2012). These shares of common stock were registered under Registration Statement Nos. 333-188315, 333-183051 and 333-162890.

On April 2, 2013, we issued $150.0 million of the Company’s First Mortgage Bonds (Bonds) in a private placement in three series. (See Note 8. Short-Term and Long-Term Debt.) Proceeds from the sale of the Bonds will be used to fund utility capital investments, repay debt, 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 2013, and we do not expect to make any additional contributions to our other postretirement benefit plan in 2013. (See Note 13. Pension and Other Postretirement Benefit Plans.)

Off-Balance Sheet Arrangements

Off-balance sheet arrangements are summarized in our 2012 Form 10-K, with additional disclosure in Note 14. Commitments, Guarantees and Contingencies.

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

LIQUIDITY AND CAPITAL RESOURCES (Continued)

Standard & Poor's recently revised its criteria for rating utility first mortgage bonds. As part of Standard & Poor's revised utility first mortgage bond criteria implementation, the senior secured rating for ALLETE was raised from "A–" to "A".

Credit Ratings	Standard & Poor's	Moody's
Issuer Credit Rating	BBB+	Baa1
Commercial Paper	A-2	P-2
Senior Secured		
First Mortgage Bonds (a)	A	A2

(a) Includes collateralized pollution control bonds.

Capital Requirements

Our capital expenditures for 2013 are expected to be approximately $375 million. For the six months ended June 30, 2013, capital expenditures totaled $100.2 million ($235.1 million for the six months ended June 30, 2012). The expenditures were primarily made in the Regulated Operations segment.

ALLETE's projected capital expenditures for the years 2013 through 2017 are presented in the table below. Actual capital expenditures may vary from the estimates due to changes in forecasted plant maintenance, regulatory decisions or approvals, future environmental requirements, base load growth, capital market conditions or execution of new business strategies.

Capital Expenditures	2013	2014	2015	2016	2017	Total
Millions						
Regulated Utility Operations						
Base and Other (a)	$208	$160	$152	$155	$138	$813
Cost Recovery (b)						
Environmental (c)	55	148	111	3	—	317
Renewable (d)	60	287	—	—	—	347
Transmission (e)	36	22	11	3	40	112
Total Cost Recovery	151	457	122	6	40	776
Regulated Utility Capital Expenditures	359	617	274	161	178	1,589
Other	16	25	11	9	3	64
Total Capital Expenditures	$375	$642	$285	$170	$181	$1,653

(a) Total capital expenditures of approximately $70 million relating to Minnesota Power's hydro system are included in Base and Other, of which approximately $55 million relating to Thomson Energy Center is expected to be spent in 2013. (See Outlook – Regulated Operations.)

(b) Estimated current capital expenditures eligible for cost recovery outside of a rate case.

(c) Environmental capital expenditures primarily relate to compliance with the MATS rule for Boswell Unit 4. (See Note 14. Commitments, Guarantees and Contingencies.) Boswell Unit 4 capital expenditures included above reflect Minnesota Power's ownership percentage of 80 percent. WPPI Energy owns 20 percent of Boswell Unit 4.

(d) Includes a total of approximately $345 million in 2013 and 2014, related to Bison 4. (See Outlook – Regulated Operations.)

(e) Transmission capital expenditures related to CapX2020 are estimated at approximately $50 million over the 2013 to 2015 period. Capital expenditures of approximately $40 million are included related to construction of the Great Northern Transmission Line. (See Outlook – Regulated Operations.)

We will finance capital expenditures from a combination of internally generated funds and debt and equity proceeds. We intend to maintain a capital structure with capital ratios near current levels. (See Liquidity and Capital Resources –

Capital Structure.)

OTHER

Environmental Matters

Our businesses are subject to regulation of environmental matters by various federal, state and local authorities. Due to future restrictive environmental requirements through legislation and/or rulemaking, we anticipate that potential expenditures for environmental matters will be material and will require significant capital investments. Environmental Matters are summarized in our 2012 Form 10-K, with additional disclosure in Note 14. Commitments, Guarantees and Contingencies. 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.

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

SECURITIES INVESTMENTS

Available-for-sale Securities. As of June 30, 2013, our available-for-sale securities portfolio consisted primarily of securities held in other postretirement plans to fund employee benefits and the cash equivalents within these plans. (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 include 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, 2013, 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, 2013.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures. As of June 30, 2013, 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.

PART II. OTHER INFORMATION

ITEM 1. LEGAL PROCEEDINGS

United Taconite Lawsuit. 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 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, 2013, because a potential loss is not currently probable or reasonably estimable; however, the Company believes it has adequate insurance limits for any potential loss. Our insurance carrier is providing a defense subject to a reservation of rights as to certain claims.

Notice of Potential Clean Air Act Citizen Lawsuit. In July 2013, the Sierra Club submitted to Minnesota Power a notice of intent to file a citizen suit under the Clean Air Act. This notice of intent alleged violations of opacity and other permit requirements at our Boswell, Laskin, and Taconite Harbor energy centers. Minnesota Power intends to vigorously defend any lawsuit that may be filed by the Sierra Club. We are unable to predict the outcome of this matter. Accordingly, an accrual related to any damages that may result from the notice of intent has not been recorded as of June 30, 2013, because a potential loss is not currently probable or reasonably estimable.

ITEM 1A. RISK FACTORS

There have been no material changes from the risk factors disclosed in Part 1, Item 1A Risk Factors of our 2012 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	
10 (a)	Amended and Restated ALLETE Non-Employee Director Stock Plan, effective May 15, 2013.
10 (b)	First Amendment to Amended and Restated Letter of Credit Agreement, dated as of June 1, 2013, between ALLETE, Inc. and Wells Fargo Bank, National Association, as Issuing Bank, Administrative Agent and sole Participating Bank.
10 (c)	July 2013 ALLETE and Affiliated Companies Compensation Recovery Policy
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 1, 2013, announcing 2013 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 1, 2013	/s/ Mark A. Schober Mark A. Schober Senior Vice President and Chief Financial Officer