ALLETE INC
Form 10-Q
August 04, 2015

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, 2015

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, without par value,
48,850,462 shares outstanding
as of June 30, 2015

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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
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. and its subsidiaries
ALLETE Properties	ALLETE Properties, LLC and its subsidiaries
ATC	American Transmission Company LLC
Bison	Bison Wind Energy Center
BNI Coal	BNI Coal, Ltd.
Boswell	Boswell Energy Center
CO_2	Carbon Dioxide
Company	ALLETE, Inc. and its subsidiaries
CSAPR	Cross-State Air Pollution Rule
DC	Direct Current
EIS	Environmental Impact Statement
Enbridge	Enbridge, Inc.
EPA	United States 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	Generally Accepted Accounting Principles in the United States of America
GHG	Greenhouse Gases
GNTL	Great Northern Transmission Line
IBEW	International Brotherhood of Electrical Workers
Invest Direct	ALLETE’s Direct Stock Purchase and Dividend Reinvestment Plan
Item ___	Item ___ of this Form 10-Q
kV	Kilovolt(s)
kWh	Kilowatt-hour(s)
Laskin	Laskin Energy Center
LIBOR	London Interbank Offered Rate
MACT	Maximum Achievable Control Technology
Magnetation	Magnetation, LLC
Manitoba Hydro	Manitoba Hydro-Electric Board
MATS	Mercury and Air Toxics Standards
Mesabi Nugget	Mesabi Nugget Delaware, LLC
Mining Resources	Mining Resources, LLC
Minnesota Power	An operating division of ALLETE, Inc.
Minnkota Power	Minnkota Power Cooperative, Inc.
MISO	Midcontinent Independent System Operator, Inc.
Montana-Dakota Utilities	Montana-Dakota Utilities Co., a division of MDU Resources Group, Inc.
MPCA	Minnesota Pollution Control Agency

Abbreviation or Acronym	Term
MPUC	Minnesota Public Utilities Commission
MW / MWh	Megawatt(s) / Megawatt-hour(s)
NAAQS	National Ambient Air Quality Standards
NDPSC	North Dakota Public Service Commission
NOL	Net Operating Loss
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 Corp.
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
Steel Dynamics	Steel Dynamics, Inc.
SWL&P	Superior Water, Light and Power Company
Taconite Harbor	Taconite Harbor Energy Center
Thomson	Thomson 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
U.S. Water Services	U.S. Water Services, Inc.
USS Corporation	United States Steel Corporation

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;
- global and domestic economic conditions affecting us or our customers;
- wholesale power market conditions;
- federal and state regulatory and legislative actions that impact regulated utility economics, including 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 and utility infrastructure, recovery of purchased power, capital investments and other expenses, including present or prospective environmental matters;
- changes in and compliance with laws and regulations;
- effects of competition, including competition for retail and wholesale customers;
- effects of restructuring initiatives in the electric industry;
- changes in tax rates or policies or in rates of inflation;
- the impacts on our Regulated Operations segment of climate change and future regulation to restrict the emissions of greenhouse gases;
- the impacts of laws and regulations related to renewable and distributed generation;
- the outcome of legal and administrative proceedings (whether civil or criminal) and settlements;
- weather conditions, natural disasters and pandemic diseases;
- our ability to access capital markets and bank financing;
- changes in interest rates and the performance of the financial markets;
- 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 and our ability to recover these costs;
- pricing, availability and transportation of fuel and other commodities and the ability to recover the costs of such commodities;
- our ability to replace a mature workforce and retain qualified, skilled and experienced personnel;
- effects of emerging technology;
- war, acts of terrorism and cyber attacks;
- our ability to manage expansion and integrate acquisitions;
- our current and potential industrial and municipal customers' ability to execute announced expansion plans;
- population growth rates and demographic patterns; and
- zoning and permitting of land held for resale, real estate development or changes in the real estate market.

Additional disclosures regarding factors that could cause our results or performance to differ from those anticipated by this report are discussed in Part 1, Item 1A, under the heading “Risk Factors” beginning on page 29 of ALLETE’s Annual Report on Form 10-K for the year ended December 31, 2014, and in “Item 1A. Risk Factors” in this Form 10-Q on page 62. 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, 2015	December 31, 2014
Assets		
Current Assets		
Cash and Cash Equivalents	$60.6	$145.8
Accounts Receivable (Less Allowance of $1.1 and $1.1)	103.9	103.0
Inventories	107.8	80.5
Prepayments and Other	36.5	82.0
Deferred Income Taxes	21.8	7.5
Total Current Assets	330.6	418.8
Property, Plant and Equipment – Net	3,451.5	3,284.8
Regulatory Assets	359.6	357.3
Investment in ATC	124.2	121.1
Other Investments	115.0	114.4
Goodwill and Intangible Assets – Net	213.4	4.8
Other Non-Current Assets	78.7	59.6
Total Assets	$4,673.0	$4,360.8
Liabilities and Equity		
Liabilities		
Current Liabilities		
Accounts Payable	$94.8	$134.1
Accrued Taxes	34.9	38.7
Accrued Interest	17.7	18.0
Long-Term Debt Due Within One Year	118.0	100.7
Notes Payable	—	3.7
Other	135.6	120.8
Total Current Liabilities	401.0	416.0
Long-Term Debt	1,272.4	1,272.8
Deferred Income Taxes	572.5	510.7
Regulatory Liabilities	104.8	94.2
Defined Benefit Pension and Other Postretirement Benefit Plans	190.0	190.9
Other Non-Current Liabilities	353.9	265.0
Total Liabilities	2,894.6	2,749.6
Commitments, Guarantees and Contingencies (Note 16)		
Equity		
ALLETE's Equity		
Common Stock Without Par Value, 80.0 Shares Authorized, 48.9 and 45.9 Shares Outstanding	1,257.1	1,107.6
Unearned ESOP Shares	(3.3)	(7.2)
Accumulated Other Comprehensive Loss	(20.2)	(21.1)
Retained Earnings	543.0	530.1
Total ALLETE Equity	1,776.6	1,609.4
Non-Controlling Interest in Subsidiaries	1.8	1.8
Total Equity	1,778.4	1,611.2

Total Liabilities and Equity	$4,673.0	$4,360.8

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, 2015	Quarter Ended June 30, 2014	Six Months Ended June 30, 2015	Six Months Ended June 30, 2014
Operating Revenue	$323.3	$260.7	$643.3	$557.2
Operating Expenses				
Fuel and Purchased Power	80.1	83.6	166.1	179.8
Transmission Services	11.3	10.5	26.2	21.3
Cost of Sales	52.3	18.9	83.5	42.4
Operating and Maintenance	85.4	74.3	165.1	148.6
Depreciation and Amortization	41.3	33.9	80.3	66.1
Taxes Other than Income Taxes	13.4	11.3	26.2	22.5
Total Operating Expenses	283.8	232.5	547.4	480.7
Operating Income	39.5	28.2	95.9	76.5
Other Income (Expense)				
Interest Expense	(16.2)	(13.5)	(31.3)	(26.3)
Equity Earnings in ATC	4.7	5.2	8.6	10.3
Other	0.7	1.9	1.8	3.9
Total Other Expense	(10.8)	(6.4)	(20.9)	(12.1)
Income Before Non-Controlling Interest and Income Taxes	28.7	21.8	75.0	64.4
Income Tax Expense	6.4	4.9	12.6	13.7
Net Income	22.3	16.9	62.4	50.7
Less: Non-Controlling Interest in Subsidiaries	(0.2)	0.1	—	0.4
Net Income Attributable to ALLETE	$22.5	$16.8	$62.4	$50.3
Average Shares of Common Stock				
Basic	48.6	42.1	47.7	41.7
Diluted	48.7	42.3	47.8	41.9
Basic Earnings Per Share of Common Stock	$0.46	$0.40	$1.31	$1.21
Diluted Earnings Per Share of Common Stock	$0.46	$0.40	$1.30	$1.20
Dividends Per Share of Common Stock	$0.505	$0.49	$1.01	$0.98

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,	
	2015	2014	2015	2014
Net Income	$22.3	$16.9	$62.4	$50.7
Other Comprehensive Income				
Unrealized Gain on Securities				
Net of Income Taxes of $–, $0.1, $0.1, and $0.1	—	0.2	0.1	0.2
Unrealized Gain on Derivatives				
Net of Income Taxes of $0.1, $–, $0.1, and $0.1	—	—	0.1	—
Defined Benefit Pension and Other Postretirement Benefit Plans				
Net of Income Taxes of $0.2, $0.2, $0.4, and $0.4	0.4	0.3	0.7	0.6
Total Other Comprehensive Income	0.4	0.5	0.9	0.8
Total Comprehensive Income	22.7	17.4	63.3	51.5
Less: Non-Controlling Interest in Subsidiaries	(0.2)	0.1	—	0.4
Comprehensive Income Attributable to ALLETE	$22.9	$17.3	$63.3	$51.1

The accompanying notes are an integral part of these statements.

ALLETE
CONSOLIDATED STATEMENT OF CASH FLOWS
Millions – Unaudited

	Six Months Ended June 30, 2015	2014
Operating Activities		
Net Income	$62.4	$50.7
Allowance for Funds Used During Construction – Equity	(1.6)	(3.8)
Income from Equity Investments – Net of Dividends	(2.3)	(1.9)
Gain on Sale of Investments	(0.1)	(0.2)
Depreciation Expense	78.7	66.0
Amortization of Intangible Assets and Other Assets	2.9	0.5
Amortization of Power Purchase Agreements	(11.0)	(6.2)
Deferred Income Tax Expense	12.3	13.6
Share-Based Compensation Expense	1.3	1.4
ESOP Compensation Expense	4.9	4.5
Defined Benefit Pension and Postretirement Benefit Expense	7.7	6.4
Bad Debt Expense	0.3	0.6
Changes in Operating Assets and Liabilities		
Accounts Receivable	17.3	21.0
Inventories	(13.4)	(12.9)
Prepayments and Other	4.2	7.0
Accounts Payable	(25.6)	(11.0)
Other Current Liabilities	47.4	(9.7)
Changes in Regulatory and Other Non-Current Assets	(9.6)	(11.5)
Changes in Regulatory and Other Non-Current Liabilities	6.5	11.6
Cash from Operating Activities	182.3	126.1
Investing Activities		
Proceeds from Sale of Available-for-sale Securities	0.7	2.7
Payments for Purchase of Available-for-sale Securities	(0.8)	(3.4)
Acquisitions of Subsidiaries – Net of Cash Acquired	(214.4)	(23.1)
Investment in ATC	(0.8)	(2.3)
Changes to Other Investments	(0.4)	30.6
Additions to Property, Plant and Equipment	(140.5)	(333.9)
Cash in Escrow for Acquisition	(15.0)	6.0
Cash for Investing Activities	(371.2)	(323.4)
Financing Activities		
Proceeds from Issuance of Common Stock	148.2	38.9
Proceeds from Issuance of Long-Term Debt	15.0	215.0
Changes in Restricted Cash	(2.9)	—
Changes in Notes Payable	(3.7)	—
Repayments of Long-Term Debt	(3.4)	(20.8)
Acquisition of Non-Controlling Interest	—	(6.0)
Debt Issuance Costs	—	(1.8)
Dividends on Common Stock	(49.5)	(41.7)
Cash from Financing Activities	103.7	183.6
Change in Cash and Cash Equivalents	(85.2)	(13.7)
Cash and Cash Equivalents at Beginning of Period	145.8	97.3

Cash and Cash Equivalents at End of Period	$60.6	$83.6

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, 2014, Consolidated Balance Sheet was derived from audited financial statements, but does not include all disclosures required by GAAP. In management's opinion, these unaudited financial statements include all adjustments necessary for a fair statement of financial results. All adjustments are of a normal, recurring nature, except as otherwise disclosed. Operating results for the six months ended June 30, 2015, are not necessarily indicative of results that may be expected for any other interim period or for the year ending December 31, 2015. For further information, refer to the Consolidated Financial Statements and notes included in our 2014 Form 10-K.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES

Reclassifications. As a result of recent acquisitions, certain financial statement captions have been added and as a result we have reclassified certain prior-period amounts on our Consolidated Balance Sheet, Consolidated Statement of Income, and Consolidated Statement of Cash Flows to conform to the presentation for the current period.

Consolidated Balance Sheet. In conformity with the current presentation of Goodwill and Intangible Assets - Net on the Consolidated Balance Sheet, we have reclassified our December 31, 2014, Consolidated Balance Sheet to include $1.6 million and $3.2 million of goodwill and intangible assets previously disclosed in Property, Plant and Equipment - Net and Other Non-Current Assets, respectively, under Goodwill and Intangible Assets - Net. There was no impact to Total Assets as a result of the reclassification.

Consolidated Statement of Income. In conformity with the current presentation of Cost of Sales on the Consolidated Statement of Income, we have reclassified $18.9 million from Operating and Maintenance Expenses to Cost of Sales for the quarter ended June 30, 2014 and $42.4 million for the six months ended June 30, 2014. Cost of Sales includes purchased gas at SWL&P, expenses incurred to deliver coal at BNI Coal, and the cost of land and other sales at ALLETE Properties. Cost of Sales also includes costs associated with the manufacture and delivery of inventories at U.S. Water Services, our integrated water management company which was acquired on February 10, 2015. (See Note 4. Acquisitions.) In addition to the presentation of Cost of Sales, we have created new captions on the Consolidated Statement of Income to provide additional detail for Transmission Services and Taxes Other than Income Taxes. Transmission Services are MISO-related costs incurred for the transmission of electricity. In conformity with the current presentation, we have reclassified from Operating and Maintenance Expenses $10.5 million of Transmission Services and $11.3 million of Taxes Other than Income Taxes for the quarter ended June 30, 2014, and $21.3 million of Transmission Services and $22.5 million of Taxes Other than Income Taxes for the six months ended June 30, 2014. There was no impact to Operating Income, Net Income, or Net Income Attributable to ALLETE as a result of these reclassifications.

Consolidated Statement of Cash Flows. In conformity with the current presentation of the Amortization of Power Purchase Agreements on the Consolidated Statement of Cash Flows, we have reclassified $5.6 million from Changes in Regulatory and Other Non-Current Liabilities to Amortization of Power Purchase Agreements for the six months ended June 30, 2014. There was no impact on cash from (for) Operating Activities, Investing Activities, and Financing Activities as a result of the reclassifications.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Inventories. Inventories are stated at the lower of cost or market. Amounts removed from inventories in our Regulated Operations segment are recorded on an average cost basis. Amounts removed from inventories in our Investments and Other segment are recorded on an average cost, first-in, first-out or specific identification basis.

Inventories	June 30, 2015	December 31, 2014
Millions		
Regulated Operations		
Fuel	$43.7	$29.0
Materials and Supplies	34.2	35.2
Total Regulated Operations	77.9	64.2
Investments and Other (a)		
Materials and Supplies	16.6	16.3
Raw Materials	2.9	—
Work in Progress	1.5	—
Finished Goods	9.1	—
Reserve for Obsolescence	(0.2)	—
Total Investments and Other	29.9	16.3
Total Inventories	$107.8	$80.5

(a) Raw Materials, Work in Progress, Finished Goods, and Reserve for Obsolescence presented relate to U.S. Water Services which was acquired on February 10, 2015.

Prepayments and Other Current Assets	June 30, 2015	December 31, 2014
Millions		
Deferred Fuel Adjustment Clause	$11.8	$16.3
Construction Costs for Development Project (a)	—	48.2
Restricted Cash (b)	7.7	2.7
Other	17.0	14.8
Total Prepayments and Other Current Assets	$36.5	$82.0

(a) Construction Costs for Development Project relate to ALLETE Clean Energy’s acquisition in November 2014 of a project to develop and construct a wind energy facility in 2015. As of June 30, 2015, these costs have been netted with contract billings. (See Billings in Excess of Costs and Estimated Earnings in Other Current Liabilities table and Note 4. Acquisitions.)

(b) Restricted Cash related to ALLETE Clean Energy’s wind energy facilities operating expense and capital distribution reserve requirements and cash pledged as collateral by U.S. Water Services for stand-by letters of credit.

Goodwill and Intangible Assets.

Goodwill. Goodwill is the excess of the purchase price (consideration transferred) over the estimated fair value of net assets of acquired businesses. In accordance with GAAP, goodwill is not amortized. The Company assesses whether there has been an impairment of goodwill annually in the third quarter and whenever an event occurs or circumstances change that would indicate the carrying amount may be impaired. Impairment testing for goodwill is done at the reporting unit level. An impairment loss is recognized when the carrying amount of the reporting unit’s net assets exceeds the estimated fair value of the reporting unit. The estimated fair value is generally determined using a discounted cash flow analysis.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Intangible Assets. Intangible assets include customer relationships, patents, non-compete agreements and trademarks and trade names. Intangible assets with definite lives consist of customer relationships, patents and non-compete agreements, which are amortized on a straight-line or accelerated basis with estimated useful lives ranging from less than 1 year to approximately 23 years. We review definite-lived intangible assets for impairment whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. Indefinite-lived intangible assets consist of trademarks and trade names, which are tested for impairment annually in the third quarter and whenever an event occurs or circumstances change that would indicate that the carrying amount may be impaired. Impairment is calculated as the excess of the asset's carrying amount over its fair value. Fair value is generally determined using a discounted cash flow analysis.

Other Non-Current Assets.

Restricted Cash. Included in Other Non-Current Assets on the Consolidated Balance Sheet was restricted cash of $20.3 million and $5.3 million as of June 30, 2015 and December 31, 2014, respectively. Restricted cash as of June 30, 2015 consisted of $15.0 million of cash held in escrow pending the closing of the Armenia Mountain wind energy facility acquisition, which occurred on July 1, 2015 (see Note 4. Acquisitions) and $5.3 million related to ALLETE Clean Energy's wind energy facilities debt service and other requirements. Restricted cash as of December 31, 2014 related primarily to ALLETE Clean Energy's wind energy facilities debt service and other requirements.

Other Current Liabilities	June 30, 2015	December 31, 2014
Millions		
Customer Deposits	$18.5	$19.7
Power Purchase Agreements (a)	24.3	19.4
Construction Deposits Received for Development Project (b)	—	54.3
Billings in Excess of Costs and Estimated Earnings (c)	54.4	—
Other	38.4	27.4
Total Other Current Liabilities	$135.6	$120.8

(a) Power Purchase Agreements were acquired in conjunction with ALLETE Clean Energy's wind energy facilities acquisitions. (See Note 4. Acquisitions.)

(b) Construction Deposits Received for Development Project relate to ALLETE Clean Energy's project to develop and construct a wind energy facility in 2015. As of June 30, 2015, these deposits have been netted with contract costs and estimated gross profit. (See Billings in Excess of Costs and Estimated Earnings below and Note 4. Acquisitions.)

(c) Billings in Excess of Costs and Estimated Earnings represents the excess of contract billings over the construction costs incurred and estimated earnings recognized. In the second quarter of 2015, the NDPSC approved the sale agreement ALLETE Clean Energy has with Montana-Dakota Utilities to develop, construct, and sell a wind energy facility in 2015. (See Note 4. Acquisitions.)

Other Non-Current Liabilities	June 30, 2015	December 31, 2014
Millions		
Asset Retirement Obligation	$122.4	$109.2
Power Purchase Agreements (a)	149.5	110.7
Contingent Consideration (b)	36.8	—
Other	45.2	45.1
Total Other Non-Current Liabilities	$353.9	$265.0

(a) Power Purchase Agreements were acquired in conjunction with ALLETE Clean Energy’s wind energy facilities acquisitions. (See Note 4. Acquisitions.)

(b) Contingent Consideration relates to the estimated fair value of the earnings-based payment resulting from the U.S. Water Services acquisition. (See Note 4. Acquisitions and Note 7. Fair Value.)

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Supplemental Statement of Cash Flows Information.

Six Months Ended June 30,	2015	2014
Millions		
Cash Paid During the Period for Interest – Net of Amounts Capitalized	$30.0	$23.7
Cash Paid During the Period for Income Taxes	$1.0	$0.2
Noncash Investing and Financing Activities		
Increase (Decrease) in Accounts Payable for Capital Additions to Property, Plant and Equipment	$(25.5)	$3.6
Capitalized Asset Retirement Costs	$7.8	$0.6
AFUDC–Equity	$1.6	$3.8
ALLETE Common Stock Contributed to the Pension Plan	—	$19.5
Contingent Consideration	$35.7	—

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.

Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity. In April 2014, the FASB issued an accounting standard update modifying the criteria for determining which disposals should be presented as discontinued operations and modifying the related disclosure requirements. Additionally, the new guidance requires that a business which qualifies as held for sale upon acquisition should be reported as discontinued operations. The new guidance was effective beginning in the first quarter of 2015, and applies prospectively to new disposals and new classifications of disposal groups as held for sale. This guidance is not expected to have a material impact on our Consolidated Financial Statements. We will consider the requirements of this standard if future transactions arise.

Revenue from Contracts with Customers. In May 2014, the FASB issued amended revenue recognition guidance to clarify the principles for recognizing revenue from contracts with customers. The guidance requires an entity to recognize revenue to depict the transfer of goods or services to customers in an amount that reflects the consideration to which an entity expects to be entitled in exchange for those goods or services. The guidance also requires expanded disclosures relating to the nature, amount, timing, and uncertainty of revenue and cash flows arising from contracts with customers. Additionally, qualitative and quantitative disclosures are required regarding customer contracts, significant judgments and changes in judgments, and assets recognized from the costs to obtain or fulfill a contract. This accounting guidance was to have been effective for the Company beginning in the first quarter of 2017 using one of two prescribed retrospective methods. On July 9, 2015, the FASB decided to defer the effective date of the standard by one year which will make the guidance effective for the Company beginning in the first quarter of 2018. Early adoption is permitted beginning in the first quarter of 2017 for public companies. The Company is evaluating the impact of the amended revenue recognition guidance on the Company’s Consolidated Financial Statements.

Presentation of Debt Issuance Costs. In April 2015, the FASB issued revised guidance addressing the presentation requirements for debt issuance costs. Under the revised guidance, all costs incurred to issue debt are to be presented on the Consolidated Balance Sheet as a direct deduction from the carrying amount of that debt liability. The revised guidance is effective for interim and annual reporting periods beginning after December 15, 2015. Debt issuance costs represent less than 1 percent of total long-term debt.

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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 our Energy Infrastructure and Related Services businesses: ALLETE Clean Energy, our business aimed at acquiring or developing capital projects that create energy solutions by way of wind, solar, biomass, hydro, natural gas, shale resources, clean coal technology and other emerging energy innovations, U.S. Water Services, our integrated water management company which was acquired on February 10, 2015, and BNI Coal, our coal mining operations in North Dakota. Investments and Other also includes ALLETE Properties, our Florida real estate investment, and other business development and corporate expenditures, unallocated interest expense, a small amount of non-rate base generation, approximately 5,000 acres of land in Minnesota, and earnings on cash and investments. Future acquisitions or growth may impact segment reporting.

Millions	Consolidated	Regulated Operations	Investments and Other
Quarter Ended June 30, 2015			
Operating Revenue	$323.3	$230.0	$93.3
Fuel and Purchased Power	80.1	80.1	—
Transmission Services	11.3	11.3	—
Cost of Sales	52.3	1.0	51.3
Operating and Maintenance	85.4	57.8	27.6
Depreciation and Amortization	41.3	33.7	7.6
Taxes Other than Income Taxes	13.4	12.1	1.3
Operating Income	39.5	34.0	5.5
Interest Expense	(16.2)	(13.3)	(2.9)
Equity Earnings in ATC	4.7	4.7	—
Other Income	0.7	0.7	—
Income Before Non-Controlling Interest and Income Taxes	28.7	26.1	2.6
Income Tax Expense	6.4	2.5	3.9
Net Income (Loss)	22.3	23.6	(1.3)
Less: Non-Controlling Interest in Subsidiaries	(0.2)	—	(0.2)
Net Income (Loss) Attributable to ALLETE	$22.5	$23.6	$(1.1)

NOTE 2. BUSINESS SEGMENTS (Continued)

Millions	Consolidated	Regulated Operations	Investments and Other
Quarter Ended June 30, 2014			
Operating Revenue	$260.7	$229.6	$31.1
Fuel and Purchased Power	83.6	83.6	—
Transmission Services	10.5	10.5	—
Cost of Sales	18.9	4.3	14.6
Operating and Maintenance	74.3	63.6	10.7
Depreciation and Amortization	33.9	29.6	4.3
Taxes Other than Income Taxes	11.3	10.6	0.7
Operating Income	28.2	27.4	0.8
Interest Expense	(13.5)	(11.4)	(2.1)
Equity Earnings in ATC	5.2	5.2	—
Other Income (Expense)	1.9	2.0	(0.1)
Income (Loss) Before Non-Controlling Interest and Income Taxes	21.8	23.2	(1.4)
Income Tax Expense (Benefit)	4.9	5.7	(0.8)
Net Income (Loss)	16.9	17.5	(0.6)
Less: Non-Controlling Interest in Subsidiaries	0.1	—	0.1
Net Income (Loss) Attributable to ALLETE	$16.8	$17.5	$(0.7)

Millions	Consolidated	Regulated Operations	Investments and Other
Six Months Ended June 30, 2015			
Operating Revenue	$643.3	$492.8	$150.5
Fuel and Purchased Power	166.1	166.1	—
Transmission Services	26.2	26.2	—
Cost of Sales	83.5	5.5	78.0
Operating and Maintenance	165.1	116.5	48.6
Depreciation and Amortization	80.3	65.8	14.5
Taxes Other than Income Taxes	26.2	23.7	2.5
Operating Income	95.9	89.0	6.9
Interest Expense	(31.3)	(26.3)	(5.0)
Equity Earnings in ATC	8.6	8.6	—
Other Income	1.8	1.6	0.2
Income Before Non-Controlling Interest and Income Taxes	75.0	72.9	2.1
Income Tax Expense	12.6	7.9	4.7
Net Income (Loss)	62.4	65.0	(2.6)
Less: Non-Controlling Interest in Subsidiaries	—	—	—
Net Income (Loss) Attributable to ALLETE	$62.4	$65.0	$(2.6)
As of June 30, 2015			
Total Assets	$4,673.0	$3,783.2	$889.8
Property, Plant and Equipment – Net	$3,451.5	$3,056.9	$394.6
Accumulated Depreciation	$1,380.1	$1,294.0	$86.1
Capital Additions	$117.9	$111.7	$6.2

NOTE 2. BUSINESS SEGMENTS (Continued)

Millions	Consolidated	Regulated Operations	Investments and Other
Six Months Ended June 30, 2014			
Operating Revenue	$557.2	$493.8	$63.4
Fuel and Purchased Power	179.8	179.8	—
Transmission Services	21.3	21.3	—
Cost of Sales	42.4	13.0	29.4
Operating and Maintenance	148.6	124.1	24.5
Depreciation and Amortization	66.1	58.4	7.7
Taxes Other than Income Taxes	22.5	20.8	1.7
Operating Income	76.5	76.4	0.1
Interest Expense	(26.3)	(22.9)	(3.4)
Equity Earnings in ATC	10.3	10.3	—
Other Income	3.9	3.8	0.1
Income (Loss) Before Non-Controlling Interest and Income Taxes	64.4	67.6	(3.2)
Income Tax Expense (Benefit)	13.7	16.2	(2.5)
Net Income (Loss)	50.7	51.4	(0.7)
Less: Non-Controlling Interest in Subsidiaries	0.4	—	0.4
Net Income (Loss) Attributable to ALLETE	$50.3	$51.4	$(1.1)
As of June 30, 2014			
Total Assets	$3,895.6	$3,424.3	$471.3
Property, Plant and Equipment – Net	$3,020.4	$2,791.7	$228.7
Accumulated Depreciation	$1,288.9	$1,221.1	$67.8
Capital Additions	$341.7	$335.6	$6.1

NOTE 3. INVESTMENTS

Investments. At June 30, 2015, our investment portfolio included 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, 2015	December 31, 2014
Millions		
ALLETE Properties	$88.6	$88.2
Available-for-sale Securities (a)	19.3	18.9
Cash Equivalents	2.8	2.9
Other	4.3	4.4
Total Other Investments	$115.0	$114.4

(a) As of June 30, 2015, the aggregate amount of available-for-sale corporate debt securities maturing in one year or less was $0.2 million, in one year to less than three years was $1.7 million, in three years to less than five years was $3.1 million, and in five or more years was $6.2 million.

NOTE 3. INVESTMENTS (Continued)

ALLETE Properties.

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 indicators of impairment on a quarterly basis and no impairments were recorded for the quarter and six months ended June 30, 2015 (none for the year ended December 31, 2014).

Available-For-Sale Securities

Millions		Gross Unrealized		
	Cost	Gain	Loss	Fair Value
June 30, 2015	$19.8	$0.3	$0.8	$19.3
December 31, 2014	$19.6	$0.2	$0.9	$18.9

	Net	Gross Realized	
	Proceeds	Gain	Loss
Quarter Ended June 30,			
2015	$0.5	$0.1	—
2014	$2.1	$0.2	—
Six Months Ended June 30,			
2015	$0.7	$0.1	—
2014	$2.7	$0.2	—

NOTE 4. ACQUISITIONS

The acquisitions below are consistent with ALLETE’s stated strategy of investing in energy infrastructure and related services businesses to complement its core regulated utility, balance exposure to business cycles and changing demand, and provide potential long-term earnings growth. The pro forma impact of the following acquisitions was not significant, either individually or in the aggregate, to the results of the Company for the six months ended June 30, 2015, and year ended December 31, 2014.

2015 Activity.

U.S. Water Services. On February 10, 2015, ALLETE acquired U.S. Water Services. Total consideration for the transaction was $202.3 million, which included payment of $166.6 million in cash and an estimated fair value of earnings-based contingent consideration of $35.7 million to be paid in 2019. The contingent consideration is presented within Other Non-Current Liabilities on the Consolidated Balance Sheet. The Consolidated Statement of Income reflects 100 percent of the results of operations of U.S. Water Services since the acquisition date as the Company has acquired 100 percent of U.S. Water Services. U.S. Water Services, an integrated industrial water management company headquartered in St. Michael, Minnesota, provides integrated water management for industry by combining chemical, equipment, engineering and service for customized solutions to reduce water and energy usage and improve efficiency. U.S. Water Services helps customers achieve efficient and sustainable use of their energy systems, is a leading provider to the biofuels industry, and has a growing presence in the power generation and midstream oil and gas industries.

NOTE 4. ACQUISITIONS (Continued)
2015 Activity (Continued)

The acquisition was accounted for as a business combination and the purchase price was allocated based on the estimated fair values of the assets acquired and the liabilities assumed at the date of acquisition. The allocation of the purchase price is subject to judgment and the preliminary estimated fair value of the assets acquired and the liabilities assumed may be adjusted when the valuation analysis is completed in subsequent periods. Preliminary estimates subject to adjustment in subsequent periods relate primarily to income taxes; subsequent adjustments could impact the amount of goodwill recorded. Fair value measurements were valued primarily using the discounted cash flow method.

Millions	
Assets Acquired	
Cash and Cash Equivalents	$0.9
Accounts Receivable	16.8
Inventories (a)	13.4
Other Current Assets (b)	5.3
Property, Plant and Equipment	10.6
Goodwill (c)	127.1
Intangible Assets (d)	83.0
Other Non-Current Assets	0.2
Total Assets Acquired	$257.3
Liabilities Assumed	
Current Liabilities	$18.7
Non-Current Liabilities	36.3
Total Liabilities Assumed	$55.0
Net Identifiable Assets Acquired	$202.3

(a) Included in Inventories was $2.7 million of fair value adjustments relating to work in progress and finished goods inventories which will be recognized as Cost of Sales within one year from the acquisition date.

(b) Included in Other Current Assets was $1.6 million relating to the fair value of sales backlog. Sales backlog will be recognized as Cost of Sales within one year from the acquisition date. Also included in Other Current Assets was restricted cash of $2.1 million relating to cash pledged as collateral for stand-by letters of credit.

(c) For tax purposes, the purchase price allocation resulted in $3.2 million of deductible Goodwill.

(d) Intangible Assets include customer relationships, patents, non-compete agreements and trademarks and trade names. (See Note 5. Goodwill and Intangible Assets.)

Acquisition-related costs of $3.0 million after-tax were expensed as incurred during the first quarter of 2015, and were recorded in Operating and Maintenance on the Consolidated Statement of Income.

Chanarambie/Viking. On April 15, 2015, ALLETE Clean Energy acquired wind energy facilities in southern Minnesota (Chanarambie/Viking) from EDF Energy Holdings Limited for $47.9 million.

The facilities have 97.5 MW of generating capability and are located near our Lake Benton facility. The wind energy facilities began commercial operations in 2003 and have PPAs in place for their entire output, which expire in 2018 (12 MW) and 2023 (85.5 MW).

NOTE 4. ACQUISITIONS (Continued)
2015 Activity (Continued)

The acquisition was accounted for as a business combination and the purchase price was allocated based on the estimated fair values of the assets acquired and the liabilities assumed at the date of acquisition. The allocation of the purchase price is subject to judgment and the preliminary estimated fair value of the assets acquired and the liabilities assumed may be adjusted when the valuation analysis is completed in subsequent periods. Preliminary estimates subject to adjustment in subsequent periods relate primarily to property, plant and equipment and PPAs; subsequent adjustments could impact the amount of goodwill recorded. Fair value measurements were valued primarily using the discounted cash flow method.

Millions	
Assets Acquired	
Current Assets	$4.8
Property, Plant and Equipment	103.0
Other Non-Current Assets (a)	0.8
Total Assets Acquired	$108.6
Liabilities Assumed	
Current Liabilities (b)	$6.7
Power Purchase Agreements	48.9
Non-Current Liabilities	5.1
Total Liabilities Assumed	$60.7
Net Identifiable Assets Acquired	$47.9

(a) Included in Other Non-Current Assets was $0.1 million of goodwill; for tax purposes, the purchase price allocation resulted in no allocation to goodwill.
(b) Current Liabilities included $5.8 million related to the current portion of Power Purchase Agreements.

Acquisition-related costs of $0.2 million after-tax were expensed as incurred during the six months ended June 30, 2015, and were recorded in Operating and Maintenance on the Consolidated Statement of Income.

Armenia Mountain. On July 1, 2015, ALLETE Clean Energy acquired 100 percent of a wind energy facility located near Troy, Pennsylvania (Armenia Mountain) from The AES Corporation (AES) and a non-controlling interest from a minority shareholder for $108.0 million, plus the assumption of existing debt. The agreement with AES is subject to a purchase price adjustment. We are currently in the process of accounting for the acquisition, therefore, certain disclosures, including the allocation of the purchase price, will be included in the Form 10-Q for the period ending September 30, 2015.

The facility has 100.5 MW of generating capability, began commercial operations in 2009, and has PPAs in place for its entire output, which expire in 2025.

Acquisition-related costs of $0.7 million after-tax were expensed as incurred during the six months ended June 30, 2015, and were recorded in Operating and Maintenance on the Consolidated Statement of Income.

Montana-Dakota Utilities. In November 2014, ALLETE Clean Energy acquired a business for $27.0 million to develop a wind facility near Hettinger, North Dakota. ALLETE Clean Energy is developing and constructing a 107 MW wind facility consisting of 43 turbines, which was approved to be sold to Montana-Dakota Utilities by the NDPSC on June 30, 2015, for approximately $200 million. Construction is expected to be completed in December 2015.

The acquisition was accounted for as a business combination and the purchase price was allocated based on the estimated fair values of the assets acquired and liabilities assumed at the date of acquisition. Fair value measurements were valued primarily using the replacement cost method and determined that the assets acquired amounted to cash of $3.6 million and construction in process of $23.4 million. There were no liabilities assumed and no recognition of goodwill.

NOTE 4. ACQUISITIONS (Continued)
2015 Activity (Continued)

As a result of the NDPSC approval of the sale agreement with Montana-Dakota Utilities, ALLETE Clean Energy began accounting for the project under the percentage of completion method of accounting for contracts. The percentage of completion used to recognize revenues and cost of sales is calculated based on the percentage of construction costs incurred at the measurement date compared to the estimated total construction costs, excluding equipment and turbine deposits in each measure. We have selected this method because we consider construction costs, excluding deposits, to be the best available measure of progress on the project. Any adjustments to the estimated percentage of completion or estimated earnings, and the related impacts to operating income, are recorded in the period they become known.

The following table summarizes contract billings, construction costs, and estimated earnings recognized for the wind facility:

	June 30, 2015
Millions	
Contract Billings	$141.2
Construction Costs	84.3
Estimated Earnings	2.5
Billings in Excess of Costs and Estimated Earnings (a)	$54.4

(a) Included in Other Current Liabilities on the Consolidated Balance Sheet.

For the six months ended June 30, 2015, revenue of $20.5 million and cost of sales of $18.0 million were recognized under the percentage of completion method of accounting for contracts and reported on the Consolidated Statement of Income as Operating Revenue and Cost of Sales, respectively. Cash flows related to construction costs incurred, contract billings, and estimated earnings were reported on the Consolidated Statement of Cash Flows as Other Current Liabilities.

As of December 31, 2014, contract billings received were $54.3 million and construction costs incurred (including the construction costs acquired) were $48.2 million and were classified as Other Current Liabilities and Prepayments and Other Current Assets, respectively, on the Consolidated Balance Sheet.

2014 Activity.

ACE Wind Acquisition. In January 2014, ALLETE Clean Energy acquired wind energy facilities located in Lake Benton, Minnesota (Lake Benton), Storm Lake, Iowa (Storm Lake II) and Condon, Oregon (Condon) from AES for $26.9 million.

Lake Benton, Storm Lake II and Condon have 104 MW, 77 MW and 50 MW of generating capability, respectively. Lake Benton and Storm Lake II began commercial operations in 1998, while Condon began operations in 2002. All three wind energy facilities have PPAs in place for their entire output, which expire in various years between 2019 and 2032.

NOTE 4. ACQUISITIONS (Continued)
2014 Activity (Continued)

ALLETE Clean Energy acquired a controlling interest in the limited liability company (LLC) which owns Lake Benton and Storm Lake II, and a controlling interest in the LLC that owns Condon. The acquisition was accounted for as a business combination and the purchase price was allocated based on the estimated fair values of the assets acquired and the liabilities assumed at the date of acquisition. Fair value measurements were valued primarily using the discounted cash flow method.

Millions	
Assets Acquired	
Cash and Cash Equivalents	$3.8
Other Current Assets	14.3
Property, Plant and Equipment	156.9
Other Non-Current Assets (a)	7.5
Total Assets Acquired	$182.5
Liabilities Assumed	
Current Liabilities (b)	$15.2
Long-Term Debt Due Within One Year	2.2
Long-Term Debt	21.1
Power Purchase Agreements	99.4
Other Non-Current Liabilities	10.6
Non-Controlling Interest (c)	7.1
Total Liabilities and Non-Controlling Interest Assumed	$155.6
Net Identifiable Assets Acquired	$26.9

(a) Included in Other Non-Current Assets was $0.3 million for the option to purchase Armenia Mountain, and goodwill of $2.9 million; for tax purposes, the purchase price allocation resulted in no allocation to goodwill.
(b) Current Liabilities included $12.4 million related to the current portion of Power Purchase Agreements.
(c) The purchase price accounting valued the non-controlling interest relating to Lake Benton, Storm Lake II and Condon at fair value using the discounted cash flow method.

In February 2014, ALLETE Clean Energy purchased the non-controlling interest related to Lake Benton and Storm Lake II for $6.0 million. This was accounted for as an equity transaction, and no gain or loss was recognized in net income or other comprehensive income.

Storm Lake I Acquisition. In December 2014, ALLETE Clean Energy acquired a wind energy facility in Storm Lake, Iowa (Storm Lake I) from NRG Energy, Inc. for $15.1 million.

Storm Lake I has 108 MW of generating capability and is located adjacent to Storm Lake II. The wind energy facility began commercial operations in 1999 and has a PPA in place for its entire output which expires in 2018.

NOTE 4. ACQUISITIONS (Continued)
2014 Activity (Continued)

The acquisition was accounted for as a business combination and the purchase price was allocated based on the estimated fair values of the assets acquired and the liabilities assumed at the date of acquisition. In connection with finalizing purchase price accounting, the Company recorded minor adjustments during the first quarter of 2015 to certain assets and liabilities, which are reflected in the table below. The result of these adjustments had no impact on the results of operations for the quarter ended March 31, 2015. Fair value measurements were valued primarily using the discounted cash flow method.

Millions	
Assets Acquired	
Cash and Cash Equivalents	$0.4
Other Current Assets	4.7
Property, Plant and Equipment	47.3
Other Non-Current Assets (a)	11.4
Total Assets Acquired	$63.8
Liabilities Assumed	
Current Liabilities (b)	$8.2
Power Purchase Agreements	23.5
Non-Current Liabilities	17.0
Total Liabilities Assumed	$48.7
Net Identifiable Assets Acquired	$15.1

(a) Included in Other Non-Current Assets was $0.4 million of restricted cash and an immaterial amount of goodwill; for tax purposes, the purchase price allocation resulted in no allocation to goodwill.
(b) Current Liabilities included $7.5 million related to the current portion of Power Purchase Agreements.

NOTE 5. GOODWILL AND INTANGIBLE ASSETS

The following table summarizes changes to goodwill by business segment for the six months ended June 30, 2015:

Millions	Investments and Other
Balance as of December 31, 2014	$2.9
Acquired Goodwill	127.2
Balance as of June 30, 2015	$130.1

NOTE 5. GOODWILL AND INTANGIBLE ASSETS (Continued)

Balances of intangible assets, net, excluding goodwill as of June 30, 2015, are as follows:

Millions	December 31, 2014	Additions as a Result of Acquisitions	Amortization	June 30, 2015
Intangible Assets				
Definite-Lived Intangible Assets				
Customer Relationships	—	$60.1	$1.3	$58.8
Developed Technology and Other (a)	$1.9	6.3	0.3	7.9
Total Definite-Lived Intangible Assets	1.9	66.4	1.6	66.7
Indefinite-Lived Intangible Assets				
Trademarks and Trade Names	—	16.6	n/a	16.6
Total Intangible Assets	$1.9	$83.0	$1.6	$83.3

(a) Developed Technology and Other includes patents, non-compete agreements, and land easements.

Customer relationships have a useful life of approximately 23 years and developed technology and other have useful lives ranging from less than 1 year to approximately 14 years (weighted average of approximately 9 years). The weighted average useful life of all definite-lived intangible assets as of June 30, 2015 is approximately 21 years.

Amortization expense of intangible assets for the six months ended June 30, 2015, was $1.6 million. The estimated amortization expense for definite-lived intangible assets for the remainder of 2015 is $2.6 million. Estimated annual amortization expense for definite-lived intangible assets is $4.3 million in 2016, $4.2 million in 2017, $4.1 million in 2018, $4.0 million in 2019, and $47.5 million thereafter.

NOTE 6. DERIVATIVES

We have one 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 which represents approximately 5 percent of the Company's outstanding long-term debt, including long-term debt due within one year, as of June 30, 2015. (See Note 10. Short-Term and Long-Term Debt.) The Swap has an effective date of August 26, 2014, and matures on August 25, 2015. The Swap involves the receipt of the one-month LIBOR in exchange for fixed interest payments over the life of the agreement at 0.75 percent without an exchange of the underlying notional amount. Cash flows from the Swap are expected to be highly effective. If it is determined that the Swap ceases to be effective, we will prospectively discontinue hedge accounting. When applicable, we use the shortcut method to assess hedge effectiveness. If the shortcut method is not applicable, we assess effectiveness using the "change-in-variable-cash-flows" method. Our assessment of hedge effectiveness resulted in no ineffectiveness recorded for the six months ended June 30, 2015. As of June 30, 2015, the fair value of the Swap was a $0.1 million liability ($0.3 million liability as of December 31, 2014) which was included in Other Current Liabilities on the Consolidated Balance Sheet. Changes in the fair value of the Swap were recorded in Accumulated Other Comprehensive Loss on the Consolidated Balance Sheet. Cash flows from the Swap are presented in the same category as the hedged item on the Consolidated Statement of Cash Flows. Amounts recorded in Other Comprehensive Income related to the Swap will be recorded in earnings when the hedged transaction occurs or when it is probable it will not occur. Gains or losses on the interest rate hedging transaction are reflected as a component of Interest Expense on the Consolidated Statement of Income.

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NOTE 7. 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 10. Fair Value to the Consolidated Financial Statements in our 2014 Form 10-K.

The following tables set forth by level within the fair value hierarchy our assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2015, and December 31, 2014. 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, which 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 is excluded from the recurring fair value measures in the tables below.

	Fair Value as of June 30, 2015			
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Total
Millions				
Assets:				
Investments (a)				
Available-for-sale – Equity Securities	$8.1	—	—	$8.1
Available-for-sale – Corporate Debt Securities	—	$11.2	—	11.2
Cash Equivalents	2.8	—	—	2.8
Total Fair Value of Assets	$10.9	$11.2	—	$22.1
Liabilities:				
Deferred Compensation (b)	—	$16.3	—	$16.3
Derivatives – Interest Rate Swap (c)	—	0.1	—	0.1
U.S. Water Services Contingent Consideration (b)	—	—	$36.8	36.8
Total Fair Value of Liabilities	—	$16.4	$36.8	$53.2
Total Net Fair Value of Assets (Liabilities)	$10.9	$(5.2)	$(36.8)	$(31.1)

(a) Included in Other Investments on the Consolidated Balance Sheet.
(b) Included in Other Non-Current Liabilities on the Consolidated Balance Sheet.
(c) Included in Current Liabilities - Other on the Consolidated Balance Sheet.

NOTE 7. FAIR VALUE (Continued)

	Fair Value as of December 31, 2014			
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Total
Millions				
Assets:				
Investments (a)				
Available-for-sale – Equity Securities	$8.1	—	—	$8.1
Available-for-sale – Corporate Debt Securities	—	$10.8	—	10.8
Cash Equivalents	2.9	—	—	2.9
Total Fair Value of Assets	$11.0	$10.8	—	$21.8
Liabilities:				
Deferred Compensation (b)	—	$16.2	—	$16.2
Derivatives – Interest Rate Swap (c)	—	0.3	—	0.3
Total Fair Value of Liabilities	—	$16.5	—	$16.5
Total Net Fair Value of Assets (Liabilities)	$11.0	$(5.7)	—	$5.3

(a) Included in Other Investments on the Consolidated Balance Sheet.
(b) Included in Other Non-Current Liabilities on the Consolidated Balance Sheet.
(c) Included in Current Liabilities - Other on the Consolidated Balance Sheet.

The following table provides a reconciliation of the beginning and ending balances of the U.S. Water Services Contingent Consideration measured at fair value using Level 3 measurements as of June 30, 2015. The acquisition contingent consideration was recorded at the acquisition date at its estimated fair value. The acquisition date fair value is measured based on the consideration expected to be transferred, discounted to present value. The discount rate is determined at the time of measurement in accordance with generally accepted valuation methods. The fair value of the acquisition contingent consideration is remeasured to arrive at estimated fair value each reporting period with the change in fair value recognized as income or expense in our Consolidated Statement of Income. Changes to the fair value of the acquisition contingent consideration can result from changes in discount rates, or in the timing and amount of earnings estimates. Using different valuation assumptions, including earnings projections or discount rates, may result in different fair value measurements and expense (or income) in future periods. The acquisition contingent consideration was measured at $36.8 million as of June 30, 2015.

Recurring Fair Value Measures	
Activity in Level 3	
Millions	
Balance as of December 31, 2014	—
Recognition of U.S. Water Services Contingent Consideration	$35.7
Accretion Expense (a)	1.1
Balance as of June 30, 2015	$36.8

(a) Included in Interest Expense on the Consolidated Statement of Income.

The Level 3 activity above is the result of the February 10, 2015, acquisition of U.S. Water Services; there was no activity in Level 3 during the year ended December 31, 2014.

For the six months ended June 30, 2015, and the year ended December 31, 2014, there were no transfers in or out of Levels 1, 2 or 3.

NOTE 7. 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, 2015	$1,390.4	$1,445.0
December 31, 2014	$1,373.5	$1,484.5

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis. Non-financial assets such as equity method investments, goodwill, intangible assets, and property, plant and equipment are measured at fair value when there is an indicator of impairment and recorded at fair value only when an impairment is recognized.

Equity Method Investment. 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. (See Note 9. Investment in ATC.) The aggregate carrying amount of the investment was $124.2 million as of June 30, 2015 ($121.1 million as of December 31, 2014). The Company assesses our investment in ATC for impairment whenever events or changes in circumstances indicate that the carrying amount of our investment in ATC may not be recoverable. For the six months ended June 30, 2015 and the year ended December 31, 2014, there were no indicators of impairment.

Goodwill. The Company assesses the impairment of goodwill annually in the third quarter and whenever an event occurs or circumstances change that would indicate that the carrying amount may be impaired. Substantially all of the Company’s goodwill is a result of the U.S. Water Services acquisition on February 10, 2015. The aggregate carrying amount of goodwill was $130.1 million and $2.9 million as of June 30, 2015, and December 31, 2014, respectively.

Impairment testing for goodwill is done at the reporting unit level. An impairment loss is recognized when the carrying amount of the reporting unit’s net assets exceeds the estimated fair value of the reporting unit. The test for impairment requires us to make several estimates about fair value, most of which are based on projected future cash flows. The Company calculates the excess of each reporting unit's fair value over its carrying amount, including goodwill, utilizing a discounted cash flow analysis. As of June 30, 2015, there have been no events or changes in circumstance which would indicate impairment of our goodwill.

Intangible Assets. The Company assesses indefinite-lived intangible assets for impairment annually in the third quarter. The Company also assesses indefinite-lived and definite-lived intangible assets whenever events or changes in circumstances indicate that the carrying amount of an intangible asset may not be recoverable. Substantially all of the Company’s intangible assets are a result of the U.S. Water Services acquisition on February 10, 2015. The aggregate carrying amount of intangible assets was $83.3 million as of June 30, 2015 ($1.9 million as of December 31, 2014). When events or changes in circumstances indicate that the carrying amount of an intangible asset may not be recoverable, the Company calculates the excess of an intangible asset's carrying amount over its undiscounted future cash flows. If the carrying amount is not recoverable, an impairment loss is recorded based on the amount by which the carrying amount exceeds the fair value. The inputs used in the fair value analysis fall within Level 3 of the fair value hierarchy due to the use of significant unobservable inputs to determine fair value. As of June 30, 2015, there have been no events or changes in circumstance which would indicate impairment of our intangible assets.

Property, Plant and Equipment. The Company assesses the impairment of property, plant, and equipment whenever events or changes in circumstances indicate that the carrying amount of property, plant, and equipment assets may not be recoverable. For the six months ended June 30, 2015, and the year ended December 31, 2014, there were no indicators of impairment.

We believe that long-standing ratemaking practices approved by applicable state and federal regulatory commissions allow for the recovery of the remaining book value of retired plant assets. We retired Taconite Harbor Unit 3 and converted Laskin to natural gas in the second quarter of 2015, which actions were included in our 2013 Integrated Resource Plan approved by the MPUC in a November 2013 order. On July 9, 2015, we announced the next steps in our EnergyForward plan, which includes the economic idling of Taconite Harbor Units 1 and 2 in the fall of 2016 and the ceasing of coal-fired operations there in 2020. We do not expect to record any impairment charge as a result of the retirement of Taconite Harbor or the conversion of Laskin.

NOTE 8. 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.

Energy-Intensive Trade-Exposed Customer Rates. The Minnesota Legislature enacted and the Governor of Minnesota signed Energy-Intensive Trade-Exposed customer ratemaking legislation in June 2015. The intent of this legislation is to enable the MPUC to address elements in rate design to better support the competitiveness of manufacturers with electrically intensive operations which compete in global markets. The Company is working with all stakeholders to develop a rate schedule and contract proposals to be filed with the MPUC. It is expected that any rate design outcomes will be implemented on a revenue neutral basis.

FERC-Approved Wholesale Rates. Minnesota Power has 16 non-affiliated municipal customers in Minnesota. SWL&P is a Wisconsin utility and a customer of Minnesota Power. On April 21, 2015, Minnesota Power amended its formula-based wholesale electric sales contract with the Nashwauk Public Utilities Commission, extending the term through June 30, 2028. The electric service agreements with the remaining 15 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 formula-based rate methodology also provides for a yearly true-up calculation for actual costs incurred. The contract terms include a termination clause requiring a three-year notice to terminate. Under the Nashwauk Public Utilities Commission agreement, no termination notice may be given prior to June 30, 2025. Under the agreements with the remaining 15 municipal customers and SWL&P, no termination notices may be given prior to June 30, 2016.

2012 Wisconsin Rate Case. SWL&P’s current 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.

Transmission Cost Recovery Rider. Minnesota Power has an approved cost recovery rider in place for certain transmission investments and expenditures. In an order dated February 23, 2015, the MPUC approved Minnesota Power’s updated billing factor 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. On May 22, 2015, we filed a transmission factor filing which includes updated costs associated with certain transmission facilities. Upon approval of the filing, we will be authorized to include updated billing rates on customer bills. As a result of the MPUC approval of the Certificate of Need for the GNTL on June 30, 2015, the project is eligible for cost recovery under our existing transmission cost recovery rider. We anticipate including our portion of the investments and expenditures for the GNTL as part of future transmission factor filings to include updated billing rates on customer bills.

Renewable Cost Recovery Rider. Minnesota Power has an approved cost recovery rider in place for investments and expenditures related to the 497 MW Bison Wind Energy Center in North Dakota. Customer billing rates for our Bison Wind Energy Center were approved by the MPUC in an order dated May 22, 2015. In November 2014, we filed a renewable resources factor filing which includes updated costs associated with Bison. Upon approval of the filing, we will be authorized to include updated billing rates on customer bills.

On February 13, 2015, Minnesota Power supplemented its November 2014 renewable resources factor filing to include costs associated with the restoration and repair of Thomson. In an order dated March 5, 2015, the MPUC approved our petition seeking cost recovery for investments and expenditures related to the restoration and repair of Thomson through a renewable resources rider.

Integrated Resource Plan. In a November 2013 order, the MPUC approved Minnesota Power's 2013 Integrated Resource Plan which 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. Significant elements of the EnergyForward plan include major wind investments in North Dakota which were completed in the fourth quarter of 2014, installation of emissions control technology underway at Boswell Unit 4, planning for the proposed GNTL, the conversion of Laskin from coal to natural gas completed in June 2015 and the retirement of Taconite Harbor Unit 3 completed in May 2015. On July 9, 2015, Minnesota Power announced the next steps in its EnergyForward plan including the economic idling of Taconite Harbor Units 1 and 2 in the fall of 2016, the ceasing of coal-fired operations there in 2020, and the addition of between 200 MW and 300 MW of natural gas generation in the next decade. We are required to submit our 2015 Integrated Resource Plan with the MPUC no later than September 1, 2015.

NOTE 8. REGULATORY MATTERS (Continued)

Boswell Mercury Emissions Reduction Plan. Minnesota Power is implementing a mercury emissions reduction project for Boswell Unit 4 in order to comply with 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. 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 approximately $260 million, of which approximately $184 million was spent through June 30, 2015. In a November 2013 order, the MPUC approved the Boswell Unit 4 mercury emissions reduction plan and cost recovery, establishing an environmental improvement rider. Customer billing rates for the environmental improvement rider were approved by the MPUC in a July 2014 order. In November 2014, we filed an updated environmental improvement factor filing which included updated costs associated with Boswell Unit 4. Upon approval of this filing, we will be authorized to include updated billing rates on customer bills.

Great Northern Transmission Line (GNTL). Minnesota Power and Manitoba Hydro have proposed construction of the GNTL, an approximately 220-mile 500 kV transmission line, between Manitoba and Minnesota's Iron Range. The GNTL is subject to various federal and state regulatory approvals. In October 2013, a Certificate of Need application was filed with the MPUC which was approved in an order dated June 30, 2015. Based on this order, our portion of the investments and expenditures for the project are eligible for cost recovery under our existing transmission cost recovery rider and are anticipated to be included in future transmission factor filings. In April 2014, Minnesota Power filed a route permit application with the MPUC and a request for a presidential permit to cross the U.S.-Canadian border with the U.S. Department of Energy. In a July 2014 order, the MPUC determined the route permit application to be complete. On June 19, 2015, the Minnesota Department of Commerce and the U.S. Department of Energy released the draft EIS for the GNTL. Public hearings on the draft EIS were held in July 2015 and comments are due by August 10, 2015. Hearings on the route permit will be held before an Administrative Law Judge in August 2015 with comments due by September 1, 2015. Manitoba Hydro must also obtain regulatory and governmental approvals related to a new transmission line in Canada. Construction of Manitoba Hydro's hydroelectric generation facility commenced in the third quarter of 2014. Upon receipt of all applicable permits and approvals, construction of the GNTL is anticipated to begin in 2016 and to be completed in 2020.

MISO Return on Equity Complaints. In November 2013, several customer groups located within the MISO service area filed complaints with the FERC requesting, among other things, a reduction in the base return on equity used by MISO transmission owners, including ALLETE, to 9.15 percent. On February 12, 2015, an additional complaint was filed with the FERC seeking an order to further reduce the base return on equity to 8.67 percent. As a result of these complaints filed with the FERC, we have recorded an estimated refund obligation for MISO revenue of $5.6 million and an estimated refund for MISO transmission expense of $3.7 million, resulting in a reserve of $1.9 million as of June 30, 2015; $1.5 million was attributable to prior years.

Regulatory Assets and Liabilities. Our regulated utility operations are subject to accounting guidance for the effect of certain types of regulation. Regulatory assets represent incurred costs that have been deferred as they are probable for recovery in customer rates. Regulatory liabilities represent obligations to make refunds to customers and amounts collected in rates for which the related costs have not yet been incurred. The Company assesses quarterly whether regulatory assets and liabilities meet the criteria for probability of future recovery or deferral. No regulatory assets or liabilities are currently earning a return. The recovery, refund or credit to rates for these regulatory assets and liabilities will occur over the periods either specified by the applicable regulatory authority or over the corresponding period related to the asset or liability.

NOTE 8. REGULATORY MATTERS (Continued)

Regulatory Assets and Liabilities	June 30, 2015	December 31, 2014
Millions		
Current Regulatory Assets (a)		
Deferred Fuel	$11.8	$16.3
Total Current Regulatory Assets	11.8	16.3
Non-Current Regulatory Assets		
Defined Benefit Pension and Other Postretirement Benefit Plans (b)	216.1	223.9
Cost Recovery Riders (c)	68.3	59.7
Income Taxes	46.9	46.6
Asset Retirement Obligations	19.2	17.8
PPACA Income Tax Deferral	5.0	5.0
Other	4.1	4.3
Total Non-Current Regulatory Assets	359.6	357.3
Total Regulatory Assets	$371.4	$373.6
Non-Current Regulatory Liabilities		
Wholesale and Retail Contra AFUDC	$50.6	$42.9
Plant Removal Obligations	19.6	22.8
Income Taxes	13.7	13.4
Defined Benefit Pension and Other Postretirement Benefit Plans (b)	2.4	3.5
Other	18.5	11.6
Total Non-Current Regulatory Liabilities	$104.8	$94.2

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

(b) Defined benefit pension and other postretirement items included in our Regulated Operations, which are otherwise required to be recognized in accumulated other comprehensive income, are recognized as regulatory assets or regulatory liabilities on the Consolidated Balance Sheet. (See Note 15. Pension and Other Postretirement Benefit Plans.)

(c) The cost recovery rider regulatory assets are primarily due to capital expenditures related to our Bison Wind Energy Center, investment in CapX2020 projects, and the Boswell Unit 4 environmental upgrade and are recognized in accordance with the accounting standards for alternative revenue programs.

NOTE 9. 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 based on a FERC-approved 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, 2015, our equity investment in ATC was $124.2 million ($121.1 million at December 31, 2014). In the first six months of 2015, we invested $0.8 million in ATC, and on July 30, 2015, we invested an additional $0.4 million. We expect to make additional investments of approximately $0.7 million in 2015.

ALLETE's Investment in ATC	
Millions	
Equity Investment Balance as of December 31, 2014	$121.1
Cash Investments	0.8
Equity in ATC Earnings	8.6

Distributed ATC Earnings	(6.3)
Equity Investment Balance as of June 30, 2015	$124.2

NOTE 9. INVESTMENT IN ATC (Continued)

ATC’s summarized financial data for the six months ended June 30, 2015 and 2014, is as follows:

	Quarter Ended		Six Months Ended	
ATC Summarized Financial Data	June 30,		June 30,	
Income Statement Data	2015	2014	2015	2014
Millions				
Revenue	$165.2	$160.0	$317.6	$323.3
Operating Expense	80.3	74.4	160.3	153.0
Other Expense	24.3	21.9	48.7	43.5
Net Income	$60.6	$63.7	$108.6	$126.8
ALLETE’s Equity in Net Income	$4.7	$5.2	$8.6	$10.3

Our equity earnings in ATC for the six months ended June 30, 2015, were $8.6 million and reflected a $1.7 million reduction related to complaints filed with the FERC by several customer groups located within the MISO service area; of which $1.1 million was attributable to ATC’s change in estimate of a refund liability relating to prior years. The groups requested, among other things, a reduction in the base return on equity used by MISO transmission owners, including ATC, to 9.15 percent. ATC's current authorized return on equity is 12.2 percent. On February 12, 2015, an additional complaint was filed with the FERC seeking an order to further reduce the base return on equity to 8.67 percent. We own approximately 8 percent of ATC and estimate that for every 50 basis point reduction in ATC’s allowed return on equity our equity earnings in ATC would be impacted annually by approximately $0.5 million on an after-tax basis ($0.9 million pre-tax).

NOTE 10. SHORT-TERM AND LONG-TERM DEBT

Short-Term Debt. As of June 30, 2015, total short-term debt outstanding was $118.0 million and consisted of long-term debt due within one year. Short-term debt outstanding as of December 31, 2014 was $104.4 million and consisted of long-term debt due within one year and notes payable.

Long-Term Debt. There were no material issuances of long-term debt in the first six months of 2015. As of June 30, 2015, total long-term debt outstanding was $1,272.4 million ($1,272.8 million as of December 31, 2014).

On July 1, 2015, ALLETE Clean Energy assumed $60.9 million of long-term debt, including $5.9 million due within one year, in conjunction with ALLETE Clean Energy’s acquisition of Armenia Mountain. (See Note 4. Acquisitions.)

On July 14, 2015, we agreed to sell $100.0 million of the Company's first mortgage bonds (Bonds) to certain institutional buyers in the private placement market. The Bonds will be sold in reliance on an exemption from registration under Section 4(a)(2) of the Securities Act of 1933, as amended, to institutional accredited investors. The Bonds will be issued on or about September 24, 2015, in two series as follows:

Maturity Date	Principal Amount	Interest Rate
September 15, 2020	$40 Million	2.80%
September 16, 2030	$60 Million	3.86%

Interest on the Bonds will be payable semi-annually on March 15 and September 15 of each year, commencing on March 15, 2016. The Company will have the option to prepay all or a portion of the Bonds at its discretion, subject to a make-whole provision; however, the September 16, 2030, series of bonds will be redeemable at par, including accrued and unpaid interest, six months prior to the maturity date. The Bonds will be subject to additional terms and conditions which are customary for these types of transactions. The Company intends to use the proceeds from the sale of the Bonds to fund utility capital expenditures and/or for general corporate purposes.

NOTE 10. SHORT-TERM AND LONG-TERM DEBT (Continued)

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, 2015, our ratio was approximately 0.44 to 1.00. Failure to meet this covenant would give rise to an event of default if not cured after notice from the lender, in which event ALLETE may need to pursue alternative sources of funding. Some of ALLETE's debt arrangements contain "cross-default" provisions that would result in an event of default if there is a failure under other financing arrangements to meet payment terms or to observe other covenants that would result in an acceleration of payments due. As of June 30, 2015, ALLETE was in compliance with its financial covenants.

NOTE 11. OTHER INCOME (EXPENSE)

	Quarter Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Millions				
AFUDC–Equity	$0.7	$2.0	$1.6	$3.8
Gain on Sale of Available-for-sale Securities	0.1	0.2	0.1	0.2
Investments and Other Income (Expense)	(0.1)	(0.3)	0.1	(0.1)
Total Other Income	$0.7	$1.9	$1.8	$3.9

NOTE 12. INCOME TAX EXPENSE

	Quarter Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Millions				
Current Tax Expense				
Federal (a)	—	—	—	—
State (a)	$0.2	$0.1	$0.3	$0.1
Total Current Tax Expense	$0.2	$0.1	$0.3	$0.1
Deferred Tax Expense				
Federal	$3.9	$2.9	$8.7	$9.2
State	2.5	2.0	4.0	4.7
Investment Tax Credit Amortization	(0.2)	(0.1)	(0.4)	(0.3)
Total Deferred Tax Expense	6.2	4.8	12.3	13.6
Total Income Tax Expense	$6.4	$4.9	$12.6	$13.7

(a) For the six months ended June 30, 2015 and 2014, the federal and state current tax expense was minimal due to the utilization of NOL carryforwards from prior periods. The NOL carryforwards resulted from the bonus depreciation provisions of the Tax Increase Prevention Act of 2014 and the American Taxpayer Relief Act of 2012.

The Company's tax provision for interim periods is determined using an estimate of its annual effective tax rate, adjusted for discrete items arising in that quarter. In each quarter, the Company updates its estimate of the annual effective tax rate, and if the estimated annual effective tax rate changes, the Company would make a cumulative adjustment in that quarter.

For the six months ended June 30, 2015, the effective tax rate was 16.8 percent (21.3 percent for the six months ended June 30, 2014). The decrease in the effective tax rate from June 30, 2014, was primarily due to increased production tax credits. The effective rate deviated from the statutory rate of approximately 41 percent primarily due to production tax credits.

NOTE 12. INCOME TAX EXPENSE (Continued)

Reconciliation of Taxes from Federal Statutory Rate to Total Income Tax Expense		
Six Months Ended June 30	2015	2014
Millions		
Income Before Non-Controlling Interest and Income Taxes	$75.0	$64.4
Statutory Federal Income Tax Rate	35 %	35 %
Income Taxes Computed at 35 percent Statutory Federal Rate	$26.3	$22.5
Increase (Decrease) in Tax Due to:		
State Income Taxes – Net of Federal Income Tax Benefit	2.8	3.1
Production Tax Credits	(19.2)	(12.8)
Regulatory Differences for Utility Plant	(0.4)	(1.6)
Other	3.1	2.5
Total Income Tax Expense	$12.6	$13.7

Uncertain Tax Positions. As of June 30, 2015, we had gross unrecognized tax benefits of $2.0 million ($2.0 million as of December 31, 2014). Of the total gross unrecognized tax benefits, $0.3 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. The unrecognized tax benefit amounts have been presented as reductions to the tax benefits associated with NOL and tax credit carryforwards on the Consolidated Balance Sheet.

ALLETE and its subsidiaries file a consolidated federal income tax return as well as combined and separate state income tax returns in various jurisdictions. ALLETE is no longer subject to federal examination for years before 2011, or state examination for years before 2010.

NOTE 13. RECLASSIFICATIONS OUT OF ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

Changes in accumulated other comprehensive income (loss), net of tax, for the quarters ended June 30, 2015 and 2014, were as follows:

	Unrealized Gains and Losses on Available-for-sale Securities	Defined Benefit Pension, Other Postretirement Items	Gains and Losses on Cash Flow Hedge	Total
Millions				
Quarter Ended June 30, 2015				
Beginning Accumulated Other Comprehensive Loss	$(0.2)	$(20.4)	—	$(20.6)
Other Comprehensive Income Before Reclassifications	—	—	—	—
Amounts Reclassified From Accumulated Other Comprehensive Loss	—	0.4	—	0.4
Net Other Comprehensive Income	—	0.4	—	0.4
Ending Accumulated Other Comprehensive Loss	$(0.2)	$(20.0)	—	$(20.2)
Quarter Ended June 30, 2014				
Beginning Accumulated Other Comprehensive Loss	$(0.1)	$(16.4)	$(0.3)	$(16.8)
Other Comprehensive Income Before Reclassifications	0.3	—	—	0.3
	(0.1)	0.3	—	0.2

Amounts Reclassified From Accumulated Other Comprehensive Income (Loss)				
Net Other Comprehensive Income	0.2	0.3	—	0.5
Ending Accumulated Other Comprehensive Income (Loss)	$0.1	$(16.1)	$(0.3)	$(16.3)

NOTE 13. RECLASSIFICATIONS OUT OF ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS) (Continued)

Reclassifications from accumulated other comprehensive income (loss) for the quarters ended June 30, 2015 and 2014, were as follows:

Amount Reclassified from Accumulated Other Comprehensive Loss	Quarter Ended June 30, 2015	June 30, 2014
Millions		
Unrealized Gains on Available-for-sale Securities (a)	$0.1	$0.2
Income Taxes (b)	(0.1)	(0.1)
Total, Net of Income Taxes	—	$0.1
Amortization of Defined Benefit Pension and Other Postretirement Items		
Prior Service Costs (c)	$0.1	$0.1
Actuarial Gains and Losses (c)	(0.7)	(0.6)
Total	(0.6)	(0.5)
Income Taxes (b)	0.2	0.2
Total, Net of Income Taxes	$(0.4)	$(0.3)
Total Reclassifications	$(0.4)	$(0.2)

(a) Included in Other Income (Expense) – Other on our Consolidated Statement of Income.

(b) Included in Income Tax Expense on our Consolidated Statement of Income.

(c) Defined benefit pension and other postretirement items excluded from our Regulated Operations are recognized in accumulated other comprehensive loss and are subsequently reclassified out of accumulated other comprehensive loss as components of net periodic pension and other postretirement benefit expense. (See Note 15. Pension and Other Postretirement Benefit Plans.)

Changes in accumulated other comprehensive income (loss), net of tax, for the six months ended June 30, 2015 and 2014, were as follows:

	Unrealized Gains and Losses on Available-for-sale Securities	Defined Benefit Pension, Other Postretirement Items	Gains and Losses on Cash Flow Hedge	Total
Millions				
Six Months Ended June 30, 2015				
Beginning Accumulated Other Comprehensive Loss	$(0.3)	$(20.7)	$(0.1)	$(21.1)
Other Comprehensive Income Before Reclassifications	0.2	—	0.1	0.3
Amounts Reclassified From Accumulated Other Comprehensive Income (Loss)	(0.1)	0.7	—	0.6
Net Other Comprehensive Income	0.1	0.7	0.1	0.9
Ending Accumulated Other Comprehensive Loss	$(0.2)	$(20.0)	—	$(20.2)
Six Months Ended June 30, 2014				
Beginning Accumulated Other Comprehensive Loss	$(0.1)	$(16.7)	$(0.3)	$(17.1)
Other Comprehensive Income Before Reclassifications	0.3	—	—	0.3
Amounts Reclassified From Accumulated Other Comprehensive Loss	(0.1)	0.6	—	0.5
Net Other Comprehensive Income	0.2	0.6	—	0.8

Ending Accumulated Other Comprehensive Income (Loss)	$0.1	$(16.1)	$(0.3)	$(16.3)

NOTE 13. RECLASSIFICATIONS OUT OF ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS) (Continued)

Reclassifications from accumulated other comprehensive income (loss) for the six months ended June 30, 2015 and 2014, were as follows:

Amount Reclassified from Accumulated Other Comprehensive Loss	Six Months Ended June 30, 2015	June 30, 2014
Millions		
Unrealized Gains on Available-for-sale Securities (a)	$0.1	$0.2
Income Taxes (b)	—	(0.1)
Total, Net of Income Taxes	$0.1	$0.1
Amortization of Defined Benefit Pension and Other Postretirement Items		
Prior Service Costs (c)	$0.2	$0.2
Actuarial Gains and Losses (c)	(1.3)	(1.2)
Total	(1.1)	(1.0)
Income Taxes (b)	0.4	0.4
Total, Net of Income Taxes	$(0.7)	$(0.6)
Total Reclassifications	$(0.6)	$(0.5)

(a) Included in Other Income (Expense) – Other on our Consolidated Statement of Income.
(b) Included in Income Tax Expense on our Consolidated Statement of Income.
(c) Defined benefit pension and other postretirement items excluded from our Regulated Operations are recognized in accumulated other comprehensive loss and are subsequently reclassified out of accumulated other comprehensive loss as components of net periodic pension and other postretirement benefit expense. (See Note 15. Pension and Other Postretirement Benefit Plans.)

NOTE 14. EARNINGS PER SHARE AND COMMON STOCK

We compute basic earnings per share using the weighted average number of shares of common stock outstanding during each period. The difference between basic and diluted earnings per share, if any, arises from outstanding stock options, non-vested restricted stock units, performance share awards granted under our Executive Long-Term Incentive Compensation Plan and common shares under the forward sale agreement (described below). For the six months ended June 30, 2015 and 2014, no options to purchase shares of common stock were excluded from the computation of diluted earnings per share.

Reconciliation of Basic and Diluted Earnings Per Share	Basic	2015 Dilutive Securities	Diluted	Basic	2014 Dilutive Securities	Diluted
Millions Except Per Share Amounts						
Quarter ended June 30,						
Net Income Attributable to ALLETE	$22.5		$22.5	$16.8		$16.8
Average Common Shares	48.6	0.1	48.7	42.1	0.2	42.3
Earnings Per Share	$0.46		$0.46	$0.40		$0.40
Six months ended June 30,						
Net Income Attributable to ALLETE	$62.4		$62.4	$50.3		$50.3
Average Common Shares	47.7	0.1	47.8	41.7	0.2	41.9
Earnings Per Share	$1.31		$1.30	$1.21		$1.20

NOTE 14. EARNINGS PER SHARE AND COMMON STOCK (Continued)

Forward Sale Agreement and Issuance of Common Stock. In February 2014, ALLETE entered into a confirmation of forward sale agreement (Agreement) with a forward counterparty in connection with a public offering of 2.8 million shares of ALLETE common stock.

Pursuant to the Agreement, the forward counterparty (or its affiliate) borrowed 2.8 million shares of ALLETE common stock from third parties and sold them to the underwriters. The forward sale price was $48.01 per share, subject to adjustment as provided in the Agreement. In September 2014, ALLETE physically settled a portion of its obligations under the Agreement by delivering approximately 1.4 million shares of common stock in exchange for cash proceeds of $65.0 million and on February 4, 2015, ALLETE physically settled the remaining portion of its obligation under the Agreement by delivering approximately 1.4 million shares of common stock in exchange for cash proceeds of $65.4 million.

In connection with the public offering of the 2.8 million shares, ALLETE granted the underwriters an option to purchase up to an additional 0.4 million shares of ALLETE common stock (the option shares). The underwriters exercised the option in full and in March 2014, the Company issued and sold the option shares to the underwriters at a price to ALLETE equal to the initial forward sale price for proceeds of $20.2 million.

Contributions to Pension. No contributions were made to the pension plan for the six months ended June 30, 2015. For the six months ended June 30, 2014, ALLETE contributed 0.4 million shares of ALLETE common stock to its pension plan. These shares of ALLETE common stock were contributed in reliance upon an exemption available pursuant to Section 4(a)(2) of the Securities Act of 1933, as amended, and had an aggregate value of $19.5 million when contributed.

NOTE 15. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS

	Pension		Other Postretirement	
Components of Net Periodic Benefit Expense (Income)	2015	2014	2015	2014
Millions				
Quarter Ended June 30,				
Service Cost	$2.5	$2.1	$1.1	$0.8
Interest Cost	7.4	7.5	1.8	1.9
Expected Return on Plan Assets	(10.1)	(9.5)	(2.8)	(2.6)
Amortization of Prior Service Costs (Credits)	0.1	—	(0.7)	(0.6)
Amortization of Net Loss	4.5	3.5	0.1	0.1
Net Periodic Benefit Expense (Income)	$4.4	$3.6	$(0.5)	$(0.4)
Six Months Ended June 30,				
Service Cost	$5.0	$4.2	$2.2	$1.7
Interest Cost	14.9	14.9	3.6	3.7
Expected Return on Plan Assets	(20.3)	(19.1)	(5.5)	(5.2)
Amortization of Prior Service Costs (Credits)	0.1	0.1	(1.5)	(1.2)
Amortization of Net Loss	9.0	7.1	0.2	0.2
Net Periodic Benefit Expense (Income)	$8.7	$7.2	$(1.0)	$(0.8)

Employer Contributions. For the six months ended June 30, 2015, no contributions were made to our defined benefit pension plan ($19.5 million for the six months ended June 30, 2014); we do not expect to make any contributions to our defined benefit pension plan in 2015. For the six months ended June 30, 2015 and 2014, we made no contributions to our other postretirement benefit plan; we do not expect to make any contributions to our other postretirement benefit plan in 2015.

NOTE 16. 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 Agreement, 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, 2015, Square Butte had total debt outstanding of $389.4 million. Annual debt service for Square Butte is expected to be approximately $45 million in each of the next five years, 2015 through 2019, 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, 2015, was $39.5 million ($29.8 million for the six months ended June 30, 2014). 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 $2.5 million during the six months ended June 30, 2015 ($5.2 million for the six months ended June 30, 2014). 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, which commenced in June 2014. Under the power sales agreement, Minnesota Power is selling 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. In 2015, Minnesota Power's portion of output sold to Minnkota Power is approximately 28 percent (23 percent in 2014).

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 from June 2016 through May 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. 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 energy facilities located near Center, North Dakota that expire in 2031 and 2032, respectively. Each agreement 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 May 2020. 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. In addition, 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 16. 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 Minnesota Power to purchase 250 MW of capacity and energy from Manitoba Hydro for 15 years beginning in 2020. The agreement is subject to construction of additional transmission capacity between Manitoba and the U.S., along with construction of new hydroelectric generating capacity in Manitoba. Construction of Manitoba Hydro's hydroelectric generation facility commenced in the third quarter of 2014. The capacity price is adjusted annually until 2020 by the change in a governmental inflationary index. The energy price is based on a formula that includes an annual fixed price component adjusted for the change in a governmental inflationary index and a natural gas index, as well as market prices.

In July 2014, Minnesota Power and Manitoba Hydro signed a long-term PPA that provides for Minnesota Power to purchase up to 133 MW of energy from Manitoba Hydro for 20 years beginning in 2020. The pricing under this PPA is based on forward market prices. The agreement was approved by the MPUC in an order dated January 30, 2015, and is subject to the construction of the GNTL. (See Great Northern Transmission Line.)

Great River Energy PPAs. In August 2014 and January 2015, Minnesota Power and Great River Energy signed long-term PPAs that provide for Minnesota Power to purchase 50 MW of capacity and energy under the first PPA and 50 MW of capacity only under the second PPA. The PPAs commence in June 2016 and expire in May 2020. Both contracts have fixed capacity pricing. The energy price in the first PPA is based on a formula that includes an annual fixed price component adjusted for changes in a natural gas index, as well as market prices.

Coal, Rail and Shipping Contracts. We have coal supply agreements providing for the purchase of a significant portion of our coal requirements through December 2016 and a portion of our coal requirements through December 2019. We also have coal transportation agreements in place for the delivery of a significant portion of our coal requirements with expiration dates through December 2018. Our minimum annual payment obligation under these supply and transportation agreements is $29.2 million for the remainder of 2015, $37.4 million in 2016, $27.6 million in 2017, $28.3 million in 2018, and $1.8 million in 2019. 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 2022. The aggregate amount of minimum lease payments for all operating leases is $15.0 million in 2015, $12.9 million in 2016, $11.8 million in 2017, $10.4 million in 2018, $9.3 million in 2019 and $29.1 million thereafter.

Transmission. We continue 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. These include the GNTL 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. In an order dated February 23, 2015, the MPUC approved Minnesota Power's updated billing factor 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. On May 22, 2015, we filed a transmission factor filing which includes updated costs associated with certain transmission facilities. Upon approval of the filing, we will be authorized to include updated billing rates on customer bills. As a result of the MPUC approval of the Certificate of

Need for the GNTL on June 30, 2015, the project is eligible for cost recovery under our existing transmission cost recovery rider. We anticipate including our portion of the investments and expenditures for the GNTL as part of future transmission factor filings to include updated billing rates on customer bills.

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 and 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.

NOTE 16. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Transmission (Continued)

On April 2, 2015, the CapX2020 transmission line project from Fargo, North Dakota to St. Cloud, Minnesota was completed and placed into service. Minnesota Power previously participated in two additional CapX2020 projects which were completed and placed into service in 2011 and 2012.

Minnesota Power invested approximately $100 million to complete the three transmission line projects. As future CapX2020 projects are identified, Minnesota Power may elect to participate on a project-by-project basis.
Great Northern Transmission Line (GNTL). As a condition of the long-term PPA signed in May 2011 with Manitoba Hydro, construction of additional transmission capacity is required. As a result, Minnesota Power and Manitoba Hydro proposed construction of the GNTL, an approximately 220-mile 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.

The GNTL is subject to various federal and state regulatory approvals. In October 2013, a Certificate of Need application was filed with the MPUC which was approved in an order dated June 30, 2015. Based on this order, our portion of the investments and expenditures for the project are eligible for cost recovery under our existing transmission cost recovery rider and are anticipated to be included in future transmission factor filings. In April 2014, Minnesota Power filed a route permit application with the MPUC and a request for a presidential permit to cross the U.S.-Canadian border with the U.S. Department of Energy. In a July 2014 order, the MPUC determined the route permit application to be complete. On June 19, 2015, the Minnesota Department of Commerce and the U.S. Department of Energy released the draft EIS for the GNTL. Public hearings on the draft EIS were held in July 2015 and comments are due by August 10, 2015. Hearings on the route permit will be held before an Administrative Law Judge in August 2015 with comments due by September 1, 2015. Manitoba Hydro must also obtain regulatory and governmental approvals related to a new transmission line in Canada. Construction of Manitoba Hydro's hydroelectric generation facility commenced in the third quarter of 2014. Upon receipt of all applicable permits and approvals, construction of the GNTL is anticipated to begin in 2016 and to be completed in 2020. Total project cost in the U.S., including substation work, is estimated to be between $560 million and $710 million, depending on the final route of the line. Minnesota Power is expected to have majority ownership of the transmission line.

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 the U.S. 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 becomes available. Accruals for environmental liabilities are included in the

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

Air. The electric utility industry is 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, baghouses and low NO_X technologies. Under currently applicable environmental regulations, these facilities are substantially compliant with applicable emission requirements.

NOTE 16. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

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 and Laskin Unit 2 between the years of 1981 and 2001. Minnesota Power received an additional NOV in April 2011 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 reached a settlement with the EPA regarding these NOVs and entered into a Consent Decree which was approved by the U.S. District Court for the District of Minnesota (Court) in September 2014. The Consent Decree provided for, among other requirements, more stringent emissions limits at all affected units, the option of refueling, retrofits or retirements at certain small coal units, and the addition of 200 MW of wind energy. Provisions of the Consent Decree require that, by no later than December 31, 2018, Boswell Units 1 and 2 must be retired, refueled, repowered, or emissions rerouted to an existing Boswell scrubber. Minnesota Power estimates that if the units are not retired, capital expenditures could range between \$20 million and \$40 million. We are evaluating our options with regard to Boswell Units 1 and 2 to comply with the Consent Decree and future anticipated environmental regulations. We are required to notify the EPA no later than December 31, 2016, whether we will retire, refuel, repower or reroute Boswell Units 1 and 2. We believe that future capital expenditures or costs to retire would likely be eligible for recovery in rates over time subject to regulatory approval in a rate proceeding.

Cross-State Air Pollution Rule (CSAPR). In April 2014, the U.S. Supreme Court issued an opinion reversing an August 2012 U.S. Court of Appeals for the D.C. Circuit decision that had vacated the CSAPR. The EPA filed a motion with the U.S. Court of Appeals for the D.C. Circuit in June 2014, to have the stay of CSAPR lifted and the CSAPR compliance deadlines tolled by three years. In October 2014, the U.S. Court of Appeals for the D.C. Circuit granted the EPA's motion, allowing the first compliance period, Phase I, to begin on January 1, 2015, with Phase II beginning in 2017.

CSAPR requires a total of 28 states in the eastern half of the United States, including Minnesota, to reduce power plant emissions that contribute to ozone or fine particulate pollution in other states. CSAPR does not require installation of controls; rather it requires that facilities have sufficient allowances to cover their emissions on an annual basis. These allowances are allocated to facilities from each state's annual budget and can be bought and sold.

In December 2014, the EPA distributed the CSAPR allowances to CSAPR-subject units for the Phase I years (2015 and 2016). Phase II allowances (2017-2020) have not been distributed. Based on our initial accounting of the NO_x and SO_2 Phase I allowances already issued, and our review of the CSAPR Phase II allowances not yet issued, we currently expect projected generation levels and emission rates will be in compliance in both Phase I and Phase II.

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 were required to be in compliance with the rule by April 2015. States had the authority to grant sources a one-year extension. The MPCA approved Minnesota Power's request for an extension of the date of compliance for the Boswell Unit 4 environmental upgrade to April 1, 2016. Compliance at Boswell Unit 4 to address the final MATS rule is expected to result in capital expenditures of approximately \$260 million through 2016, of which approximately \$184 million was spent through June 30, 2015. Boswell Unit 3 is also subject to the MATS rule; however, the emission reduction investments completed in 2009 at our Boswell Unit 3 generating unit substantially meet the requirements of the MATS rule. Our EnergyForward plan, which was approved as part of our 2013 Integrated Resource Plan by the MPUC in a November 2013 order, also included the conversion of Laskin Units 1 and 2 to natural gas in 2015 to position the Company for MATS compliance. In January 2014, the MPCA approved Minnesota Power's application to extend the deadline for Taconite Harbor Unit 3 to comply with MATS to June 1, 2015, in order to align the retirement at Unit 3 with MISO's resource planning year. Laskin Units 1 and 2 were converted to natural gas in June 2015 and Taconite Harbor Unit 3 was retired in May 2015.

NOTE 16. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

On June 29, 2015, the U.S. Supreme Court reversed and remanded an earlier U.S. Court of Appeals for the D.C. Circuit decision on the MATS rule. The U.S. Supreme Court ruled that it was unreasonable for the EPA to deem cost of compliance irrelevant in determining that regulation of emissions of hazardous air pollutants from power plants was "appropriate and necessary" under Section 112 of the Clean Air Act. The MATS rule remains in effect until the U.S. Court of Appeals for the D.C. Circuit acts on the remand. The U.S. Supreme Court decision is not expected to have a material impact on Minnesota Power generation due to ongoing emission reduction obligations under the Minnesota Mercury Emissions Reduction Act and the Consent Decree. (See New Source Review.)

Minnesota Mercury Emissions Reduction Act/Rule. In order to comply with the 2006 Minnesota Mercury Emissions Reduction Act, which was incorporated into rules promulgated by the MPCA in September 2014, Minnesota Power must implement a mercury emissions reduction project for Boswell Unit 4 by December 31, 2018. The Boswell Unit 4 environmental upgrade discussed above, which is required to be completed by April 1, 2016 (see Mercury and Air Toxics Standards (MATS) Rule), will fulfill the requirements of the Minnesota Mercury Emissions Reduction Act.

EPA National Emission Standards for Hazardous Air Pollutants for Major Sources: Industrial, Commercial and Institutional Boilers and Process Heaters. A final rule issued by the EPA for Industrial Boiler Maximum Achievable Control Technology (Industrial Boiler MACT) became effective in December 2012. Major existing sources have until January 31, 2016, to achieve compliance with the final rule. Minnesota Power's Hibbard Renewable Energy Center and Rapids Energy Center are subject to this rule. We expect compliance to consist largely of adjustments to our operating practices; therefore the costs for complying with the final rule are not expected to be material.

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 the 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. In November 2014, the EPA proposed a 65 to 70 parts per billion (ppb) NAAQS for ground level ozone. The EPA is proposing to update both the primary ozone standard and the secondary standard. Both standards would be 8-hour standards set within a range of 65 to 70 ppb. The EPA is also seeking comment on levels for the primary standard as low as 60 ppb. The EPA has announced it will accept comments on all aspects of the proposal, including retaining the existing standard. A final rule is expected to be issued in the fourth quarter of 2015. The costs for complying with the final ozone NAAQS cannot be estimated at this time.

Particulate Matter NAAQS. The EPA finalized the Particulate Matter NAAQS in September 2006. Since then, the EPA has established more stringent 24-hour and annual average fine particulate matter ($PM_{2.5}$) standards; the 24-hour coarse particulate matter standard has remained unchanged. 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 annual $PM_{2.5}$ standard, the EPA is also revising aspects of relevant monitoring, designation and permitting requirements. New projects and permits must comply with the new standard, which is generally demonstrated by modeling at the facility level.

Under the final rule, states will be responsible for additional PM2.5 monitoring, which will likely be accomplished by relocating or repurposing existing monitors. The EPA asked states to submit attainment designations by December

2013, based on already available monitoring data, and issued designations of the 2012 revised primary annual fine particulate attainment status in December 2014. The EPA designated the entire state of Minnesota as unclassifiable/attainment; however, Minnesota sources may ultimately be required to reduce their emissions to assist with attainment in neighboring states. Accordingly, the costs for complying with the final Particulate Matter NAAQS cannot be estimated at this time.

NOTE 16. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

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 may require the EPA to evaluate modeling data to determine attainment. In April 2012, the MPCA notified Minnesota Power that modeling had been suspended as a result of the EPA's announcement that the SIP submittals would not require modeling demonstrations for states, such as Minnesota, where ambient monitors indicate compliance with the new standard. The EPA notified states that their infrastructure SIPs for maintaining attainment of the standard were required to be submitted to the EPA for approval by June 2013. However, the State of Minnesota has delayed completing the documents pending EPA guidance to states for preparing the SIP submittal. The MPCA has indicated it will communicate with affected sources once it has more information on how the state will meet the EPA's SIP requirements. Guidance was expected in 2013 but has been delayed. 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.

Class I Air Quality Petitions. In July 2014, the Fond du Lac Band of Lake Superior Chippewa (Fond du Lac Band) announced that it intends to petition the EPA to redesignate its reservation air shed from Class II to Class I air quality pursuant to Section 164(c) of the Clean Air Act. The Fond du Lac Band does not currently possess authority to directly regulate air quality. Class I air shed status, if granted, would allow the Fond du Lac Band to impose more stringent Clean Air Act protections within the boundaries of the Fond du Lac reservation, including the reservation air shed, near Cloquet, Minnesota. Five other reservations across the U.S. have applied for and received Class I status. A public hearing was held by the Fond du Lac Band in October 2014, and the public comment period on the petition expired in November 2014. After the Fond du Lac Band prepares responses to the comments, it is anticipated to make a formal submittal request to the EPA. The Company has requested additional clarification from the Fond du Lac Band and the MPCA on the final regulatory structure that may arise from a Class I redesignation.

In January 2015, the Bad River Band of Lake Superior Chippewa (Bad River Band) also announced it intends to petition the EPA to redesignate its reservation, which is located approximately 100 miles east of Duluth, Minnesota, from Class II to Class I air quality pursuant to Section 164(c) of the Clean Air Act. Public hearings were held in March 2015, and the public comment period expired in May 2015. After the Bad River Band prepares responses to the comments, it is also anticipated to make a formal submittal request to the EPA.

There is no deadline for the approval, denial, or modification of these requests by the EPA. We are unable to determine the impact of potential Class I status on the Company's operations at this time.

Climate Change. The scientific community generally accepts that emissions of GHG are linked to global climate change which 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;
- Improving efficiency of our energy generating facilities;
- 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. In June 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.

EPA Regulation of GHG Emissions. In May 2010, the EPA issued the 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.

NOTE 16. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

In late 2010, the EPA issued guidance to permitting authorities and affected sources to facilitate incorporation of the Tailoring Rule permitting requirements into the Title V and PSD permitting programs. The guidance stated that the project-specific, top-down 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.

In June 2014, the U.S. Supreme Court invalidated the aspect of the Tailoring Rule that established lower permitting thresholds for GHG than for other pollutants subject to PSD. However, the court also upheld the EPA's power to require BACT for GHG from sources already subject to regulation under PSD. Minnesota Power's coal-fired generating facilities are already subject to regulation under PSD, so we anticipate that ultimately PSD for GHG will apply to our facilities, but the timing of the promulgation of a replacement for the Tailoring Rule is uncertain. The PSD applies to existing facilities only when they undertake a major modification that increases emissions. At this time, we are unable to predict the compliance costs that we might incur.

In March 2012, the EPA announced a proposed rule to apply CO_2 emission New Source Performance Standards (NSPS), under Section 111(b) of the Clean Air Act, to new fossil fuel-fired electric generating units. The proposed NSPS would have applied only to new or re-powered units. Based on the volume of comments received, the EPA announced its intent to re-propose the rule. In September 2013, the EPA retracted its March 2012 proposal and announced the release of a revised NSPS for new or re-powered utility CO_2 emissions.

In June 2014, the EPA announced a proposed rule under Section 111(d) of the Clean Air Act for existing power plants entitled "Carbon Pollution Emission Guidelines for Existing Stationary Sources: Electric Generating Units" (CPP). The EPA is expected to finalize such rules by the summer of 2015. In the CPP, the EPA proposes to set state-specific goals for CO_2 emissions from the power sector. The EPA maintains such goals are achievable if a state undertakes a combination of measures across its power sector that constitute the EPA's guideline for a Best System of Emission Reductions (BSER).

The EPA proposed that BSER is comprised of four building blocks: 1) improved fossil fuel power plant efficiency, 2) increased reliance on low-emitting power sources by generating more electricity from existing natural gas combined cycle units, 3) building more or preserving existing zero- and low-emitting power sources, including renewable and nuclear energy, and 4) more efficient electricity use by consumers.

The EPA then established state goals, expressed as a carbon intensity target in CO_2 tons per megawatt hour, by estimating the achievability of the building blocks in each state. Using 2012 emissions data, the EPA derived interim goals for states to be met over the years 2020-2029, as well as a final goal to be met in 2030 and thereafter. Under the CPP, each state would be required to develop a state implementation plan by June 30, 2016. We submitted comments on the CPP to the EPA.

The EPA submitted its final draft of the CPP to the White House Office of Management and Budget on July 1, 2015, and the final rule is expected to be released in the third quarter of 2015. Minnesota Power is currently evaluating the CPP as it relates to the State of Minnesota and its potential impact on the Company.

Minnesota has already initiated several measures consistent with those called for under the CAP and CPP. Minnesota Power is implementing its EnergyForward strategic plan that provides for significant emission reductions and diversifying its electricity generation mix to include more renewable and natural gas energy. (See Note 8. Regulatory

Matters.)

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.

Minnesota's Next Generation Energy Act of 2007. In April 2014, a U.S. District Court for the District of Minnesota ruled that part of Minnesota's Next Generation Energy Act of 2007 violated the Commerce Clause of the U.S. Constitution. The portions of the law which were ruled unconstitutional prohibited the importation of power from a new CO_2-producing facility outside of Minnesota and prohibited the entry into new long-term power purchase agreements that would increase CO_2 emissions in Minnesota. The State of Minnesota appealed the decision to the U.S. Court of Appeals for the Eighth Circuit in May 2014.

NOTE 16. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

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 impacted by the facility's intake structure or cooling system. The Section 316(b) rule was published in the Federal Register in August 2014, with an effective date in October 2014. The Section 316(b) standards will be implemented through NPDES permits issued to the covered facilities with compliance timing dependent on individual NPDES renewal schedules. No NPDES permits have been re-issued containing Section 316(b) requirements since the final rule was published, so at this time we are unable to determine the final cost of compliance; however, our preliminary assessment suggests costs of compliance could be up to approximately $15 million. We would seek recovery of any additional costs through a general rate case.

Steam Electric Power Generating Effluent Guidelines. In April 2013, the EPA announced proposed revisions to the federal effluent guidelines for steam electric power generating stations under the Clean Water Act. 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 in June 2013, and public comments were due in September 2013. The EPA is expected to issue the final rule by September 30, 2015. Compliance with the final rule, as proposed, 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.

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 (CCR) generated by the electric utility sector. The proposal sought comments on three general regulatory schemes for coal ash under Subtitle D of Resource Conservation and Recovery Act (RCRA) (non-hazardous) or Subtitle C of RCRA (hazardous).

The EPA issued the final CCR rule in December 2014 under Subtitle D (non-hazardous) of RCRA which was published in the Federal Register on April 27, 2015. The rule includes additional requirements for new landfill and impoundment construction as well as closure activities related to certain existing impoundments. The final rule also includes provisions that could incentivize early closure of existing impoundments within a three-year window. Costs of compliance, primarily for Boswell and Laskin, could be up to approximately $100 million. The Company continues to work on minimizing costs on behalf of customers through evaluation of beneficial re-use and recycling of CCR and CCR-related waters. We would seek recovery of any additional costs through a general rate case.

NOTE 16. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)

Other Matters.

ALLETE Clean Energy. ALLETE Clean Energy acquired wind energy facilities in 2014 and 2015, which have PPAs in place for their entire output and expire in various years between 2018 and 2032. (See Note 4. Acquisitions.)

U.S. Water Services. As of June 30, 2015, U.S. Water Services has $4.5 million outstanding in stand-by letters of credit.

BNI Coal. As of June 30, 2015, BNI Coal had surety bonds outstanding of $49.5 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 for an additional $0.6 million to provide for BNI Coal's total reclamation liability, which is currently estimated at $49.3 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, 2015, 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 $5.8 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. At June 30, 2015, we owned 72 percent of the assessable land in the Town Center District (72 percent at December 31, 2014) and 93 percent of the assessable land in the Palm Coast Park District (93 percent at December 31, 2014). At these ownership levels, our annual assessments related to capital improvement and special assessment bonds 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.

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. We do not expect the outcome of these matters to have a material effect on our financial position, results of operations or cash flows.

ITEM 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 and notes to those statements, Management's Discussion and Analysis of Financial Condition and Results of Operations from the 2014 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 headings: "Forward-Looking Statements" located on page 5, "Risk

Factors" located in Part I, Item 1A, beginning on page 29 of our 2014 Form 10-K, and in "Item 1A. Risk Factors" in this Form 10-Q on page 62. The risks and uncertainties described in this Form 10-Q and our 2014 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 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 144,000 retail customers. Minnesota Power also has 16 non-affiliated municipal customers in Minnesota. SWL&P is a Wisconsin utility 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.

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

Investments and Other is comprised primarily of our Energy Infrastructure and Related Services businesses: ALLETE Clean Energy, U.S. Water Services and BNI Coal. ALLETE Clean Energy is our business aimed at acquiring or developing capital projects that create energy solutions by way of wind, solar, biomass, hydro, natural gas, shale resources, clean coal technology and other emerging energy innovations. U.S. Water Services is our integrated water management company which was acquired on February 10, 2015. BNI Coal is our coal mining operations in North Dakota. Investments and Other also includes ALLETE Properties, our Florida real estate investment, and other business development and corporate expenditures, unallocated interest expense, a small amount of non-rate base generation, approximately 5,000 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, 2015, unless otherwise indicated. All subsidiaries are wholly-owned unless otherwise specifically indicated. References in this report to "we," "us" and "our" are to ALLETE and its subsidiaries, collectively.

Financial Overview

The following net income discussion summarizes a comparison of the six months ended June 30, 2015, to the six months ended June 30, 2014.

Net income attributable to ALLETE for the six months ended June 30, 2015, was $62.4 million, or $1.30 per diluted share, compared to $50.3 million, or $1.20 per diluted share, for the same period of 2014. Net income for 2015 reflected a $3.9 million after-tax expense, or $0.08 per share, for acquisition costs for U.S. Water Services and ALLETE Clean Energy's wind energy facilities acquisitions. (See Note 4. Acquisitions.) Net income in 2014 reflected a $2.5 million after-tax expense, or $0.06 per share, reflecting a liability associated with environmental mitigation projects required as part of the EPA NOV Consent Decree settlement. In addition, net income for 2014 reflected a $1.4 million after-tax expense, or $0.03 per share, of acquisition costs for ALLETE Clean Energy's wind energy facilities acquisitions in January 2014. Net income for 2015 reflected higher net income at Minnesota Power and ALLETE Clean Energy. Earnings per share dilution was $0.19 due to additional shares of common stock outstanding as of June 30, 2015.

Regulated Operations net income attributable to ALLETE was $65.0 million for the six months ended June 30, 2015, compared to net income of $51.4 million for the same period of 2014. Net income for 2015 reflected higher net income at Minnesota Power primarily due to higher cost recovery rider revenue, production tax credits, power marketing sales as the Minnkota Power sales agreement commenced June 1, 2014, and lower operating and maintenance expenses. These impacts were partially offset by higher depreciation and interest expenses. In addition, during the second quarter of 2015, Minnesota Power recorded a reserve for estimated refunds of $1.1 million after-tax due to the MISO return on equity complaints, of which $0.9 million after-tax was attributable to prior years. (See Note 8. Regulatory Matters.) Our equity earnings in ATC for the six months ended June 30, 2015 reflected a $1.0 million after-tax reduction related to the MISO return on equity complaints, of which $0.6 million after-tax was attributable to prior years. (See Note 9. Investment in ATC.) Net income in 2014 reflected a $2.5 million after-tax expense reflecting a liability associated with environmental mitigation projects required as part of the EPA NOV Consent Decree settlement.

Investments and Other net loss attributable to ALLETE was $2.6 million for the six months ended June 30, 2015, compared to a net loss of $1.1 million for the same period of 2014. Net income for 2015 reflected a $3.9 million after-tax expense, or $0.08 per share, for acquisition costs for U.S. Water Services and ALLETE Clean Energy's wind energy facilities acquisitions. Net income at ALLETE Clean Energy increased over 2014 primarily due to operations of the wind energy facilities which were acquired in 2014 and recognition of estimated profit on the development and construction of a wind facility which will be sold to Montana-Dakota Utilities. The net loss for 2015 also included higher interest and income tax expenses. During the six months ended June 30, 2015, we reflected additional income tax expense in our Investments and Other segment of $4.1 million to reflect total tax expense at our estimated annual consolidated effective tax rate of 16.8 percent. The net loss for 2014 reflected a $1.4 million after-tax expense for acquisition costs for ALLETE Clean Energy’s wind energy facilities acquisitions.

COMPARISON OF THE QUARTERS ENDED JUNE 30, 2015 AND 2014

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

Regulated Operations

Operating Revenue increased $0.4 million from 2014 primarily due to higher kWh sales and cost recovery rider revenue, mostly offset by lower fuel adjustment clause recoveries, transmission revenue, and gas sales.

Revenue from Regulated Operations increased $7.6 million due to a 7.3 percent increase in kWh sales. 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, and increased 76.4 percent in 2015 compared to 2014 primarily due to the commencement of the Minnkota Power sales agreement on June 1, 2014. (See Note 16. Commitments, Guarantees and Contingencies.) Sales to our residential, commercial, and municipal customers decreased primarily due to unseasonably cold temperatures in 2014 compared to the same period in 2015. Heating degree days in Duluth, Minnesota were approximately 18 percent lower in the second quarter of 2015 compared to the same period in 2014. Sales to our industrial customers decreased 11.9 percent primarily due to reduced taconite production. Although industrial kWh sales decreased for the second quarter of 2015, demand revenue from our Large Power Customers was comparable to the same period in 2014.

Kilowatt-hours Sold Quarter Ended June 30,	2015	2014	Quantity Variance	% Variance
Millions				
Regulated Utility				
Retail and Municipal				
Residential	227	249	(22)	(8.8)%
Commercial	331	333	(2)	(0.6)%
Industrial	1,575	1,788	(213)	(11.9)%
Municipal	187	198	(11)	(5.6)%
Total Retail and Municipal	2,320	2,568	(248)	(9.7)%
Other Power Suppliers	1,113	631	482	76.4%
Total Regulated Utility Kilowatt-hours Sold	3,433	3,199	234	7.3%

Revenue from electric sales to taconite/iron concentrate customers accounted for 23 percent of Regulated Operations operating revenue in 2015 (27 percent in 2014). Revenue from electric sales to paper, pulp and secondary wood product customers accounted for 8 percent of Regulated Operations operating revenue in 2015 (8 percent in 2014). Revenue from electric sales to pipelines and other industrial customers accounted for 8 percent of Regulated Operations operating revenue in 2015 (8 percent in 2014).

Cost recovery rider revenue increased $7.6 million primarily due to the completion of our Bison Wind Energy Center and CapX2020 projects as well as higher capital expenditures related to our Boswell Unit 4 environmental upgrade.

Fuel adjustment clause recoveries decreased $8.7 million due to lower fuel and purchased power costs attributable to our retail and municipal customers. (See Operating Expenses - Fuel and Purchased Power Expense.)

Transmission revenue decreased $3.8 million primarily due to a reserve recorded in the second quarter of 2015 due to the MISO return on equity complaints. (See Operating Expenses - Transmission Services and Note 8. Regulatory Matters.)

Gas sales at SWL&P decreased $3.7 million from 2014 as a result of unseasonably cold weather in 2014. (See Cost of Sales.)

Operating Expenses decreased $6.2 million, or 3 percent, from 2014.

Fuel and Purchased Power expense decreased $3.5 million, or 4 percent, from 2014 primarily due to lower purchased power prices in 2015 compared to 2014. Fuel and purchased power expense related to our retail and municipal customers is recovered through the fuel adjustment clause. (See Operating Revenue.)

Transmission Services expense increased $0.8 million, or 8 percent, from 2014 primarily due to higher MISO–related expenses which were partially offset by an estimated refund for MISO transmission expense due to the MISO return on equity complaints. (See Operating Revenue and Note 8. Regulatory Matters.)

COMPARISON OF THE QUARTERS ENDED JUNE 30, 2015 AND 2014 (Continued)
Regulated Operations (Continued)

Cost of Sales decreased $3.3 million, or 77 percent, from 2014 due to lower purchased gas at SWL&P. (See Operating Revenue.)

Operating and Maintenance expense decreased $5.8 million, or 9 percent, from 2014 primarily due to a $4.2 million expense that was recorded in the second quarter of 2014 to reflect a liability associated with environmental mitigation projects required as part of an EPA NOV Consent Decree settlement. Also contributing to the decrease in operating and maintenance expense were lower salary and wage expenses.

Depreciation and Amortization expense increased $4.1 million, or 14 percent, from 2014 primarily reflecting additional property, plant and equipment in service.

Taxes Other than Income Taxes increased $1.5 million, or 14 percent, from 2014 primarily due to higher property tax expenses resulting from higher taxable plant and rates.

Interest Expense increased $1.9 million, or 17 percent, from 2014 primarily due to higher average long-term debt balances.

Equity Earnings in ATC decreased $0.5 million, or 10 percent, from 2014 primarily due to a $0.3 million expense related to the MISO return on equity complaints.

Income Tax Expense decreased $3.2 million, or 56 percent, from 2014 primarily due to increased production tax credits as a result of the additions to the Bison Wind Energy Center which was placed in service in December 2014.

Investments and Other

Operating Revenue increased $62.2 million, or 200 percent, from 2014 primarily due to an increase in revenue from U.S. Water Services which was acquired on February 10, 2015. Also contributing to the increase was higher revenue at ALLETE Clean Energy primarily due to the recognition of revenue from the development and construction of a wind facility under the percentage of completion method of accounting for contracts, and the operations of recently acquired wind energy facilities. BNI Coal, which operates under cost-plus fixed fee contracts, also had an increase in revenue as a result of more tons sold and higher expenses in 2015. (See Cost of Sales.)

Operating Expenses increased $57.5 million, or 190 percent, from 2014.

Cost of Sales increased $36.7 million, or 251 percent, from 2014 primarily due to the acquisition of U.S. Water Services and ALLETE Clean Energy's recognition of costs to develop and construct a wind facility under the percentage of completion method of accounting for contracts. Also contributing to the increase were higher expenses at BNI Coal which are recovered through cost-plus fixed fee contracts. (See Operating Revenue.) Cost of sales also included $1.0 million of expense relating to fair value adjustments for inventories and sales backlog which resulted from the U.S. Water Services acquisition. Purchase accounting requires inventories and sales backlog at the date of acquisition to be recognized at fair value. The total estimated fair value adjustment to inventories and sales backlog of $4.3 million will be reflected in Cost of Sales over approximately one year from the date of acquisition. (See Note 4. Acquisitions.)

Operating and Maintenance expense increased $16.9 million, or 158 percent, from 2014 primarily due to the inclusion of expenses from recent acquisitions and $1.6 million of acquisition costs relating to the acquisitions of ALLETE Clean Energy's wind energy facilities.

Depreciation and Amortization expense increased $3.3 million, or 77 percent, from 2014 reflecting additional property, plant and equipment in service primarily due to recent acquisitions. Also contributing to the increase was the amortization of intangibles acquired through the U.S. Water Services acquisition.

Taxes Other than Income Taxes increased $0.6 million, or 86 percent, from 2014 primarily due to higher property taxes at ALLETE Clean Energy primarily resulting from the wind energy facilities acquisitions in 2014.

Interest Expense increased $0.8 million, or 38 percent, from 2014 primarily due to accretion expense for the U.S Water Services contingent consideration liability. (See Note. 4 Acquisitions and Note 7. Fair Value.)

COMPARISON OF THE QUARTERS ENDED JUNE 30, 2015 AND 2014 (Continued)
Investments and Other (Continued)

Income Tax Expense increased $4.7 million from 2014 primarily due to higher pretax income and additional income tax expense as GAAP requires the recognition of quarterly income tax expense at the estimated annual effective tax rate. The estimated annual effective tax rate could differ from what a quarterly effective tax rate would otherwise be on a standalone basis, and this may cause quarter to quarter differences in the timing of income taxes. During the second quarter we reflected additional income tax expense in our Investments and Other segment of $2.5 million to reflect total tax expense at our estimated annual consolidated effective tax rate of 16.8 percent. Of this amount, $1.2 million was related to the first quarter as we increased our estimated annual effective tax rate during the second quarter to 16.8 percent from 13.5 percent as of March 31, 2015.

Income Taxes – Consolidated

For the quarter ended June 30, 2015, the effective tax rate was 22.3 percent (22.5 percent for the quarter ended June 30, 2014). The effective tax rate deviated from the statutory rate of approximately 41 percent primarily due to production tax credits. (See Note 12. Income Tax Expense.)

COMPARISON OF THE SIX MONTHS ENDED JUNE 30, 2015 AND 2014

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

Regulated Operations

Operating Revenue decreased $1.0 million from 2014 primarily due to lower fuel adjustment clause recoveries, gas sales, and transmission revenue, mostly offset by higher cost recovery rider revenue and kWh sales.

Fuel adjustment clause recoveries decreased $18.7 million due to lower fuel and purchased power costs attributable to our retail and municipal customers. (See Operating Expenses - Fuel and Purchased Power Expense.)

Gas sales at SWL&P decreased $8.5 million from 2014 as a result of unseasonably cold weather during the first half of 2014. (See Cost of Sales.)

Transmission revenue decreased $0.8 million from 2014 primarily due to a reserve recorded in the second quarter of 2015 due to the MISO return on equity complaints. (See Operating Expenses - Transmission Services and Note 8. Regulatory Matters.)

Cost recovery rider revenue increased $15.7 million primarily due to the completion of our Bison Wind Energy Center and CapX2020 projects as well as higher capital expenditures related to our Boswell Unit 4 environmental upgrade.

Revenue from Regulated Operations increased $9.7 million due to a 7.4 percent increase in kWh sales. 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, and increased 50.6 percent in 2015 compared to 2014 primarily due to the commencement of the Minnkota Power sales agreement on June 1, 2014. (See Note 16. Commitments, Guarantees and Contingencies.) Sales to our residential, commercial, and municipal customers decreased primarily due to unseasonably cold temperatures in 2014 compared to the same period in 2015. Heating degree days in Duluth, Minnesota were approximately 15 percent lower in the first half of 2015 compared to the same period in 2014. Sales to our industrial customers decreased 2.2 percent primarily due to reduced taconite production. Although industrial kWh sales decreased for the six months ended June 30, 2015, demand revenue from our Large Power Customers was comparable to the same period in 2014.

COMPARISON OF THE SIX MONTHS ENDED JUNE 30, 2015 AND 2014 (Continued)
Regulated Operations (Continued)

Kilowatt-hours Sold Six Months Ended June 30,	2015	2014	Quantity Variance	% Variance
Millions				
Regulated Utility				
Retail and Municipal				
Residential	583	647	(64)	(9.9)%
Commercial	715	728	(13)	(1.8)%
Industrial	3,525	3,604	(79)	(2.2)%
Municipal	420	440	(20)	(4.5)%
Total Retail and Municipal	5,243	5,419	(176)	(3.2)%
Other Power Suppliers	2,004	1,331	673	50.6 %
Total Regulated Utility Kilowatt-hours Sold	7,247	6,750	497	7.4 %

Revenue from electric sales to taconite/iron concentrate customers accounted for 24 percent of Regulated Operations operating revenue in 2015 (26 percent in 2014). Revenue from electric sales to paper, pulp and secondary wood product customers accounted for 8 percent of Regulated Operations operating revenue in 2015 (8 percent in 2014). Revenue from electric sales to pipelines and other industrial customers accounted for 7 percent of Regulated Operations operating revenue in 2015 (7 percent in 2014).

Operating Expenses decreased $13.6 million, or 3 percent, from 2014.

Fuel and Purchased Power expense decreased $13.7 million, or 8 percent, from 2014 due to lower purchased power prices in 2015 compared to 2014. Fuel and purchased power expense related to our retail and municipal customers is recovered through the fuel adjustment clause. (See Operating Revenue.)

Transmission Services expense increased $4.9 million, or 23 percent, from 2014 primarily due to higher MISO–related expenses which were partially offset by an estimated refund for MISO transmission expense due to the MISO return on equity complaints. (See Operating Revenue and Note 8. Regulatory Matters.)

Cost of Sales decreased $7.5 million, or 58 percent, from 2014 due to lower purchased gas at SWL&P. (See Operating Revenue.)

Operating and Maintenance expense decreased $7.6 million, or 6 percent, from 2014 primarily due to a $4.2 million expense that was recorded in the second quarter of 2014 to reflect a liability associated with environmental mitigation projects required as part of an EPA NOV Consent Decree settlement. Also contributing to the decrease in operating and maintenance expense were lower salary and wage expenses.

Depreciation and Amortization expense increased $7.4 million, or 13 percent, from 2014 primarily reflecting additional property, plant and equipment in service.

Taxes Other than Income Taxes increased $2.9 million, or 14 percent, from 2014 primarily due to higher property tax expenses resulting from higher taxable plant and rates.

Interest Expense increased $3.4 million, or 15 percent, from 2014 primarily due to higher average long-term debt balances.

Equity Earnings in ATC decreased $1.7 million, or 17 percent, from 2014 primarily due to a $1.7 million expense related to the MISO return on equity complaints; of the $1.7 million expense, $1.1 million was attributable to ATC's change in estimate of a refund liability relating to prior years.

Other Income decreased $2.2 million, or 58 percent, from 2014 primarily due to lower AFUDC–Equity.

Income Tax Expense decreased $8.3 million, or 51 percent, from 2014 primarily due to increased production tax credits as a result of the completion of the Bison Wind Energy Center in December 2014.

COMPARISON OF THE SIX MONTHS ENDED JUNE 30, 2015 AND 2014 (Continued)

Investments and Other

Operating Revenue increased $87.1 million, or 137 percent, from 2014 primarily due to an increase in revenue from U.S. Water Services which was acquired on February 10, 2015. Also contributing to the increase was higher revenue at ALLETE Clean Energy primarily due to the recognition of revenue from the development and construction of a wind facility under the percentage of completion method of accounting for contracts and the operations of the recently acquired wind energy facilities. BNI Coal, which operates under cost-plus fixed fee contracts, also had an increase in revenue as a result of more tons sold and higher expenses in 2015. (See Cost of Sales.)

Operating Expenses increased $80.3 million, or 127 percent, from 2014.

Cost of Sales increased $48.6 million, or 165 percent, from 2014 primarily due to the acquisition of U.S. Water Services and ALLETE Clean Energy's recognition of costs to develop and construct a wind energy facility under the percentage of completion method of accounting for contracts. Also contributing to the increase was higher expenses at BNI Coal primarily due to increased contractor services and repair expenses, which are recovered through cost-plus fixed fee contracts. (See Operating Revenue.) Cost of sales also included $1.6 million of expense relating to fair value adjustments for inventories and sales backlog which resulted from the U.S. Water Services acquisition. Purchase accounting requires inventories and sales backlog at the date of acquisition to be recognized at fair value. The total estimated fair value adjustment to inventories and sales backlog of $4.3 million will be reflected in Cost of Sales over approximately one year from the date of acquisition. (See Note 4. Acquisitions.)

Operating and Maintenance expense increased $24.1 million, or 98 percent, from 2014 primarily due to the inclusion of expenses from recent acquisitions and $4.8 million of acquisition costs relating to the acquisitions of U.S Water Services and ALLETE Clean Energy's wind energy facilities.

Depreciation and Amortization expense increased $6.8 million, or 88 percent, from 2014 reflecting additional property, plant and equipment in service primarily due to recent acquisitions. Also contributing to the increase was the amortization of intangibles acquired through the U.S. Water Services acquisition.

Taxes Other than Income Taxes increased $0.8 million, or 47 percent, from 2014 primarily due to higher property taxes at ALLETE Clean Energy resulting from wind energy facilities acquisitions.

Interest Expense increased $1.6 million, or 47 percent, from 2014 primarily due to accretion expense for the U.S. Water Services contingent consideration liability and higher average long-term debt balances. (See Note. 4 Acquisitions and Note 7. Fair Value.)

Income Tax Expense increased $7.2 million from 2014 primarily due to higher pretax income and additional income tax expense as GAAP requires the recognition of quarterly income tax expense at the estimated annual effective tax rate. The estimated annual effective tax rate could differ from what a quarterly effective tax rate would otherwise be on a standalone basis, and this may cause quarter to quarter differences in the timing of income taxes. During the six months ended June 30, 2015, we reflected additional income tax expense in our Investments and Other segment of $4.1 million to reflect total tax expense at our estimated annual consolidated effective tax rate of 16.8 percent.

Income Taxes – Consolidated

For the six months ended June 30, 2015, the effective tax rate was 16.8 percent (21.3 percent for the six months ended June 30, 2014). The decrease in the effective tax rate from June 30, 2014, was primarily due to increased production tax credits. The effective rate deviated from the statutory rate of approximately 41 percent primarily due to production tax credits. (See Note 12. 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 2014 Form 10-K. As a result of our acquisition of U.S. Water Services on February 10, 2015, the valuation of intangible assets and goodwill are considered critical accounting policies.

Valuation of Goodwill and Intangible Assets

When we acquire a business, the assets acquired and liabilities assumed are recorded at their respective fair values as of the acquisition date. Determining the fair value of intangible assets acquired as part of a business combination requires us to make significant estimates. These estimates include the amount and timing of projected future cash flows, the discount rate used to discount those cash flows to present value, the assessment of the asset's life cycle, and the consideration of legal, technical, regulatory, economic, and competitive risks. The fair value assigned to intangible assets is determined by estimating the future cash flows of each project and discounting the net cash flows back to their present values. The discount rate used is determined at the time of measurement in accordance with accepted valuation standards.

Goodwill. Goodwill is the excess of the purchase price (consideration transferred) over the estimated fair value of net assets of acquired businesses. In accordance with GAAP, goodwill is not amortized. The Company assesses whether there has been an impairment of goodwill annually in the third quarter and whenever an event occurs or circumstances change that would indicate the carrying amount may be impaired. Impairment testing for goodwill is done at the reporting unit level. An impairment loss is recognized when the carrying amount of the reporting unit's net assets exceeds the estimated fair value of the reporting unit. The test for impairment requires us to make several estimates about fair value, most of which are based on projected future cash flows. Our estimates associated with the goodwill impairment test are considered critical due to the amount of goodwill recorded on our Consolidated Balance Sheet and the judgment required in determining fair value, including projected future cash flows. The results of our annual impairment test are discussed in Note 7. Fair Value in this Form 10-Q. Goodwill was $130.1 million and $2.9 million as of June 30, 2015 and December 31, 2014, respectively.

Intangible Assets. Intangible assets include customer relationships, patents, non-compete agreements and trademarks and trade names. Intangible assets with definite lives consist of customer relationships, patents, and non-compete agreements, which are amortized on a straight-line or accelerated basis with estimated useful lives ranging from less than 1 year to 23 years. We review definite-lived intangible assets for impairment whenever events or circumstances indicate that the carrying amount of an asset may not be recoverable. Indefinite-lived intangible assets consist of trademarks and trade names, which are tested for impairment annually in the third quarter and whenever an event occurs or circumstances change that would indicate that the carrying amount may be impaired. Impairment is calculated as the excess of the asset's carrying amount over its fair value. Our impairment reviews are based on an estimated future cash flow approach that requires significant judgment with respect to future revenue and expense growth rates, selection of appropriate discount rate, and other assumptions and estimates. We use estimates that are consistent with our business plans and a market participant view of the assets being evaluated. The results of our annual impairment test are discussed in Note 7. Fair Value in this Form 10-Q. Actual results may differ from our estimates due to a number of risk factors, including those which are discussed in Item 1A, "Risk Factors" in this Form 10-Q. Intangible assets, net of accumulated amortization, were $83.3 million and $1.9 million as of June 30, 2015 and December 31, 2014, respectively.

OUTLOOK

For additional information see our 2014 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 long-term objectives of achieving average earnings per share growth of 5 percent per year and providing a dividend payout competitive with our industry.

ALLETE is predominantly a regulated utility through Minnesota Power, SWL&P and an investment in ATC. Minnesota Power believes it is well positioned for the future as it executes on its EnergyForward initiative and serves a potentially growing industrial customer base. 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 regulators to earn a fair rate of return. We believe that ATC is poised for future growth both organically and through its partnership with Duke Energy.

OUTLOOK (Continued)

In February 2015, ALLETE acquired U.S. Water Services, consistent with ALLETE's stated strategy of investing in energy infrastructure and related services to complement its core regulated utility, balance exposure to business cycles and changing demand, and provide potential long-term earnings growth. ALLETE will now focus its energy infrastructure and related service efforts on ALLETE Clean Energy, U.S. Water Services and BNI Coal. ALLETE Clean Energy has a growing portfolio of wind energy facilities, and U.S. Water Services provides integrated water management to a growing base of industrial and commercial customers. ALLETE's Energy Infrastructure and Related Services businesses primarily have contracted or recurring revenue.

ALLETE is focused on providing sustainable solutions to our customers, as exemplified by the EnergyForward and Power of One initiatives at Minnesota Power, renewable energy investments at ALLETE Clean Energy, and investment in U.S. Water Services.

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 energy 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 customer viability. 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. (See Regulated Operations – EnergyForward.) 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 regulators to earn a fair rate of return. We project that Minnesota Power will not earn its allowed rate of return in 2015.

Regulatory Matters. Entities within our Regulated Operations segment are under the jurisdiction of the MPUC, the FERC, the PSCW or the NDPSC. See Note 8. Regulatory Matters for discussion of regulatory matters within our Minnesota, FERC, Wisconsin and North Dakota jurisdictions.

Industrial Customers and Prospective Additional Load.

Industrial Customers. Electric power is one of several key inputs in the taconite mining, iron concentrate, paper, pulp and secondary wood products, and pipeline industries. Approximately 46 percent of our Regulated Utility kWh sales in the six months ended June 30, 2015 (53 percent in the six months ended June 30, 2014) 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 American Iron and Steel Institute (AISI), an association of North American steel producers, reported that U.S. raw steel production operated at approximately 73 percent of capacity during the first six months of 2015 compared to 77 percent in the first six months of 2014. Many steel producers have reduced production this year, citing higher levels of imports and lower prices. Some Minnesota taconite and iron concentrate producers have reduced production in response to declining U.S. taconite demand primarily resulting from the higher level of imports and lower prices.

Our taconite customers may experience annual variations in production levels due to such factors as economic conditions, short-term demand changes or maintenance outages. We estimate that a one million ton change in our taconite customers' production would impact our annual earnings per share by approximately $0.03, net of expected power marketing sales at current prices. Changes in wholesale electric prices or customer contractual demand nominations could impact this estimate. Long-term reductions in taconite production or a permanent shut down of a taconite customer may lead us to file a rate case to recover lost revenues.

OUTLOOK (Continued)
Industrial Customers and Prospective Additional Load (Continued)

Minnesota Power's Large Power taconite customers, subject to demand nomination requirements, nominate demand levels for their energy needs each December, March, and August for the following four-month periods. Based on nominations received on July 31, 2015, Minnesota Power's Large Power taconite customers nominated at approximately 80 percent of full demand levels for September 2015, and approximately 90 percent of full demand levels for October through December 2015. When there are reductions in demand nominations, we will market any available power to Other Power Suppliers in an effort to mitigate any earnings impact. Sales to Other Power Suppliers are dependent upon the availability of generation and are sold at market-based prices into the MISO market on a daily basis or through bilateral agreements in various durations. We can make no assurances that our power marketing efforts would fully offset any reduction in earnings resulting from lower demand nominations from our taconite customers.

USS Corporation. On July 31, 2015, Minnesota Power received near full demand nominations for September through December 2015 from USS Corporation. In the second quarter of 2015, USS Corporation temporarily idled its Minnesota Ore Operations - Keetac plant in Keewatin, MN and a portion of its Minnesota Ore Operations - Minntac plant in Mountain Iron, MN. These actions were due to its current inventory levels and ongoing adjustment of its steel producing operations throughout North America. Global influences in the market, including a higher level of imports, unfairly traded products and reduced steel prices, were cited as having an impact. Both facilities are Large Power Customers of Minnesota Power.

Magnetation. On May 5, 2015, Magnetation announced that it had reached an agreement with holders of more than 70 percent of its 11.0 percent senior secured notes due in 2018 to restructure its balance sheet and provide liquidity to support long-term operations. To implement this restructuring, Magnetation announced that it had filed voluntary petitions for reorganization under Chapter 11 of the Bankruptcy Code in the United States Bankruptcy Court for the District of Minnesota, citing the significant decrease in global iron ore prices and its existing capital structure.

Magnetation stated that it intends to continue to pay suppliers and vendors in full under normal terms for goods and services provided after the bankruptcy filing date of May 5, 2015. Magnetation stated that it expects its mining and pelletizing operations and customer shipments to continue in the ordinary course throughout the reorganization.

Magnetation is a Large Power Customer of Minnesota Power. On July 24, 2015, Minnesota Power filed a petition with the MPUC for approval of a new Electric Service Agreement (Agreement) for service to both Magnetation's Plant 2 and Plant 4 facilities, and this Agreement has a term through at least December 31, 2025. This Agreement is subject to both MPUC and bankruptcy court approvals. On July 31, 2015, Minnesota Power received full demand nominations for September through December 2015, indicating full production. Minnesota Power's pre-petition amounts due from Magnetation are less than $1 million.

United Taconite. On July 29, 2015, Cliffs Natural Resources Inc. (Cliffs) announced the temporary idling of its United Taconite plant in Eveleth, Minnesota, citing high levels of inventories, lower demand from its customers, and the high rate of imported steel. Cliffs stated that the idling of production at the plant will be initiated as soon as feasible and completed by the end of August; returning to production as soon as demand from customers return. Cliffs also stated that the idling offers a chance to start reworking the plant to produce a fully fluxed taconite pellet. That new product will replace a flux pellet now made at Cliffs' Empire/Tilden operation in Michigan which is scheduled to shut down at the end of 2016. United Taconite produced approximately 4.9 million tons of taconite in 2014.

Steel Dynamics. On May 26, 2015, Steel Dynamics announced the decision to idle its Minnesota Operations for an initial 24 month period. Its Minnesota Operations include Mesabi Nugget and Mining Resources, both of which are Minnesota Power retail customers. Steel Dynamics cited the significant decline in pig iron pricing as the reasoning behind its decision. Mesabi Nugget and Mining Resources account for a combined 30 MW of load for Minnesota Power.

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. We cannot predict the outcome of these projects.

Nashwauk Public Utilities Commission. On April 21, 2015, the Company amended its formula-based wholesale electric sales agreement with the Nashwauk Public Utilities Commission for all of its electric service requirements, extending the term through June 30, 2028. A new Essar taconite facility is currently under construction in the city of Nashwauk, and the Nashwauk Public Utilities Commission also amended and extended its electric service agreement with Essar. Upon completion, this facility would result in up to approximately 110 MW of additional load for Minnesota Power. Essar announced the completion of project financing in October 2014 and has stated that it expects to achieve full production capability in 2016.

OUTLOOK (Continued)
Industrial Customers and Prospective Additional Load (Continued)

PolyMet. Minnesota Power has a long-term contract with PolyMet, which is planning to start a new copper-nickel and precious metal (non-ferrous) mining operation in northeastern Minnesota. On June 22, 2015, PolyMet announced the preliminary final EIS has been completed and is undergoing review by state and federal agencies prior to publication of the final EIS in the Federal Register and Minnesota Environmental Quality Board Monitor, which is expected in November 2015. Following publication, the final EIS requires an adequacy decision by the Minnesota Department of Natural Resources and Records of Decision by the federal agencies before final action can be taken on the required permits to construct and operate the mining operation, which are expected in 2016. Minnesota Power could supply between 45 MW and 50 MW of load under a ten-year power supply contract that would begin upon start-up of the mining operations.

Enbridge. Minnesota Power has a long-term contract with Enbridge that extends through December 31, 2020. Enbridge owns and operates a crude oil and liquids transportation system in North America including in our service territories. Enbridge is expanding the capacity at two pumping stations located in Minnesota Power's service territory in Deer River and Floodwood, Minnesota, with the project expected to be completed by the end of 2015. Enbridge also plans to construct a pipeline connecting its Beaver Lodge Station, near Tioga, North Dakota, to an existing terminal in Superior, Wisconsin by 2017. On June 5, 2015, the MPUC granted the certificate of need for the pipeline which will now go through the route permitting process. Upon completion and full operation of these projects, we expect to supply between 20 MW and 30 MW of additional load.

EnergyForward. In January 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. Our Bison Wind Energy Center added 205 MW of capacity in the fourth quarter of 2014, bringing total capacity to 497 MW. (See Renewable Energy.)
- The installation of approximately $260 million in emissions control technology underway at Boswell Unit 4 to further reduce emissions of SO_2, particulates and mercury. (See Boswell Mercury Emission Reduction Plan.)
- Planning for the proposed GNTL to deliver hydroelectric power from northern Manitoba by 2020. (See Transmission.)
- The conversion of Laskin from coal to cleaner-burning natural gas which was completed in June 2015.
- Retirement of Taconite Harbor Unit 3, one of three coal-fired units at Taconite Harbor.

On July 9, 2015, Minnesota Power announced the next steps in its EnergyForward plan, which will reduce carbon emissions, increase the use of renewable resources and add natural gas to meet customer electric service needs in a balanced, reliable and cost-effective way. Significant additional elements of the plan include:

- Economic idling of the Taconite Harbor Units 1 and 2 in the fall of 2016 and the ceasing of coal-fired operations there in 2020.
- Adding between 200 MW and 300 MW of cleaner and flexible natural gas generation to Minnesota Power's portfolio within the next decade.
- Building both large and small scale solar generation.
- Expanding the potential for additional energy efficiency savings.

Integrated Resource Plan. In a November 2013 order, the MPUC approved Minnesota Power's 2013 Integrated Resource Plan which details elements of our EnergyForward strategic plan, announced in January 2013, and includes an analysis of a variety of existing and future energy resource alternatives and a projection of customer cost impact by class. We are required to submit our 2015 Integrated Resource Plan with the MPUC no later than September 1, 2015.

Renewable Energy. In February 2007, Minnesota enacted a law requiring 25 percent of electric utilities' total retail and municipal energy sales in Minnesota to be from renewable energy sources by 2025. The law also requires electric utilities 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's 2013 Integrated Resource Plan, which was approved by the MPUC in a November 2013 order, included an update on its plans and progress in meeting the Minnesota renewable energy milestones through 2025. (See EnergyForward.)

OUTLOOK (Continued)
EnergyForward (Continued)

Minnesota Power continues to execute its renewable energy strategy through key renewable projects that will ensure we meet the identified state mandate at the lowest cost for customers. We exceeded the interim milestone requirements and we expect 28 percent of the Company's total retail and municipal energy sales will be supplied by renewable energy sources in 2015.

Minnesota Solar Energy Standard. 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 10 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; however, any costs are expected to be recovered in customer rates.

Wind Energy. Our wind energy facilities consist of the 497 MW Bison Wind Energy Center located in North Dakota, which was placed in service in various phases between 2010 and 2014, and the 25 MW Taconite Ridge Energy Center located in northeastern Minnesota. 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 an order dated May 22, 2015. In November 2014, we filed a renewable resources factor filing which includes updated costs associated with Bison. Upon approval of the filing, we will be authorized to include updated billing rates on customer bills.

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 May 2020. 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. In addition, 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.

In May 2011, Minnesota Power and Manitoba Hydro signed an additional long-term PPA. The PPA provides for Minnesota Power to purchase 250 MW of capacity and energy from Manitoba Hydro for 15 years beginning in 2020. The agreement is subject to construction of additional transmission capacity between Manitoba and the U.S., along with construction of new hydroelectric generating capacity in Manitoba. Construction of Manitoba Hydro's hydroelectric generation facility commenced in the third quarter of 2014. The capacity price is adjusted annually until 2020 by the change in a governmental inflationary index. The energy price is based on a formula that includes an annual fixed price component adjusted for the change in a governmental inflationary index and a natural gas index, as well as market prices.

In July 2014, Minnesota Power and Manitoba Hydro signed a long-term PPA that provides for Minnesota Power to purchase up to 133 MW of energy from Manitoba Hydro for 20 years beginning in 2020. The pricing under this PPA is based on forward market prices. The agreement was approved by the MPUC in an order dated January 30, 2015, and is subject to the construction of the GNTL. (See Transmission.)

Hydro Operations. On February 13, 2015, Minnesota Power supplemented its November 2014 renewable resources factor filing to include costs associated with the restoration and repair of Thomson. In an order dated March 5, 2015, the MPUC approved our petition seeking cost recovery of investments and expenditures related to the restoration and repair of Thomson through a renewable resources rider.

OUTLOOK (Continued)
EnergyForward (Continued)

Boswell Mercury Emissions Reduction Plan. Minnesota Power is implementing a mercury emissions reduction project for Boswell Unit 4 in order to comply with 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. 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 approximately $260 million, of which approximately $184 million was spent through June 30, 2015. In a November 2013 order, the MPUC approved the Boswell Unit 4 mercury emissions reduction plan and cost recovery, establishing an environmental improvement rider. Customer billing rates for the environmental improvement rider were approved by the MPUC in a July 2014 order. In November 2014, we filed an updated environmental improvement factor filing which included updated costs associated with Boswell Unit 4. Upon approval of this filing, we will be authorized to include updated billing rates on customer bills.

Transmission. We continue 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. These include the GNTL 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.

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 and 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.

On April 2, 2015, the CapX2020 transmission line project from Fargo, North Dakota to St. Cloud, Minnesota was completed and placed into service. Minnesota Power previously participated in two additional CapX2020 projects which were completed and placed into service in 2011 and 2012.

Minnesota Power invested approximately $100 million to complete the three transmission line projects. As future CapX2020 projects are identified, Minnesota Power may elect to participate on a project-by-project basis.

Great Northern Transmission Line (GNTL). As a condition of the long-term PPA signed in May 2011 with Manitoba Hydro, construction of additional transmission capacity is required. As a result, Minnesota Power and Manitoba Hydro proposed construction of the GNTL, an approximately 220-mile 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.

The GNTL is subject to various federal and state regulatory approvals. In October 2013, a Certificate of Need application was filed with the MPUC which was approved in an order dated June 30, 2015. Based on this order, our portion of the investments and expenditures for the project are eligible for cost recovery under our existing transmission cost recovery rider and are anticipated to be included in future transmission factor filings. In April 2014, Minnesota Power filed a route permit application with the MPUC and a request for a presidential permit to cross the U.S.-Canadian border with the U.S. Department of Energy. In a July 2014 order, the MPUC determined the route permit application to be complete. On June 19, 2015, the Minnesota Department of Commerce and the U.S. Department of Energy released the draft EIS for the GNTL. Public hearings on the draft EIS were held in July 2015 and comments are due by August 10, 2015. Hearings on the route permit will be held before an Administrative Law Judge in August 2015 with comments due by September 1, 2015. Manitoba Hydro must also obtain regulatory and governmental approvals related to a new transmission line in Canada. Construction of Manitoba Hydro's hydroelectric generation facility commenced in the third quarter of 2014. Upon receipt of all applicable permits and approvals, construction of the GNTL is anticipated to begin in 2016 and to be completed in 2020. Total project cost in the U.S., including substation work, is estimated to be between $560 million and $710 million, depending on the final route of the line. Minnesota Power is expected to have majority ownership of the transmission line.

Investment in ATC. As of June 30, 2015, our equity investment in ATC was $124.2 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. ATC’s 10-year transmission assessment, which covers the years 2014 through 2023, identifies a need for between $3.3 billion and $3.9 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 2015, we invested $0.8 million in ATC, and on July 30, 2015, we invested an additional $0.4 million. We expect to make additional investments of $0.7 million in 2015. (See Note 9. Investment in ATC.)

OUTLOOK (Continued)
Transmission (Continued)

Our equity earnings in ATC for the six months ended June 30, 2015, were $8.6 million and reflected a $1.7 million reduction related to complaints filed with the FERC by several customer groups located within the MISO service area; of which $1.1 million was attributable to ATC's change in estimate of a refund liability relating to prior years. The groups requested, among other things, a reduction in the base return on equity used by MISO transmission owners, including ATC, to 9.15 percent. ATC's current authorized return on equity is 12.2 percent. On February 12, 2015, an additional complaint was filed with the FERC seeking an order to further reduce the base return on equity used to 8.67 percent. We own approximately 8 percent of ATC and estimate that for every 50 basis point reduction in ATC's allowed return on equity our equity earnings in ATC would be impacted annually by approximately $0.5 million on an after-tax basis ($0.9 million pre-tax).

Investments and Other.

ALLETE Clean Energy. ALLETE Clean Energy aims to acquire or develop capital projects that create energy solutions by way of wind, solar, biomass, hydro, natural gas, shale resources, clean coal technology and other emerging energy innovations. In January 2014, ALLETE Clean Energy acquired wind energy facilities located in Lake Benton, Minnesota (Lake Benton), Storm Lake, Iowa (Storm Lake II) and Condon, Oregon (Condon) from The AES Corporation (AES) for $26.9 million.

Lake Benton, Storm Lake II and Condon have 104 MW, 77 MW and 50 MW of generating capability, respectively. Lake Benton and Storm Lake II began commercial operations in 1999, while Condon began operations in 2002. All three wind energy facilities have PPAs in place for their entire output, which expire in various years between 2019 and 2032.

In November 2014, ALLETE Clean Energy acquired a business for $27.0 million to develop a wind facility near Hettinger, North Dakota. ALLETE Clean Energy is developing and constructing a 107 MW wind facility consisting of 43 turbines, which was approved to be sold to Montana-Dakota Utilities by the NDPSC on June 30, 2015 for approximately $200 million. Construction is expected to be completed in December 2015.

In December 2014, ALLETE Clean Energy acquired a wind energy facility in Storm Lake, Iowa (Storm Lake I) from NRG Energy, Inc. for $15.1 million. Storm Lake I has 108 MW of generating capability and is located adjacent to Storm Lake II. The wind energy facility began commercial operations in 1999 and has a PPA in place for its entire output which expires in 2018.

On April 15, 2015, ALLETE Clean Energy acquired wind energy facilities in southern Minnesota (Chanarambie/Viking) from EDF Energy Holdings Limited for $47.9 million, subject to a working capital adjustment. The facilities have 97.5 MW of generating capability and are located near our Lake Benton facility. The wind energy facilities began commercial operations in 2003 and have PPAs in place for their entire output, which expire in 2018 (12 MW) and 2023 (85.5 MW).

On July 1, 2015, ALLETE Clean Energy acquired a wind energy facility located near Troy, Pennsylvania (Armenia Mountain) from The AES Corporation (AES) and a non-controlling interest from a minority shareholder for $108.0 million, plus the assumption of existing debt. The agreement with AES is subject to a purchase price adjustment. The facility has 100.5 MW of generating capability, began commercial operations in 2009, and has PPAs in place for its entire output, which expire in 2025.

U.S. Water Services. On February 10, 2015, ALLETE acquired U.S. Water Services. Headquartered in St. Michael, Minnesota, U.S. Water Services provides integrated water management for industry by combining chemical, equipment, engineering and service for customized solutions to reduce water and energy usage and improve efficiency. U.S. Water Services helps customers achieve efficient and sustainable use of their energy systems, is a leading provider to the biofuels industry, and has a growing presence in the power generation and midstream oil and gas industries. The acquisition is not expected to have a material impact on 2015 earnings per share. (See Note 4. Acquisitions.)

BNI Coal. BNI Coal anticipates selling 4.4 million tons of coal in 2015 (4.0 million tons were sold in 2014) and has sold 2.1 million tons through June 30, 2015 (1.8 million tons were sold as of June 30, 2014). BNI Coal operates under cost-plus fixed fee agreements extending through December 31, 2037.

ALLETE Properties. ALLETE Properties represents our Florida real estate investment. Market conditions can impact land sales and could result in our inability to cover our cost basis, operating expenses or fixed carrying costs such as community development district assessments and property taxes.

OUTLOOK (Continued)
Investments and Other (Continued)

Our strategy for ALLETE Properties has been to complete and maintain key entitlements and infrastructure improvements without requiring significant additional investment, and sell assets in the portfolio over time in order to optimize cash flows in support of future investment opportunities and growth initiatives. Opportunities for growth and investment in our energy infrastructure and related services strategy may impact management's decisions to divest all or portions of the ALLETE Properties' asset portfolio; this could impact the timing and pricing of divestitures. 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
As of June 30, 2015	Acres (a)	Units (b)	Sq. Ft. (b)
Current Development Projects			
Town Center	958	2,359	2,236,700
Palm Coast Park	3,777	3,746	3,096,800
Total Current Development Projects	4,735	6,105	5,333,500
Planned Development Project			
Ormond Crossings	2,883	2,950	3,215,000
Other			
Lake Swamp Wetland Mitigation Project	3,050	(c)	(c)
Total of Development Projects	10,668	9,055	8,548,500

(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) 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 1,661 acres of other land available-for-sale.

Income Taxes. ALLETE's aggregate federal and multi-state statutory tax rate is approximately 41 percent for 2015. On an ongoing basis, ALLETE has 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, production tax credits, AFUDC–Equity, depletion, as well as other items. The annual effective rate can also be impacted by such items as changes in income from operations before non-controlling interest and income taxes, state and federal tax law changes that become effective during the year, business combinations and configuration changes, tax planning initiatives and resolution of prior years' tax matters. Due primarily to increased federal production tax credits as a result of wind generation, we expect our effective tax rate to be approximately 17 percent for 2015. 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 12. Income Tax Expense.)

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LIQUIDITY AND CAPITAL RESOURCES

Liquidity Position. ALLETE is well-positioned to meet the Company's liquidity needs. As of June 30, 2015, we had cash and cash equivalents of $60.6 million, $369.5 million in available consolidated lines of credit and a debt-to-capital ratio of 44 percent.

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

Millions	June 30, 2015	%	December 31, 2014	%
ALLETE Equity	$1,776.6	56	$1,609.4	54
Non-Controlling Interest	1.8	—	1.8	—
Long-Term Debt (Including Current Maturities)	1,390.4	44	1,373.5	46
Notes Payable	—	—	3.7	—
	$3,168.8	100	$2,988.4	100

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

For the Six Months Ended June 30, Millions	2015	2014
Cash and Cash Equivalents at Beginning of Period	$145.8	$97.3
Cash Flows from (used for)		
Operating Activities	182.3	126.1
Investing Activities	(371.2)	(323.4)
Financing Activities	103.7	183.6
Change in Cash and Cash Equivalents	(85.2)	(13.7)
Cash and Cash Equivalents at End of Period	$60.6	$83.6

Operating Activities. Cash from operating activities was $182.3 million for the six months ended June 30, 2015 ($126.1 million for the six months ended June 30, 2014). Cash from operating activities was higher in 2015 primarily due to higher net income and contract billings in excess of construction costs and estimated earnings related to the wind facility under development by ALLETE Clean Energy for sale to Montana-Dakota Utilities in December 2015. (See Note 4. Acquisitions.)

Investing Activities. Cash used for investing activities was $371.2 million for the six months ended June 30, 2015 ($323.4 million for the six months ended June 30, 2014). The increase in cash used for investing activities was primarily due to the U.S. Water Services acquisition on February 10, 2015, ALLETE Clean Energy's April 15, 2015 acquisition, and a transfer of cash included in Other Investments to Cash and Cash Equivalents in 2014, partially offset by lower capital expenditures in 2015.

Financing Activities. Cash from financing activities was $103.7 million for the six months ended June 30, 2015 ($183.6 million for the six months ended June 30, 2014). The decrease in cash from financing activities was primarily due to higher proceeds from the issuance of long-term debt in 2014, partially offset by higher proceeds from the issuance of common stock in 2015.

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, 2015, we had available consolidated bank lines of credit aggregating $369.5 million ($408.4 million available as of December 31, 2014), the majority of which expire in November 2018. In addition, as of June 30, 2015, we had 2.0 million original issue shares of our common stock available for issuance through Invest Direct, our direct stock purchase and dividend reinvestment plan, and 4.0 million original issue shares of common stock available for issuance through a distribution agreement with Lampert Capital

Markets, Inc. (See Securities.) The amount and timing of future sales of our securities will depend upon market conditions and our specific needs.

LIQUIDITY AND CAPITAL RESOURCES (Continued)

Securities. We entered into a distribution agreement with Lampert Capital Markets, Inc., in 2008, as amended most recently in February 2015, with respect to the issuance and sale of up to an aggregate of 13.6 million shares of our common stock, without par value, of which 4.0 million remain available for issuance. For the six months ended June 30, 2015, 1.3 million shares of common stock were issued under this agreement, resulting in net proceeds of $69.9 million (0.2 million shares were issued for the six months ended June 30, 2014, resulting in net proceeds of $8.2 million). The shares issued in 2015 were offered and sold pursuant to Registration Statement No. 333-190335.

During the six months ended June 30, 2015, we issued 0.2 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 $12.9 million (0.2 million shares were issued for the six months ended June 30, 2014, resulting in net proceeds of $10.5 million). These shares of common stock were registered under Registration Statement Nos. 333-188315, 333-183051 and 333-162890.

In February 2014, ALLETE entered into a confirmation of forward sale agreement (Agreement) with a forward counterparty in connection with a public offering of 2.8 million shares of ALLETE common stock. Pursuant to the Agreement, the forward counterparty (or its affiliate) borrowed 2.8 million shares of ALLETE common stock from third parties and sold them to the underwriters. The forward sale price was $48.01 per share, subject to adjustment as provided in the Agreement. In September 2014, ALLETE physically settled a portion of its obligations under the Agreement by delivering approximately 1.4 million shares of common stock in exchange for cash proceeds of $65.0 million and on February 4, 2015, ALLETE physically settled the remaining portion of its obligation under the Agreement by delivering approximately 1.4 million shares of common stock in exchange for cash proceeds of $65.4 million.

In connection with the public offering of the 2.8 million shares, ALLETE granted the underwriters an option to purchase up to an additional 0.4 million shares of ALLETE common stock (the option shares). The underwriters exercised the option in full and in March 2014, the Company issued and sold the option shares to the underwriters at a price to ALLETE equal to the initial forward sale price for proceeds of $20.2 million.

On July 14, 2015, we agreed to sell $100.0 million of the Company's first mortgage bonds (Bonds) to certain institutional buyers in the private placement market in two series on or about September 24, 2015. The Company intends to use the proceeds from the sale of the Bonds to fund utility capital expenditures and/or for general corporate purposes. (See Note 10. Short-Term and Long-Term Debt.)

Financial Covenants. See Note 10. 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 make any contributions to our defined benefit pension plan or our other postretirement benefit plan in 2015. (See Note 15. Pension and Other Postretirement Benefit Plans.)

Off-Balance Sheet Arrangements. Off-balance sheet arrangements are summarized in our 2014 Form 10-K, with additional disclosure in Note 16. Commitments, Guarantees and Contingencies.

Capital Requirements. Our capital expenditures for 2015 are expected to be approximately $280 million. For the six months ended June 30, 2015, capital expenditures totaled $117.9 million ($341.7 million for the six months ended June 30, 2014). The expenditures were primarily made in the Regulated Operations segment.

OTHER

Environmental Matters.

Our businesses are subject to regulation of environmental matters by various federal, state and local authorities. Due to future 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 2014 Form 10-K, with additional disclosure in Note 16. Commitments, Guarantees and Contingencies.

Employees.

Minnesota Power and SWL&P have an aggregate of 579 employees who are members of the International Brotherhood of Electrical Workers (IBEW) Local 31. The current labor agreements with IBEW Local 31 expire on January 31, 2018.

BNI Coal has 175 employees, of which 126 are members of IBEW Local 1593. The current labor agreement with IBEW Local 1593 expires on March 31, 2019.

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. At June 30, 2015, our available-for-sale securities portfolio consisted primarily of securities held in other postretirement plans to fund employee benefits. (See Note 3. Investments.)

COMMODITY PRICE RISK

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

POWER MARKETING

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

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

ITEM 3. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK (Continued)

INTEREST RATE RISK

We are exposed to risks resulting from changes in interest rates as a result of our issuance of variable rate debt. We manage our interest rate risk by varying the issuance and maturity dates of our fixed rate debt, limiting the amount of variable rate debt, and continually monitoring the effects of market changes in interest rates. 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, 2015, 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 $0.6 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, 2015.

ITEM 4. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures. As of June 30, 2015, 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

For information regarding material legal and regulatory proceedings, see Note 5. Regulatory Matters and Note 12. Commitments, Guarantees and Contingencies to our Consolidated Financial Statements in the 2014 Form 10-K and Note 8. Regulatory Matters and Note 16. Commitments, Guarantees and Contingencies herein. Such information is incorporated herein by reference.

ITEM 1A. RISK FACTORS

Our 2014 Form 10-K includes a detailed discussion of our risk factors. The information presented below updates, and should be read in conjunction with, the risk factors and information disclosed in our 2014 Form 10-K.

ALLETE has a significant goodwill and intangible asset balance related to its acquisition of U.S. Water Services. A determination that goodwill or intangible assets have been impaired could result in a significant non-cash charge to earnings.

We had approximately $213 million of goodwill and intangible assets recorded on our Consolidated Balance Sheet as of June 30, 2015, primarily relating to our acquisition of U.S. Water Services on February 10, 2015. If we make changes in our business strategy or if market or other conditions adversely affect operations of our Investments and Other businesses, we may be required to record an impairment charge. Declines in projected operating cash flows at certain of our reported units may result in goodwill impairments. Depending on the amount of the impairment, an impairment could have a material adverse effect on our results of operations.

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

None.

ITEM 3. DEFAULTS UPON SENIOR SECURITIES

None.

ITEM 4. MINE SAFETY DISCLOSURES

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

ITEM 5. OTHER INFORMATION

None.

ITEM 6. EXHIBITS

Exhibit Number	
31(a)	Rule 13a-14(a)/15d-14(a) Certification by the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(b)	Rule 13a-14(a)/15d-14(a) Certification by the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32	Section 1350 Certification of Periodic Report by the Chief Executive Officer and the Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
95	Mine Safety
99	ALLETE News Release dated August 4, 2015, announcing 2015 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 4, 2015	/s/ Steven Q. DeVinck Steven Q. DeVinck Senior Vice President and Chief Financial Officer
August 4, 2015	/s/ Steven W. Morris Steven W. Morris Controller