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

Form 10-K

(Mark One)

☒ Annual Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the fiscal year ended **December 31, 2015**

☐ 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)	(I.R.S. Employer Identification No.)

30 West Superior Street, Duluth, Minnesota 55802-2093

(Address of principal executive offices, including zip code)

(218) 279-5000

(Registrant's telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, without par value	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act:

None

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

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Website, 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). Yes ☒ No ☐

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, 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 ☒ 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 ☐ No ☒

The aggregate market value of voting stock held by nonaffiliates on June 30, 2015, was $2,256,186,129.

As of February 1, 2016, there were 49,111,849 shares of ALLETE Common Stock, without par value, outstanding.

Documents Incorporated By Reference

Portions of the Proxy Statement for the 2016 Annual Meeting of Shareholders are incorporated by reference in Part III.

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Definitions

The following abbreviations or acronyms are used in the text. References in this report to “we,” “us” and “our” are to ALLETE, Inc. and its subsidiaries, collectively.

Abbreviation or Acronym	Term
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
ALLETE Transmission Holdings	ALLETE Transmission Holdings (formerly Rainy River Energy Corporation - Wisconsin)
ArcelorMittal	ArcelorMittal USA, Inc.
ATC	American Transmission Company LLC
Basin	Basin Electric Power Cooperative
Bison	Bison Wind Energy Center
BNI Energy	BNI Coal, Ltd. d/b/a BNI Energy
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	Environmental Protection Agency
ESOP	Employee Stock Ownership Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Form 8-K	ALLETE Current Report on Form 8-K
Form 10-K	ALLETE Annual Report on Form 10-K
Form 10-Q	ALLETE Quarterly Report on Form 10-Q
GAAP	Accounting Principles Generally Accepted in the United States
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
IRP	Integrated Resource Plan
Item ___	Item ___ of this Form 10-K
kV	Kilovolt(s)
kWh	Kilowatt-hour
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
MBtu	Million British thermal units

Definitions (continued)

Abbreviation or Acronym	Term
Mesabi Nugget	Mesabi Nugget Delaware, 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.
Moody's	Moody's Investors Service, Inc.
MPCA	Minnesota Pollution Control Agency
MPUC	Minnesota Public Utilities Commission
MW / MWh	Megawatt(s) / Megawatt-hour(s)
NAAQS	National Ambient Air Quality Standards
NDPSC	North Dakota Public Service Commission
NERC	North American Electric Reliability Corporation
NOL	Net Operating Loss
Non-residential	Retail and 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-K
NPDES	National Pollutant Discharge Elimination System
NYSE	New York Stock Exchange
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
RSOP	Retirement Savings and Stock Ownership Plan
SEC	Securities and Exchange Commission
SIP	State Implementation Plan
SO_2	Sulfur Dioxide
Square Butte	Square Butte Electric Cooperative
Standard & Poor's	Standard & Poor's Ratings Services
SWL&P	Superior Water, Light and Power Company
Taconite Harbor	Taconite Harbor Energy Center
Taconite Ridge	Taconite Ridge 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
TransAlta	TransAlta Energy Marketing (U.S.) Inc.
U.S.	United States of America
U.S. Water Services	U.S. Water Services Holding Company and its subsidiaries
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 meaning) are not statements of historical facts and may be forward-looking.

In connection with the safe harbor provisions of the Private Securities Litigation Reform Act of 1995, we are 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-K, 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;
- changes in and compliance with laws and regulations;
- changes in tax rates or policies or in rates of inflation;
- 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;
- changes in operating expenses and capital expenditures and our ability to raise revenues from our customers in regulated rates or sales price increases at our Energy Infrastructure and Related Services businesses;
- the impacts of commodity prices on ALLETE and our customers;
- our ability to attract 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;
- population growth rates and demographic patterns;
- 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;
- effects of competition, including competition for retail and wholesale customers;
- effects of restructuring initiatives in the electric industry;
- the impacts on our Regulated Operations segment of climate change and future regulation to restrict the emissions of greenhouse gases;
- effects of increased deployment of distributed low-carbon electricity generation resources;
- the impacts of laws and regulations related to renewable and distributed generation;
- pricing, availability and transportation of fuel and other commodities and the ability to recover the costs of such commodities;
- our current and potential industrial and municipal customers' ability to execute announced expansion plans;
- real estate market conditions where our legacy Florida real estate investment is located may not improve;
- the success of efforts to realize value from, invest in, and develop new opportunities in, our Energy Infrastructure and Related Services businesses; and
- factors affecting Energy Infrastructure and Related Services businesses, including fluctuations in the volume of customer orders, unanticipated cost increases, changes in legislation and regulations impacting the industries in which the customers served operate, the effects of weather, credit worthiness of customers, ability to obtain materials required to perform services, and changing market conditions.

Additional disclosures regarding factors that could cause our results or performance to differ from those anticipated by this report are discussed in Item 1A under the heading "Risk Factors" beginning on page 25 of this Form 10-K. Any forward-looking statement speaks only as of the date on which such statement is made, and we undertake no obligation to update any forward-looking statement to reflect events or circumstances after the date on which that statement is made or to reflect the occurrence of unanticipated events. New factors emerge from time to time, and it is not possible for management to predict all of these factors, nor can it assess the impact of each of these factors on the businesses of ALLETE or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statement. Readers are urged to carefully review and consider the various disclosures made by ALLETE in this Form 10-K and in other reports filed with the SEC that attempt to identify the risks and uncertainties that may affect ALLETE's business.

Part I

Item 1. Business

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 145,000 retail customers. Minnesota Power also has 16 non-affiliated municipal customers in Minnesota. SWL&P is a Wisconsin utility and a wholesale customer of Minnesota Power. SWL&P provides regulated electric, natural gas and water service in northwestern Wisconsin to approximately 15,000 electric customers, 13,000 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.

ALLETE Clean Energy was established in 2011, and focuses on developing, acquiring and operating clean and renewable energy projects. ALLETE Clean Energy currently owns and operates, in four states, approximately 535 MW of nameplate capacity wind energy generation that are under long-term power sales agreements. In addition, ALLETE Clean Energy constructed a 107 MW wind energy facility for sale to Montana-Dakota Utilities; construction and sale were completed in 2015.

U.S. Water Services is our integrated water management company which was acquired on February 10, 2015.

Corporate and Other is comprised of BNI Energy, our coal mining operations in North Dakota, ALLETE Properties, our legacy Florida real estate investment, 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 December 31, 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.

Year Ended December 31	**2015**	**2014**	**2013**
Consolidated Operating Revenue – Millions *(a)*	$1,486.4	$1,136.8	$1,018.4
Percentage of Consolidated Operating Revenue			
Regulated Operations	67%	88%	91%
ALLETE Clean Energy *(a)(b)*	18%	3%	—
U.S. Water Services *(c)*	8%	—	—
Corporate and Other	7%	9%	9%
	100%	100%	100%

(a) Includes the construction and sale of a wind energy facility by ALLETE Clean Energy to Montana-Dakota Utilities for $197.7 million in 2015. (See Note 7. Acquisitions.)

(b) Reflects operations acquired in conjunction with the ALLETE Clean Energy wind energy facilities acquisitions. (See Note 7. Acquisitions.)

(c) U.S. Water Services was acquired on February 10, 2015. (See Note 7. Acquisitions.)

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

REGULATED OPERATIONS

Electric Sales / Customers

Regulated Utility Kilowatt-hours Sold Year Ended December 31	2015	%	2014	%	2013	%
Millions						
Retail and Municipal						
Residential	1,113	8	1,204	9	1,177	9
Commercial	1,462	10	1,468	10	1,455	11
Industrial	6,635	46	7,487	54	7,338	55
Municipal	833	6	864	6	999	8
Total Retail and Municipal	10,043	70	11,023	79	10,969	83
Other Power Suppliers	4,310	30	2,904	21	2,278	17
Total Regulated Utility Kilowatt-hours Sold	14,353	100	13,927	100	13,247	100

Industrial Customers. In 2015, industrial customers represented 46 percent of total regulated utility kilowatt-hour sales. Our industrial customers are primarily in the taconite mining, iron concentrate, paper, pulp and secondary wood products, and pipeline industries.

Industrial Customer Kilowatt-hours Sold Year Ended December 31	2015	%	2014	%	2013	%
Millions						
Taconite/Iron Concentrate	4,000	60	4,880	65	4,851	66
Paper, Pulp and Secondary Wood Products	1,456	22	1,499	20	1,505	21
Pipelines and Other Industrial	1,179	18	1,108	15	982	13
Total Industrial Customer Kilowatt-hours Sold	6,635	100	7,487	100	7,338	100

Eight Minnesota Power taconite and iron concentrate customers produce approximately 77 percent of the iron ore produced in the U.S. according to the U.S. Geological Survey's 2012 Minerals Yearbook published in September 2014. Sales to taconite customers and iron concentrate customers represented 4,000 million kilowatt-hours, or 60 percent, of total industrial customer kilowatt-hour sales in 2015. Taconite, an iron-bearing rock of relatively low iron content, is abundantly available in northern Minnesota and an important domestic source of raw material for the steel industry. Taconite processing plants use large quantities of electric power to grind the iron-bearing rock, and agglomerate and pelletize the iron particles into taconite pellets. Iron concentrate reclamation facilities also use large quantities of electricity to extract and process iron-bearing tailings left from previous mining operations to produce iron ore concentrate.

Minnesota Power provides electric service to five taconite customers capable of producing up to approximately 41 million tons of taconite pellets annually. Four of these customers are Large Power Customers (see *Large Power Customer Contracts*). The fifth is Northshore Mining, owned and operated by Cliffs Natural Resources Inc., which self-generates a majority of its power, and is capable of producing approximately 6 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. Minnesota Power also provides electric service to three iron concentrate facilities capable of producing up to approximately 4 million tons of iron concentrate per year. Iron concentrate is used in the production of taconite pellets.

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 71 percent of capacity in 2015 (77 percent in 2014 and in 2013). Many steel producers reduced production in 2015, citing higher levels of imports and lower prices. Some Minnesota taconite and iron concentrate producers reduced production in 2015 in response to declining U.S. steel production.

REGULATED OPERATIONS (Continued)
Industrial Customers (Continued)

The following table reflects Minnesota Power's taconite customers' production levels for the past ten years.

Minnesota Power Taconite Customer Production

Year	Tons (Millions)
2015*	30
2014	39
2013	37
2012	39
2011	39
2010	35
2009	17
2008	39
2007	38
2006	39

Source: Minnesota Department of Revenue 2015 Mining Tax Guide for years 2006 - 2014.
** Preliminary data from the Minnesota Department of Revenue.*

Minnesota Power's 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 Minnesota Power's 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 Minnesota Power to file a rate case to recover lost revenue.

In addition to serving the taconite industry, Minnesota Power serves a number of customers in the paper, pulp and secondary wood products industry, which represented 1,456 million kilowatt-hours, or 22 percent, of total industrial customer kilowatt-hour sales in 2015. The four major paper and pulp mills we serve reported operating at, or near, full capacity in 2015. In September 2014, Boise, Inc. (Boise) provided the required one-year written notice of its intent to install additional generation at its International Falls, Minnesota, paper mill which was completed in 2015. Boise's reduction in demand is not expected to have a material impact on the Company's consolidated financial position, results of operations, or cash flows.

Large Power Customer Contracts. Minnesota Power has 9 Large Power Customer contracts, each serving requirements of 10 MW or more of customer load. The customers consist of five taconite producing facilities (two of which are owned by one company and are served under a single contract), two concentrate reclamation facilities (both of which are owned by one company and are served under a single contract), and four paper and pulp mills.

Large Power Customer contracts require Minnesota Power to have a certain amount of generating capacity available. In turn, each Large Power Customer is required to pay a minimum monthly demand charge that covers the fixed costs associated with having this capacity available to serve the customer, including a return on common equity. Most contracts allow customers to establish the level of megawatts subject to a demand charge on a four-month basis and require that a portion of their megawatt needs be committed on a take-or-pay basis for at least a portion of the term of the agreement. In addition to the demand charge, each Large Power Customer is billed an energy charge for each kilowatt-hour used that recovers the variable costs incurred in generating electricity. Three of the Large Power Customers have interruptible service which provides a discounted demand rate in exchange for the ability to interrupt the customers during system emergencies. Minnesota Power also provides incremental production service for customer demand levels above the contractual take-or-pay levels. There is no demand charge for this service and energy is priced at an increment above Minnesota Power's cost. Incremental production service is interruptible.

Large Power Customer Contracts (Continued)

All contracts with Large Power Customers continue past the contract termination date unless the required advance notice of cancellation has been given. The required advance notice of cancellation varies from one to four years. Such contracts minimize the impact on earnings that otherwise would result from significant reductions in kilowatt-hour sales to such customers. Large Power Customers are required to take all of their purchased electric service requirements from Minnesota Power for the duration of their contracts. The rates and corresponding revenue associated with capacity and energy provided under these contracts are subject to change through the same regulatory process governing all retail electric rates. (See Item 1. Business – Regulated Operations – Regulatory Matters – Electric Rates.)

Minnesota Power, as permitted by the MPUC, requires its taconite-producing Large Power Customers to pay weekly for electric usage based on monthly energy usage estimates. These customers receive estimated bills based on Minnesota Power's estimate of the customer's energy usage, forecasted energy prices, and fuel clause adjustment estimates. Minnesota Power's four taconite-producing Large Power Customers have generally predictable energy usage on a week-to-week basis, and any differences that occur are trued-up the following month.

Contract Status for Minnesota Power Large Power Customers
As of February 1, 2016

Customer	Industry	Location	Ownership	Earliest Termination Date
ArcelorMittal USA, Inc. – Minorca Mine *(a)*	Taconite	Virginia, MN	ArcelorMittal S.A.	December 31, 2025
Hibbing Taconite Co. *(b)*	Taconite	Hibbing, MN	62.3% ArcelorMittal S.A. 23.0% Cliffs Natural Resources Inc. 14.7% USS Corporation	January 31, 2020
United Taconite LLC *(b)*	Taconite	Eveleth, MN	Cliffs Natural Resources Inc.	January 31, 2020
USS Corporation (USS – Minnesota Ore) *(b)(c)*	Taconite	Mt. Iron, MN and Keewatin, MN	USS Corporation	January 31, 2020
Boise, Inc.	Paper	International Falls, MN	Packaging Corporation of America	December 31, 2023
UPM, Blandin Paper Mill *(b)*	Paper	Grand Rapids, MN	UPM-Kymmene Corporation	January 31, 2020
NewPage Corporation *(d)*	Paper and Pulp	Duluth, MN	Verso Corporation	December 31, 2022
Sappi Cloquet LLC *(b)*	Paper and Pulp	Cloquet, MN	Sappi Limited	January 31, 2020
Magnetation, LLC *(e)*	Iron Concentrate	Coleraine, MN and Bovey, MN	50.1% Magnetation, Inc. 49.9% AK Steel Corporation	December 31, 2025

(a) In November 2015, Minnesota Power and ArcelorMittal USA, Inc. signed a new 10-year electric service agreement through December 31, 2025, which was approved by the MPUC in an order dated February 2, 2016.
(b) The contract will terminate four years from the date of written notice from either Minnesota Power or the customer. No notice of contract cancellation has been given by either party. Thus, the earliest date of cancellation is January 31, 2020.
(c) USS Corporation owns both the Minntac Plant in Mountain Iron, MN, and the Keewatin Taconite Plant in Keewatin, MN.
(d) On January 7, 2015, Verso Corporation acquired NewPage Corporation. This acquisition does not impact Minnesota Power's electric service agreement with NewPage Corporation. On January 26, 2016, Verso Corporation announced that it had filed voluntary petitions for reorganization under Chapter 11 of the Bankruptcy Code. (See Item 7. Management's Discussion and Analysis – Outlook – Industrial Customers and Prospective Additional Load.)
(e) 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, with a term through at least December 31, 2025. This Agreement was approved by the MPUC in an order dated February 2, 2016, and is subject to bankruptcy court approval. (See Item 7. Management's Discussion and Analysis – Outlook – Industrial Customers and Prospective Additional Load.)

Residential and Commercial Customers. In 2015, residential and commercial customers represented 18 percent of total regulated utility kilowatt-hour sales. Minnesota Power provides regulated utility electric service in northeastern Minnesota to approximately 144,000 residential and commercial customers. SWL&P provides regulated electric, natural gas and water service in northwestern Wisconsin to approximately 15,000 electric customers, 13,000 natural gas customers and 10,000 water customers.

Municipal Customers. In 2015, municipal customers represented 6 percent of total regulated utility kilowatt-hour sales. Minnesota Power has 16 non-affiliated municipal customers in Minnesota.

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 agreement with one other municipal customer is 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 Minnesota Power's 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.

In September 2015, Minnesota Power amended its wholesale electric contracts with 14 municipal customers, extending the contract terms through December 31, 2024. These contracts include fixed capacity charges through 2018; beginning in 2019, the capacity charge will not increase by more than two percent or decrease by more than negative one percent from the previous year's capacity charge and will be determined using a cost-based formula methodology. The base energy charge for each year of the contract term will be set each January 1, subject to monthly adjustment, and is also determined using a cost-based formula methodology.

All of the wholesale contracts include a termination clause requiring a three-year notice to terminate. In January 2016, one of Minnesota Power's municipal customers provided notice of its intent to terminate its contract effective June 30, 2019. Minnesota Power currently provides approximately 29 MW of average monthly demand to this customer. Under the Nashwauk Public Utilities Commission agreement, no termination notice may be given prior to June 30, 2025. The remaining 14 municipal customers may not give termination notices prior to December 31, 2021.

Other Power Suppliers. The Company also enters into off-system sales with Other Power Suppliers. These sales are sold at market-based prices into the MISO market on a daily basis or through bilateral agreements of various durations.

Basin Power Sales Agreements. Minnesota Power has an agreement to sell 100 MW of capacity and energy to Basin for a ten-year period which expires in April 2020. The capacity charge is based on a fixed monthly schedule with a minimum annual escalation provision. The energy charge is based on a fixed monthly schedule and provides for annual escalation based on the cost of fuel. The agreement allows Minnesota Power to recover a pro rata share of increased costs related to emissions that occur during the last five years of the contract. On July 9, 2015, Minnesota Power entered into an additional agreement to sell 100 MW of capacity only to Basin at fixed rates for a two-year period beginning in June 2016.

Minnkota Power Sales Agreement. Minnesota Power has a power sales agreement with Minnkota Power, which commenced June 1, 2014. Under the power sales agreement, Minnesota Power is selling a portion of its entitlement 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. Of Minnesota Power's 50 percent output entitlement, it sold to Minnkota Power approximately 28 percent in 2015 (23 percent in 2014). (See Note 12. Commitments, Guarantees and Contingencies.)

Seasonality

The operations of our industrial customers, which make up a large portion of our sales portfolio, are not typically subject to significant seasonal variations. (See *Electric Sales / Customers.*) As a result, Minnesota Power is generally not subject to significant seasonal fluctuations in electric sales.

Power Supply

In order to meet its customers' electric requirements, Minnesota Power utilizes a mix of its own generation and purchased power. At December 31, 2015, Minnesota Power's generation is primarily coal-fired, but also includes approximately 180 MW of natural gas-fired and biomass co-fired generation, 120 MW of hydroelectric generation, and 522 MW of nameplate capacity wind energy generation. Purchased power consists of long-term coal, wind and hydro PPAs as well as market purchases. The following table reflects Minnesota Power's generating capabilities as of December 31, 2015, and total electrical output for 2015. Minnesota Power had an annual net peak load of 1,631 MW on January 4, 2015.

Regulated Utility Power Supply	Unit No.	Year Installed	Net Capability		Year Ended December 31, 2015 Generation and Purchases	
			MW		MWh	%
Coal-Fired						
Boswell Energy Center	1	1958	67			
in Cohasset, MN	2	1960	67			
	3	1973	364			
	4	1980	468	*(a)*		
			966		6,265,756	42.8
Laskin Energy Center in Hoyt Lakes, MN	1 & 2	1953	—	*(b)*	86,046	0.6
Taconite Harbor Energy Center	1	1957	77			
in Schroeder, MN	2	1957	77			
	3	1967	—	*(b)*		
			154		1,051,950	7.2
Total Coal-Fired			1,120		7,403,752	50.6
Biomass/Coal/Natural Gas						
Hibbard Renewable Energy Center in Duluth, MN	3 & 4	1949, 1951	63		973	—
Cloquet Energy Center in Cloquet, MN	5	2001	22		115,987	0.8
Laskin Energy Center in Hoyt Lakes, MN *(b)*	1 & 2	1953	95		3,282	—
Total Biomass/Coal/Natural Gas			180		120,242	0.8
Hydro *(c)*						
Group consisting of ten stations in MN	Multiple	Multiple	120		424,119	2.9
Wind *(d)*						
Taconite Ridge Energy Center in Mt. Iron, MN	Multiple	2008	25		67,415	0.5
Bison Wind Energy Center in Oliver and Morton Counties, ND	Multiple	2010-2014	497		1,539,600	10.5
Total Wind			522		1,607,015	11.0
Total Company Generation			1,942		9,555,128	65.3
Long-Term Purchased Power						
Lignite Coal - Square Butte near Center, ND *(e)*					1,660,101	11.4
Wind - Oliver County, ND					334,836	2.3
Hydro - Manitoba Hydro in Manitoba, Canada					310,572	2.1
Total Long-Term Purchased Power					2,305,509	15.8
Other Purchased Power *(f)*					2,771,470	18.9
Total Purchased Power					5,076,979	34.7
Total			1,942		14,632,107	100.0

(a) *Boswell Unit 4 net capability shown above reflects Minnesota Power's ownership percentage of 80 percent. WPPI Energy owns 20 percent of Boswell Unit 4. (See Note 4. Jointly-Owned Facilities and Projects.)*

(b) *Laskin Energy Center was converted from coal to natural gas in June 2015 and Taconite Harbor Unit 3 was retired in May 2015 as outlined in Minnesota Power's 2013 IRP. Future plans for Taconite Harbor are included in Minnesota Power's 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 at Taconite Harbor in 2020. (See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Outlook – EnergyForward.)*

(c) *Hydro consists of ten stations with 34 generating units and a total nameplate capacity of 120 MW. Thomson returned to full production in the fourth quarter of 2015.*

(d) *Taconite Ridge consists of 10 wind turbine generator units with a total nameplate capacity of 25 MW. The Bison Wind Energy Center consists of 165 wind turbine generator units, with a total nameplate capacity of 497 MW.*

(e) *Minnesota Power has a power sales agreement with Minnkota Power, which commenced June 1, 2014. Under the power sales agreement, Minnesota Power is selling a portion of its entitlement from Square Butte to Minnkota Power. (See Electric Sales / Customers.)*

(f) *Includes short-term market purchases in the MISO market and from Other Power Suppliers.*

Fuel. Minnesota Power purchases low-sulfur, sub-bituminous coal from the Powder River Basin region located in Montana and Wyoming. Coal consumption in 2015 for electric generation at Minnesota Power's coal-fired generating stations was 4.4 million tons. As of December 31, 2015, Minnesota Power had coal inventories of 1.6 million tons (1.0 million tons as of December 31, 2014). Minnesota Power's coal supply agreements have expiration dates through 2016 for a significant portion of its coal requirements and 2019 for a portion of its coal requirements. In 2016, Minnesota Power expects to obtain coal under these coal supply agreements and in the spot market. Minnesota Power also continues to explore other future coal supply options and believes that adequate supplies of low-sulfur, sub-bituminous coal will continue to be available.

On January 11, 2016, one of Minnesota Power's coal suppliers, Arch Coal, Inc. (Arch Coal), announced that it had filed voluntary petitions for reorganization under Chapter 11 of the Bankruptcy Code and that it had reached an agreement with the majority of its senior lenders on the terms of a financial restructuring. The United States Bankruptcy Court for the Eastern District of Missouri authorized Arch Coal to enter into and perform under coal contracts in the ordinary course of business.

Minnesota Power anticipates receiving its contracted fuel from Arch Coal in 2016 and beyond. In the event that circumstances would change, Minnesota Power purchases fuel for its power plants from four large coal producers and believes there are adequate supplies in the marketplace to procure fuel from alternative sources, should it be necessary. Additionally, Minnesota Power has approximately 1.6 million tons of coal inventories as of December 31, 2015 (4.4 million tons consumed in 2015).

Minnesota Power also has transportation agreements in place for the delivery of a significant portion of its coal requirements. These transportation agreements have expiration dates through 2018. The delivered costs of fuel for Minnesota Power's generation are recoverable from Minnesota Power's utility customers through the fuel adjustment clause.

Coal Delivered to Minnesota Power **Year Ended December 31**	**2015**	**2014**	**2013**
Average Price per Ton	$27.00	$26.52	$28.90
Average Price per MBtu	$1.49	$1.47	$1.60

Long-Term Purchased Power. Minnesota Power has contracts to purchase capacity and energy from various entities, including output from certain coal, wind and hydro generating facilities.

Square Butte PPA. Under the long-term agreement with Square Butte, which expires at the end of 2026, Minnesota Power is entitled to 50 percent of the output of a 455-MW coal-fired generating unit located near Center, North Dakota. (See Note 12. Commitments, Guarantees and Contingencies.) BNI Energy supplies lignite coal to Square Butte. This lignite supply is sufficient to provide fuel for the anticipated useful life of the generating unit. Square Butte's cost of lignite burned in 2015 was approximately $1.55 per MBtu. (See *Electric Sales / Customers – Minnkota Power Sales Agreement*.)

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 Minnesota Power only pays for energy as it is delivered.

Manitoba Hydro PPAs. Minnesota Power has five long-term PPAs with Manitoba Hydro. The first PPA 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. Under the second PPA, Minnesota Power is purchasing 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 a third PPA. This 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. In September 2015, Manitoba Hydro submitted the final preferred route and EIS for the additional transmission capacity in Canada to the Manitoba Conservation and Water Stewardship for regulatory approval. Construction of Manitoba Hydro's hydroelectric generation facility commenced in 2014. (See *Transmission and Distribution – Great Northern Transmission Line*.) 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 fourth 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 PPA was approved by the MPUC in an order dated January 30, 2015, and is subject to the construction of the GNTL.

In October 2015, Minnesota Power and Manitoba Hydro signed a fifth PPA that provides for Minnesota Power to purchase 50 MW of capacity at fixed prices. The PPA begins in June 2017 and expires in May 2020.

Great River Energy PPAs. In August 2014, January 2015 and October 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, 50 MW of capacity only under the second PPA, and 50 MW of capacity only under the third PPA. The first and second PPAs begin in June 2016 and expire in May 2020, and the third PPA begins in June 2017 and expires in May 2020. All of these 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.

TransAlta PPAs. In September 2015, Minnesota Power and TransAlta signed PPAs that provide for Minnesota Power to purchase 50 MW of energy during off-peak hours and 100 MW of energy during on-peak hours beginning in January 2017 and expiring through December 2019. The energy prices are fixed throughout the terms of the PPAs.

Transmission and Distribution

We have electric transmission and distribution lines of 500 kV (8 miles), 345 kV (242 miles), 250 kV (465 miles), 230 kV (765 miles), 161 kV (43 miles), 138 kV (130 miles), 115 kV (1,268 miles) and less than 115 kV (6,295 miles). We own and operate 177 substations with a total capacity of 10,980 megavoltamperes. Some of our transmission and distribution lines interconnect with other utilities.

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 in service. Minnesota Power previously participated in two additional CapX2020 projects which were completed and placed in 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 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, Minnesota Power's portion of the investments and expenditures for the project are eligible for cost recovery under its existing transmission cost recovery rider and are anticipated to be included in future transmission factor filings. In an order dated December 17, 2015, the FERC approved our request to recover on construction work in progress related to the GNTL from Minnesota Power's wholesale customers. 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 October 30, 2015, the Minnesota Department of Commerce and the U.S. Department of Energy released the final EIS for the GNTL. On January 4, 2016, an administrative law judge recommended approval of the route permit for the GNTL. A final decision on the route permit by the MPUC is expected in the first quarter of 2016. Manitoba Hydro must also obtain regulatory and governmental approvals related to a new transmission line in Canada. In September 2015, Manitoba Hydro submitted the final preferred route and EIS for the transmission line in Canada to the Manitoba Conservation and Water Stewardship for regulatory approval. Construction of Manitoba Hydro's hydroelectric generation facility commenced in 2014. Upon receipt of all applicable permits and approvals, construction of the GNTL is expected to begin by 2017 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

Our wholly-owned subsidiary, ALLETE Transmission Holdings, 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. We account for our investment in ATC under the equity method of accounting. As of December 31, 2015, our equity investment in ATC was $124.5 million ($121.1 million at December 31, 2014). (See Note 6. Investment in ATC.)

Our equity earnings in ATC for the year ended December 31, 2015, were $16.3 million and reflected a $5.2 million reduction related to complaints filed with the FERC by several customer groups located within the MISO service area; of which $2.4 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. On December 29, 2015, a federal administrative law judge ruled that the MISO transmission users have been charged an unreasonable base return on equity and proposed a reduction to 10.32 percent, subject to approval or adjustment by the FERC. A final decision from the FERC on the administrative law judge's recommendation is currently expected in 2016. 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).

ATC's 10-year transmission assessment, which covers the years 2015 through 2024, identifies a need for between $3.7 billion and $4.5 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.

ATC and Duke Energy Corporation are partners in a joint venture, Duke-American Transmission Co. (DATC) which builds, owns and operates electric transmission facilities in North America. DATC is subject to the rules and regulations of the FERC, various independent system operators and state regulatory authorities.

Properties

Our Regulated Operations businesses own office and service buildings, an energy control center, repair shops and storerooms in various localities. All of the electric plants are subject to mortgages, which collateralize the outstanding first mortgage bonds of Minnesota Power and SWL&P. Most of the generating plants and substations are located on real property owned by Minnesota Power or SWL&P, subject to the lien of a mortgage, whereas most of the electric lines are located on real property owned by others with appropriate easement rights or necessary permits from governmental authorities. WPPI Energy owns 20 percent of Boswell Unit 4. WPPI Energy has the right to use our transmission line facilities to transport its share of Boswell generation. (See Note 4. Jointly-Owned Facilities and Projects.)

REGULATED OPERATIONS (Continued)

Regulatory Matters

We are subject to the jurisdiction of various regulatory authorities and other organizations. The MPUC has regulatory authority over Minnesota Power's retail service area in Minnesota, retail rates, retail services, capital structure, issuance of securities and other matters. The FERC has jurisdiction over the licensing of hydroelectric projects, the establishment of rates and charges for transmission of electricity in interstate commerce and electricity sold at wholesale (including the rates for Minnesota Power's municipal customers), natural gas transportation, certain accounting and record-keeping practices, certain activities of our regulated utilities, and the operations of ATC. The NERC has been certified by the FERC as the national electric reliability organization and has jurisdiction over certain aspects of our Regulated Operations' generation and transmission operations, including cybersecurity relating to generation and transmission reliability. The PSCW has regulatory authority over SWL&P's retail sales of electricity, natural gas, water, issuances of securities, and other matters. The NDPSC has jurisdiction over site and route permitting of generation and transmission facilities necessary for construction in North Dakota.

Electric Rates. All rates and contract terms in our Regulated Operations are subject to approval by applicable regulatory authorities. Minnesota Power designs its retail electric service rates based on cost of service studies under which allocations are made to the various classes of customers as approved by the MPUC. Nearly all retail sales include billing adjustment clauses, which adjust electric service rates for changes in the cost of fuel and purchased energy, recovery of current and deferred conservation improvement program expenditures and recovery of certain environmental, transmission and renewable expenditures.

Minnesota Public Utilities Commission.

2010 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. Subsequent to this last order, and as authorized by the MPUC, Minnesota Power has increased revenue under cost recovery riders for environmental, renewable and transmission investments. (See *Transmission Cost Recovery Rider, Renewable Cost Recovery Rider and Boswell Mercury Emissions Reduction Plan*.) Revenue from cost recovery riders was $86.0 million in 2015 ($69.9 million in 2014 and $40.5 million in 2013).

Energy-Intensive Trade-Exposed (EITE) Customer Rates. The Minnesota Legislature enacted EITE customer ratemaking legislation in June 2015. The legislation establishes that it is the energy policy of the state to have competitive rates for certain industries such as mining and forest products. On November 13, 2015, Minnesota Power filed a rate schedule for EITE customers and a corresponding rider for EITE cost recovery with the MPUC. The rate proposal is revenue, and cash flow, neutral. On February 11, 2016, the MPUC dismissed the petition without prejudice, offering Minnesota Power the option to refile the petition with additional information or initiate a new petition. Minnesota Power is evaluating the MPUC's decision.

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 3, 2016, 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. 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 the existing transmission cost recovery rider. Minnesota Power anticipates including its portion of the investments and expenditures for the GNTL in future transmission factor filings to include updated billing rates on customer bills. (See *Transmission and Distribution – Great Northern Transmission Line.*)

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 the Bison Wind Energy Center were approved by the MPUC in an order dated May 22, 2015. In November 2014, Minnesota Power filed a renewable resources factor filing which includes updated costs associated with Bison. Upon approval of the filing, Minnesota Power 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 Minnesota Power's petition seeking cost recovery for investments and expenditures related to the restoration and repair of Thomson through a renewable resources rider.

Annual Automatic Adjustment (AAA) of Charges. Minnesota Power's AAA filings made in 2012, 2013, 2014 and 2015 are pending MPUC approval, and represent approximately $700 million in retail fuel cost recovery collected but subject to refund. These filings have historically been approved, and Minnesota Power currently expects full recovery of amounts represented by each AAA filing, although we cannot predict the outcome of the filings at the MPUC.

Integrated Resource Plan (IRP). In a November 2013 order, the MPUC approved Minnesota Power's 2013 IRP which detailed its *EnergyForward* strategic plan, announced in January 2013. Significant elements of the *EnergyForward* plan include major wind investments in North Dakota which were completed in the fourth quarter of 2014, the installation of emissions control technology at Boswell Unit 4 completed in December 2015, 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 September 1, 2015, Minnesota Power filed its 2015 IRP with the MPUC which contains the next steps in its *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. (See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Outlook – EnergyForward.)

Boswell Mercury Emissions Reduction Plan. In August 2012, Minnesota Power filed its mercury emissions reduction plan for Boswell Unit 4 with the MPUC and the MPCA in order to comply with the Minnesota Mercury Emissions Reduction Act and the Federal MATS rule. Construction on the project to implement the Boswell Unit 4 mercury emissions reduction plan was completed with project costs totaling approximately $220 million through December 31, 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 an order dated August 24, 2015. On September 30, 2015, Minnesota Power filed an updated environmental improvement factor filing which included updated costs associated with Boswell Unit 4. Upon approval of the filing, Minnesota Power will be authorized to include updated billing rates on customer bills.

Boswell Remaining Life Petition. On November 17, 2015, Minnesota Power filed a petition with the MPUC for approval to extend Boswell's remaining life to 2050 for all units and utilize the existing environmental improvement rider to credit a portion of the depreciation expense savings to customers. The extension request is based on the significant multi-emissions retrofit work done at Boswell Unit 3 and Boswell Unit 4.

Conservation Improvement Program (CIP). Minnesota requires electric utilities to spend a minimum of 1.5 percent of net gross operating revenues from service provided in the state on energy CIPs each year. These investments are recovered from certain retail customers through a combination of the conservation cost recovery charge included in retail base rates and a conservation program adjustment, which is adjusted annually through the CIP consolidated filing. The MPUC allows utilities to accumulate, in a deferred account for future cost recovery, all CIP expenditures, any financial incentive earned for cost-effective program achievements, and a carrying charge on the deferred account balance. Minnesota Power refers to its conservation programs collectively as the "Power of One". In June 2013, Minnesota Power submitted a triennial filing for 2014 through 2016, which was subsequently approved by the Minnesota Department of Commerce. Minnesota Power's CIP investment goal was $7.1 million for 2015 ($6.9 million for 2014; $6.0 million for 2013), with actual spending of $6.6 million in 2015 ($7.2 million in 2014; $6.4 million in 2013). The investment goal for 2016 is $7.3 million.

Minnesota requires each utility to establish an annual energy-savings goal of 1.5 percent of annual retail energy sales. On April 1, 2015, Minnesota Power submitted its 2014 CIP filing that requested a CIP financial incentive of $6.2 million. The requested CIP financial incentive was approved by the MPUC in an order dated September 16, 2015, and was recorded as revenue and as a regulatory asset. The approved financial incentive will be recovered through customer billing rates in 2015 and 2016. In 2014 and 2013, the CIP financial incentive recognized was $8.7 million and $7.1 million, respectively. CIP financial incentives are recognized in the period in which the MPUC approves the filing. The MPUC implemented certain limitations on amounts recoverable for the utility performance incentive program for recovery years beginning in 2015.

Federal Energy Regulatory Commission. The FERC has jurisdiction over the licensing of hydroelectric projects, the establishment of rates and charges for transmission of electricity in interstate commerce and electricity sold at wholesale (including the rates for Minnesota Power's municipal and wholesale customers), natural gas transportation, certain accounting and record-keeping practices, certain activities of our regulated utilities, and the operations of ATC. FERC jurisdiction also includes enforcement of NERC mandatory electric reliability standards. Violations of FERC rules are subject to enforcement action by the FERC including financial penalties up to $1 million per day per violation.

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. On December 29, 2015, a federal administrative law judge ruled that the MISO transmission users have been charged an unreasonable base return on equity and proposed a reduction to 10.32 percent, subject to approval or adjustment by the FERC. A final decision from the FERC on the administrative law judge's recommendation is expected in 2016. As a result of these complaints filed with the FERC and the administrative law judge's recommendation, Minnesota Power has recorded an estimated refund obligation for MISO revenue of $7.2 million and an estimated refund for MISO transmission expense of $4.5 million, resulting in a reserve of $2.7 million as of December 31, 2015; $1.5 million was attributable to prior years.

Public Service Commission of Wisconsin. The PSCW has regulatory authority over SWL&P's retail sales of electricity, natural gas and water, issuances of securities and other matters. 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.

North Dakota Public Service Commission. The NDPSC has jurisdiction over site and route permitting of generation and transmission facilities in North Dakota.

Regional Organizations

Midcontinent Independent System Operator, Inc. Minnesota Power and SWL&P are members of MISO, a regional transmission organization. While Minnesota Power and SWL&P retain ownership of their respective transmission assets, their transmission networks are under the regional operational control of MISO. Minnesota Power and SWL&P take and provide transmission service under the MISO open access transmission tariff. MISO continues its efforts to oversee the safe, cost-effective delivery of electric power across all or parts of 15 states and the Canadian province of Manitoba which includes nearly 175,000 MW of generating capacity.

North American Electric Reliability Corporation. The NERC has been certified by the FERC as the national electric reliability organization. The NERC ensures the reliability of the North American bulk power system. The NERC oversees eight regional entities that establish requirements, approved by the FERC, for reliable operation and maintenance of power generation facilities and transmission systems. Minnesota Power is subject to these reliability requirements and can incur significant penalties for non-compliance.

Midwest Reliability Organization (MRO). Minnesota Power is a member of the MRO, one of the eight regional entities overseen by the NERC. MRO's primary responsibilities are to: ensure compliance with mandatory reliability standards by entities who own, operate, or use the interconnected, international Bulk Power System; conduct assessments of the grid's ability to meet electricity demand in the region; and analyze regional system events.

The MRO region spans the Canadian provinces of Saskatchewan and Manitoba, and all or parts of the states of Illinois, Iowa, Minnesota, Michigan, Montana, Nebraska, North Dakota, South Dakota and Wisconsin. The region includes more than 130 organizations that are involved in the production and delivery of power to more than 20 million people. These organizations include municipal utilities, cooperatives, investor-owned utilities, transmission system operators, a federal power marketing agency, Canadian Crown corporations, and independent power producers.

Minnesota Legislation

Renewable Energy. In February 2007, Minnesota enacted a law requiring 25 percent of electric utilities' applicable retail and municipal energy sales in Minnesota to be from renewable energy sources by 2025. The law also requires Minnesota Power to meet interim milestones of 12 percent by 2012, 17 percent by 2016 and 20 percent by 2020. The law allows the MPUC to modify or delay meeting a milestone if implementation will cause significant ratepayer cost or technical reliability issues. If a utility is not in compliance with a milestone, the MPUC may order the utility to construct facilities, purchase renewable energy or purchase renewable energy credits. Minnesota Power's 2015 IRP, which was filed with the MPUC on September 1, 2015, includes an update on its plans and progress in meeting the Minnesota renewable energy milestones through 2025. (See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Outlook – EnergyForward.)

Minnesota Power continues to execute its renewable energy strategy through key renewable projects that will ensure it meets the identified state mandate at the lowest cost for customers. Minnesota Power has exceeded the interim milestone requirements to date with approximately 27 percent of its applicable retail and municipal energy sales 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 has two solar projects under development. On August 21, 2015, Minnesota Power filed for MPUC approval of a 10 MW utility scale solar project at Camp Ripley, a Minnesota Army National Guard base and training facility near Little Falls, Minnesota. At a hearing on January 28, 2016, the MPUC approved the Camp Ripley solar project as eligible to meet the solar energy standard and for current cost recovery, subject to certain compliance requirements. On September 10, 2015, Minnesota Power filed for MPUC approval of a 1 MW community solar garden project in Saint Louis County, Minnesota. If the community solar garden project is also approved, Minnesota Power believes these projects will meet approximately one-third of the overall mandate and approximately one-fourth of the mandate related to solar photovoltaic devices with a nameplate capacity of 20 kilowatts or less. Costs associated with these projects are expected to be recovered from customers.

Energy-Intensive Trade-Exposed (EITE) Customer Rates. The Minnesota Legislature enacted EITE customer ratemaking legislation in June 2015. The legislation establishes that it is the energy policy of the state to have competitive rates for certain industries such as mining and forest products. On November 13, 2015, Minnesota Power filed a rate schedule for EITE customers and a corresponding rider for EITE cost recovery with the MPUC. The rate proposal is revenue, and cash flow, neutral. On February 11, 2016, the MPUC dismissed the petition without prejudice, offering Minnesota Power the option to refile the petition with additional information or initiate a new petition. Minnesota Power is evaluating the MPUC's decision.

Competition

Retail electric energy sales in Minnesota and Wisconsin are made to customers in assigned service territories. As a result, most retail electric customers in Minnesota do not have the ability to choose their electric supplier. Large energy users of 2 MW and above that are located outside of a municipality are allowed to choose a supplier upon MPUC approval. Minnesota Power serves 11 Large Power facilities over 10 MW, none of which have engaged in a competitive rate process. No other large commercial or small industrial customers in Minnesota Power's service territory have sought a provider outside Minnesota Power's service territory since 1994. Retail electric and natural gas customers in Wisconsin do not have the ability to choose their energy supplier. In both states, however, electricity may compete with other forms of energy. Customers may also choose to generate their own electricity, or substitute other forms of energy for their manufacturing processes.

For the year ended December 31, 2015, 6 percent of our Regulated Operations' electric energy sales were to municipal customers in Minnesota by contract. These customers have the right to seek an energy supply from any wholesale electric service provider upon contract expiration. In April 2015, Minnesota Power amended its formula-based wholesale electric sales contract with the Nashwauk Public Utilities Commission, extending the term through June 30, 2028. In September 2015, Minnesota Power amended its wholesale electric contracts with 14 of its municipal customers, extending the contract terms through December 31, 2024. In January 2016, one of Minnesota Power's municipal customers provided notice of its intent to terminate its contract effective June 30, 2019. Minnesota Power currently provides approximately 29 MW of average monthly demand to this customer. (See *Electric Sales / Customers.*)

The FERC has continued with its efforts to promote a more competitive wholesale market through open-access electric transmission and other means. As a result, our electric sales to Other Power Suppliers and our purchases to supply our retail and wholesale load are made in the competitive market.

Franchises

Minnesota Power holds franchises to construct and maintain an electric distribution and transmission system in 91 cities. The remaining cities, villages and towns served by Minnesota Power do not require a franchise to operate. SWL&P serves customers under electric, natural gas and/or water franchises in 1 city and 14 villages or towns.

ENERGY INFRASTRUCTURE AND RELATED SERVICES

ALLETE Clean Energy

ALLETE Clean Energy was established in 2011, and focuses on developing, acquiring and operating clean and renewable energy projects. ALLETE Clean Energy currently owns and operates approximately, in four states, 535 MW of nameplate capacity wind energy generation that are under long-term power sales agreements. In addition, ALLETE Clean Energy constructed a 107 MW wind energy facility for sale to Montana-Dakota Utilities; construction and sale were completed in 2015.

Wind Energy Facility	Location	Capacity MW	PPA MW	PPA Expiration
Armenia Mountain	Pennsylvania	100.5	100%	2024
Chanarambie/Viking	Minnesota	97.5		
PPA 1			12%	2018
PPA 2			88%	2023
Condon	Oregon	50	100%	2022
Lake Benton	Minnesota	104	100%	2028
Storm Lake I	Iowa	108	100%	2019
Storm Lake II	Iowa	77		
PPA 1			90%	2019
PPA 2			10%	2032

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 is located in 49 states and Canada and has an established base of approximately 4,000 customers. U.S. Water Services differentiates itself from the competition by developing synergies between established solutions in engineering, equipment, and chemical water treatment and helping customers achieve efficient and sustainable use of their water and energy systems. U.S. Water Services is a leading provider to the biofuels industry, and also serves the food and beverage, industrial, power generation, and midstream oil and gas industries. U.S. Water Services principally relies upon recurring revenue from a diverse mix of industrial customers.

CORPORATE AND OTHER

Corporate and Other is comprised of BNI Energy, our coal mining operations in North Dakota, ALLETE Properties, our legacy Florida real estate investment, 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. (See Outlook.)

BNI Energy

BNI Energy is a supplier of lignite in North Dakota, producing approximately 4 million tons annually and has lignite reserves of an estimated 650 million tons. Two electric generating cooperatives, Minnkota Power and Square Butte, presently consume virtually all of BNI Energy's production of lignite under cost-plus fixed fee coal supply agreements extending to December 31, 2037. (See Item 1. Business – Regulated Operations – Power Supply – Long-Term Purchased Power and Note 12. Commitments, Guarantees and Contingencies.) The mining process disturbs and reclaims between 200 and 250 acres per year. Laws require that the reclaimed land be at least as productive as it was prior to mining. As of December 31, 2015, BNI Energy had a $22.1 million asset reclamation obligation ($20.3 million at December 31, 2014) included in Other Non-Current Liabilities on our Consolidated Balance Sheet. These costs are included in the cost-plus fixed fee contract, for which an asset reclamation cost receivable was included in Other Non-Current Assets on our Consolidated Balance Sheet. The asset reclamation obligation is guaranteed by surety bonds and a letter of credit. (See Note 12. Commitments, Guarantees and Contingencies.)

CORPORATE AND OTHER (Continued)

ALLETE Properties

ALLETE Properties represents our legacy Florida real estate investment. 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.

In recent years, market conditions for real estate in Florida have required us to review our land inventories for impairment. In response to market conditions and recent transaction activity, during the fourth quarter of 2015 the Company reevaluated its strategy related to the real estate assets of ALLETE Properties. The revised strategy incorporates the possibility of a bulk sale of its entire portfolio which, if consummated, is likely to result in sales proceeds below the book value of the real estate assets. ALLETE also continues to pursue sales of individual parcels over time. Proceeds from such a sale would be strategically deployed to support growth in our energy infrastructure and related services businesses. ALLETE will continue to maintain key entitlements and infrastructure without making additional investments or acquisitions.

In connection with implementing the revised strategy in 2015, management evaluated its impairment analysis for its real estate assets using updated assumptions to determine estimated future net cash flows on an undiscounted basis. Future net cash flows were adjusted to consider the possibility of a bulk sale of its entire portfolio, in addition to sales over time under the existing divestiture plan. Estimated fair values were based upon current market data and pricing for individual parcels. Our impairment analysis incorporates a probability-weighted approach considering the alternative courses of sales noted above.

Based on the results of undiscounted cash flow analysis, the undiscounted future net cash flows were not adequate to recover the carrying value of the real estate assets totaling $83.3 million. Estimated fair value was derived from current market interest in the property for a bulk sale of its entire portfolio, and discounted cash flow analysis of estimated selling price for sales over time. As a result, a non-cash impairment charge of $36.3 million was recorded in 2015 to reduce the carrying value of the real estate to its estimated fair value at December 31, 2015.

If our real estate assets are sold differently than anticipated, the actual results could be materially different from our undiscounted future net cash flow analysis.

In 2014 and 2013, impairment analyses of estimated undiscounted future net cash flows were conducted based on the strategy existing at that time, and indicated that the cash flows were adequate to recover the carrying value of ALLETE Properties real estate assets. As a result, no impairment was recorded for the years ended December 31, 2014 and 2013.

ALLETE Properties' major projects are Town Center, Palm Coast Park and Ormond Crossings. Separately, the Lake Swamp wetland mitigation bank was permitted on land that was previously part of Ormond Crossings. See Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations – Outlook for more information on ALLETE Properties' land holdings.

Seller Financing. ALLETE Properties occasionally provides seller financing to certain qualified buyers. At December 31, 2015, outstanding finance receivables were $1.6 million, net of reserves, with maturities through 2017. These finance receivables accrue interest at market-based rates and are collateralized by the financed properties.

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

CORPORATE AND OTHER (Continued)

Non-Rate Base Generation

As of December 31, 2015, non-rate base generation consists of 29 MW of generation at Rapids Energy Center. In 2015, we sold 0.1 million MWh of non-rate base generation (0.1 million MWh in 2014 and in 2013).

Non-Rate Base Power Supply	Unit No.	Year Installed	Year Acquired	Net Capability (MW)
Rapids Energy Center *(a)*				
in Grand Rapids, MN				
Steam – Biomass *(b)*	6 & 7	1969, 1980	2000	27
Hydro	4 & 5	1917, 1948	2000	2

(a) The net generation is primarily dedicated to the needs of one customer.
(b) Rapids Energy Center's fuel supply is supplemented by coal.

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 or have already been promulgated by both the EPA and state authorities. Minnesota Power's facilities are subject to additional regulation under many of these proposals. In preparation and response to these regulations, Minnesota Power is reshaping its generation portfolio over time to reduce its reliance on coal, has installed cost-effective emission control technology, and advocates for sound science and policy during rulemaking implementation.

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. We anticipate that although many of the state and federal environmental regulations have been finalized, or will be finalized in the near future, potential expenditures for future environmental matters may be material and may 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. (See Note 12. Commitments, Guarantees and Contingencies.)

EMPLOYEES

At December 31, 2015, ALLETE had 1,945 employees, of which 1,923 were full-time.

Minnesota Power and SWL&P have an aggregate of 554 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 Energy has 173 employees, of which 127 are members of IBEW Local 1593. The current labor agreement with IBEW Local 1593 expires on March 31, 2019.

AVAILABILITY OF INFORMATION

ALLETE makes its SEC filings, including its annual report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and any amendments to those reports filed or furnished pursuant to Section 13(e) or 15(d) of the Securities Exchange Act of 1934, available free of charge on ALLETE's website, www.allete.com, as soon as reasonably practicable after they are electronically filed with or furnished to the SEC.

EXECUTIVE OFFICERS OF THE REGISTRANT

As of February 22, 2016, these are the executive officers of ALLETE:

Executive Officers	Initial Effective Date
Alan R. Hodnik, Age 56	
Chairman, President and Chief Executive Officer	May 10, 2011
President and Chief Executive Officer	May 1, 2010
Robert J. Adams, Age 53	
Senior Vice President – Energy-Centric Businesses and Chief Risk Officer	November 14, 2015
Vice President – Energy-Centric Businesses and Chief Risk Officer	June 23, 2014
Vice President – Business Development and Chief Risk Officer	May 13, 2008
Deborah A. Amberg, Age 50	
Senior Vice President, General Counsel and Secretary	January 1, 2006
Patrick L. Cutshall, Age 51	
Treasurer	January 1, 2016
Steven Q. DeVinck, Age 56	
Senior Vice President and Chief Financial Officer	March 3, 2014
Controller and Vice President – Business Support	December 5, 2009
David J. McMillan, Age 54	
Senior Vice President – External Affairs	January 1, 2012
Senior Vice President – Marketing, Regulatory and Public Affairs	January 1, 2006
Executive Vice President – Minnesota Power	January 1, 2006
Steven W. Morris, Age 54	
Controller	March 3, 2014

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

Mr. Morris was Director - Accounting.
Mr. Cutshall was Director - Investments and Tax; Director - Investments.

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

The present term of office of the executive officers listed above extends to the first meeting of our Board of Directors after the next annual meeting of shareholders. Both meetings are scheduled for May 10, 2016.

Item 1A. Risk Factors

The risks and uncertainties discussed below could materially affect our business, financial position, and results of operations and should be carefully considered by stakeholders. The risks and uncertainties in this section are not the only ones we face; additional risks and uncertainties that we are not presently aware of, or that we currently consider immaterial, may also affect our business operations, financial position, results of operations and cash flows. Accordingly, the risks described below should be carefully considered together with other information set forth in this report and in future reports that are filed with the SEC.

Entity-wide Risks

We rely on access to financing sources and capital markets. If we do not have access to sufficient capital in the amounts and at the times needed, our ability to execute our business plans, make capital expenditures or pursue other strategic actions that we may otherwise rely on for future growth could be adversely affected.

We rely on access to financing sources and capital markets as sources of liquidity for capital requirements not satisfied by our cash flow from operations. If we are not able to access capital on satisfactory terms, or at all, the ability to maintain our business or to implement our business plans may be adversely affected. Market disruptions or a downgrade of our credit ratings may increase the cost of borrowing or adversely affect our ability to access capital markets. Such disruptions could include a significant economic downturn, the financial distress of non-affiliated electric utility companies or financial services companies, a deterioration in capital market conditions, or volatility in commodity prices.

A deterioration in general economic conditions may have adverse impacts on our financial position, results of operations and cash flows.

If economic conditions deteriorate on a national or regional level, it may have a negative impact on the Company and our customers. This impact may include volatility and unpredictability in the demand for the products and services offered by our businesses, the loss of existing customers, tempered growth strategies, production cutbacks, or bankruptcies. It is also possible that an uncertain economy could affect expenses including pension costs, interest costs, and uncollectible accounts, or lead to reductions in the value of certain real estate and other investments.

We may be impacted by new state or federal legislation, or regulations, and compliance could have an adverse effect on our businesses.

We are subject to, and affected by, extensive state and federal legislation and regulation. We believe that our businesses comply with applicable laws and regulations. If it were determined that they failed to comply, we could become subject to fines or penalties or be required to implement additional compliance measures or actions, the cost of which could be material. Adoption of new laws, rules, regulations, principles, or practices by federal or state agencies, or changes to present laws, rules, regulations, principles, or practices and their interpretations, could have an adverse effect on our financial position, results of operations and cash flows.

The inability to attract and retain a qualified workforce including, but not limited to, executive officers, key employees and employees with specialized skills, could have an adverse effect on our operations.

The success of our business heavily depends on the leadership of our executive officers and key employees to implement our business strategy. The inability to maintain a qualified workforce including, but not limited to, executive officers, key employees and employees with specialized skills, may negatively affect our ability to service our existing or new customers, or successfully manage our business or achieve our business objectives. Personnel costs may increase due to competitive pressures or terms of collective bargaining agreements with union employees.

Market performance and other changes could decrease the value of pension and postretirement benefit plan assets, which may result in significant additional funding requirements and increased annual expenses.

The performance of the capital markets impacts the values of the assets that are held in trust to satisfy future obligations under our pension and postretirement benefit plans. We have significant obligations to these plans and the trusts hold significant assets. These assets are subject to market fluctuations and will yield uncertain returns, which may fall below our projected rates of return. A decline in the market value of the pension and postretirement benefit plan assets would increase the funding requirements under our benefit plans if asset returns do not recover. Additionally, our pension and postretirement benefit plan liabilities are sensitive to changes in interest rates. As interest rates decrease, the liabilities increase, potentially increasing benefit expense and funding requirements. Our pension and postretirement benefit plan costs are generally recoverable in our electric rates as allowed by our regulators or through our cost-plus fixed fee coal supply agreements at BNI Energy. However, there is no certainty that regulators will continue to allow recovery of these rising costs in the future.

We are exposed to significant reputation risk.

The Company and its subsidiaries could suffer negative impacts to their reputations as a result of operational incidents, violations of corporate compliance policies, regulatory violations, or other events which may result in negative customer perception and increased regulatory oversight, each of which could have an adverse effect on our financial position, results of operations and cash flows.

Catastrophic events, such as acts of war and natural disasters, may adversely affect our operations.

Catastrophic events such as fires, earthquakes, explosions, floods, ice storms, tornadoes, or similar occurrences could adversely affect the Company's facilities, operations, financial position, results of operations and cash flows. Although the Company has contingency plans and employs crisis management to respond and recover operations in the event of a severe disruption resulting from such events, these measures may not be successful. Furthermore, despite these measures, if such an occurrence were to occur, our financial position, results of operations and cash flows could be adversely affected.

We are vulnerable to acts of terrorism or cybersecurity attacks.

Our operations may be targets of terrorist activities, including cybersecurity attacks, which could disrupt our ability to produce or distribute some portion of our products. We could be subject to computer viruses, terrorism, theft and sabotage, which may also disrupt our operations and/or adversely impact our results of operations. Our businesses require the continued operation of sophisticated information technology systems and network infrastructure. Our technology systems may be vulnerable to disability, failures or unauthorized access due to hacking, viruses, acts of war or terrorism and other causes. If our technology systems were to fail or be breached and we were unable to recover in a timely manner, we may be unable to fulfill critical business functions and sensitive, confidential and other data could be compromised, which could have an adverse effect on our financial position, results of operations and cash flows.

Government challenges to our tax positions, as well as tax law changes and the inherent difficulty in quantifying potential tax effects of business decisions, could adversely affect our results of operations and liquidity.

We are required to make judgments in order to estimate tax obligations. These judgments include reserves for potential adverse outcomes for tax positions that may be challenged by tax authorities. The obligations, which include income taxes and taxes other than income taxes, involved complex matters that ultimately could be litigated. We also estimate our ability to use tax benefits, including those in the form of carryforwards and tax credits that are recorded as deferred tax assets on our Consolidated Balance Sheet. A disallowance of these tax benefits could have an adverse impact on our financial position, results of operations and cash flows.

We plan to utilize our carryforwards and tax credits in the future to reduce our income tax obligations. If we cannot generate enough taxable income in the future to utilize all of our carryforwards and tax credits before they expire, we may incur adverse charges to earnings. If the Internal Revenue Service disagrees with the deductions resulting from our tax planning strategies, our financial position, results of operations and cash flows may be adversely impacted.

Regulated Operations Risks

Our results of operations could be negatively impacted if our Large Power Customers experience an economic downturn, incur work stoppages, fail to compete effectively in the economy, experience decreased demand, or experience a decline in prices for their product.

Minnesota Power's 9 Large Power Customers accounted for 22 percent of our 2015 consolidated operating revenue (31 percent in 2014; 31 percent in 2013), of which one of these customers accounted for 7.7 percent of consolidated revenue in 2015 (11.9 percent in 2014; 12.0 percent in 2013). These customers are involved in cyclical industries that by their nature are adversely impacted by economic downturns and are subject to strong competition in the marketplace. Many of our Large Power Customers also have unionized workforces which put them at risk for work stoppages. Additionally, the North American paper and pulp industry also faces declining demand due to the impact of electronic substitution for print and changing customer needs.

Accordingly, if our customers experience an economic downturn, incur a work stoppage (including strikes, lock-outs or other events), fail to compete effectively in the economy, experience decreased demand or experience a decline in prices for their product, there could be adverse effects on their operations and, consequently, this could have a negative impact on our results of operations if we are unable to remarket at similar prices the energy that would otherwise have been sold to such Large Power Customers.

Our utility operations are subject to an extensive legal and regulatory framework under federal and state laws as well as regulations imposed by other organizations that may have a negative impact on our business and results of operations.

We are subject to an extensive legal and regulatory framework imposed under federal and state law including regulations administered by the FERC, the MPUC, the MPCA, the PSCW, the NDPSC and the EPA as well as regulations administered by other organizations including the NERC. These laws and regulations relate to allowed rates of return, capital structure, financings, rate and cost structure, acquisition and disposal of assets and facilities, construction and operation of generation, transmission and distribution facilities (including the ongoing maintenance and reliable operation of such facilities), recovery of purchased power costs and capital investments, approval of integrated resource plans and present or prospective wholesale and retail competition, among other things. Energy policy initiatives at the state or federal level could increase incentives for distributed generation, municipal utility ownership, or local initiatives could introduce generation or distribution requirements, that could change the current integrated utility model. Our transmission systems and electric generation facilities are subject to the NERC mandatory reliability standards, including cybersecurity standards. Compliance with these standards may lead to increased operating costs and capital expenditures. If it was determined that we were not in compliance with these mandatory reliability standards or other statutes, rules and orders, we could incur substantial monetary penalties and other sanctions, which could adversely affect our results of operations.

These laws and regulations significantly influence our operations and may affect our ability to recover costs from our customers. We are required to have numerous permits, licenses, approvals and certificates from the agencies and other organizations that regulate our business. We believe we have obtained the necessary permits, licenses, approvals and certificates for our existing operations and that our business is conducted in accordance with applicable laws; however, we are unable to predict the impact on our operating results from the future regulatory activities of any of these agencies and other organizations. Changes in regulations or the adoption of new regulations could have an adverse impact on our results of operations.

Our ability to obtain rate adjustments to maintain reasonable rates of return depends upon regulatory action under applicable statutes and regulations, and we cannot provide assurance that rate adjustments will be obtained or reasonable authorized rates of return on capital will be earned. Minnesota Power and SWL&P, from time to time, file rate cases with, or otherwise seek cost recovery authorization from, federal and state regulatory authorities. If Minnesota Power and SWL&P do not receive an adequate amount of rate relief in rate cases, including if rates are reduced, if increased rates are not approved on a timely basis or costs are otherwise unable to be recovered through rates, or if cost recovery is not granted at the requested level, we may experience an adverse impact on our financial position, results of operations and cash flows. We are unable to predict the impact on our business and results of operations from future legislation or regulatory activities of any of these agencies or organizations.

Our operations pose certain environmental risks that could adversely affect our financial position and results of operations, including effects of environmental laws and regulations, physical risks associated with climate change and initiatives designed to reduce the impact of GHG emissions.

We are subject to extensive environmental laws and regulations affecting many aspects of our present and future operations, including air quality, water quality and usage, waste management, reclamation, hazardous wastes, avian mortality and natural resources. These laws and regulations can result in increased capital expenditures, environmental emission allowance trading, operating and other costs, as a result of compliance, remediation, containment and monitoring obligations, particularly with regard to laws relating to power plant emissions, coal ash, water discharge and wind energy generation facilities.

These laws and regulations could restrict the output of some existing facilities, limit the use of some fuels in the production of electricity, require the installation of additional pollution control equipment, require participation in environmental emission allowance trading, and/or lead to other environmental considerations and costs, which could have an adverse impact on our business, operations and results of operations.

These laws and regulations generally require us to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals. Both governmental authorities and private parties may seek to enforce applicable environmental laws and regulations.

Existing environmental regulations may be revised and new regulations seeking to protect the environment may be adopted or become applicable to us. Revised or additional regulations which result in increased compliance costs or additional operating restrictions, particularly if those costs are not fully recoverable from customers, could have an adverse effect on our results of operations.

The scientific community generally accepts that emissions of GHG are linked to global climate change. Physical risks of climate change, such as more frequent or more extreme weather events, changes in temperature and precipitation patterns, changes to ground and surface water availability, and other related phenomena, could affect some, or all, of our operations. Severe weather or other natural disasters could be destructive, which could result in increased costs. An extreme weather event within our utility service areas can also directly affect our capital assets, causing disruption in service to customers due to downed wires and poles or damage to other operating equipment. These all have the potential to adversely affect our business and operations.

Proposals for voluntary initiatives to reduce GHGs such as CO_2, a by-product of burning fossil fuels, have been discussed within Minnesota, among a group of Midwestern states that includes Minnesota and in the United States Congress. 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. The implementation of the CAP could have an adverse impact on our results of operations if additional capital expenditures and operating costs are required and if those costs are not fully recovered from customers.

In 2014, the EPA announced a proposed rule under Section 111(d) of the Clean Air Act for existing power plants (CPP). In 2015, the EPA issued the CPP, together with a proposed federal implementation plan and a model rule for emissions trading. The CPP establishes uniform CO_2 emission performance rates for existing fossil fuel-fired and natural gas-fired combined cycle generating units, setting state-specific goals for CO_2 emissions from the power sector. State goals under the CPP include interim goals to be met over the years 2022 through 2029, as well as a final goal to be met in 2030 and thereafter. Under the CPP, each state is required to develop a state implementation plan by September 6, 2016, or by September 6, 2018, if granted an extension. The implementation of the CPP could have an adverse impact on our results of operations if additional capital expenditures and operating costs are required and if those costs are not fully recovered from customers.

There is significant uncertainty regarding whether new laws or regulations will be adopted to reduce GHGs and what effect any such laws or regulations would have on us. In 2015, coal was the primary fuel source for 77 percent of the energy produced by our generating facilities. Future limits on GHG emissions would likely require us to incur significant increases in capital expenditures and operating costs, which if significant, could result in the closure of certain coal-fired energy centers, impairment of assets, or otherwise adversely affect our results of operations, particularly if implementation costs are not fully recoverable from customers.

We cannot predict the amount or timing of all future expenditures related to environmental matters because of uncertainty as to applicable regulations or requirements. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all potentially responsible parties. Violations of certain environmental statutes, rules and regulations could expose ALLETE to third party disputes and potentially significant monetary penalties, as well as other sanctions for non-compliance.

The operation and maintenance of our electric generation and transmission facilities are subject to operational risks that could adversely affect our financial position, results of operations and cash flows.

The operation of generating facilities involves many risks, including start-up operations risks, breakdown or failure of facilities, the dependence on a specific fuel source, inadequate fuel supply, availability of fuel transportation, or the impact of unusual or adverse weather conditions or other natural events, as well as the risk of performance below expected levels of output or efficiency. A significant portion of our facilities were constructed many years ago. In particular, older generating equipment, even if maintained in accordance with good engineering practices, may require significant capital expenditures to continue operating at peak efficiency. Generation and transmission facilities and equipment are also likely to require periodic upgrades and improvements due to changing environmental standards and technological advances. We could be subject to costs associated with any unexpected failure to produce and/or deliver power, including failure caused by breakdown or forced outage, as well as repairing damage to facilities due to storms, natural disasters, wars, sabotage, terrorist acts and other catastrophic events.

Our ability to successfully and timely complete capital improvements to existing facilities or other capital projects is contingent upon many variables.

We expect to incur significant capital expenditures in making capital improvements to our existing electric generation facilities and in the development and/or construction of new transmission facilities. Should any such efforts be unsuccessful or not completed in a timely manner, we could be subject to additional costs or impairments which could have an adverse impact on our financial position and results of operation.

Our electrical generating operations may not have access to adequate and reliable transmission and distribution facilities necessary to deliver electricity to our customers.

We depend on our own transmission and distribution facilities, as well as facilities owned by other utilities, to deliver the electricity produced and sold to our customers, and to other energy suppliers. If transmission capacity is inadequate, our ability to sell and deliver electricity may be limited. We may have to forgo sales or may have to buy more expensive wholesale electricity that is available in the capacity-constrained area. In addition, any infrastructure failure that interrupts or impairs delivery of electricity to our customers could negatively impact the satisfaction of our customers, which could have an adverse impact on our business, operations and results of operations.

Our results of operations could be impacted by declining wholesale power prices.

Wholesale prices for electricity have declined in recent years primarily due to low natural gas prices. If there are reductions in demand from customers or if we lose customers, we will market any available power to Other Power Suppliers in an effort to mitigate any earnings impact. Sales to Other Power Suppliers are sold at market-based prices into the MISO market on a daily basis or through bilateral agreements in various durations. Due to the low wholesale prices for electricity, we can make no assurances that our power marketing efforts would fully offset any reduction in earnings resulting from the lower demand from existing customers or the loss of customers.

The price of electricity and fuel may be volatile.

Volatility in market prices for electricity and fuel could adversely impact our financial position and results of operations and may result from:

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

Fluctuations in our fuel and purchased power costs related to our retail and municipal customers are passed on to customers through the fuel adjustment clause. Volatility in market prices for our fuel and purchase power costs primarily impacts our sales to Other Power Suppliers.

Demand for energy may decrease.

Our results of operations are impacted by the demand for energy in our service territories. There could be lower demand for energy due to a loss of customers as a result of economic conditions, customers constructing their own generation facilities, higher costs and rates charged to customers, or loss of service territory or franchises. Further, the energy conservation and technological advances that increase energy efficiency may temporarily or permanently reduce the demand for energy products. In addition, there are state and federal regulations requiring mandatory conservation measures, which would reduce the demand for energy. Continuing technology improvements and regulatory developments may make customer and third party-owned generation technologies such as rooftop solar systems, wind turbines, microturbines and battery storage systems more cost effective and feasible for more of our customers. If more customers utilize their own generation, demand for energy from us would decline. There may not be future economic growth opportunities that would enable us to replace the lost energy demand from these customers. Therefore a decrease in demand for energy could adversely impact our financial position, results of operations and cash flows.

We may not be able to successfully implement our strategic objectives of growing load at our utilities if current or potential industrial or municipal customers are unable to successfully implement expansion plans, including the inability to obtain necessary governmental permits.

As part of our long-term strategy, we pursue new wholesale and retail loads in and around our service territories. Currently, there are several companies in our service territories that are in the process of developing natural resource-based projects that represent long-term growth potential and load diversity for our Regulated Operations businesses. These projects may include construction of new facilities and restarts of old facilities, both of which require permitting and/or approvals to be obtained before the projects can be successfully implemented. If a project does not obtain any necessary governmental (including environmental) permits and approvals or if these customers are unable to successfully implement expansion plans, our long-term strategy and thus our results of operations could be adversely impacted.

Energy Infrastructure and Related Services Risks

The generation of electricity from ALLETE Clean Energy’s wind energy facilities depends heavily on suitable meteorological conditions.

ALLETE Clean Energy’s facilities are geographically diverse; however, if wind conditions are unfavorable, ALLETE Clean Energy's electricity generation and revenue from its wind energy facilities may be substantially below its expectations. The electricity produced and revenues generated by a wind energy facility are highly dependent on suitable wind conditions and associated weather conditions, which are beyond ALLETE Clean Energy’s control. Furthermore, components of its systems could be damaged by severe weather, such as hailstorms, lightning or tornadoes. In addition, replacement and spare parts for key components of ALLETE Clean Energy’s diverse turbine portfolio may be difficult or costly to acquire or may be unavailable. Unfavorable weather and atmospheric conditions could impair the effectiveness of ALLETE Clean Energy’s assets or reduce their output beneath their rated capacity or require shutdown of key equipment, impeding operation of its wind energy facilities.

As contracts with its counterparties expire, ALLETE Clean Energy may not be able to replace them with agreements on similar terms.

ALLETE Clean Energy is party to long-term PPAs which expire in various years between 2018 and 2032. These PPA expirations are prior to the end of the estimated useful lives of the respective wind energy facilities. If, for any reason, ALLETE Clean Energy is unable to enter into new agreements with existing or new counterparties on similar terms once the current agreements expire, or sell energy in the wholesale market resulting in similar revenue, our financial position, results of operations and cash flows could be adversely affected.

Counterparties to ALLETE Clean Energy’s offtake agreements may not fulfill their obligations.

ALLETE Clean Energy is party to long-term PPAs with a limited number of creditworthy counterparties. If, for any reason, any of the counterparties under these agreements are unable or unwilling to fulfill their related contractual obligations, and ALLETE Clean Energy is unable to remarket the energy resulting in similar revenue, our financial position, results of operations and cash flows could be adversely affected.

The inability to successfully manage and grow our Energy Infrastructure and Related Services businesses could adversely affect our results of operations.

Our Energy Infrastructure and Related Services businesses consist of ALLETE Clean Energy and U.S. Water Services. The Company's strategy for these businesses includes growth through acquisitions, project development for others, and by adding customers, products, and new geographies. This strategy depends, in part, on the Company’s ability to successfully identify and evaluate acquisition opportunities and consummate acquisitions on acceptable terms. The Company may compete with other companies for these acquisition opportunities, which may increase the Company’s cost of making acquisitions and the Company may be unsuccessful in pursuing these acquisition opportunities. These companies may be able to pay more for acquisitions and may be able to identify, evaluate, bid for and purchase a greater number of assets than the Company’s financial or human resources permit. If the Company is unable to execute its strategy of growth through acquisitions, project development for others, and/or the addition of new customers, products and geographies, it may impede our long-term objectives of achieving average annual earnings per share growth of a minimum of 5 percent and providing a dividend payout competitive with our industry.

Acquisitions are subject to uncertainties. If we are unable to successfully integrate and manage future acquisitions or strategic investments, this could have an adverse impact on our results of operations. Our actual results may also differ from our expectations due to factors such as the ability to obtain timely regulatory or governmental approvals, integration and operational issues and the ability to retain management and other key personnel.

U.S. Water Services principally relies upon recurring revenues from a diverse mix of industrial customers. Some of these customers can be adversely affected by low commodity prices such as those for ethanol and oil which may cause these customers to purchase fewer of U.S. Water Services’ products and services. If U.S. Water Services is unable to retain its existing customers, add new customers, or if it experiences reduced demand for its products and services, adverse impacts on our results of operations could occur that would prevent us from achieving our future growth expectations.

ALLETE has a significant amount of goodwill and intangible assets. A determination that goodwill or intangible assets have been impaired could result in a significant non-cash charge to earnings.

We had approximately $215 million of goodwill and intangible assets recorded on our Consolidated Balance Sheet as of December 31, 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 Energy Infrastructure and Related Services 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. An impairment could have an adverse effect on our results of operations.

Corporate and Other Risks

BNI Energy may be adversely impacted by its exposure to customer concentration and environmental laws and regulations.

BNI Energy sells lignite to two electric generating cooperatives, Minnkota Power and Square Butte, and could be adversely impacted if these customers were unable or unwilling to fulfill their related contractual obligations. In addition, BNI Energy and its customers may be adversely impacted by environmental laws and regulations which could have an adverse effect on our financial position, results of operations and cash flows.

Real estate market conditions where our legacy Florida real estate investment is located may not improve.

During the fourth quarter of 2015, the Company reevaluated its strategy related to the real estate assets of ALLETE Properties. The revised strategy incorporates the possibility of a bulk sale of its entire portfolio, in addition to sales over time. However, continued adverse market conditions could impact the timing of land sales, which could result in little to no sales, while still incurring operating expenses such as community development district assessments and property taxes, resulting in continued annual net operating losses at ALLETE Properties. Furthermore, weak market conditions could put the properties at risk for further impairment which could adversely impact our results of operations.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

A discussion of our properties is included in Item 1. Business and is incorporated by reference herein.

Item 3. Legal Proceedings

A discussion of material regulatory proceedings is included in Item 1. Business and is incorporated by reference herein.

We are involved in litigation arising in the normal course of business. Also in the normal course of business, we are involved in tax, regulatory and other governmental audits, inspections, investigations and other proceedings that involve state and federal taxes, safety, 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 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-K.

Part II

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

Our common stock is listed on the NYSE under the symbol ALE. We have paid dividends, without interruption, on our common stock since 1948. A quarterly dividend of $0.52 per share on our common stock is payable on March 1, 2016, to the shareholders of record on February 16, 2016. The timing and amount of future dividends will depend upon earnings, cash requirements, the financial condition of the Company, applicable government regulations and other factors deemed relevant by the ALLETE Board of Directors.

The following table shows dividends declared per share, and the high and low prices of our common stock for the periods indicated as reported by the NYSE:

	2015			2014		
	Price Range		Dividends	Price Range		Dividends
Quarter	High	Low	Declared	High	Low	Declared
First	$59.73	$51.16	$0.505	$52.73	$47.96	$0.49
Second	$52.98	$46.27	0.505	$52.54	$47.51	0.49
Third	$52.49	$45.29	0.505	$51.56	$44.39	0.49
Fourth	$52.90	$47.93	0.505	$57.97	$44.19	0.49
Annual Total			$2.02			$1.96

At February 1, 2016, there were approximately 24,000 common stock shareholders of record.

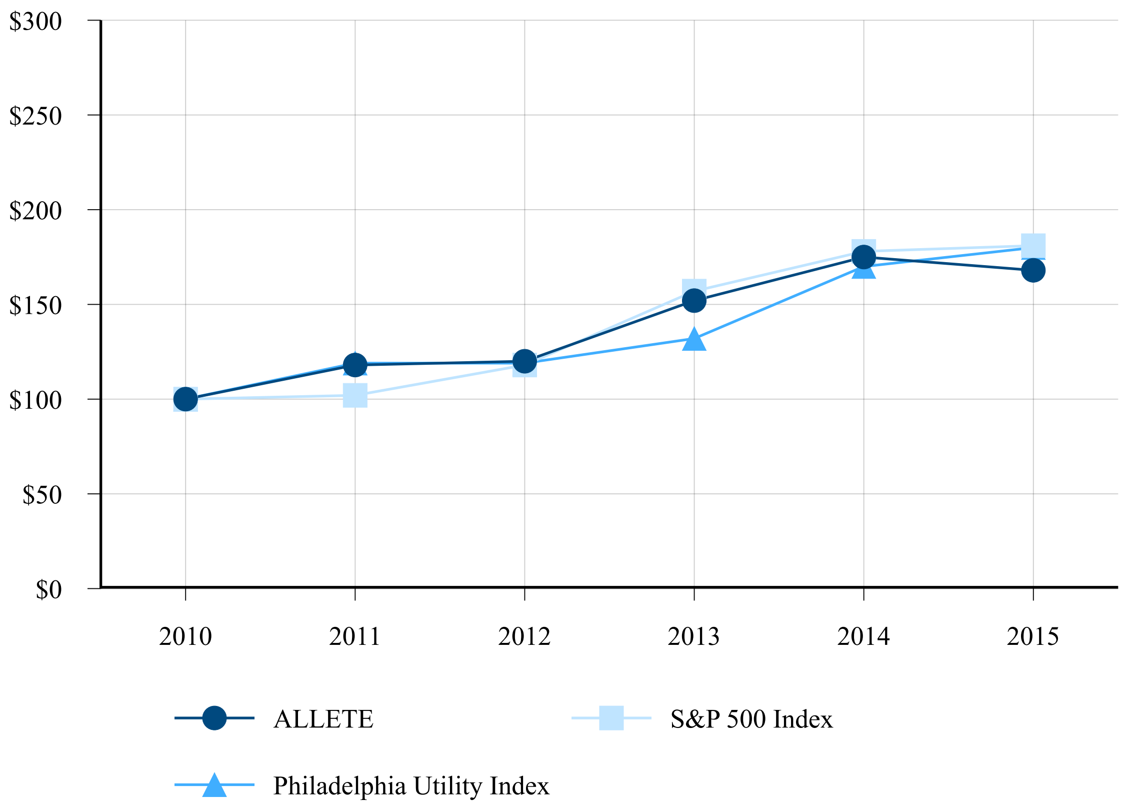
Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities (Continued)

Performance Graph.

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

The calculations assume a $100 investment on December 31, 2010, and reinvestment of dividends.

Total Shareholder Return for the Five Years Ending December 31, 2015



	2010	2011	2012	2013	2014	2015
ALLETE	$100	$118	$120	$152	$175	$168
S&P 500 Index	$100	$102	$118	$157	$178	$181
Philadelphia Utility Index	$100	$119	$119	$132	$170	$180

Item 6. Selected Financial Data

	2015	2014	2013	2012	2011
Millions					
Operating Revenue *(a)*	$1,486.4	$1,136.8	$1,018.4	$961.2	$928.2
Operating Expenses	$1,275.7	$948.0	$864.3	$806.0	$778.2
Net Income	$141.5	$125.5	$104.7	$97.1	$93.6
Less: Non-Controlling Interest in Subsidiaries *(b)*	0.4	0.7	—	—	(0.2)
Net Income Attributable to ALLETE	$141.1	$124.8	$104.7	$97.1	$93.8
Common Stock Dividends	97.9	83.8	75.2	69.1	62.1
Earnings Retained in Business	$43.2	$41.0	$29.5	$28.0	$31.7
Shares Outstanding – Millions					
Year-End	49.1	45.9	41.4	39.4	37.5
Average *(c)*					
Basic	48.3	42.9	39.7	37.6	35.3
Diluted	48.4	43.1	39.8	37.6	35.4
Diluted Earnings Per Share	$2.92	$2.90	$2.63	$2.58	$2.65
Total Assets	$4,907.1	$4,360.8	$3,476.8	$3,253.4	$2,876.0
Long-Term Debt	$1,568.7	$1,272.8	$1,083.0	$933.6	$857.9
Return on Common Equity	8.0%	8.6%	8.3%	8.6%	9.1%
Common Equity Ratio	53%	54%	55%	54%	56%
Dividends Declared per Common Share	$2.02	$1.96	$1.90	$1.84	$1.78
Dividend Payout Ratio	69%	68%	72%	71%	67%
Book Value Per Share at Year-End	$37.18	$35.04	$32.43	$30.50	$28.77
Capital Expenditures by Segment					
Regulated Operations	$224.4	$583.5	$326.3	$418.2	$228.0
ALLETE Clean Energy	8.6	4.2	—	—	—
U.S. Water Services	2.9	—	—	—	—
Corporate and Other	15.9	16.6	13.2	14.0	18.8
Total Capital Expenditures	$251.8	$604.3	$339.5	$432.2	$246.8

(a) In 2015, operating revenue included the construction and sale of a wind energy facility from ALLETE Clean Energy to Montana-Dakota Utilities for $197.7 million. (See Note 7. Acquisitions.)

(b) In 2014 and 2015, non-controlling interest related to the January 2014 acquisition made by ALLETE Clean Energy. (See Note 7. Acquisitions.) In 2011, non-controlling interest related to ALLETE Properties was purchased during that year.

(c) Excludes unallocated ESOP shares in each of the years 2011 through 2014. (See Note 13. Common Stock and Earnings Per Share.)

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion should be read in conjunction with our Consolidated Financial Statements and notes to those statements and the other financial information appearing elsewhere in this report. In addition to historical information, the following discussion and other parts of this Form 10-K contain forward-looking information that involves risks and uncertainties. Readers are cautioned that forward-looking statements should be read in conjunction with our disclosures in this Form 10-K under the headings: "Forward-Looking Statements" located on page 6 and "Risk Factors" located in Item 1A. The risks and uncertainties described in this 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.

Overview

Basis of Presentation. During 2015, management updated our reportable segment presentation to reflect the manner in which we operate, assess and allocate resources after our recent acquisitions. We now present three reportable segments, Regulated Operations, ALLETE Clean Energy and U.S. Water Services. Prior period amounts have been revised to conform with the current business segment presentation.

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 145,000 retail customers. Minnesota Power also has 16 non-affiliated municipal customers in Minnesota. SWL&P is a Wisconsin utility and a wholesale customer of Minnesota Power. SWL&P provides regulated electric, natural gas and water service in northwestern Wisconsin to approximately 15,000 electric customers, 13,000 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. (See Item 1. Business – Regulated Operations – Regulatory Matters.)

ALLETE Clean Energy was established in 2011, and focuses on developing, acquiring and operating clean and renewable energy projects. ALLETE Clean Energy currently owns and operates, in four states, approximately 535 MW of nameplate capacity wind energy generation that are under long-term power sales agreements. In addition, ALLETE Clean Energy constructed a 107 MW wind energy facility for sale to Montana-Dakota Utilities; construction and sale were completed in 2015.

U.S. Water Services is our integrated water management company which was acquired on February 10, 2015.

Corporate and Other is comprised of BNI Energy, our coal mining operations in North Dakota, ALLETE Properties, our legacy Florida real estate investment, 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 December 31, 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.

2015 Financial Overview

The following net income discussion summarizes a comparison of the year ended December 31, 2015, to the year ended December 31, 2014.

Net income attributable to ALLETE for 2015 was $141.1 million, or $2.92 per diluted share, compared to $124.8 million, or $2.90 per diluted share, for 2014. Net income for 2015 included a $22.3 million after-tax, or $0.46 per share, non-cash impairment charge relating to the real estate assets of ALLETE Properties, and $4.8 million of after-tax expense, or $0.10 per share, for acquisition costs related to U.S. Water Services and ALLETE Clean Energy's wind energy facilities acquisitions in 2015. (See Note 7. Acquisitions.) Net income for 2014 included 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 and a $1.4 million after-tax expense, or $0.03 per share, of acquisition costs related to ALLETE Clean Energy's wind energy facilities acquisition which closed in January 2014. (See Note 7. Acquisitions and Note 12. Commitments, Guarantees and Contingencies.) Net income for 2015 increased primarily due to higher net income at Minnesota Power and ALLETE Clean Energy. Earnings per share dilution was $0.36 due to additional shares of common stock outstanding as of December 31, 2015. (See Note 13. Common Stock and Earnings Per Share.)

2015 Financial Overview (Continued)

Regulated Operations net income attributable to ALLETE was $131.6 million in 2015, compared to $123.0 million in 2014. Net income for 2015 increased primarily due to higher net income at Minnesota Power resulting from higher cost recovery rider revenue, production tax credits, power marketing sales as the Minnkota Power sales agreement commenced in June 2014, and lower operating and maintenance expenses. These increases were partially offset by lower industrial sales and higher depreciation, interest and property tax expense. In addition, Minnesota Power recorded a reserve for estimated refunds of $1.6 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 5. Regulatory Matters.) Our equity earnings in ATC for 2015 also reflected a $3.0 million after-tax charge related to the MISO return on equity complaints, of which approximately $1.4 million after-tax was attributable to prior years. (See Note 6. Investment in ATC.) Net income for 2014 included 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.

ALLETE Clean Energy net income attributable to ALLETE was $29.9 million in 2015, compared to net income of $3.3 million in 2014. Net income for 2015 increased primarily due to the recognition of profit of $20.4 million after-tax, or $0.42 per share, on the construction of a wind energy facility which was sold to Montana-Dakota Utilities in 2015, and the income generated from the operations of wind energy facilities which were acquired in 2015 and December 2014. Net income for 2015 also included $1.8 million of after-tax expense, or $0.04 per share, for acquisition costs relating to the acquisitions of the Chanarambie/Viking and Armenia Mountain wind energy facilities. The net income for 2014 included a $1.4 million after-tax expense, or $0.03 per share, for acquisition costs related to ALLETE Clean Energy's wind energy facilities acquisition in January 2014.

U.S. Water Services net income attributable to ALLETE was $0.9 million for the period from February 10, 2015, through December 31, 2015. Net income included $2.2 million of after-tax expense related to purchase accounting for inventories and sales backlog; the total impact of this purchase accounting adjustment was $2.5 million after-tax, and is expected to be recognized through the first quarter of 2016. (See Note 7. Acquisitions.)

Corporate and Other net loss attributable to ALLETE was $21.3 million in 2015, compared to a net loss of $1.5 million in 2014. The net loss for 2015 included a $22.3 million after-tax, or $0.46 per share, non-cash impairment charge relating to the real estate assets of ALLETE Properties, and a $3.0 million after-tax expense, or $0.06 per share, for acquisition costs related to the acquisition of U.S. Water Services. BNI Energy recorded net income of $6.7 million in 2015 ($6.1 million in 2014) as deliveries of coal increased in 2015. ALLETE Properties recorded a net loss of $23.3 million in 2015 (net loss of $2.3 million in 2014), which was primarily attributable to the aforementioned non-cash impairment charge.

2015 Compared to 2014

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

Regulated Operations

Year Ended December 31	2015	2014
Millions		
Operating Revenue	$991.2	$1,003.5
Fuel and Purchased Power	328.1	356.1
Transmission Services	54.1	45.6
Cost of Sales	7.9	17.3
Operating and Maintenance	229.6	240.8
Depreciation and Amortization	135.1	118.0
Taxes Other than Income Taxes	46.2	41.9
Operating Income	190.2	183.8
Interest Expense	(53.9)	(49.2)
Equity Earnings in ATC	16.3	19.6
Other Income	3.4	7.8
Income Before Income Taxes	156.0	162.0
Income Tax Expense	24.4	39.0
Net Income Attributable to ALLETE	$131.6	$123.0

2015 Compared to 2014 (Continued)
Regulated Operations (Continued)

Operating Revenue decreased $12.3 million, or 1 percent, from 2014 primarily due to lower fuel adjustment clause recoveries, gas sales, and financial incentives under the Minnesota Conservation Improvement Program, partially offset by higher cost recovery rider revenue, kWh sales, FERC formula based rates, and transmission revenue.

Fuel adjustment clause recoveries decreased $37.1 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 $11.0 million from 2014 primarily as a result of unseasonably cold weather during the first half of 2014 and a warmer than average 2015. (See *Cost of Sales.*)

Financial incentives under the Minnesota Conservation Improvement Program decreased $2.5 million from 2014 as a result of annual limits placed on recoveries beginning in 2015.

Cost recovery rider revenue increased $17.8 million primarily due to the completion of the Bison Wind Energy Center and CapX2020 projects as well as higher capital expenditures related to the Boswell Unit 4 environmental upgrade.

Revenue from Regulated Operations increased $14.7 million due to a 3.1 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 48.4 percent in 2015 compared to 2014 primarily due to the commencement of the Minnkota Power sales agreement in June 2014. (See Note 12. Commitments, Guarantees and Contingencies.) Sales to our residential and municipal customers were impacted by unseasonably cold temperatures in 2014 and warmer than average temperatures in 2015. Heating degree days in Duluth, Minnesota, were approximately 16 percent lower in 2015 compared to 2014. Sales to our industrial customers decreased 11.4 percent primarily due to reduced taconite production.

Kilowatt-hours Sold	2015	2014	Quantity Variance	% Variance
Millions				
Regulated Utility				
Retail and Municipal				
Residential	1,113	1,204	(91)	(7.6)
Commercial	1,462	1,468	(6)	(0.4)
Industrial	6,635	7,487	(852)	(11.4)
Municipal	833	864	(31)	(3.6)
Total Retail and Municipal	10,043	11,023	(980)	(8.9)
Other Power Suppliers	4,310	2,904	1,406	48.4
Total Regulated Utility Kilowatt-hours Sold	14,353	13,927	426	3.1

Revenue from electric sales to taconite and iron concentrate customers accounted for 17 percent of consolidated operating revenue in 2015 (25 percent in 2014). Revenue from electric sales to paper, pulp and secondary wood product customers accounted for 6 percent of consolidated operating revenue in 2015 (8 percent in 2014). Revenue from electric sales to pipelines and other industrial customers accounted for 6 percent of consolidated operating revenue in 2015 (7 percent in 2014).

Revenue to our wholesale customers under our FERC formula based rates increased $6.9 million primarily due to additional renewable, environmental and other investments.

Transmission revenue increased $2.7 million primarily due to higher MISO-related revenue, which was partially offset by an estimated refund for MISO transmission revenue due to the MISO return on equity complaints. (See *Operating Expenses - Transmission Services* and Note 5. Regulatory Matters.)

2015 Compared to 2014 (Continued)
Regulated Operations (Continued)

Operating Expenses decreased $18.7 million, or 2.3 percent, from 2014.

Fuel and Purchased Power Expense decreased $28.0 million, or 8 percent, from 2014 primarily due to lower purchased power and fuel prices in 2015 compared to 2014, partially offset by higher kWh sales in 2015. 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 $8.5 million, or 19 percent, from 2014 primarily due to higher MISO-related expense, which was partially offset by an estimated refund for MISO transmission expense due to the MISO return on equity complaints. (See *Operating Revenue* and Note 5. Regulatory Matters.)

Cost of Sales decreased $9.4 million, or 54 percent, from 2014 due to lower purchased gas at SWL&P. (See *Operating Revenue.*)

Operating and Maintenance Expense decreased $11.2 million, or 5 percent, from 2014, due to cost reduction efforts and the absence of a $4.2 million expense that was recorded in 2014 to reflect a liability associated with environmental mitigation projects required as part of an EPA NOV Consent Decree settlement. Cost reduction efforts resulted in lower wage, vehicle fleet and miscellaneous employee expenses. These reductions were partially offset by increased expense for the operation and maintenance of the 205 MW addition at our Bison Wind Energy Center that went into service in December 2014.

Depreciation and Amortization Expense increased $17.1 million, or 14 percent, from 2014 primarily due to additional property, plant and equipment in service.

Taxes Other than Income Taxes increased $4.3 million, or 10 percent, from 2014 primarily due to higher property tax expenses resulting from higher taxable plant and rates.

Interest Expense increased $4.7 million, or 10 percent, from 2014 primarily due to higher average long-term debt balances.

Equity Earnings in ATC decreased $3.3 million, or 17 percent, from 2014 primarily due to a $5.2 million expense related to the MISO return on equity complaints, of which $2.4 million was attributable to ATC's change in estimate of a refund liability relating to prior years. (See Note 6. Investment in ATC.)

Other Income decreased $4.4 million, or 56 percent, from 2014 primarily due to lower AFUDC–Equity.

Income Tax Expense decreased $14.6 million, or 37 percent, from 2014 primarily due to increased production tax credits as a result of the 205 MW addition to the Bison Wind Energy Center in December 2014.

ALLETE Clean Energy

Year Ended December 31	2015	2014
Millions		
Operating Revenue	$262.1	$33.2
Net Income Attributable to ALLETE	$29.9	$3.3

Operating Revenue increased $228.9 million from 2014 primarily due to the recognition of $197.7 million of revenue from the construction and sale of a wind energy facility to Montana-Dakota Utilities. (See Note 7. Acquisitions.) The acquisitions of Storm Lake I in December 2014, Chanarambie/Viking in April 2015 and Armenia Mountain in July 2015 also contributed to the increase in revenue in 2015 compared to 2014.

2015 Compared to 2014 (Continued)
ALLETE Clean Energy (Continued)

	Year Ended December 31,			
	2015		2014	
Production and Operating Revenue	**kWh**	**Revenue**	**kWh**	**Revenue**
Millions				
Wind Energy Facility				
Lake Benton	265.1	$13.5	264.7	$13.4
Storm Lake II	186.4	11.7	169.4	11.1
Condon	84.1	7.8	91.5	8.2
Storm Lake I	230.7	12.1	9.0	0.5
Chanarambie/Viking	199.1	9.8	—	—
Armenia Mountain	111.6	9.5	—	—
Construction Profit	—	197.7	—	—
Total	1,077.0	$262.1	534.6	$33.2

Net Income Attributable to ALLETE increased $26.6 million from 2014. Net income in 2015 included $20.4 million after-tax, or $0.46 per share, due to the profit from the construction and sale of a wind energy facility to Montana-Dakota Utilities, and $6.9 million related to income generated from the full year of operations of Storm Lake I and the additions of Chanarambie/Viking and Armenia Mountain. Net income in 2015 included $1.8 million of after-tax expense, or $0.04 per share, for acquisition costs related to the acquisitions of the Chanarambie/Viking and Armenia Mountain wind energy facilities. Net income in 2014 included a $1.4 million after-tax expense, or $0.03 per share, for acquisition costs related to the January 2014 acquisition.

U.S. Water Services

For the period February 10, 2015 through December 31	2015
Millions	
Operating Revenue	$119.8
Net Income Attributable to ALLETE	$0.9

Operating Revenue was $119.8 million for the period February 10, 2015, through December 31, 2015. Revenue from chemical and related services, which includes recurring revenue contracts for the delivery and service of chemicals, amounted to $92.5 million for the period February 10, 2015, through December 31, 2015. Revenue from equipment and related services, which includes sales of water treatment equipment, amounted to $27.3 million for the period February 10, 2015, through December 31, 2015. U.S. Water Services strives to provide a full-service product offering to customers including equipment, chemicals, engineering and service.

Net Income Attributable to ALLETE was $0.9 million for the period February 10, 2015, through December 31, 2015. Net income included $2.2 million of after-tax expense related to purchase accounting for inventories and sales backlog; the total impact of this purchase accounting adjustment was $2.5 million after-tax, and is expected to be recognized through the first quarter of 2016.

Corporate and Other

Operating Revenue increased $13.2 million, or 13 percent, from 2014 primarily due to an increase in revenue at BNI Energy, which operates under cost-plus fixed fee contracts, as a result of higher expenses and increased coal delivered in 2015. Increased sales at ALLETE Properties also contributed to the increase.

Net Income Attributable to ALLETE decreased $19.8 million from 2014 primarily due to a $22.3 million after-tax, or $0.46 per share, non-cash impairment charge relating to the real estate assets of ALLETE Properties. (See Note 1. Operations and Significant Accounting Policies.) Also contributing to the decrease was a $3.0 million after-tax expense, or $0.06 per share, for acquisition costs related to the acquisition of U.S. Water Services. In 2015, results reflected slightly higher net income at BNI Energy.

2015 Compared to 2014 (Continued)

Income Taxes – Consolidated

For the year ended December 31, 2015, the effective tax rate was 15.2 percent (22.6 percent for the year ended December 31, 2014). The decrease from the year ended December 31, 2014, was primarily due to increased production tax credits in 2015 related to additional wind energy generation. The effective tax rate deviated from the statutory rate of approximately 41 percent primarily due to production tax credits and the deduction for AFUDC–Equity. (See Note 15. Income Tax Expense.)

2014 Compared to 2013

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

Regulated Operations

Year ended December 31	2014	2013
Millions		
Operating Revenue	$1,003.5	$925.5
Fuel and Purchased Power	356.1	334.8
Transmission Services	45.6	32.3
Cost of Sales	17.3	12.6
Operating and Maintenance	240.8	239.1
Depreciation and Amortization	118.0	110.2
Taxes Other than Income Taxes	41.9	38.4
Operating Income	183.8	158.1
Interest Expense	(49.2)	(44.4)
Equity Earnings in ATC	19.6	20.3
Other Income	7.8	4.7
Income Before Income Taxes	162.0	138.7
Income Tax Expense	39.0	35.1
Net Income Attributable to ALLETE	$123.0	$103.6

Operating Revenue increased $78 million, or 8 percent, from 2013 primarily due to a 5.1 percent increase in kilowatt-hour sales, higher cost recovery rider revenue, transmission revenue, gas sales and fuel adjustment clause recoveries.

Revenue from Regulated Operations increased $30.5 million due to a 5.1 percent increase in kilowatt-hour sales. The increase was primarily due to a 27.5 percent increase in kilowatt-hour sales to Other Power Suppliers. Sales to Other Power Suppliers are sold at market-based prices into the MISO market on a daily basis or through bilateral agreements of various durations, and increased due to the commencement of the Minnkota Power sales agreement in June 2014. (See Note 12. Commitments, Guarantees and Contingencies.) Also contributing to the increase were higher sales to industrial customers resulting from increased industrial production. The decrease in sales to our municipal customers reflects a wholesale customer contract expiration effective December 31, 2013.

Kilowatt-hours Sold	2014	2013	Quantity Variance	% Variance
Millions				
Regulated Utility				
Retail and Municipal				
Residential	1,204	1,177	27	2.3
Commercial	1,468	1,455	13	0.9
Industrial	7,487	7,338	149	2.0
Municipal	864	999	(135)	(13.5)
Total Retail and Municipal	11,023	10,969	54	0.5
Other Power Suppliers	2,904	2,278	626	27.5
Total Regulated Utility Kilowatt-hours Sold	13,927	13,247	680	5.1

Revenue from electric sales to taconite and iron concentrate customers accounted for 25 percent of consolidated operating revenue in 2014 (25 percent in 2013). Revenue from electric sales to paper, pulp and secondary wood product customers accounted for 8 percent of consolidated operating revenue in 2014 (8 percent in 2013). Revenue from electric sales to pipelines and other industrial customers accounted for 7 percent of consolidated operating revenue in 2014 (6 percent in 2013).

Cost recovery rider revenue increased $29.4 million primarily due to higher capital expenditures related to the Bison Wind Energy Center and the Boswell Unit 4 environmental upgrade.

Transmission revenue increased $7.7 million primarily due to the commencement of recovery of our transmission investment related to the 230 kV transmission system upgrade placed in service in March 2013 and higher MISO related revenue. (See *Operating Expenses – Transmission Services*.)

Revenue from gas sales at SWL&P increased $4.6 million as a result of unseasonably cold weather during the first four months of 2014. (See *Operating Expenses – Cost of Sales*.)

Fuel adjustment clause recoveries increased $4.7 million due to higher fuel and purchased power costs attributable to our retail and municipal customers. (See *Operating Expenses – Fuel and Purchased Power Expense.*)

Operating Expenses increased $52.3 million, or 7 percent, from 2013.

Fuel and Purchased Power Expense increased $21.3 million, or 6 percent, from 2013 primarily due to an increase in purchased power resulting from higher kWh sales and higher wholesale prices. 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 $13.3 million, or 41 percent, from 2013 primarily due to higher MISO-related expense. (See *Operating Revenue.*)

Cost of Sales increased $4.7 million, or 37 percent, from 2013 due to higher gas sales in 2014; purchased gas expenses are recovered from our customers through a purchased gas adjustment clause. (See *Operating Revenue*.)

Operating and Maintenance Expense increased $1.7 million, or 1 percent, from 2013. In 2014, a $4.2 million expense was recorded to reflect a liability associated with environmental mitigation projects required as part of the EPA NOV Consent Decree settlement which was partially offset by lower benefit expense. Employee benefit expense was lower due to higher discount rates in 2014 attributable to our defined benefit pension and other postretirement benefit plans.

Depreciation and Amortization Expense increased $7.8 million, or 7 percent, from 2013 reflecting additional property, plant and equipment in service.

Taxes Other than Income Taxes increased $3.5 million, or 9 percent, from 2013 primarily due to higher taxable plant and rates.

Interest Expense increased $4.8 million, or 11 percent, from 2013 primarily due to higher average long-term debt balances.

Equity Earnings in ATC decreased $0.7 million, or 3 percent, from 2013 primarily due to ATC recording an estimated refund liability for complaints filed with the FERC related to the allowed MISO return on equity for transmission owners.

Income Tax Expense increased $3.9 million, or 11 percent, from 2013 primarily due to higher pretax income in 2014, partially offset by higher federal production tax credits in 2014.

2014 Compared to 2013 (Continued)

ALLETE Clean Energy

Year ended December 31,	2014	2013
Millions		
Operating Revenue	$33.2	—
Net Income (Loss) Attributable to ALLETE	$3.3	$(3.4)

Operating Revenue increased $33.2 million from 2013 due to the acquisitions of Storm Lake II, Condon and Lake Benton in January 2014, and Storm Lake I in December 2014. Prior to these acquisitions, ALLETE Clean Energy had no revenue generating assets.

	Year Ended December 31, 2014	
Production and Operating Revenue	**kWh**	**Revenue**
Millions		
Wind Energy Facility		
Lake Benton	264.7	$13.4
Storm Lake II	169.4	11.1
Condon	91.5	8.2
Storm Lake I	9.0	0.5
Total	534.6	$33.2

Net Income Attributable to ALLETE increased $6.7 million from 2013. Net income for 2014 included a $1.4 million after-tax expense, or $0.03 per share, for acquisition costs related to ALLETE Clean Energy's wind energy facilities acquisition in January 2014. Net income in 2014 increased primarily due to the acquisitions of the wind energy facilities in January 2014.

U.S. Water Services

U.S. Water Services was acquired on February 10, 2015.

Corporate and Other

Operating Revenue increased $7.2 million, or 8 percent, from 2013 primarily due to a $2.7 million increase in revenue at BNI Energy, which operates under cost-plus fixed fee contracts, resulting from increased coal deliveries and higher expenses in 2014. ALLETE Properties revenue increased $1.8 million primarily due to higher wetland mitigation bank credit sales.

Net Income Attributable to ALLETE decreased $6.0 million from 2013 primarily due to gains on sales of investments in 2013, and higher state income tax expense in 2014.

Income Taxes – Consolidated

For the year ended December 31, 2014, the effective tax rate was 22.6 percent (21.5 percent for the year ended December 31, 2013). The increase from the year ended December 31, 2013, was primarily due to higher pretax income in 2014, partially offset by increased federal production tax credits in 2014 related to additional wind energy generation. The effective tax rate deviated from the statutory rate of approximately 41 percent primarily due to deductions for AFUDC–Equity, investment tax credits, federal production tax credits, state income tax credits and depletion. (See Note 15. Income Tax Expense.)

Critical Accounting Policies

The preparation of financial statements and related disclosures in conformity with GAAP requires management to make various estimates and assumptions that affect amounts reported in the Consolidated Financial Statements. These estimates and assumptions may be revised, which may have a material effect on the Consolidated Financial Statements. Actual results may differ from these estimates and assumptions. These policies are discussed with the Audit Committee of our Board of Directors on a regular basis. We believe the following policies are most critical to our business and the understanding of our results of operations.

Regulatory Accounting. Our regulated utility operations are accounted for in accordance with the accounting standards for the effects of certain types of regulation. These standards require us to reflect the effect of regulatory decisions in our financial statements. 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. This assessment considers factors such as, but not limited to, changes in the regulatory environment and recent rate orders to other regulated entities under the same jurisdiction. If future recovery or refund of costs becomes no longer probable, the assets and liabilities would be recognized in current period net income or other comprehensive income. (See Note 5. Regulatory Matters.)

Pension and Postretirement Health and Life Actuarial Assumptions. We account for our pension and postretirement benefit obligations in accordance with the accounting standards for defined benefit pension and other postretirement plans. These standards require the use of several important assumptions, including the expected long-term rate of return on plan assets, the discount rate, and mortality assumptions, among others, in determining our obligations and the annual cost of our pension and postretirement benefits. In establishing the expected long-term rate of return on plan assets, we determine the long-term historical performance of each asset class, adjust these for current economic conditions and, utilizing the target allocation of our plan assets, forecast the expected long-term rate of return. Our pension asset allocation at December 31, 2015 was approximately 47 percent equity securities, 39 percent debt, 8 percent private equity, and 6 percent real estate. Our postretirement health and life asset allocation at December 31, 2015, was approximately 57 percent equity securities, 35 percent debt, and 8 percent private equity. Equity securities consist of a mix of market capitalization sizes with domestic and international securities. In 2015, we used expected long-term rates of return of 8.00 percent in our actuarial determination of our pension expense and 6.40 percent to 8.00 percent in our actuarial determination of our other postretirement expense. The actuarial determination uses an asset smoothing methodology for actual returns to reduce the volatility of varying investment performance over time. We review our expected long-term rate of return assumption annually and will adjust it to respond to changing market conditions. A one-quarter percent decrease in the expected long-term rate of return would increase the annual expense for pension and other postretirement benefits by approximately $1.6 million, pretax.

The discount rate is computed using a bond matching study which utilizes a portfolio of high quality bonds that produce cash flows similar to the projected costs of our pension and other postretirement plans. In 2015, we used discount rates of 4.30 percent and 4.33 percent in our actuarial determination of our pension and other postretirement expense, respectively. We review our discount rates annually and will adjust them to respond to changing market conditions. A one-quarter percent decrease in the discount rate would increase the annual expense for pension and other postretirement benefits by approximately $1.8 million, pretax.

The mortality assumptions used to calculate our pension and other postretirement benefit obligations as of December 31, 2015 considered a modified RP-2014 mortality table and an updated mortality projection scale. (See Note 17. Pension and Other Postretirement Benefit Plans.)

Critical Accounting Policies (Continued)

Impairment of Long-Lived Assets. We review our long-lived assets, which include the legacy real estate assets of ALLETE Properties, for indicators of impairment in accordance with the accounting standards for property, plant and equipment on a quarterly basis.

In accordance with the accounting standards for property, plant and equipment, if indicators of impairment exist, we test our real estate assets for recoverability by comparing the carrying amount of the asset to the undiscounted future net cash flows expected to be generated by the asset. Cash flows are assessed at the lowest level of identifiable cash flows, which may include a bulk sale of its entire portfolio, the sale of each individual land parcel, combining various parcels, or other combinations thereof. Our consideration of possible impairment for our real estate assets requires us to make estimates of future net cash flows on an undiscounted basis. The undiscounted future net cash flows are impacted by trends and factors known to us at the time they are calculated and our expectations related to: management's best estimate of future sales prices; holding period and timing of sales; method of disposition; and future expenditures necessary to maintain the operations, including community development district assessments, property taxes and normal operation and maintenance costs. These estimates and expectations are specific to each land parcel, may vary among each land parcel, and may change in the future. If the excess of undiscounted future net cash flows over the carrying amount of a property is small, there is a greater risk of future impairment in the event of such future changes and any resulting impairment charges could be material.

In recent years, market conditions for real estate in Florida have required us to review our land inventories for impairment. In response to market conditions and recent transaction activity, during the fourth quarter of 2015 the Company reevaluated its strategy related to the real estate assets of ALLETE Properties. The revised strategy incorporates the possibility of a bulk sale of its entire portfolio which, if consummated, is likely to result in sales proceeds below the book value of the real estate assets. ALLETE also continues to pursue sales of individual parcels over time. Proceeds from such a sale would be strategically deployed to support growth in our energy infrastructure and related services businesses. ALLETE will continue to maintain key entitlements and infrastructure without making additional investments or acquisitions.

In connection with implementing the revised strategy in 2015, management evaluated its impairment analysis for its real estate assets using updated assumptions to determine estimated future net cash flows on an undiscounted basis. Future net cash flows were adjusted to consider the possibility of a bulk sale of its entire portfolio, in addition to sales over time under the existing divestiture plan. Estimated fair values were based upon current market data and pricing for individual parcels. Our impairment analysis incorporates a probability-weighted approach considering the alternative courses of sales noted above.

Based on the results of undiscounted cash flow analysis, the undiscounted future net cash flows were not adequate to recover the carrying value of the real estate assets totaling $83.3 million. Estimated fair value was derived from current market interest in the property for a bulk sale of its entire portfolio, and discounted cash flow analysis of estimated selling price for sales over time. As a result, a non-cash impairment charge of $36.3 million was recorded in 2015 to reduce the carrying value of the real estate to its estimated fair value at December 31, 2015.

If our real estate assets are sold differently than anticipated, the actual results could be materially different from our undiscounted future net cash flow analysis.

In 2014 and 2013, impairment analyses of estimated undiscounted future net cash flows were conducted based on the strategy existing at that time, and indicated that the cash flows were adequate to recover the carrying value of ALLETE Properties real estate assets. As a result, no impairment was recorded for the years ended December 31, 2014 and 2013.

Taxation. We are required to make judgments regarding the potential tax effects of various financial transactions and our ongoing operations to estimate our obligations to taxing authorities. These tax obligations include income, real estate and sales/use taxes. Judgments related to income taxes require the recognition in our financial statements of the largest tax benefit of a tax position that is "more-likely-than-not" to be sustained on audit. Tax positions that do not meet the "more-likely-than-not" criteria are reflected as a tax liability in accordance with the accounting standards for uncertainty in income taxes. We record a valuation allowance against our deferred tax assets to the extent it is more-likely-than-not that some portion or all of the deferred tax assets will not be realized.

Critical Accounting Policies (Continued)
Taxation (Continued)

We are subject to income taxes in various jurisdictions. We make assumptions and judgments each reporting period to estimate our income tax assets, liabilities, benefits, and expenses. Judgments and assumptions are supported by historical data and reasonable projections. Our assumptions and judgments include the application of tax statutes and regulations, and projections of future federal taxable income, state taxable income, and state apportionment to determine our ability to utilize NOL and credit carryforwards prior to their expiration. Significant changes in assumptions regarding future federal and state taxable income or change in tax rates could require new or increased valuation allowances which could result in a material impact on our results of operations.

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 fourth 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 10. Fair Value in this Form 10-K. Goodwill was $130.6 million and $2.9 million as of December 31, 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 approximately 3 years to approximately 22 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 fourth 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 an 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 10. Fair Value in this Form 10-K. 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-K. Intangible assets, net of accumulated amortization, were $84.6 million and $1.9 million as of December 31, 2015, and December 31, 2014, respectively.

Outlook

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 annual earnings per share growth of a minimum of 5 percent and providing a dividend payout competitive with our industry.

ALLETE is predominately a regulated utility through Minnesota Power, SWL&P and an investment in ATC. ALLETE's strategy is to remain predominately a regulated utility while investing in its Energy Infrastructure and Related Services businesses to complement its regulated businesses, balance exposure to the utility's industrial customers, and provide potential long-term earnings growth. ALLETE expects net income from Regulated Operations to be approximately 85 percent to 90 percent of total consolidated net income in 2016. Over the next several years, the contribution of the Energy Infrastructure and Related Services businesses to net income is expected to increase as ALLETE grows these operations. ALLETE expects its businesses to provide regulated, contracted or recurring revenues and to support sustained growth in net income and cash flow.

Outlook (Continued)

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 *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 2016.

Regulatory Matters. Entities within our Regulated Operations segment are under the jurisdiction of the MPUC, the FERC, the PSCW or the NDPSC. See Item 1. Business – Regulated Operations – 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 2015 (54 percent in 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. Four of these customers are Large Power Customers (see *Large Power Customer Contracts*). The fifth is Northshore Mining, owned and operated by Cliffs Natural Resources Inc., which self-generates a majority of its power, and is capable of producing approximately 6 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. Minnesota Power also provides electric service to three iron concentrate customers capable of producing up to approximately 4 million tons of iron concentrate per year. Iron concentrate is used in the production of taconite pellets.

There has been a general historical correlation between U.S. steel production and Minnesota taconite production. The World Steel Association, an association of over 150 steel producers, national and regional steel industry associations, and steel research institutes representing around 85 percent of world steel production, projected U.S. steel consumption in 2016 will increase compared to 2015. The American Iron and Steel Institute (AISI), an association of North American steel producers, reported that U.S. raw steel production operated at approximately 71 percent of capacity in 2015 (77 percent in 2014 and in 2013). Many steel producers reduced production in 2015, citing higher levels of imports and lower prices. Some Minnesota taconite and iron concentrate producers reduced production in 2015 in response to declining U.S. steel production. While steel consumption is expected to increase in the U.S. in 2016, the high level of imports and lower prices may impact Minnesota taconite production in 2016.

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

The following table reflects Minnesota Power's taconite customers' production levels for the past ten years.

Minnesota Power Taconite Customer Production	
Year	**Tons (Millions)**
2015*	30
2014	39
2013	37
2012	39
2011	39
2010	35
2009	17
2008	39
2007	38
2006	39

Source: Minnesota Department of Revenue 2015 Mining Tax Guide for years 2006 - 2014.
** Preliminary data from the Minnesota Department of Revenue.*

Minnesota Power's 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 Minnesota Power's 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 Minnesota Power to file a rate case to recover lost revenue.

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 December 1, 2015, Minnesota Power's Large Power taconite customers nominated at approximately 80 percent of full demand levels for January through April 2016.

Minnesota Power proactively sells power that is temporarily not required by industrial customers in the wholesale power markets to optimize the value of its generating facilities. Minnesota Power has remarketed a significant portion of the power not expected to be taken by the idled taconite facilities and is well positioned to serve the power needs for those facilities in the event they resume production sooner than currently indicated.

In addition to serving the taconite industry, Minnesota Power serves a number of customers in the paper, pulp and secondary wood products industry. The four major paper and pulp mills we serve reported operating at, or near, full capacity in 2015, and similar levels are expected in 2016. In September 2014, Boise, Inc. (Boise) provided the required one-year written notice of its intent to install additional generation at its International Falls, Minnesota, paper mill which was completed in 2015. Boise's reduction in demand is not expected to have a material impact on the Company's consolidated financial position, results of operations, or cash flows.

USS Corporation. In the second quarter of 2015, USS Corporation temporarily idled its Minnesota Ore Operations - Keetac plant in Keewatin, Minnesota, and a portion of its Minnesota Ore Operations - Minntac plant in Mountain Iron, Minnesota. These actions were due to high 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. In the third quarter of 2015, USS Corporation returned its Minntac plant to full production. USS Corporation's Keetac plant remains idled. Both facilities are Large Power Customers of Minnesota Power. USS Corporation has the capability to produce approximately 5 million tons and 15 million tons of taconite annually at its Keetac and Minntac plants, respectively.

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

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. Minnesota Power's pre-petition amounts due from Magnetation are less than $1 million.

Magnetation's Plant 4 iron concentrate facility 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, with a term through at least December 31, 2025. This Agreement was approved by the MPUC in an order dated February 2, 2016, and is subject to bankruptcy court approval.

On January 6, 2016, Magnetation announced a temporary production curtailment at its Plant 2 iron concentrate facility in Bovey, Minnesota, effective January 18, 2016, in order to balance its production with its customers' needs.

United Taconite. In August 2015, Cliffs Natural Resources Inc. (Cliffs) temporarily idled 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 has said the plant will return to production as soon as demand from customers returns. 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 operation in Michigan which is scheduled to shut down at the end of 2016. United Taconite has the capability to produce approximately 5 million tons of taconite annually.

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 industrial customers. Steel Dynamics cited the significant decline in pig iron pricing as the reason behind its decision. Mesabi Nugget and Mining Resources account for a combined 30 MW of load for Minnesota Power when fully operational.

Verso Corporation. On January 26, 2016, Verso Corporation and its subsidiaries announced that they had filed voluntary petitions for reorganization under Chapter 11 of the Bankruptcy Code in the United States Bankruptcy Court for the District of Delaware, citing a decline in demand for its products and a significant increase in foreign imports. NewPage Corporation is a subsidiary of Verso Corporation and a Large Power Customer of Minnesota Power. Verso Corporation stated it expects the reorganization process to have virtually no impact on its daily business and intends to pay suppliers in full for goods and services delivered after the bankruptcy filing date of January 26, 2016. Minnesota Power's pre-petition amounts due from NewPage Corporation are $2.7 million.

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, Minnesota Power 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. We expect minimal electricity sales to the Nashwauk Public Utilities Commission for electric service to Essar Steel Minnesota's taconite mine and processing facility 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 November 6, 2015, PolyMet announced the completion of the final EIS by state and federal agencies, which was subsequently published in the Federal Register and Minnesota Environmental Quality Board Monitor. The final EIS requires an adequacy decision by the Minnesota Department of Natural Resources and Records of Decision by the federal agencies, which are expected in 2016, before final action can be taken on the required permits to construct and operate the mining operation. 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 recently completed an expansion at two pumping stations located in Minnesota Power's service territory in Deer River and Floodwood, Minnesota resulting in load growth of approximately 15 MW. Subject to the receipt of required permits, Enbridge plans to construct a pipeline connecting its Beaver Lodge Station, near Tioga, North Dakota, to an existing terminal in Superior, Wisconsin (Sandpiper). Enbridge is also planning a replacement of its Line 3 pipeline running from Canada, through Minnesota, and into its Superior terminal. Completion and full operation of the Sandpiper and Line 3 replacement projects, expected in 2019, would result in between 15 MW and 25 MW of additional load at SWL&P.

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. The 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 emissions control technology at Boswell Unit 4 completed in December 2015 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, which was retired in May 2015.

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 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-fired 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 (IRP). In a November 2013 order, the MPUC approved Minnesota Power's 2013 IRP which detailed elements of its *EnergyForward* strategic plan, announced in January 2013. On September 1, 2015, Minnesota Power filed its 2015 IRP with the MPUC which contains the next steps in its *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.

Renewable Energy. In February 2007, Minnesota enacted a law requiring 25 percent of electric utilities' applicable retail and municipal energy sales in Minnesota to be from renewable energy sources by 2025. The law also requires Minnesota Power to meet interim milestones of 12 percent by 2012, 17 percent by 2016 and 20 percent by 2020. The law allows the MPUC to modify or delay meeting a milestone if implementation will cause significant ratepayer cost or technical reliability issues. If a utility is not in compliance with a milestone, the MPUC may order the utility to construct facilities, purchase renewable energy or purchase renewable energy credits. Minnesota Power's 2015 IRP, which was filed with the MPUC on September 1, 2015, includes an update on its plans and progress in meeting the Minnesota renewable energy milestones through 2025. (See *EnergyForward*.)

Minnesota Power continues to execute its renewable energy strategy through key renewable projects that will ensure it meets the identified state mandate at the lowest cost for customers. Minnesota Power has exceeded the interim milestone requirements to date with approximately 27 percent of its applicable retail and municipal energy sales supplied by renewable energy sources in 2015. Minnesota Power expects 31 percent of its applicable retail and municipal energy sales will be supplied by renewable energy sources in 2016.

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 has two solar projects under development. On August 21, 2015, Minnesota Power filed for MPUC approval of a 10 MW utility scale solar project at Camp Ripley, a Minnesota Army National Guard base and training facility near Little Falls, Minnesota. At a hearing on January 28, 2016, the MPUC approved the Camp Ripley solar project as eligible to meet the solar energy standard and for current cost recovery, subject to certain compliance requirements. On September 10, 2015, Minnesota Power filed for MPUC approval of a 1 MW community solar garden project in Saint Louis County, Minnesota. If the community solar garden project is also approved, Minnesota Power believes these projects will meet approximately one-third of the overall mandate and approximately one-fourth of the mandate related to solar photovoltaic devices with a nameplate capacity of 20 kilowatts or less. Costs associated with these projects are expected to be recovered from customers.

Wind Energy. Minnesota Power's 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. Minnesota Power also has 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 the Bison Wind Energy Center were approved by the MPUC in an order dated May 22, 2015. In November 2014, Minnesota Power filed a renewable resources factor filing which includes updated costs associated with Bison. Upon approval of the filing, Minnesota Power 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 its 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 five long-term PPAs with Manitoba Hydro. The first PPA 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. Under the second PPA, Minnesota Power is purchasing 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 a third PPA. This 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. In September 2015, Manitoba Hydro submitted the final preferred route and EIS for the additional transmission capacity in Canada to the Manitoba Conservation and Water Stewardship for regulatory approval. Construction of Manitoba Hydro's hydroelectric generation facility commenced in 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 fourth 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 PPA 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.*)

In October 2015, Minnesota Power and Manitoba Hydro signed a fifth PPA that provides for Minnesota Power to purchase 50 MW of capacity at fixed prices. The PPA begins in June 2017 and expires in May 2020.

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 Minnesota Power's petition seeking cost recovery of investments and expenditures related to the restoration and repair of Thomson through a renewable resources rider. Thomson returned to full production in the fourth quarter of 2015.

Boswell Mercury Emissions Reduction Plan. In August 2012, Minnesota Power filed its mercury emissions reduction plan for Boswell Unit 4 with the MPUC and the MPCA in order to comply with the Minnesota Mercury Emissions Reduction Act and the Federal MATS rule. Construction on the project to implement the Boswell Unit 4 mercury emissions reduction plan was completed with project costs totaling approximately $220 million through December 31, 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 an order dated August 24, 2015. On September 30, 2015, Minnesota Power filed an updated environmental improvement factor filing which included updated costs associated with Boswell Unit 4. Upon approval of the filing, Minnesota Power 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. See also Item 1. Business – Regulated Operations.

Energy Infrastructure and Related Services.

ALLETE Clean Energy.

ALLETE Clean Energy was established in 2011, and focuses on developing, acquiring and operating clean and renewable energy projects. ALLETE Clean Energy currently owns and operates, in four states, approximately 535 MW of nameplate capacity wind energy generation that are under long-term power sales agreements. In addition, ALLETE Clean Energy constructed a 107 MW wind energy facility for sale to Montana-Dakota Utilities; construction and sale were completed in 2015.

ALLETE Clean Energy believes the market for renewable energy in North America is robust, driven by several factors including environmental regulation, tax incentives, societal expectations and continual technology advances. The recent Clean Power Plan is an example of an environmental regulation that we believe will drive renewable energy development.

ALLETE Clean Energy's strategy includes the safe, reliable, optimal and profitable operation of its existing facilities. This includes a strong safety culture, the continuous pursuit of operational efficiencies at existing facilities, and cost controls. While ALLETE Clean Energy generally acquires facilities in liquid power markets, ALLETE Clean Energy's strategy also includes the exploration of power sales agreement extensions upon expiration of existing contracts.

ALLETE Clean Energy will pursue steady growth through acquisitions or project development for others. ALLETE Clean Energy is targeting acquisitions of existing facilities with a purchase price in the $50 million to $100 million range, and which have long-term power sales agreements in place for the facility's output. At this time, ALLETE Clean Energy expects acquisitions will be primarily wind or solar facilities in North America.

Outlook (Continued)
ALLETE Clean Energy (Continued)

ALLETE Clean Energy will manage risk by having a diverse portfolio of assets, which will include power sales contract expiration and geographic diversity. The current mix of power sales agreement expiration and geographic location is as follows:

Wind Energy Facility	Location	Capacity MW	PPA MW	PPA Expiration
Armenia Mountain	Pennsylvania	100.5	100%	2024
Chanarambie/Viking	Minnesota	97.5		
PPA 1			12%	2018
PPA 2			88%	2023
Condon	Oregon	50	100%	2022
Lake Benton	Minnesota	104	100%	2028
Storm Lake I	Iowa	108	100%	2019
Storm Lake II	Iowa	77		
PPA 1			90%	2019
PPA 2			10%	2032

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 is located in 49 states and Canada and has an established base of approximately 4,000 customers. U.S. Water Services differentiates itself from the competition by developing synergies between established solutions in engineering, equipment, and chemical water treatment and helping customers achieve efficient and sustainable use of their water and energy systems. U.S. Water Services is a leading provider to the biofuels industry, and also serves the food and beverage, industrial, power generation, and midstream oil and gas industries. U.S. Water Services principally relies upon recurring revenues from a diverse mix of industrial customers.

Our strategy is to grow U.S. Water Services' North American presence by adding customers, products, and new geographies. We believe water scarcity and a growing emphasis on conservation will continue to drive significant growth in the industrial, commercial, and governmental sectors leading to organic revenue growth for U.S. Water Services. U.S. Water Services also expects to pursue periodic strategic tuck-in acquisitions with a purchase price in the $10 million to $50 million range. Priority will be given to acquisitions which expand its geographic reach, add new technology, or deepen its capabilities to serve its expanding customer base.

Corporate and Other.

Corporate and Other is comprised of BNI Energy, our coal mining operations in North Dakota, ALLETE Properties, our Florida real estate investment, 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.

BNI Energy. In 2015, BNI Energy sold 4.3 million tons of coal (4.0 million tons in 2014) and anticipates 2016 sales will be similar to 2015. BNI Energy operates under cost-plus fixed fee agreements extending through December 31, 2037.

ALLETE Properties. ALLETE Properties represents our legacy 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.

In recent years, market conditions for real estate in Florida have required us to review our land inventories for impairment. In response to market conditions and recent transaction activity, during the fourth quarter of 2015 the Company reevaluated its strategy related to the real estate assets of ALLETE Properties. The revised strategy incorporates the possibility of a bulk sale of its entire portfolio which, if consummated, is likely to result in sales proceeds below the book value of the real estate assets. ALLETE also continues to pursue sales of individual parcels over time. Proceeds from such a sale would be strategically deployed to support growth in our energy infrastructure and related services businesses. ALLETE will continue to maintain key entitlements and infrastructure without making additional investments or acquisitions.

Outlook (Continued)
Corporate and Other (Continued)

In connection with implementing the revised strategy in 2015, management evaluated its impairment analysis for its real estate assets using updated assumptions to determine estimated future net cash flows on an undiscounted basis. Future net cash flows were adjusted to consider the possibility of a bulk sale of its entire portfolio, in addition to sales over time under the existing divestiture plan. Estimated fair values were based upon current market data and pricing for individual parcels. Our impairment analysis incorporates a probability-weighted approach considering the alternative courses of sales noted above.

Based on the results of undiscounted cash flow analysis, the undiscounted future net cash flows were not adequate to recover the carrying value of the real estate assets totaling $83.3 million. Estimated fair value was derived from current market interest in the property for a bulk sale of its entire portfolio, and discounted cash flow analysis of estimated selling price for sales over time. As a result, a non-cash impairment charge of $36.3 million was recorded in 2015 to reduce the carrying value of the real estate to its estimated fair value at December 31, 2015.

If our real estate assets are sold differently than anticipated, the actual results could be materially different from our undiscounted future net cash flow analysis.

In 2014 and 2013, impairment analyses of estimated undiscounted future net cash flows were conducted based on the strategy existing at that time, and indicated that the cash flows were adequate to recover the carrying value of ALLETE Properties real estate assets. As a result, no impairment was recorded for the years ended December 31, 2014 and 2013.

ALLETE Properties' major projects are Town Center, Palm Coast Park and Ormond Crossings. Separately, the Lake Swamp wetland mitigation bank was permitted on land that was previously part of Ormond Crossings.

Summary of Projects As of December 31, 2015	**Acres *(a)***	**Residential Units *(b)***	**Non-residential Sq. Ft. *(b)***
Projects			
Town Center	958	2,359	2,236,700
Palm Coast Park	3,582	3,554	3,096,800
Ormond Crossings	2,883	2,950	3,215,000
Total Projects	7,423	8,863	8,548,500
Other			
Lake Swamp Wetland Mitigation Bank	3,050	*(c)*	*(c)*
Total of Projects	10,473	8,863	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 approximately 1,400 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 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. Primarily due to federal production tax credits as a result of wind energy generation, we expect our effective tax rate to be approximately 20 percent for 2016. We also expect that our effective tax rate will be lower than the statutory rate over the next nine years due to production tax credits attributable to our wind energy generation.

Liquidity and Capital Resources

Liquidity Position. ALLETE is well-positioned to meet the Company's liquidity needs. As of December 31, 2015, we had cash and cash equivalents of $97.0 million, $394.4 million in available consolidated lines of credit and a debt-to-capital ratio of 47 percent.

Capital Structure. ALLETE's capital structure for each of the last three years is as follows:

As of December 31	2015	%	2014	%	2013	%
Millions						
ALLETE Equity	$1,820.2	53	$1,609.4	54	$1,342.9	55
Non-Controlling Interest	2.2	—	1.8	—	—	—
Long-Term Debt (Including Current Maturities)	1,605.0	47	1,373.5	46	1,110.2	45
Notes Payable	1.6	—	3.7	—	—	—
	$3,429.0	100	$2,988.4	100	$2,453.1	100

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

Year Ended December 31	2015	2014	2013
Millions			
Cash and Cash Equivalents at Beginning of Period	$145.8	$97.3	$80.8
Cash Flows from (used for)			
Operating Activities	340.1	269.8	239.4
Investing Activities	(618.8)	(625.7)	(336.6)
Financing Activities	229.9	404.4	113.7
Change in Cash and Cash Equivalents	(48.8)	48.5	16.5
Cash and Cash Equivalents at End of Period	$97.0	$145.8	$97.3

Operating Activities. Cash from operating activities was higher in 2015 primarily due to higher net income and non-cash items (primarily depreciation expense and impairment of real estate), and increased recoveries through our cost recovery riders, partially offset by timing of accounts payable payments.

Cash from operating activities in 2014 was higher than 2013 primarily due to higher net income, cash contributions of $10.8 million in 2013 to other postretirement benefit plans, and timing of accounts payable payments, which were partially offset by increased fuel inventory purchases in 2014.

Investing Activities. Cash used for investing activities in 2015 was lower than 2014 primarily due to lower capital expenditures in 2015, partially offset by increased acquisitions of subsidiaries. (See Note 7. Acquisitions.)

Cash used for investing activities in 2014 was higher than 2013 primarily due to higher capital expenditures and ALLETE Clean Energy acquisitions in 2014, partially offset by a transfer of cash included in Other Investments to Cash and Cash Equivalents in 2014.

Financing Activities. Cash from financing activities in 2015 was lower than 2014 primarily due to lower proceeds from the net issuance of long-term debt and common stock in 2015, increased dividends on common stock in 2015 and construction deposits received in 2014 for the development of the wind energy facility which was completed and sold to Montana-Dakota Utilities in 2015.

Cash from financing activities in 2014 was higher than 2013 primarily due to proceeds from the issuance of long-term debt and the issuance of common stock in 2014, partially offset by increased payments on long-term debt and dividends on common stock in 2014.

Liquidity and Capital Resources (Continued)

Working Capital. Additional working capital, if and when needed, generally is provided by consolidated bank lines of credit or the sale of securities or commercial paper. As of December 31, 2015, we had consolidated bank lines of credit aggregating $408.4 million ($408.4 million as of December 31, 2014), the majority of which expire in November 2018. We had $12.4 million outstanding in standby letters of credit and $1.6 million outstanding in draws under our lines of credit as of December 31, 2015 ($47.5 million in standby letters of credit and $3.7 million outstanding in draws as of December 31, 2014). In addition, as of December 31, 2015, we had 1.8 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.

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 shares remain available for issuance. For the year ended December 31, 2015, 1.3 million shares of common stock were issued under this agreement, resulting in net proceeds of $69.9 million (1.9 million shares for net proceeds of $90.0 million for the year ended December 31, 2014; 1.3 million shares for net proceeds of $63.4 million for the year ended December 31, 2013). The shares sold January 1, 2013 through August 1, 2013, were offered and sold pursuant to Registration Statement No. 333-170289. On August 2, 2013, we filed Registration Statement No. 333-190335, pursuant to which the remaining shares will continue to be offered for sale, from time to time.

During the year ended December 31, 2015, we issued a total of 0.4 million shares of common stock through Invest Direct, the Employee Stock Purchase Plan, and the Retirement Savings and Stock Ownership Plan, resulting in net proceeds of $25.9 million (0.5 million shares were issued during the year ended December 31, 2014, resulting in net proceeds of $25.4 million; 0.7 million shares were issued during the year ended December 31, 2013, resulting in net proceeds of $34.8 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 November 5, 2015, Armenia Mountain Wind, LLC (Armenia Mountain) issued and sold $84.5 million of its 3.26 percent Senior Secured Notes due December 31, 2024, to certain institutional accredited investors in the private placement market. Armenia Mountain used a portion of the proceeds to refinance the debt assumed when Armenia Mountain was acquired, and plans to use the remaining proceeds for general corporate purposes. (See Note 7. Acquisitions and Note 11. Short-Term and Long-Term Debt.)

On August 25, 2015, the Company entered into a $125 million Term Loan Agreement with JPMorgan Chase Bank, N.A., as a lender and administrative agent, and Bank of America, N.A., as a lender (Term Loan). Proceeds from the Term Loan will be used for general corporate purposes, including the refinancing of the $75 million Term Loan Agreement due August 25, 2015. (See Note 11. Short-Term and Long-Term Debt.)

On September 24, 2015, we issued $100 million of ALLETE first mortgage bonds (Bonds) in the private placement market in two series. 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 11. Short-Term and Long-Term Debt.)

Financial Covenants. See Note 11. Short-Term and Long-Term Debt for information regarding our financial covenants.

Off-Balance Sheet Arrangements. Off-balance sheet arrangements are discussed in Note 12. Commitments, Guarantees and Contingencies.

Liquidity and Capital Resources (Continued)

Contractual Obligations and Commercial Commitments. ALLETE has contractual obligations and other commitments that will need to be funded in the future, in addition to its capital expenditure programs. Following is a summarized table of contractual obligations and other commercial commitments as of December 31, 2015.

		Payments Due by Period			
Contractual Obligations *(a)* **As of December 31, 2015**	**Total**	**Less than 1 Year**	**1 to 3 Years**	**4 to 5 Years**	**After 5 Years**
Millions					
Long-Term Debt	$2,447.2	$100.8	$377.9	$266.0	$1,702.5
Pension *(b)*	421.1	39.8	81.6	83.5	216.2
Other Postretirement Benefit Plans *(b)*	92.1	8.3	17.4	18.4	48.0
Operating Lease Obligations	77.7	14.0	23.7	16.8	23.2
PPA Obligations *(c)*	466.7	60.4	175.8	136.0	94.5
Other Purchase Obligations	114.7	57.0	55.9	1.8	—
Total Contractual Obligations	$3,619.5	$280.3	$732.3	$522.5	$2,084.4

(a) Excludes $2.4 million of non-current unrecognized tax benefits due to uncertainty regarding the timing of future cash payments related to uncertain tax positions.

(b) Represents the estimated future benefit payments for our defined benefit pension and other postretirement plans through 2025.

(c) Excludes the agreement with Manitoba Hydro expiring in 2022, as this contract is for surplus energy only, and the agreements with Manitoba Hydro commencing in 2020, as our obligations under these contracts are subject to the construction of a hydro generation facility by Manitoba Hydro and additional transmission capacity. Also excludes Oliver Wind I and Oliver Wind II, as Minnesota Power only pays for energy as it is delivered. (See Item 1. Business – Regulated Operations – Power Supply.)

Long-Term Debt. Our long-term debt obligations, including long-term debt due within one year, represent the principal amount of bonds, notes and loans which are recorded on our Consolidated Balance Sheet, plus interest. The table above assumes that the interest rates in effect at December 31, 2015, remain constant through the remaining term. (See Note 11. Short-Term and Long-Term Debt.)

Pension and Other Postretirement Benefit Plans. Our pension and other postretirement benefit plan obligations represent our current estimate of future benefit payments through 2025. Pension contributions will be dependent on several factors including realized asset performance, future discount rate and other actuarial assumptions, Internal Revenue Service and other regulatory requirements, and contributions required to avoid benefit restrictions for the pension plans. Funding for the other postretirement benefit plans is impacted by realized asset performance, future discount rate and other actuarial assumptions, and utility regulatory requirements. These amounts are estimates and will change based on actual market performance, changes in interest rates and any changes in governmental regulations. (See Note 17. Pension and Other Postretirement Benefit Plans.)

PPA Obligations. PPA obligations represent our Square Butte, Manitoba Hydro, Minnkota Power, Great River Energy, TransAlta and other purchase power contracts. (See Note 12. Commitments, Guarantees and Contingencies.)

Other Purchase Obligations. Other purchase obligations represents our minimum purchase commitments under coal and rail contracts, and purchase obligations for certain capital expenditure projects. (See Note 12. Commitments, Guarantees and Contingencies.)

Liquidity and Capital Resources (Continued)

Credit Ratings. Access to reasonably priced capital markets is dependent in part on credit and ratings. Our securities have been rated by Standard & Poor's and by Moody's. Rating agencies use both quantitative and qualitative measures in determining a company's credit rating. These measures include business risk, liquidity risk, competitive position, capital mix, financial condition, predictability of cash flows, management strength and future direction. Some of the quantitative measures can be analyzed through a few key financial ratios, while the qualitative ones are more subjective. Our current credit ratings are listed in the table below:

Credit Ratings	Standard & Poor's	Moody's
Issuer Credit Rating	BBB+	A3
Commercial Paper	A-2	P-2
First Mortgage Bonds	A	A1

The disclosure of these credit ratings is not a recommendation to buy, sell or hold our securities. Ratings are subject to revision or withdrawal at any time by the assigning rating organization. Each rating should be evaluated independently of any other rating.

Common Stock Dividends. ALLETE is committed to providing a competitive dividend to its shareholders while at the same time funding its growth. The Company's long-term objective is to maintain a dividend payout ratio similar to our peers and provide for future dividend increases. Our targeted payout range is between 60 percent to 65 percent. In 2015, we paid out 69 percent (68 percent in 2014; 72 percent in 2013) of our per share earnings in dividends. On January 21, 2016, our Board of Directors declared a dividend of $0.52 per share, which is payable on March 1, 2016, to shareholders of record at the close of business on February 16, 2016.

Capital Requirements

ALLETE's projected capital expenditures for the years 2016 through 2020 are presented in the following table. Actual capital expenditures may vary from the estimates due to changes in forecasted plant maintenance, regulatory decisions or approvals, future environmental requirements, base load growth, capital market conditions or executions of new business strategies.

Capital Expenditures	2016	2017	2018	2019	2020	Total
Millions						
Regulated Utility Operations						
Base and Other	$120	$140	$175	$105	$100	$640
Cost Recovery *(a)*						
Environmental	20	—	—	—	—	20
Renewable	—	5	—	—	—	5
Transmission *(b)*	25	95	80	85	50	335
Total Cost Recovery	45	100	80	85	50	360
Regulated Utility Capital Expenditures	165	240	255	190	150	1,000
Other	30	40	35	35	30	170
Total Capital Expenditures	$195	$280	$290	$225	$180	$1,170

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

(b) Our portion of transmission capital expenditures related to construction of the GNTL is estimated at approximately $330 million through 2020. (See Item 1. Business – Regulated Operations – Transmission and Distribution.)

We are well positioned to meet our financing needs due to adequate operating cash flows, available additional working capital, and access to capital markets. We will finance capital expenditures from a combination of internally generated funds and debt and equity issuance proceeds. We intend to maintain a capital structure with capital ratios near current levels. (See *Capital Structure.*)

Environmental and Other Matters

Our businesses are subject to regulation of environmental matters by various federal, state and local authorities. We anticipate that although many of the state and federal environmental regulations have been finalized, or will be finalized in the near future, potential expenditures for future environmental matters may be material and may require significant capital investments. We are unable to predict the outcome of the issues discussed in Note 12. Commitments, Guarantees and Contingencies. (See Item 1. Business – Environmental Matters.)

Liquidity and Capital Resources (Continued)

Market Risk

Securities Investments.

Available-for-Sale Securities. At December 31, 2015, our available-for-sale securities portfolio consisted primarily of securities held in other postretirement plans to fund employee benefits. (See Note 9. Investments.)

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. The following table presents the long-term debt obligations and the corresponding weighted average interest rate at December 31, 2015.

	Expected Maturity Date							
Interest Rate Sensitive Financial Instruments	**2016**	**2017**	**2018**	**2019**	**2020**	**Thereafter**	**Total**	**Fair Value**
Dollars in Millions								
Long-Term Debt								
Fixed Rate	$33.7	$63.3	$63.4	$56.3	$89.4	$1,123.7	$1,429.8	$1,500.8
Average Interest Rate – %	6.3	5.6	2.3	7.2	4.0	4.4	4.5	
Variable Rate	$2.6	$130.3	$0.7	$0.2	$13.6	$27.8	$175.2	$175.2
Average Interest Rate – %	5.0	1.0	4.8	4.8	0.1	0.1	0.9	

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 December 31, 2015, an increase of 100 basis points in interest rates would impact the amount of pretax interest expense by $1.7 million. This amount was determined by considering the impact of a hypothetical 100 basis point increase to the average variable interest rate on the variable rate debt outstanding as of December 31, 2015.

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. SWL&P's exposure to price risk for natural gas is significantly mitigated by the current regulatory framework, which allows the commodity cost to be passed through to customers. 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. Minnesota Power's power marketing activities consist of: (1) purchasing energy in the wholesale market to serve its regulated service territory when energy requirements exceed generation output; and (2) selling excess available energy and purchased power. From time to time, Minnesota Power may have excess energy that is temporarily not required by retail and municipal customers in its regulated service territory. Minnesota Power actively sells any excess energy to the wholesale market to optimize the value of its 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.

Recently Adopted Accounting Standards.

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

Item 7A. Quantitative and Qualitative Disclosures about Market Risk

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

Item 8. Financial Statements and Supplementary Data

See our Consolidated Financial Statements as of December 31, 2015 and 2014, and for each of the three years in the period ended December 31, 2015, and supplementary data, which are indexed in Item 15(a).

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

Not applicable.

Item 9A. Controls and Procedures

Conclusion Regarding the Effectiveness of Disclosure Controls and Procedures

As of December 31, 2015, evaluations were performed, under the supervision and with the participation of management, including our principal executive officer and principal financial officer, on 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.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f) or 15d-15(f). Under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, we conducted an evaluation of the effectiveness of our internal control over financial reporting based on the updated Internal Control – Integrated Framework (2013 framework) issued by the Committee of Sponsoring Organizations of the Treadway Commission. The 2013 framework supersedes the original framework issued in 1992 and is effective for all dates after December 15, 2014. Based on our evaluation under the 2013 framework, our management concluded that our internal control over financial reporting was effective as of December 31, 2015.

The effectiveness of the Company's internal control over financial reporting as of December 31, 2015, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which is included herein.

On February 10, 2015, the Company completed the acquisition of U.S. Water Services. As a result, management has excluded U.S. Water Services from our assessment of internal control over financial reporting. U.S. Water Services is a wholly-owned subsidiary whose total assets and total revenues represent 5 percent and 8 percent, respectively, of the related Consolidated Financial Statement amounts as of and for the year ended December 31, 2015.

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.

Item 9B. Other Information

Not applicable.

Part III

Item 10. Directors, Executive Officers and Corporate Governance

Unless otherwise stated, the information required by this Item is incorporated by reference herein from our Proxy Statement for the 2016 Annual Meeting of Shareholders (2016 Proxy Statement) under the following headings:

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

Our 2016 Proxy Statement will be filed with the SEC within 120 days after the end of our 2015 fiscal year.

Code of Ethics. We have adopted a written Code of Ethics that applies to all of our employees, including our chief executive officer, chief financial officer and controller. A copy of our Code of Ethics is available on our website at www.allete.com and print copies are available without charge upon request to ALLETE, Inc., Attention: Secretary, 30 West Superior St., Duluth, Minnesota 55802. Any amendment to the Code of Ethics or any waiver of the Code of Ethics will be disclosed on our website at www.allete.com promptly following the date of such amendment or waiver.

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

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

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

Item 11. Executive Compensation

The information required for this Item is incorporated by reference herein from the "Compensation Discussion and Analysis," the "Compensation of Executive Officers," the "Compensation Committee Report" and the "Director Compensation" sections in our 2016 Proxy Statement.

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

The information required for this Item is incorporated by reference herein from the "Ownership of ALLETE Common Stock – Securities Owned by Certain Beneficial Owners," the "Ownership of ALLETE Common Stock – Securities Owned by Directors and Management" and the "Equity Compensation Plan Information" sections in our 2016 Proxy Statement.

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

The information required for this Item is incorporated by reference herein from the "Corporate Governance" section in our 2016 Proxy Statement.

We have adopted a Related Person Transaction Policy which is available on our website at www.allete.com. Print copies are available without charge, upon request. Any amendment to this policy will be disclosed on our website at www.allete.com promptly following the date of such amendment.

Item 14. Principal Accounting Fees and Services

The information required for this Item is incorporated by reference herein from the "Audit Committee Report" section in our 2016 Proxy Statement.

Part IV

Item 15. Exhibits and Financial Statement Schedules

(a)	Certain Documents Filed as Part of this Form 10-K.	
(1)	Financial Statements	Page
	ALLETE	
	Report of Independent Registered Public Accounting Firm	70
	Consolidated Balance Sheet at December 31, 2015 and 2014	71
	For the Three Years Ended December 31, 2015	
	Consolidated Statement of Income	72
	Consolidated Statement of Comprehensive Income	73
	Consolidated Statement of Cash Flows	74
	Consolidated Statement of Shareholders' Equity	75
	Notes to Consolidated Financial Statements	76
(2)	Financial Statement Schedules	
	Schedule II – ALLETE Valuation and Qualifying Accounts and Reserves	135
	All other schedules have been omitted either because the information is not required to be reported by ALLETE or because the information is included in the Consolidated Financial Statements or the notes.	
(3)	Exhibits including those incorporated by reference.	

Exhibit Number

*3(a)1	—	Articles of Incorporation, amended and restated as of May 8, 2001 (filed as Exhibit 3(b) to the March 31, 2001, Form 10-Q, File No. 1-3548).
*3(a)2	—	Amendment to Articles of Incorporation, dated as of September 20, 2004 (filed as Exhibit 3 to the September 21, 2004, Form 8-K, File No. 1-3548).
*3(a)3	—	Amendment to Articles of Incorporation, dated as of May 12, 2009 (filed as Exhibit 3 to the June 30, 2009, Form 10-Q, File No. 1-3548).
*3(a)4	—	Amendment to Articles of Incorporation, dated as of May 11, 2010 (filed as Exhibit 3(a) to the May 14, 2010, Form 8-K, File No. 1-3548).
*3(a)5	—	Amendment to Certificate of Assumed Name, filed with the Minnesota Secretary of State on May 8, 2001 (filed as Exhibit 3(a) to the March 31, 2001, Form 10-Q, File No. 1-3548).
*3(b)	—	Bylaws, as amended effective May 11, 2010 (filed as Exhibit 3(b) to the May 14, 2010, Form 8-K, File No. 1-3548).
*4(a)1	—	Mortgage and Deed of Trust, dated as of September 1, 1945, between Minnesota Power & Light Company (now ALLETE) and The Bank of New York Mellon (formerly Irving Trust Company) and Andres Serrano (successor to Richard H. West), Trustees (filed as Exhibit 7(c), File No. 2-5865).
*4(a)2	—	Supplemental Indentures to ALLETE's Mortgage and Deed of Trust:

Number	Dated as of	Reference File	Exhibit
First	March 1, 1949	2-7826	7(b)
Second	July 1, 1951	2-9036	7(c)
Third	March 1, 1957	2-13075	2(c)
Fourth	January 1, 1968	2-27794	2(c)
Fifth	April 1, 1971	2-39537	2(c)
Sixth	August 1, 1975	2-54116	2(c)
Seventh	September 1, 1976	2-57014	2(c)
Eighth	September 1, 1977	2-59690	2(c)
Ninth	April 1, 1978	2-60866	2(c)
Tenth	August 1, 1978	2-62852	2(d)2
Eleventh	December 1, 1982	2-56649	4(a)3
Twelfth	April 1, 1987	33-30224	4(a)3
Thirteenth	March 1, 1992	33-47438	4(b)
Fourteenth	June 1, 1992	33-55240	4(b)
Fifteenth	July 1, 1992	33-55240	4(c)
Sixteenth	July 1, 1992	33-55240	4(d)
Seventeenth	February 1, 1993	33-50143	4(b)
Eighteenth	July 1, 1993	33-50143	4(c)
Nineteenth	February 1, 1997	1-3548 (1996 Form 10-K)	4(a)3
Twentieth	November 1, 1997	1-3548 (1997 Form 10-K)	4(a)3
Twenty-first	October 1, 2000	333-54330	4(c)3
Twenty-second	July 1, 2003	1-3548 (June 30, 2003, Form 10-Q)	4
Twenty-third	August 1, 2004	1-3548 (Sept. 30, 2004, Form 10-Q)	4(a)
Twenty-fourth	March 1, 2005	1-3548 (March 31, 2005, Form 10-Q)	4
Twenty-fifth	December 1, 2005	1-3548 (March 31, 2006, Form 10-Q)	4
Twenty-sixth	October 1, 2006	1-3548 (2006 Form 10-K)	4
Twenty-seventh	February 1, 2008	1-3548 (2007 Form 10-K)	4(a)3
Twenty-eighth	May 1, 2008	1-3548 (June 30, 2008, Form 10-Q)	4
Twenty-ninth	November 1, 2008	1-3548 (2008 Form 10-K)	4(a)3
Thirtieth	January 1, 2009	1-3548 (2008 Form 10-K)	4(a)4
Thirty-first	February 1, 2010	1-3548 (March 31, 2010, Form 10-Q)	4
Thirty-second	August 1, 2010	1-3548 (Sept. 30, 2010, Form 10-Q)	4
Thirty-third	July 1, 2012	1-3548 (July 2, 2012, Form 8-K)	4
Thirty-fourth	April 1, 2013	1-3548 (April 2, 2013, Form 8-K)	4
Thirty-fifth	March 1, 2014	1-3548 (March 31, 2014, Form 10-Q)	4
Thirty-sixth	June 1, 2014	1-3548 (June 30, 2014, Form 10-Q)	4
Thirty-seventh	September 1, 2014	1-3548 (Sept. 30, 2014, Form 10-Q)	4
Thirty-eighth	September 1, 2015	1-3548 (Sept. 30, 2015, Form 10-Q)	4(a)

Exhibit Number

*4(b)1	—	Mortgage and Deed of Trust, dated as of March 1, 1943, between Superior Water, Light and Power Company and Chemical Bank & Trust Company and Howard B. Smith, as Trustees, both succeeded by U.S. Bank National Association, as Trustee (filed as Exhibit 7(c), File No. 2-8668).
*4(b)2	—	Supplemental Indentures to Superior Water, Light and Power Company's Mortgage and Deed of Trust:

Number	Dated as of	Reference File	Exhibit
First	March 1, 1951	2-59690	2(d)(1)
Second	March 1, 1962	2-27794	2(d)1
Third	July 1, 1976	2-57478	2(e)1
Fourth	March 1, 1985	2-78641	4(b)
Fifth	December 1, 1992	1-3548 (1992 Form 10-K)	4(b)1
Sixth	March 24, 1994	1-3548 (1996 Form 10-K)	4(b)1
Seventh	November 1, 1994	1-3548 (1996 Form 10-K)	4(b)2
Eighth	January 1, 1997	1-3548 (1996 Form 10-K)	4(b)3
Ninth	October 1, 2007	1-3548 (2007 Form 10-K)	4(c)3
Tenth	October 1, 2007	1-3548 (2007 Form 10-K)	4(c)4
Eleventh	December 1, 2008	1-3548 (2008 Form 10-K)	4(c)3
Twelfth	December 2, 2013	1-3548 (2013 Form 10-K)	4(c)3

*4(c)	—	Note Purchase Agreement, dated as of June 8, 2007, between ALLETE and Thrivent Financial for Lutherans and The Northwestern Mutual Life Insurance Company (filed as Exhibit 10(a) to the June 30, 2007, Form 10-Q, File No. 1-3548).
*4(d)	—	Term Loan Agreement dated as of August 25, 2015, among ALLETE, as Borrower, the Lenders party hereto, JPMorgan Chase Bank, N.A., as Administrative Agent, and J.P. Morgan Securities LLC, as Sole Lead Arranger and Sole Book Runner (filed as Exhibit 4 to the August 28, 2015, Form 8-K, File No. 1-3548).
*4(e)	—	Note Purchase and Guarantee Agreement dated as of November 5, 2015, among Armenia Mountain Wind LLC, AMW I Holding, LLC and the purchasers named therein (filed as Exhibit 4 to the November 12, 2015, Form 8-K, File No. 1-3548).
*10(a)	—	Power Purchase and Sale Agreement, dated as of May 29, 1998, between Minnesota Power, Inc. (now ALLETE) and Square Butte Electric Cooperative (filed as Exhibit 10 to the June 30, 1998, Form 10-Q, File No. 1-3548).
*10(b)	—	Credit Agreement dated as of November 4, 2013 among ALLETE, as Borrower, the lenders party thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, and J.P. Morgan Securities LLC, as Sole Lead Arranger and Sole Book Runner (filed as Exhibit 10 to the November 4, 2013, Form 8-K, File No. 1-3548).
*10(c)1	—	Financing Agreement between Collier County Industrial Development Authority and ALLETE dated as of July 1, 2006 (filed as Exhibit 10(b)1 to the June 30, 2006, Form 10-Q, File No. 1-3548).
*10(c)2	—	Amended and Restated Letter of Credit Agreement, dated as of June 3, 2011, among ALLETE, the participating banks and Wells Fargo Bank, National Association, as Administrative Agent and Issuing Bank (filed as Exhibit 10(b) to the June 30, 2011, Form 10-Q, File No. 1-3548).
*10(c)3	—	First Amendment to Amended and Restated Letter of Credit Agreement, dated as of June 1, 2013, between ALLETE and Wells Fargo Bank, National Association, as Issuing Bank, Administrative Agent and Sole Participating Bank (filed as Exhibit 10(b) to the June 30, 2013, Form 10-Q, File No. 1-3548).
*10(d)	—	Agreement dated December 16, 2005, among ALLETE, Wisconsin Public Service Corporation and WPS Investments, LLC (filed as Exhibit 10(g) to the 2009 Form 10-K, File No. 1-3548).
+*10(e)1	—	ALLETE Executive Annual Incentive Plan, as amended and restated, effective January 1, 2011 (filed as Exhibit 10(h)1 to the 2010 Form 10-K, File No. 1-3548).
+*10(e)2	—	ALLETE Executive Annual Incentive Plan Form of Award Effective 2012 (filed as Exhibit 10(h)4 to the 2011 Form 10-K, File No. 1-3548).
+*10(e)3	—	ALLETE Executive Annual Incentive Plan Form of Award Effective 2013 (filed as Exhibit 10(f)5 to the 2012 Form 10-K, File No. 1-3548).
+*10(e)4	—	ALLETE Executive Annual Incentive Plan Form of Award Effective 2014 (filed as Exhibit 10(e)6 to the 2013 Form 10-K, File No. 1-3548).
+*10(e)5	—	ALLETE Executive Annual Incentive Plan Form of Award Effective 2015 (filed as Exhibit 10(e)6 to the 2014 Form 10-K, File No. 1-3548).
+10(e)6	—	ALLETE Executive Annual Incentive Plan Form of Award Effective 2016.
+*10(f)1	—	ALLETE and Affiliated Companies Supplemental Executive Retirement Plan (SERP I), as amended and restated, effective January 1, 2009 (filed as Exhibit 10(i)4 to the 2008 Form 10-K, File No. 1-3548).
+*10(f)2	—	Amendment to the ALLETE and Affiliated Companies Supplemental Executive Retirement Plan (SERP I), effective January 1, 2011 (filed as Exhibit 10(i)2 to the 2010 Form 10-K, File No. 1-3548).
+*10(f)3	—	ALLETE and Affiliated Companies Supplemental Executive Retirement Plan II (SERP II), as amended and restated, effective January 1, 2015 (filed as Exhibit 10(f)3 to the 2014 Form 10-K, File No.1-3548).
+*10(g)1	—	Minnesota Power and Affiliated Companies Executive Investment Plan I, as amended and restated, effective November 1, 1988 (filed as Exhibit 10(c) to the 1988 Form 10-K, File No. 1-3548).

Exhibit Number		
+*10(g)2	—	Amendments through December 2003 to the Minnesota Power and Affiliated Companies Executive Investment Plan I (filed as Exhibit 10(v)2 to the 2003 Form 10-K, File No. 1-3548).
+*10(g)3	—	July 2004 Amendment to the Minnesota Power and Affiliated Companies Executive Investment Plan I (filed as Exhibit 10(b) to the June 30, 2004, Form 10-Q, File No. 1-3548).
+*10(g)4	—	August 2006 Amendment to the Minnesota Power and Affiliated Companies Executive Investment Plan I (filed as Exhibit 10(b) to the September 30, 2006, Form 10-Q, File No. 1-3548).
+*10(h)1	—	Minnesota Power and Affiliated Companies Executive Investment Plan II, as amended and restated, effective November 1, 1988 (filed as Exhibit 10(d) to the 1988 Form 10-K, File No. 1-3548).
+*10(h)2	—	Amendments through December 2003 to the Minnesota Power and Affiliated Companies Executive Investment Plan II (filed as Exhibit 10(w)2 to the 2003 Form 10-K, File No. 1-3548).
+*10(h)3	—	July 2004 Amendment to the Minnesota Power and Affiliated Companies Executive Investment Plan II (filed as Exhibit 10(c) to the June 30, 2004, Form 10-Q, File No. 1-3548).
+*10(h)4	—	August 2006 Amendment to the Minnesota Power and Affiliated Companies Executive Investment Plan II (filed as Exhibit 10(c) to the September 30, 2006, Form 10-Q, File No. 1-3548).
+*10(i)	—	ALLETE Deferred Compensation Trust Agreement, as amended and restated, effective December 15, 2012 (filed as Exhibit 10(j) to the 2012 Form 10-K, File No. 1-3548).
+*10(j)1	—	ALLETE Executive Long-Term Incentive Compensation Plan as amended and restated effective January 1, 2006 (filed as Exhibit 10 to the May 16, 2005, Form 8-K, File No. 1-3548).
+*10(j)2	—	Amendment to the ALLETE Executive Long-Term Incentive Compensation Plan, effective January 1, 2011 (filed as Exhibit 10(m)2 to the 2010 Form 10-K, File No. 1-3548).
+*10(j)3	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2010 (filed as Exhibit 10(m)8 to the 2009 Form 10-K, File No. 1-3548).
+*10(j)4	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Restricted Stock Unit Grant Effective 2010 (filed as Exhibit 10(m)9 to the 2009 Form 10-K, File No. 1-3548).
+*10(j)5	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2011 (filed as Exhibit 10(m)11 to the 2010 Form 10-K, File No. 1-3548).
+*10(j)6	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Restricted Stock Unit Grant Effective 2011 (filed as Exhibit 10(m)12 to the 2010 Form 10-K, File No. 1-3548).
+*10(j)7	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2012 (filed as Exhibit 10(m)12 to the 2011 Form 10-K, File No. 1-3548).
+*10(j)8	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Restricted Stock Unit Grant Effective 2012 (filed as Exhibit 10(m)13 to the 2011 Form 10-K, File No. 1-3548).
+*10(j)9	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2013 (filed as Exhibit 10(k)14 to the 2012 Form 10-K, File No. 1-3548).
+*10(j)10	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Restricted Stock Unit Grant Effective 2013 (filed as Exhibit 10(k)15 to the 2012 Form 10-K, File No. 1-3548).
+*10(j)11	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2014 (filed as Exhibit 10(j)14 to the 2013 Form 10-K, File No. 1-3548).
+*10(j)12	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Restricted Stock Unit Grant Effective 2014 (filed as Exhibit 10(j)15 to the 2013 Form 10-K, File No. 1-3548).
+*10(j)13	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2015 (filed as Exhibit 10(j)16 to the 2014 Form 10-K, File No. 1-3548).
+*10(j)14	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Restricted Stock Unit Grant Effective 2015 (filed as Exhibit 10(j)17 to the 2014 Form 10-K, File No. 1-3548).
+*10(k)1	—	ALLETE Executive Long-Term Incentive Compensation Plan effective January 1, 2016 (filed November 6, 2015, as Exhibit 99 to Form S-8, File No. 333-207846).
+10(k)2	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Restricted Stock Unit Grant Effective 2016.
+10(k)3	—	Form of ALLETE Executive Long-Term Incentive Compensation Plan Performance Share Grant Effective 2016.
+*10(l)1	—	Minnesota Power (now ALLETE) Non-Employee Director Stock Plan, effective May 9, 1995 (filed as Exhibit 10 to the March 31, 1995, Form 10-Q, File No. 1-3548).
+*10(l)2	—	Amendments through December 2003 to the Minnesota Power (now ALLETE) Non-Employee Director Stock Plan (filed as Exhibit 10(z)2 to the 2003 Form 10-K, File No. 1-3548).
+*10(l)3	—	July 2004 Amendment to the ALLETE Non-Employee Director Stock Plan (filed as Exhibit 10(e) to the June 30, 2004, Form 10-Q, File No. 1-3548).
+*10(l)4	—	January 2007 Amendment to the ALLETE Non-Employee Director Stock Plan (filed as Exhibit 10(n)4 to the 2006 Form 10-K, File No. 1-3548).
+*10(l)5	—	May 2009 Amendment to the ALLETE Non-Employee Director Stock Plan (filed as Exhibit 10(b) to the June 30, 2009, Form 10-Q, File No. 1-3548).
+*10(l)6	—	May 2010 Amendment to the ALLETE Non-Employee Director Stock Plan (filed as Exhibit 10(a) to the June 30, 2010, Form 10-Q, File No. 1-3548).

Exhibit Number

+*10(l)7	—	October 2010 Amendment to the ALLETE Non-Employee Director Stock Plan (filed as Exhibit 10 to the September 30, 2010, Form 10-Q, File No. 1-3548).
+*10(l)8	—	Amended and Restated ALLETE Non-Employee Director Stock Plan, effective May 15, 2013 (filed as Exhibit 10(a) to the June 30, 2013, Form 10-Q, File No. 1-3548).
+*10(m)1	—	ALLETE Non-Management Director Compensation Summary effective January 19, 2012 (filed as Exhibit 10(n)10 to the 2011 Form 10-K, File No. 1-3548).
+*10(m)2	—	ALLETE Non-Management Director Compensation Summary effective January 1, 2014 (filed as Exhibit 10(l)4 to the 2013 Form 10-K, File No. 1-3548).
+*10(m)3	—	ALLETE Non-Employee Director Compensation Summary effective January 1, 2015 (filed as Exhibit 10(l)5 to the 2014 Form 10-K, File No. 1-3548).
+*10(n)1	—	Minnesota Power (now ALLETE) Non-Employee Director Compensation Deferral Plan Amended and Restated, effective January 1, 1990 (filed as Exhibit 10(ac) to the 2002 Form 10-K, File No. 1-3548).
+*10(n)2	—	October 2003 Amendment to the Minnesota Power (now ALLETE) Non-Employee Director Compensation Deferral Plan (filed as Exhibit 10(aa)2 to the 2003 Form 10-K, File No. 1-3548).
+*10(n)3	—	January 2005 Amendment to the ALLETE Non-Employee Director Compensation Deferral Plan (filed as Exhibit 10(c) to the March 31, 2005, Form 10-Q, File No. 1-3548).
+*10(n)4	—	October 2006 Amendment to the ALLETE Non-Employee Director Compensation Deferral Plan (filed as Exhibit 10(d) to the September 30, 2006, Form 10-Q, File No. 1-3548).
+*10(n)5	—	July 2012 Amendment to the ALLETE Non-Employee Director Compensation Deferral Plan (filed as Exhibit 10(n)5 to the 2012 Form 10-K, File No. 1-3548).
+*10(o)1	—	ALLETE Non-Employee Director Compensation Deferral Plan II, effective May 1, 2009 (filed as Exhibit 10(a) to the June 30, 2009, Form 10-Q, File No. 1-3548).
+*10(o)2	—	ALLETE Non-Employee Director Compensation Deferral Plan II, as amended and restated, effective July 24, 2012 (filed as Exhibit 10(o)2 to the 2012 Form 10-K, File No. 1-3548).
+*10(p)	—	ALLETE Non-Employee Director Compensation Trust Agreement, as amended and restated, effective December 15, 2012 (filed as Exhibit 10(p)2 to the 2012 Form 10-K, File No. 1-3548).
+*10(q)	—	ALLETE and Affiliated Companies Change in Control Severance Plan, as amended and restated, effective January 19, 2011 (filed as Exhibit 10(q) to the 2010 Form 10-K, File No. 1-3548).
12	—	Computation of Ratios of Earnings to Fixed Charges.
21	—	Subsidiaries of the Registrant.
23	—	Consent of Independent Registered Public Accounting Firm.
31(a)	—	Rule 13a-14(a)/15d-14(a) Certification by the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31(b)	—	Rule 13a-14(a)/15d-14(a) Certification by the Chief Financial Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32	—	Section 1350 Certification of Annual Report by the Chief Executive Officer and Chief Financial Officer Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
95	—	Mine Safety.
99	—	ALLETE News Release dated February 18, 2016, announcing earnings for the year ended December 31, 2015. **(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

Exhibits (Continued)

ALLETE or its subsidiaries are obligors under various long-term debt instruments including, but not limited to, the following:

- $38,995,000 original principal amount, of City of Cohasset, Minnesota, Variable Rate Demand Revenue Refunding Bonds (ALLETE, formerly Minnesota Power & Light Company, Project) Series 1997A ($13,500,000 remaining principal balance);
- $27,800,000 of Collier County Industrial Development Authority, Industrial Development Variable Rate Demand Refunding Revenue Bonds Series 2006;
- $6,370,000 of City of Superior, Wisconsin, Collateralized Utility Revenue Refunding Bonds Series 2007A; and
- $6,130,000 of City of Superior, Wisconsin, Collateralized Utility Revenue Bonds Series 2007B.

Pursuant to Regulation S-K, Item 601(b)(4)(iii), the long-term debt instruments above are not filed as exhibits because the total amount of debt authorized under each of these omitted instruments does not exceed 10 percent of our total consolidated assets. We will furnish copies of these instruments to the SEC upon its request.

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* *Incorporated herein by reference as indicated.*

\+ *Management contract or compensatory plan or arrangement pursuant to Item 15(b).*

Signatures

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

ALLETE, Inc.

Dated: February 22, 2016

By /s/ Alan R. Hodnik
Alan R. Hodnik
Chairman, President, Chief Executive Officer

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

Signature	Title	Date
/s/ Alan R. Hodnik Alan R. Hodnik	Chairman, President, Chief Executive Officer and Director (Principal Executive Officer)	February 22, 2016
/s/ Steven Q. DeVinck Steven Q. DeVinck	Senior Vice President and Chief Financial Officer (Principal Financial Officer)	February 22, 2016
/s/ Steven W. Morris Steven W. Morris	Controller (Principal Accounting Officer)	February 22, 2016

Signatures (Continued)

Signature	Title	Date
/s/ Kathryn W. Dindo Kathryn W. Dindo	Director	February 22, 2016
/s/ Sidney W. Emery, Jr. Sidney W. Emery, Jr.	Director	February 22, 2016
/s/ George G. Goldfarb George G. Goldfarb	Director	February 22, 2016
/s/ James S. Haines, Jr. James S. Haines, Jr.	Director	February 22, 2016
/s/ James J. Hoolihan James J. Hoolihan	Director	February 22, 2016
/s/ Heidi E. Jimmerson Heidi E. Jimmerson	Director	February 22, 2016
/s/ Madeleine W. Ludlow Madeleine W. Ludlow	Director	February 22, 2016
/s/ Douglas C. Neve Douglas C. Neve	Director	February 22, 2016
/s/ Leonard C. Rodman Leonard C. Rodman	Director	February 22, 2016

Report of Independent Registered Public Accounting Firm

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

In our opinion, the accompanying consolidated balance sheets and the related consolidated statements of income, comprehensive income, shareholders' equity and cash flows present fairly, in all material respects, the financial position of ALLETE, Inc. and its subsidiaries at December 31, 2015 and December 31, 2014 and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2015 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under Item 15(a)(2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015 based on criteria established in *Internal Control - Integrated Framework* (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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

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

As described in Management's Report on Internal Control over Financial Reporting, management has excluded U.S. Water Services from its assessment of internal control over financial reporting as of December 31, 2015 because it was acquired by the Company in a purchase business combination during 2015. We have also excluded U.S. Water Services from our audit of internal control over financial reporting. U.S. Water Services is a wholly-owned subsidiary whose total assets and total revenues represent 5 percent and 8 percent, respectively, of the related consolidated financial statement amounts as of and for the year ended December 31, 2015.

/s/ PricewaterhouseCoopers LLP

Minneapolis, Minnesota
February 22, 2016

CONSOLIDATED FINANCIAL STATEMENTS

ALLETE Consolidated Balance Sheet

As of December 31	2015	2014
Millions		
Assets		
Current Assets		
Cash and Cash Equivalents	$97.0	$145.8
Accounts Receivable (Less Allowance of $1.0 and $1.1)	121.2	103.0
Inventories	117.1	80.5
Prepayments and Other	35.7	82.0
Deferred Income Taxes	—	7.5
Total Current Assets	371.0	418.8
Property, Plant and Equipment – Net	3,669.1	3,284.8
Regulatory Assets	372.0	357.3
Investment in ATC	124.5	121.1
Other Investments	74.6	114.4
Goodwill and Intangible Assets – Net	215.2	4.8
Other Non-Current Assets	80.7	59.6
Total Assets	$4,907.1	$4,360.8
Liabilities and Equity		
Liabilities		
Current Liabilities		
Accounts Payable	$88.8	$134.1
Accrued Taxes	44.0	38.7
Accrued Interest	18.6	18.0
Long-Term Debt Due Within One Year	36.3	100.7
Notes Payable	1.6	3.7
Other	86.1	120.8
Total Current Liabilities	275.4	416.0
Long-Term Debt	1,568.7	1,272.8
Deferred Income Taxes	579.8	510.7
Regulatory Liabilities	105.0	94.2
Defined Benefit Pension and Other Postretirement Benefit Plans	206.8	190.9
Other Non-Current Liabilities	349.0	265.0
Total Liabilities	3,084.7	2,749.6
Commitments, Guarantees and Contingencies (Note 12)		
Equity		
ALLETE's Equity		
Common Stock Without Par Value, 80.0 Shares Authorized, 49.1 and 45.9 Shares Outstanding	1,271.4	1,107.6
Unearned ESOP Shares	—	(7.2)
Accumulated Other Comprehensive Loss	(24.5)	(21.1)
Retained Earnings	573.3	530.1
Total ALLETE Equity	1,820.2	1,609.4
Non-Controlling Interest in Subsidiaries	2.2	1.8
Total Equity	1,822.4	1,611.2
Total Liabilities and Equity	$4,907.1	$4,360.8

The accompanying notes are an integral part of these statements.

ALLETE Consolidated Statement of Income

Year Ended December 31	2015	2014	2013
Millions Except Per Share Amounts			
Operating Revenue	$1,486.4	$1,136.8	$1,018.4
Operating Expenses			
Fuel and Purchased Power	328.1	356.1	334.8
Transmission Services	54.1	45.6	32.3
Cost of Sales	302.3	77.9	71.2
Operating and Maintenance	333.5	287.1	267.7
Depreciation and Amortization	170.0	135.7	116.6
Taxes Other than Income Taxes	51.4	45.6	41.7
Impairment of Real Estate	36.3	—	—
Total Operating Expenses	1,275.7	948.0	864.3
Operating Income	210.7	188.8	154.1
Other Income (Expense)			
Interest Expense	(64.9)	(54.8)	(50.3)
Equity Earnings in ATC	16.3	19.6	20.3
Other	4.7	8.6	9.3
Total Other Expense	(43.9)	(26.6)	(20.7)
Income Before Non-Controlling Interest and Income Taxes	166.8	162.2	133.4
Income Tax Expense	25.3	36.7	28.7
Net Income	141.5	125.5	104.7
Less: Non-Controlling Interest in Subsidiaries	0.4	0.7	—
Net Income Attributable to ALLETE	$141.1	$124.8	$104.7
Average Shares of Common Stock			
Basic	48.3	42.9	39.7
Diluted	48.4	43.1	39.8
Basic Earnings Per Share of Common Stock	$2.92	$2.91	$2.64
Diluted Earnings Per Share of Common Stock	$2.92	$2.90	$2.63
Dividends Per Share of Common Stock	$2.02	$1.96	$1.90

The accompanying notes are an integral part of these statements.

ALLETE Consolidated Statement of Comprehensive Income

Year Ended December 31	2015	2014	2013
Millions			
Net Income	$141.5	$125.5	$104.7
Other Comprehensive Income (Loss)			
Unrealized Loss on Securities			
Net of Income Taxes of $(0.3), $(0.2) and $–	(0.5)	(0.2)	—
Unrealized Gain on Derivatives			
Net of Income Taxes of $0.1, $0.1 and $–	0.1	0.2	0.1
Defined Benefit Pension and Other Postretirement Benefit Plans			
Net of Income Taxes of $(2.2), $(2.8) and $3.3	(3.0)	(4.0)	4.8
Total Other Comprehensive Income (Loss)	(3.4)	(4.0)	4.9
Total Comprehensive Income	138.1	121.5	109.6
Less: Non-Controlling Interest in Subsidiaries	0.4	0.7	—
Comprehensive Income Attributable to ALLETE	$137.7	$120.8	$109.6

The accompanying notes are an integral part of these statements.

ALLETE Consolidated Statement of Cash Flows

Year Ended December 31	2015	2014	2013
Millions			
Operating Activities			
Net Income	$141.5	$125.5	$104.7
Allowance for Funds Used During Construction – Equity	(3.3)	(7.8)	(4.6)
Income from Equity Investments – Net of Dividends	(1.8)	(2.6)	(4.2)
Impairment of Real Estate	36.3	—	—
Gain on Sales of Investments and Property, Plant and Equipment	(0.2)	(0.2)	(2.6)
Depreciation Expense	165.9	135.7	116.6
Amortization of Power Purchase Agreements	(23.2)	(12.7)	—
Amortization of Other Intangible Assets and Other Assets	5.6	0.7	1.0
Deferred Income Tax Expense	25.1	32.7	28.6
Share-Based Compensation Expense	2.6	2.3	2.4
ESOP Compensation Expense	9.0	9.1	8.4
Defined Benefit Pension and Other Postretirement Benefit Expense	15.4	12.8	21.0
Bad Debt Expense	1.6	1.8	1.3
Changes in Operating Assets and Liabilities			
Accounts Receivable	1.1	(3.5)	(8.6)
Inventories	(22.1)	(17.5)	10.5
Prepayments and Other	3.7	4.8	(1.4)
Accounts Payable	(19.3)	10.9	1.1
Other Current Liabilities	5.1	(3.5)	1.4
Cash Contributions to Defined Benefit Pension and Other Postretirement Plans	—	—	(10.8)
Changes in Regulatory and Other Non-Current Assets	0.6	(21.3)	(18.3)
Changes in Regulatory and Other Non-Current Liabilities	(3.5)	2.6	(7.1)
Cash from Operating Activities	340.1	269.8	239.4
Investing Activities			
Proceeds from Sale of Available-for-sale Securities	1.7	3.6	16.1
Payments for Purchase of Available-for-sale Securities	(2.3)	(5.0)	(4.7)
Acquisitions of Subsidiaries – Net of Cash Acquired	(333.3)	(60.3)	—
Investment in ATC	(1.6)	(3.9)	(3.1)
Changes to Other Investments	3.1	33.0	(12.3)
Additions to Property, Plant and Equipment	(286.8)	(572.8)	(328.5)
Construction Costs for Development Project	—	(25.7)	—
Cash in Escrow for Acquisition	—	5.4	(5.4)
Proceeds from Sale of Property, Plant and Equipment	0.4	—	1.3
Cash for Investing Activities	(618.8)	(625.7)	(336.6)
Financing Activities			
Proceeds from Issuance of Common Stock	161.2	200.6	98.2
Proceeds from Issuance of Long-Term Debt	324.5	375.0	169.8
Changes in Restricted Cash	8.5	(1.8)	—
Changes in Notes Payable	(2.1)	3.7	—
Repayments of Long-Term Debt	(160.2)	(134.5)	(77.7)
Acquisition of Non-Controlling Interest	—	(6.0)	—
Construction Deposits Received for Development Project	—	54.3	—
Debt Issuance Costs	(4.1)	(3.1)	(1.4)
Dividends on Common Stock	(97.9)	(83.8)	(75.2)
Cash from Financing Activities	229.9	404.4	113.7
Change in Cash and Cash Equivalents	(48.8)	48.5	16.5
Cash and Cash Equivalents at Beginning of Period	145.8	97.3	80.8
Cash and Cash Equivalents at End of Period	$97.0	$145.8	$97.3

The accompanying notes are an integral part of these statements.

ALLETE Consolidated Statement of Shareholders' Equity

Millions	Total Shareholders' Equity	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Unearned ESOP Shares	Common Stock
Balance as of December 31, 2012	$1,201.0	$459.6	$(22.0)	$(21.3)	$784.7
Comprehensive Income					
Net Income	104.7	104.7			
Other Comprehensive Income – Net of Tax					
Unrealized Gain on Derivatives – Net	0.1		0.1		
Defined Benefit Pension and Other Postretirement Plans – Net	4.8		4.8		
Total Comprehensive Income Attributable to ALLETE	109.6				
Common Stock Issued – Net	100.5				100.5
Dividends Declared	(75.2)	(75.2)			
ESOP Shares Earned	7.0			7.0	
Balance as of December 31, 2013	1,342.9	489.1	(17.1)	(14.3)	885.2
Comprehensive Income					
Net Income	125.5	125.5			
Other Comprehensive Income – Net of Tax					
Unrealized Loss on Securities – Net	(0.2)		(0.2)		
Unrealized Gain on Derivatives – Net	0.2		0.2		
Defined Benefit Pension and Other Postretirement Plans – Net	(4.0)		(4.0)		
Total Comprehensive Income	121.5				
Non-Controlling Interest in Subsidiaries	(0.7)	(0.7)			
Total Comprehensive Income Attributable to ALLETE	120.8				
Common Stock Issued – Net	222.4				222.4
Dividends Declared	(83.8)	(83.8)			
ESOP Shares Earned	7.1			7.1	
Balance as of December 31, 2014	1,609.4	530.1	(21.1)	(7.2)	1,107.6
Comprehensive Income					
Net Income	141.5	141.5			
Other Comprehensive Income – Net of Tax					
Unrealized Loss on Securities – Net	(0.5)		(0.5)		
Unrealized Gain on Derivatives – Net	0.1		0.1		
Defined Benefit Pension and Other Postretirement Plans – Net	(3.0)		(3.0)		
Total Comprehensive Income	138.1				
Non-Controlling Interest in Subsidiaries	(0.4)	(0.4)			
Total Comprehensive Income Attributable to ALLETE	137.7				
Common Stock Issued – Net	163.8				163.8
Dividends Declared	(97.9)	(97.9)			
ESOP Shares Earned	7.2			7.2	
Balance as of December 31, 2015	$1,820.2	$573.3	$(24.5)	—	$1,271.4

The accompanying notes are an integral part of these statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES

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

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

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

Reclassifications. As a result of recent acquisitions, certain financial statement captions have been added and we have reclassified certain prior-period amounts on our Consolidated Balance Sheet and Consolidated Statement of Income 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 $77.9 million from Operating and Maintenance expenses to Cost of Sales for the year ended December 31, 2014, and $71.2 million for the year ended December 31, 2013. Cost of Sales includes purchased gas at SWL&P, expenses incurred to deliver coal at BNI Energy, 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 which was acquired on February 10, 2015, and ALLETE Clean Energy's cost to construct a wind energy facility that was sold to Montana-Dakota Utilities in 2015. (See Note 7. 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 $45.6 million of Transmission Services and $45.6 million of Taxes Other than Income Taxes for the year ended December 31, 2014, and $32.3 million of Transmission Services and $41.7 million of Taxes Other than Income Taxes for the year ended December 31, 2013. There was no impact to Operating Income, Net Income, or Net Income Attributable to ALLETE as a result of these reclassifications.

Business Segments. During the year ended December 31, 2015, management updated our reportable segment presentation to reflect the manner in which we operate, assess, and allocate resources after our recent acquisitions. We now present three reportable segments, Regulated Operations, ALLETE Clean Energy, and U.S. Water Services. Our segments were determined in accordance with the guidance on segment reporting. We measure performance of our operations through budgeting and monitoring of contributions to consolidated net income by each business segment.

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 145,000 retail customers. Minnesota Power also has 16 non-affiliated municipal customers in Minnesota. SWL&P is a Wisconsin utility and a wholesale customer of Minnesota Power. SWL&P provides regulated electric, natural gas and water service in northwestern Wisconsin to approximately 15,000 electric customers, 13,000 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.

ALLETE Clean Energy was established in 2011, and focuses on developing, acquiring and operating clean and renewable energy projects. ALLETE Clean Energy currently owns and operates, in four states, approximately 535 MW of nameplate capacity wind energy generation that are under long-term power sales agreements. In addition, ALLETE Clean Energy constructed a 107 MW wind energy facility for sale to Montana-Dakota Utilities; construction and sale were completed in 2015.

U.S. Water Services is our integrated water management company which was acquired on February 10, 2015.

Corporate and Other is comprised of BNI Energy, ALLETE Properties, 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.

BNI Energy, a wholly-owned subsidiary, mines and sells lignite coal to two North Dakota mine-mouth generating units, one of which is Square Butte. In 2015, Square Butte supplied 50 percent (227.5 MW) of its output to Minnesota Power under long-term contracts. (See Note 12. Commitments, Guarantees and Contingencies.)

ALLETE Properties represents our legacy Florida real estate investment. Our strategy for the assets had been to complete and maintain key entitlements and infrastructure improvements without requiring significant additional investment, sell the portfolio when opportunities arise and reinvest the proceeds in our growth initiatives. During the fourth quarter of 2015 the Company reevaluated its strategy related to the real estate assets of ALLETE Properties. The revised strategy incorporates the possibility of a bulk sale of its entire portfolio which, if consummated, is likely to result in sales proceeds below the book value of the real estate assets. ALLETE also continues to pursue sales of individual parcels over time. Proceeds from such a sale would be strategically deployed to support growth in our energy infrastructure and related services businesses. ALLETE will continue to maintain key entitlements and infrastructure without making additional investments or acquisitions. (See Note 9. Investments.)

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

Supplemental Statement of Cash Flow Information

Consolidated Statement of Cash Flows Year Ended December 31	2015	2014	2013
Millions			
Cash Paid During the Period for Interest – Net of Amounts Capitalized	$59.0	$51.3	$47.5
Cash Paid During the Period for Income Taxes	$0.4	$5.1	$0.5
Noncash Investing and Financing Activities			
Increase (Decrease) in Accounts Payable for Capital Additions to Property, Plant and Equipment	$(40.6)	$21.7	$8.3
Capitalized Asset Retirement Costs	$12.4	$22.4	$(0.7)
AFUDC–Equity	$3.3	$7.8	$4.6
ALLETE Common Stock Contributed to the Defined Benefit Pension Plan	—	$19.5	—
Contingent Consideration	$35.7	—	—

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

Accounts Receivable As of December 31	2015	2014
Millions		
Trade Accounts Receivable		
Billed	$105.3	$85.5
Unbilled	16.9	18.6
Less: Allowance for Doubtful Accounts	1.0	1.1
Total Accounts Receivable	$121.2	$103.0

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Concentration of Credit Risk. We are subject to concentration of credit risk primarily as a result of accounts receivable. Minnesota Power sells electricity to 9 Large Power Customers. Receivables from these customers totaled $9.2 million at December 31, 2015 ($14.7 million at December 31, 2014). Minnesota Power does not obtain collateral to support utility receivables, but monitors the credit standing of major customers. In addition, Minnesota Power's taconite-producing Large Power Customers are on a weekly billing cycle, which allows us to closely manage collection of amounts due. One of these customers accounted for 7.7 percent of consolidated operating revenue in 2015 (11.9 percent in 2014; 12.0 percent in 2013).

Long-Term Finance Receivables. Long-term finance receivables relating to our real estate operations are collateralized by property sold, accrue interest at market-based rates and are net of an allowance for doubtful accounts. We assess delinquent finance receivables by comparing the balance of such receivables to the estimated fair value of the collateralized property. If the fair value of the property is less than the finance receivable, we record a reserve for the difference. We estimate fair value based on recent property tax assessed values or current appraisals.

Available-for-Sale Securities. Available-for-sale securities are recorded at fair value with unrealized gains and losses included in accumulated other comprehensive income (loss), net of tax. Unrealized losses that are other than temporary are recognized in earnings. We use the specific identification method as the basis for determining the cost of securities sold. Our policy is to review available-for-sale securities for other than temporary impairment on a quarterly basis by assessing such factors as the share price trends and the impact of overall market conditions. (See Note 9. Investments.)

Inventories. Inventories are stated at the lower of cost or market. Amounts removed from inventories in our Regulated Operations and ALLETE Clean Energy segments are recorded on an average cost basis. Amounts removed from inventories in our U.S. Water Services and Corporate and Other segments are recorded on an average cost, first-in, first-out or specific identification basis.

Inventories

As of December 31	**2015**	**2014**
Millions		
Fuel *(a)*	$58.1	$29.0
Materials and Supplies	49.1	51.5
Raw Materials	2.7	—
Finished Goods	7.5	—
Reserve for Obsolescence	(0.3)	—
Total Inventories	$117.1	$80.5

(a) Fuel consists primarily of coal inventory at Minnesota Power. During 2015, Minnesota Power increased its coal inventory to take advantage of favorable pricing.

Prepayments and Other Current Assets

As of December 31	**2015**	**2014**
Millions		
Deferred Fuel Adjustment Clause	$10.6	$16.3
Construction Costs for Development Project *(a)*	—	48.2
Restricted Cash *(b)*	5.6	2.7
Other	19.5	14.8
Total Prepayments and Other Current Assets	$35.7	$82.0

(a) Construction Costs for Development Project related to ALLETE Clean Energy's project to construct a wind energy facility which was sold in 2015. (See Note 7. Acquisitions.)

(b) Restricted Cash includes collateral deposits required under ALLETE Clean Energy's loan agreements and collateral deposits required for U.S. Water Services' standby letters of credit.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Property, Plant and Equipment. Property, plant and equipment are recorded at original cost and are reported on the balance sheet net of accumulated depreciation. Expenditures for additions, significant replacements, improvements and major plant overhauls are capitalized; maintenance and repair costs are expensed as incurred. Gains or losses on non-rate base property, plant and equipment are recognized when they are retired or otherwise disposed. When regulated utility property, plant and equipment are retired or otherwise disposed, no gain or loss is recognized in accordance with the accounting standards for the effects of certain types of regulation. Our Regulated Operations capitalize AFUDC, which includes both an interest and equity component. AFUDC represents the cost of both debt and equity funds used to finance utility plant additions during construction periods. AFUDC amounts capitalized are included in rate base and are recovered from customers as the related property is depreciated. Upon MPUC approval of cost recovery, the recognition of AFUDC ceases. (See Note 3. Property, Plant and Equipment.)

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. Minnesota Power retired Taconite Harbor Unit 3 and converted Laskin to natural gas in 2015, which were actions included in Minnesota Power's 2013 IRP approved by the MPUC in a November 2013 order. On September 1, 2015, Minnesota Power filed its 2015 IRP with the MPUC. The 2015 IRP contains the next steps in Minnesota Power's *EnergyForward* plan including the economic idling of Taconite Harbor Units 1 and 2 in the fall of 2016 and the ceasing of coal-fired operations at Taconite Harbor in 2020. We do not expect to record any impairment charge as a result of the retirement of Taconite Harbor Unit 3, the ceasing of coal-fired operations at Taconite Harbor Units 1 and 2, or the conversion of Laskin. In addition, we expect to be able to continue depreciating these assets over their established remaining useful lives; however we are unable to predict the impact of unanticipated regulatory outcomes resulting in changes to their established remaining useful lives. The remaining net book value for Taconite Harbor as of December 31, 2015 was approximately $100 million. We would seek recovery in a general rate case of additional depreciation expense as a result of material changes in useful lives.

Impairment of Long-Lived Assets. Land inventory is accounted for as held for use and is recorded at cost or estimated fair value. We review our long-lived assets, which include the legacy real estate assets of ALLETE Properties, for indicators of impairment in accordance with the accounting standards for property, plant and equipment on a quarterly basis.

In accordance with the accounting standards for property, plant and equipment, if indicators of impairment exist, we test our real estate assets for recoverability by comparing the carrying amount of the asset to the undiscounted future net cash flows expected to be generated by the asset. Cash flows are assessed at the lowest level of identifiable cash flows, which may include a bulk sale of its entire portfolio, the sale of each individual land parcel, combining various parcels, or other combinations thereof. Our consideration of possible impairment for our real estate assets requires us to make estimates of future net cash flows on an undiscounted basis. The undiscounted future net cash flows are impacted by trends and factors known to us at the time they are calculated and our expectations related to: management's best estimate of future sales prices; holding period and timing of sales; method of disposition; and future expenditures necessary to maintain the operations, including community development district assessments, property taxes and normal operation and maintenance costs. These estimates and expectations are specific to each land parcel, may vary among each land parcel, and may change in the future. If the excess of undiscounted future net cash flows over the carrying amount of a property is small, there is a greater risk of future impairment in the event of such future changes and any resulting impairment charges could be material.

In recent years, market conditions for real estate in Florida have required us to review our land inventories for impairment. In response to market conditions and recent transaction activity, during the fourth quarter of 2015 the Company reevaluated its strategy related to the real estate assets of ALLETE Properties. The revised strategy incorporates the possibility of a bulk sale of its entire portfolio which, if consummated, is likely to result in sales proceeds below the book value of the real estate assets. ALLETE also continues to pursue sales of individual parcels over time. Proceeds from such a sale would be strategically deployed to support growth in our energy infrastructure and related services businesses. ALLETE will continue to maintain key entitlements and infrastructure without making additional investments or acquisitions.

In connection with implementing the revised strategy in 2015, management evaluated its impairment analysis for its real estate assets using updated assumptions to determine estimated future net cash flows on an undiscounted basis. Future net cash flows were adjusted to consider the possibility of a bulk sale of its entire portfolio, in addition to sales over time under the existing divestiture plan. Estimated fair values were based upon current market data and pricing for individual parcels. Our impairment analysis incorporates a probability-weighted approach considering the alternative courses of sales noted above.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)
Impairment of Long-Lived Assets (Continued)

Based on the results of undiscounted cash flow analysis, the undiscounted future net cash flows were not adequate to recover the carrying value of the real estate assets totaling $83.3 million. Estimated fair value was derived from current market interest in the property for a bulk sale of its entire portfolio, and discounted cash flow analysis of estimated selling price for sales over time. As a result, a non-cash impairment charge of $36.3 million was recorded in 2015 to reduce the carrying value of the real estate to its estimated fair value at December 31, 2015.

If our real estate assets are sold differently than anticipated, the actual results could be materially different from our undiscounted future net cash flow analysis.

In 2014 and 2013, impairment analyses of estimated undiscounted future net cash flows were conducted based on the strategy existing at that time, and indicated that the cash flows were adequate to recover the carrying value of ALLETE Properties real estate assets. As a result, no impairment was recorded for the years ended December 31, 2014 and 2013.

Derivatives. ALLETE is exposed to certain risks relating to its business operations that can be managed through the use of derivative instruments. ALLETE may enter into derivative instruments to manage those risks including interest rate risk related to certain variable-rate borrowings.

Accounting for Stock-Based Compensation. We apply the fair value recognition guidance for share-based payments. Under this guidance, we recognize stock-based compensation expense for all share-based payments granted, net of an estimated forfeiture rate. (See Note 18. Employee Stock and Incentive Plans.)

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. To align with the annual budgeting and forecasting process, goodwill is assessed annually in the fourth quarter for impairment 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.

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, which are amortized using an attrition model, and patents and non-compete agreements, which are amortized on a straight-line basis with estimated useful lives ranging from approximately 3 years to approximately 22 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 fourth 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. As of December 31, 2015, included in Other Non-Current Assets on the Consolidated Balance Sheet was restricted cash of $8.1 million related to collateral deposits required under ALLETE Clean Energy's loan agreements ($5.3 million as of December 31, 2014).

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Other Current Liabilities **As of December 31**	**2015**	**2014**
Millions		
Customer Deposits	$15.1	$19.7
Power Purchase Agreements *(a)*	23.3	19.4
Construction Deposits Received for Development Project *(b)*	—	54.3
Other *(c)*	47.7	27.4
Total Other Current Liabilities	$86.1	$120.8

(a) Power Purchase Agreements acquired in conjunction with the ALLETE Clean Energy wind energy facilities acquisitions. (See Note 7. Acquisitions.)

(b) Construction Deposits Received for Development Project relate to ALLETE Clean Energy's project to construct a wind energy facility which was sold in 2015. (See Note 7. Acquisitions.)

(c) Increase in 2015 includes customer refund liabilities of approximately $7 million, pending regulatory approval.

Other Non-Current Liabilities **As of December 31**	**2015**	**2014**
Millions		
Asset Retirement Obligation	$131.4	$109.2
Power Purchase Agreements *(a)*	138.1	110.7
Contingent Consideration *(b)*	36.6	—
Other	42.9	45.1
Total Other Non-Current Liabilities	$349.0	$265.0

(a) Power Purchase Agreements acquired in conjunction with the ALLETE Clean Energy wind energy facilities acquisitions. (See Note 7. 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 7. Acquisitions and Note 10. Fair Value.)

Environmental Liabilities. We review environmental matters on a quarterly basis. Accruals for environmental matters are recorded when it is probable that a liability has been incurred and the amount of the liability can be reasonably estimated, based on current law and existing technologies. 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 expensed unless recoverable in rates from customers. (See Note 12. Commitments, Guarantees and Contingencies.)

Revenue Recognition.

Regulated Operations utility rates are under the jurisdiction of Minnesota, Wisconsin and federal regulatory authorities. Customers are billed on a cycle basis. Revenue is accrued for service provided but not yet billed. Regulated utility electric rates include adjustment clauses that: (1) bill or credit customers for fuel and purchased energy costs above or below the base levels in rate schedules; (2) bill retail customers for the recovery of conservation improvement program expenditures not collected in base rates; and (3) bill customers for the recovery of certain transmission, renewable energy and environmental expenditures. Fuel and purchased power expense is deferred to match the period in which the revenue for fuel and purchased power expense is collected from customers pursuant to the fuel adjustment clause.

Revenue from our cost recovery riders (renewable resources, transmission and environmental improvement) is accounted for in accordance with the accounting standards for alternative revenue programs. These standards allow for recognizing revenue under an alternative revenue program if the program is established by an order from the utility's regulatory commission, the order allows automatic adjustment of future rates, the amount of the revenue recognized is objectively determinable and probable of recovery, and the revenue will be collected within 24 months following the end of the annual period in which it is recognized. Revenue recognized using the alternative revenue program guidance is included in Operating Revenue on our Consolidated Statement of Income and Regulatory Assets on our Consolidated Balance Sheet until it is subsequently collected from customers.

Minnesota Power participates in MISO. MISO transactions are accounted for on a net hourly basis in each of the day-ahead and real-time markets. Minnesota Power records net sales in Operating Revenue and net purchases in Fuel and Purchased Power Expense on our Consolidated Statement of Income. The revenue and charges from MISO related to serving retail and municipal electric customers are recorded on a net basis as Fuel and Purchased Power Expense.

ALLETE Clean Energy recognizes revenue from the sale of energy under long-term PPAs. Revenue is recognized when delivered to an agreed upon point or production is curtailed at the request of its customers at specified prices. As part of the wind energy facilities acquisitions in 2014 and 2015, ALLETE Clean Energy assumed various PPAs that were above or below estimated market prices at the time of acquisition and amortizes the resulting differences between contract prices and estimated market prices to Operating Revenue. In 2015, we recognized $23.2 million of non-cash revenue amortization relating to the difference between contract prices and estimated market prices as an increase in Operating Revenue on the Consolidated Statement of Income ($12.7 million in 2014).

U.S. Water Services recognizes revenue from the sale of products when the earnings process is complete. This generally occurs when products are shipped to the customer in accordance with the contract or purchase order, ownership and risk of loss have passed to the customer, collectibility is reasonably assured, and pricing is fixed and determinable. Revenue from services is recognized as the services are performed.

Corporate and Other

BNI Energy recognizes coal sales when delivered at the cost of production plus a specified profit per ton of coal delivered.

ALLETE Properties records full profit recognition on sales of real estate upon closing, provided that cash collections are at least 20 percent of the contract price and the other requirements under the guidance for sales of real estate are met. From time to time, certain contracts with customers allow us to receive participation revenue from land sales to third parties if various formula-based criteria are achieved.

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

Income Taxes. ALLETE and its subsidiaries file a consolidated federal income tax return as well as combined and separate state income tax returns. We account for income taxes using the liability method in accordance with the accounting standards for income taxes. Under the liability method, deferred income tax assets and liabilities are established for all temporary differences in the book and tax basis of assets and liabilities, based upon enacted tax laws and rates applicable to the periods in which the taxes become payable.

Due to the effects of regulation on Minnesota Power and SWL&P, certain adjustments made to deferred income taxes are, in turn, recorded as regulatory assets or liabilities. Federal investment tax credits have been recorded as deferred credits and are being amortized to income tax expense over the service lives of the related property. In accordance with the accounting standards for uncertainty in income taxes, we are required to recognize in our financial statements the largest tax benefit of a tax position that is "more-likely-than-not" to be sustained on audit, based solely on the technical merits of the position as of the reporting date. The term "more-likely-than-not" means more than 50 percent likely. (See Note 15. Income Tax Expense.)

Excise Taxes. We collect excise taxes from our customers levied by government entities. These taxes are stated separately on the billing to the customer and recorded as a liability to be remitted to the government entity. We account for the collection and payment of these taxes on a net basis.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Purchase Accounting. In accordance with the authoritative accounting guidance, the purchase price of an acquired business is generally allocated to the assets acquired and liabilities assumed at their estimated fair values on the date of acquisition. Any unallocated purchase price amount is recognized as goodwill on the Consolidated Balance Sheet if it exceeds the estimated fair value and as a bargain purchase gain on the Consolidated Income Statement if it is below the estimated fair value. Determining the fair value of assets acquired and liabilities assumed requires management's judgment, and the utilization of independent valuation experts as well as involves the use of significant estimates and assumptions with respect to the timing and amounts of future cash inflows and outflows, discount rates, market prices and asset lives, among other items. The judgments made in the determination of the estimated fair value assigned to the assets acquired and liabilities assumed, as well as the estimated useful life of each asset and the duration of each liability, can materially impact the financial statements in periods after acquisition, such as through depreciation and amortization expense. (See Note 7. Acquisitions.)

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 will be applied prospectively to disposals and classifications of disposal groups as held for sale. The impact of this guidance on our consolidated financial position, results of operations or cash flows will be evaluated when 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. The adoption of this update is not expected to have a material impact on our Consolidated Financial Statements.

Simplifying the Measurement of Inventory. In July 2015, the FASB issued an accounting standard which requires entities that measure inventory using the first-in, first-out or average cost methods to measure inventory at the lower of cost or net realizable value. Net realizable value is defined as estimated selling price in the ordinary course of business less reasonably predictable costs of completion, disposal and transportation. This accounting guidance is effective for the Company beginning in the first quarter of 2017; early adoption is permitted. The adoption of this update is not expected to have a material impact on our Consolidated Financial Statements.

Balance Sheet Classification of Deferred Taxes. In November 2015, the FASB issued an accounting standard to simplify the presentation of deferred income taxes. Under the new standard, both deferred tax liabilities and assets are required to be classified as noncurrent instead of separating deferred taxes into current and noncurrent amounts. This accounting guidance is effective for interim and annual reporting periods beginning after December 15, 2016, with early adoption permitted. During the fourth quarter of 2015, we elected to prospectively adopt the new standard, reclassifying $39.4 million of current deferred income tax assets to noncurrent deferred income tax liabilities on our Consolidated Balance Sheet for 2015. Previously reported periods have not been adjusted. The adoption of this guidance had no impact on our Consolidated Statement of Income, Consolidated Statement of Comprehensive Income and Consolidated Statement of Cash Flows.

NOTE 2. BUSINESS SEGMENTS

During the year ended December 31, 2015, management updated our reportable segment presentation to reflect the manner in which we operate, assess, and allocate resources after our recent acquisitions. We now present three reportable segments, Regulated Operations, ALLETE Clean Energy, and U.S. Water Services. Prior period amounts have been revised to conform with the current business segment presentation.

Regulated Operations includes three operating segments which consist of 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. ALLETE Clean Energy is our business focused on 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. The ALLETE Clean Energy and U.S. Water Services reportable segments comprise our Energy Infrastructure and Related Services businesses. We also present Corporate and Other which includes two operating segments, BNI Energy, our coal mining operations in North Dakota, and ALLETE Properties, our legacy Florida real estate investment, along with 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.

NOTE 2. BUSINESS SEGMENTS (Continued)

Year Ended December 31	2015	2014	2013
Millions			
Operating Revenue			
Regulated Operations	$991.2	$1,003.5	$925.5
Energy Infrastructure and Related Services			
ALLETE Clean Energy	262.1	33.2	—
U.S. Water Services	119.8	—	—
Corporate and Other	113.3	100.1	92.9
Total Operating Revenue	$1,486.4	$1,136.8	$1,018.4
Net Income (Loss) Attributable to ALLETE			
Regulated Operations *(a)*	$131.6	$123.0	$103.6
Energy Infrastructure and Related Services			
ALLETE Clean Energy	29.9	3.3	(3.4)
U.S. Water Services	0.9	—	—
Corporate and Other *(a)*	(21.3)	(1.5)	4.5
Total Net Income Attributable to ALLETE	$141.1	$124.8	$104.7
Depreciation and Amortization			
Regulated Operations	$135.1	$118.0	$110.2
Energy Infrastructure and Related Services			
ALLETE Clean Energy	18.7	10.1	—
U.S. Water Services	7.3	—	—
Corporate and Other	8.9	7.6	6.4
Total Depreciation and Amortization	$170.0	$135.7	$116.6
Impairment of Real Estate			
Corporate and Other	$36.3	—	—
Interest Expense			
Regulated Operations *(a)*	$53.9	$49.2	$44.4
Energy Infrastructure and Related Services			
ALLETE Clean Energy	3.3	0.8	—
U.S. Water Services	1.4	—	—
Corporate and Other *(a)*	8.6	7.1	8.2
Eliminations *(a)*	(2.3)	(2.3)	(2.3)
Total Interest Expense	$64.9	$54.8	$50.3
Equity Earnings in ATC			
Regulated Operations	$16.3	$19.6	$20.3
Income Tax Expense (Benefit)			
Regulated Operations	$24.4	$39.0	$35.1
Energy Infrastructure and Related Services			
ALLETE Clean Energy	21.0	2.3	(2.3)
U.S. Water Services	0.9	—	—
Corporate and Other	(21.0)	(4.6)	(4.1)
Total Income Tax Expense	$25.3	$36.7	$28.7

(a) During 2015, an intercompany loan agreement was entered into and interest expense was allocated to certain subsidiaries. The amounts are eliminated in consolidation. Prior period segment results have been revised to conform to the current presentation as if the intercompany loan existed as of January 1, 2013.

NOTE 2. BUSINESS SEGMENTS (Continued)

As of December 31	2015	2014
Millions		
Assets		
Regulated Operations	$3,862.6	$3,709.6
Energy Infrastructure and Related Services		
ALLETE Clean Energy	504.6	291.9
U.S. Water Services	258.3	—
Corporate and Other	281.6	359.3
Total Assets	$4,907.1	$4,360.8
Capital Expenditures		
Regulated Operations	$224.4	$583.5
Energy Infrastructure and Related Services		
ALLETE Clean Energy	8.6	4.2
U.S. Water Services	2.9	—
Corporate and Other	15.9	16.6
Total Capital Expenditures	$251.8	$604.3

NOTE 3. PROPERTY, PLANT AND EQUIPMENT

Property, Plant and Equipment

As of December 31	2015	2014
Millions		
Regulated Operations	$4,336.7	$3,903.3
Construction Work in Progress	101.2	355.4
Accumulated Depreciation	(1,323.8)	(1,260.2)
Regulated Operations – Net	3,114.1	2,998.5
ALLETE Clean Energy	467.3	203.7
Construction Work in Progress	4.0	1.3
Accumulated Depreciation	(24.0)	(8.4)
ALLETE Clean Energy – Net	447.3	196.6
U.S. Water Services	15.6	—
Accumulated Depreciation	(3.4)	—
U.S. Water Services – Net	12.2	—
Corporate and Other *(a)*	165.6	152.5
Construction Work in Progress	4.5	4.6
Accumulated Depreciation	(74.6)	(67.4)
Corporate and Other – Net	95.5	89.7
Property, Plant and Equipment – Net	$3,669.1	$3,284.8

(a) Primarily includes BNI Energy and a small amount of non-rate base generation.

Depreciation is computed using the straight-line method over the estimated useful lives of the various classes of assets.

Estimated Useful Lives of Property, Plant and Equipment

Regulated Operations		ALLETE Clean Energy	5 to 44 years
Generation	10 to 50 years	U.S. Water Services	3 to 39 years
Transmission	44 to 67 years	Corporate and Other	3 to 39 years
Distribution	18 to 65 years		

NOTE 3. PROPERTY, PLANT AND EQUIPMENT (Continued)

Asset Retirement Obligations. We recognize, at fair value, obligations associated with the retirement of certain tangible, long-lived assets that result from the acquisition, construction, development or normal operation of the asset. Asset retirement obligations (ARO) relate primarily to the decommissioning of our coal-fired and wind energy facilities and land reclamation at BNI Energy, and are included in Other Non-Current Liabilities on our Consolidated Balance Sheet. The associated retirement costs are capitalized as part of the related long-lived asset and depreciated over the useful life of the asset. Removal costs associated with certain distribution and transmission assets have not been recognized, as these facilities have indeterminate useful lives.

Conditional asset retirement obligations have been identified for treated wood poles and remaining polychlorinated biphenyl and asbestos-containing assets; however, removal costs have not been recognized because they are considered immaterial to our Consolidated Financial Statements.

Long-standing ratemaking practices approved by applicable state and federal regulatory commissions have allowed provisions for future plant removal costs in depreciation rates. These plant removal cost recoveries are classified either as AROs or as a regulatory liability for non-AROs. To the extent annual accruals for plant removal costs differ from accruals under approved depreciation rates, a regulatory asset has been established in accordance with the guidance for AROs. (See Note 5. Regulatory Matters.)

Asset Retirement Obligations

Millions	
Obligation as of December 31, 2013	$81.8
Accretion	5.5
Liabilities Recognized *(a)*	23.0
Liabilities Settled	(0.5)
Revisions in Estimated Cash Flows	(0.6)
Obligation as of December 31, 2014	109.2
Accretion	7.3
Liabilities Recognized *(b)*	5.1
Liabilities Settled	(2.6)
Revisions in Estimated Cash Flows	12.4
Obligation as of December 31, 2015	$131.4

(a) The increase in 2014 is related to BNI Energy for coal mining expansion and ALLETE Clean Energy due to wind energy facilities acquisitions. (See Note 7. Acquisitions.)

(b) The increase in 2015 is related to the ALLETE Clean Energy wind energy facilities acquisitions in 2015. (See Note 7. Acquisitions.)

NOTE 4. JOINTLY-OWNED FACILITIES AND PROJECTS

Boswell Unit 4. Minnesota Power owns 80 percent of the 585 MW Boswell Unit 4. While Minnesota Power operates the plant, certain decisions about the operations of Boswell Unit 4 are subject to the oversight of a committee on which it and WPPI Energy, the owner of the remaining 20 percent, have equal representation and voting rights. Each owner must provide its own financing and is obligated to its ownership share of operating costs. Minnesota Power's share of direct operating expenses of Boswell Unit 4 is included in operating expense on our Consolidated Statement of Income.

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 in service. Minnesota Power previously participated in two additional CapX2020 projects which were completed and placed in service in 2011 and 2012.

NOTE 4. JOINTLY-OWNED FACILITIES AND PROJECTS (Continued)

Minnesota Power's investments in jointly-owned facilities and projects and the related ownership percentages are as follows:

Regulated Utility Plant As of December 31	Plant in Service	Accumulated Depreciation	Construction Work in Progress	% Ownership
Millions				
2015				
Boswell Unit 4	$668.2	$195.0	$6.9	80
CapX2020 Projects	101.1	3.4	—	9.3 - 14.7
Total	$769.3	$198.4	$6.9	
2014				
Boswell Unit 4	$419.1	$209.1	$168.1	80
CapX2020 Projects	55.5	1.7	44.0	9.3 - 14.7
Total	$474.6	$210.8	$212.1	

NOTE 5. REGULATORY MATTERS

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

2010 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. Subsequent to this last order, and as authorized by the MPUC, Minnesota Power has increased revenue under cost recovery riders for environmental, renewable and transmission investments. (See *Transmission Cost Recovery Rider, Renewable Cost Recovery Rider and Boswell Mercury Emissions Reduction Plan*.) Revenue from cost recovery riders was $86.0 million in 2015 ($69.9 million in 2014 and $40.5 million in 2013).

Energy-Intensive Trade-Exposed (EITE) Customer Rates. The Minnesota Legislature enacted EITE customer ratemaking legislation in June 2015. The legislation establishes that it is the energy policy of the state to have competitive rates for certain industries such as mining and forest products. On November 13, 2015, Minnesota Power filed a rate schedule for EITE customers and a corresponding rider for EITE cost recovery with the MPUC. The rate proposal is revenue, and cash flow, neutral. On February 11, 2016, the MPUC dismissed the petition without prejudice, offering Minnesota Power the option to refile the petition with additional information or initiate a new petition. Minnesota Power is evaluating the MPUC's decision.

FERC-Approved Wholesale Rates. Minnesota Power has 16 non-affiliated municipal customers in Minnesota. SWL&P is a Wisconsin utility and a wholesale 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 SWL&P and one other municipal customer 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 Minnesota Power's 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.

In September 2015, Minnesota Power amended its wholesale electric contracts with 14 municipal customers, extending the contract terms through December 31, 2024. These contracts include fixed capacity charges through 2018; beginning in 2019, the capacity charge will not increase by more than two percent or decrease by more than one percent from the previous year's capacity charge and will be determined using a cost-based formula methodology. The base energy charge for each year of the contract term will be set each January 1, subject to monthly adjustment, and is also determined using a cost-based formula methodology.

NOTE 5. REGULATORY MATTERS (Continued)

All of the wholesale contracts include a termination clause requiring a three-year notice to terminate. In January 2016, one of Minnesota Power's municipal customers provided notice of its intent to terminate its contract effective June 30, 2019. Minnesota Power currently provides approximately 29 MW of average monthly demand to this customer. Under the Nashwauk Public Utilities Commission agreement, no termination notice may be given prior to June 30, 2025. Under the agreement with SWL&P, no termination notice may be given prior to June 30, 2016. The remaining 14 municipal customers may not give termination notices prior to December 31, 2021.

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 3, 2016, 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. 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 the existing transmission cost recovery rider. Minnesota Power anticipates including its portion of the investments and expenditures for the GNTL in 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 the Bison Wind Energy Center were approved by the MPUC in an order dated May 22, 2015. In November 2014, Minnesota Power filed a renewable resources factor filing which includes updated costs associated with Bison. Upon approval of the filing, Minnesota Power 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 Minnesota Power's petition seeking cost recovery for investments and expenditures related to the restoration and repair of Thomson through a renewable resources rider.

Annual Automatic Adjustment (AAA) of Charges. Minnesota Power's AAA filings made in 2012, 2013, 2014 and 2015 are pending MPUC approval, and represent approximately $700 million in retail fuel cost recovery collected but subject to refund. These filings have historically been approved, and Minnesota Power currently expects full recovery of amounts represented by each AAA filing, although we cannot predict the outcome of the filings at the MPUC.

Integrated Resource Plan (IRP). In a November 2013 order, the MPUC approved Minnesota Power's 2013 IRP which detailed its *EnergyForward* strategic plan, announced in January 2013. Significant elements of the *EnergyForward* plan include major wind investments in North Dakota which were completed in the fourth quarter of 2014, the installation of emissions control technology at Boswell Unit 4 completed in December 2015, 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 September 1, 2015, Minnesota Power filed its 2015 IRP with the MPUC which includes an analysis of a variety of existing and future energy resource alternatives and a projection of customer cost impact by class. The 2015 IRP also contains the next steps in Minnesota Power's *EnergyForward* plan including the economic idling of Taconite Harbor Units 1 and 2 in the fall of 2016, the ceasing of coal-fired operations at Taconite Harbor in 2020, and the addition of between 200 MW and 300 MW of natural gas-fired generation in the next decade.

Boswell Mercury Emissions Reduction Plan. In August 2012, Minnesota Power filed its mercury emissions reduction plan for Boswell Unit 4 with the MPUC and the MPCA in order to comply with the Minnesota Mercury Emissions Reduction Act and the Federal MATS rule. Construction on the project to implement the Boswell Unit 4 mercury emissions reduction plan was completed with project costs totaling approximately $220 million through December 31, 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 an order dated August 24, 2015. On September 30, 2015, Minnesota Power filed an updated environmental improvement factor filing which included updated costs associated with Boswell Unit 4. Upon approval of the filing, Minnesota Power will be authorized to include updated billing rates on customer bills.

NOTE 5. REGULATORY MATTERS (Continued)

Boswell Remaining Life Petition. On November 17, 2015, Minnesota Power filed a petition with the MPUC for approval to extend Boswell's remaining life to 2050 for all units and utilize the existing environmental improvement rider to credit a portion of the depreciation expense savings to customers. The extension request is based on the significant multi-emissions retrofit work done at Boswell Unit 3 and Boswell Unit 4.

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, Minnesota Power's portion of the investments and expenditures for the project are eligible for cost recovery under its existing transmission cost recovery rider and are anticipated to be included in future transmission factor filings. In an order dated December 17, 2015, the FERC approved our request to recover on construction work in progress related to the GNTL from Minnesota Power's wholesale customers. 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 October 30, 2015, the Minnesota Department of Commerce and the U.S. Department of Energy released the final EIS for the GNTL. On January 4, 2016, an administrative law judge recommended approval of the route permit for the GNTL. A final decision on the route permit by the MPUC is expected in the first quarter of 2016. Manitoba Hydro must also obtain regulatory and governmental approvals related to a new transmission line in Canada. In September 2015, Manitoba Hydro submitted the final preferred route and EIS for the transmission line in Canada to the Manitoba Conservation and Water Stewardship for regulatory approval. Construction of Manitoba Hydro's hydroelectric generation facility commenced in 2014. Upon receipt of all applicable permits and approvals, construction of the GNTL is expected to begin by 2017 and to be completed in 2020.

Conservation Improvement Program (CIP). Minnesota requires electric utilities to spend a minimum of 1.5 percent of net gross operating revenues from service provided in the state on energy CIPs each year. These investments are recovered from certain retail customers through a combination of the conservation cost recovery charge included in retail base rates and a conservation program adjustment, which is adjusted annually through the CIP consolidated filing. The MPUC allows utilities to accumulate, in a deferred account for future cost recovery, all CIP expenditures, any financial incentive earned for cost-effective program achievements, and a carrying charge on the deferred account balance. Minnesota Power refers to its conservation programs collectively as the "Power of One". In June 2013, Minnesota Power submitted a triennial filing for 2014 through 2016, which was subsequently approved by the Minnesota Department of Commerce. Minnesota Power's CIP investment goal was $7.1 million for 2015 ($6.9 million for 2014; $6.0 million for 2013), with actual spending of $6.6 million in 2015 ($7.2 million in 2014; $6.4 million in 2013).

Minnesota requires each utility to establish an annual energy-savings goal of 1.5 percent of annual retail energy sales. On April 1, 2015, Minnesota Power submitted its 2014 CIP filing that requested a CIP financial incentive of $6.2 million. The requested CIP financial incentive was approved by the MPUC in an order dated September 16, 2015, and was recorded as revenue and as a regulatory asset. The approved financial incentive will be recovered through customer billing rates in 2015 and 2016. In 2014 and 2013, the CIP financial incentive recognized was $8.7 million and $7.1 million, respectively. CIP financial incentives are recognized in the period in which the MPUC approves the filing. he MPUC implemented certain limitations on amounts recoverable for the utility performance incentive program for recovery years beginning in 2015.

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. On December 29, 2015, a federal administrative law judge ruled that the MISO transmission users have been charged an unreasonable base return on equity and proposed a reduction to 10.32 percent, subject to approval or adjustment by the FERC. A final decision from the FERC on the administrative law judge's recommendation is expected in 2016. As a result of these complaints filed with the FERC and the administrative law judge's recommendation, Minnesota Power has recorded an estimated refund obligation for MISO revenue of $7.2 million and an estimated refund for MISO transmission expense of $4.5 million, resulting in a reserve of $2.7 million as of December 31, 2015; $1.5 million was attributable to prior years.

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 has two solar projects under development. On August 21, 2015, Minnesota Power filed for MPUC approval of a 10 MW utility scale solar project at Camp Ripley, a Minnesota Army National Guard base and training facility near Little Falls, Minnesota. At a hearing on January 28, 2016, the MPUC approved the Camp Ripley solar project as eligible to meet the solar energy standard and for current cost recovery, subject to certain compliance requirements. On September 10, 2015, Minnesota Power filed for MPUC approval of a 1 MW community solar garden project in Saint Louis County, Minnesota. If the community solar garden project is also approved, Minnesota Power believes these projects will meet approximately one-third of the overall mandate and approximately one-fourth of the mandate related to solar photovoltaic devices with a nameplate capacity of 20 kilowatts or less. Costs associated with these projects are expected to be recovered from customers.

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.

Regulatory Assets and Liabilities As of December 31	2015	2014
Millions		
Current Regulatory Assets *(a)*		
Deferred Fuel Adjustment Clause	$10.6	$16.3
Total Current Regulatory Assets	10.6	16.3
Non-Current Regulatory Assets		
Defined Benefit Pension and Other Postretirement Benefit Plans *(b)*	219.3	223.9
Income Taxes *(c)*	64.2	46.6
Cost Recovery Riders *(d)*	58.0	59.7
Asset Retirement Obligations *(e)*	21.6	17.8
PPACA Income Tax Deferral	5.0	5.0
Other	3.9	4.3
Total Non-Current Regulatory Assets	372.0	357.3
Total Regulatory Assets	$382.6	$373.6
Non-Current Regulatory Liabilities		
Wholesale and Retail Contra AFUDC *(f)*	$58.0	$42.9
Plant Removal Obligations	22.1	22.8
Income Taxes *(c)*	6.1	13.4
Defined Benefit Pension and Other Postretirement Benefit Plans *(b)*	0.9	3.5
Other	17.9	11.6
Total Non-Current Regulatory Liabilities	$105.0	$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 as actuarial gains and losses as well as prior service costs and credits, are recognized as regulatory assets or regulatory liabilities on the Consolidated Balance Sheet. The asset or liability will decrease as the deferred items are amortized and recognized as components of net periodic benefit cost. (See Note 17. Pension and Other Postretirement Benefit Plans.)

(c) These costs represent the difference between deferred income taxes recognized for financial reporting purposes and amounts previously billed to our customers. This balance will decrease over the remaining life of the related temporary differences and flow through current income taxes.

(d) The cost recovery rider regulatory assets are revenues not yet collected from our customers primarily due to capital expenditures related to the 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. The cost recovery rider regulatory assets as of December 31, 2015 will be recovered over the next two years.

(e) Asset retirement obligations will accrete and be amortized over the lives of the related property with asset retirement obligations.

(f) Wholesale and Retail Contra AFUDC represents amortization to offset AFUDC Equity and Debt recorded during the construction period of our cost recovery rider projects prior to placing the projects in service. The regulatory liability will decrease over the remaining depreciable life of the related asset.

NOTE 6. INVESTMENT IN ATC

Our wholly-owned subsidiary, ALLETE Transmission Holdings, 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. We account for our investment in ATC under the equity method of accounting. As of December 31, 2015, our equity investment in ATC was $124.5 million ($121.1 million at December 31, 2014). On January 29, 2016, we invested an additional $1.2 million in ATC. In total, we expect to invest approximately $6.2 million throughout 2016.

ALLETE's Investment in ATC

Year Ended December 31	2015	2014
Millions		
Equity Investment Beginning Balance	$121.1	$114.6
Cash Investments	1.6	3.9
Equity in ATC Earnings	16.3	19.6
Distributed ATC Earnings	(14.5)	(17.0)
Equity Investment Ending Balance	$124.5	$121.1

ATC Summarized Financial Data

Balance Sheet Data

As of December 31	2015	2014
Millions		
Current Assets	$80.5	$66.4
Non-Current Assets	3,957.6	3,728.7
Total Assets	$4,038.1	$3,795.1
Current Liabilities	$330.3	$313.1
Long-Term Debt	1,800.0	1,701.0
Other Non-Current Liabilities	245.0	163.8
Members' Equity	1,662.8	1,617.2
Total Liabilities and Members' Equity	$4,038.1	$3,795.1

Income Statement Data

Year Ended December 31	2015	2014	2013
Millions			
Revenue	$615.8	$635.0	$626.3
Operating Expense	319.3	307.4	295.1
Other Expense	96.1	88.9	83.6
Net Income	$200.4	$238.7	$247.6
ALLETE's Equity in Net Income	$16.3	$19.6	$20.3

Our equity earnings in ATC for the year ended December 31, 2015, were $16.3 million and reflected a $5.2 million reduction related to complaints filed with the FERC by several customer groups located within the MISO service area; of which $2.4 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. On December 29, 2015, a federal administrative law judge ruled that the MISO transmission users have been charged an unreasonable base return on equity and proposed a reduction to 10.32 percent, subject to approval or adjustment by the FERC. A final decision from the FERC on the administrative law judge's recommendation is currently expected in 2016. 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 7. 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 years ended December 31, 2015, and 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 through 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 for U.S. Water Services since the acquisition date as the Company has acquired 100 percent of U.S. Water Services.

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 purchase price accounting, which was finalized in 2015, is reflected in the following table. 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
Intangible Assets *(c)*	83.0
Goodwill *(d)*	122.9
Other Non-Current Assets	0.2
Total Assets Acquired	$253.1
Liabilities Assumed	
Current Liabilities	$19.2
Non-Current Liabilities	31.6
Total Liabilities Assumed	$50.8
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 standby letters of credit.

(c) Intangible Assets include customer relationships, patents, non-compete agreements, and trademarks and trade names. (See Note 8. Goodwill and Intangible Assets.)

(d) For tax purposes, the purchase price allocation resulted in $2.9 million of deductible goodwill.

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

NOTE 7. ACQUISITIONS (Continued)
2015 Activity (Continued)

Chanarambie/Viking. On April 15, 2015, ALLETE Clean Energy acquired 100 percent of wind energy facilities in southern Minnesota (Chanarambie/Viking) from EDF Renewable Energy, Inc. for $48.0 million.

The facilities have 97.5 MW of generating capability and are located near ALLETE Clean Energy's 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).

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 purchase price accounting, which was finalized in 2015, is reflected in the following table. 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)*	1.0
Total Assets Acquired	$108.8
Liabilities Assumed	
Current Liabilities *(b)*	$6.7
Power Purchase Agreements	49.0
Non-Current Liabilities	5.1
Total Liabilities Assumed	$60.8
Net Identifiable Assets Acquired	$48.0

(a) Included in Other Non-Current Assets was $0.3 million of goodwill. For tax purposes, the purchase price allocation resulted in no allocation to goodwill.
(b) Current Liabilities included $5.9 million related to the current portion of Power Purchase Agreements.

Acquisition-related costs of $0.2 million after-tax were expensed as incurred during 2015 and 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 minority shareholder for $111.1 million, plus the assumption of existing debt.

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 2024.

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 purchase price accounting, which was finalized in 2015, is reflected in the following table. Fair value measurements were valued primarily using the discounted cash flow method.

Millions	
Assets Acquired	
Current Assets *(a)*	$9.0
Property, Plant and Equipment	156.2
Other Non-Current Assets *(b)*	14.4
Total Assets Acquired	**$179.6**
Liabilities Assumed	
Current Liabilities	$2.9
Long-Term Debt Due Within One Year	5.9
Long-Term Debt	55.0
Other Non-Current Liabilities	4.7
Total Liabilities Assumed	**$68.5**
Net Identifiable Assets Acquired	**$111.1**

(a) Included in Current Assets was $1.0 million related to the current portion of Power Purchase Agreements and $6.0 million of restricted cash related to collateral deposits required under its loan agreement.
(b) Included in Other Non-Current Assets was $8.2 million related to the non-current portion of Power Purchase Agreements, $6.1 million of restricted cash related to collateral deposits required under its loan agreements, and an immaterial amount of goodwill. For tax purposes, the purchase price allocation resulted in no allocation to goodwill.

Acquisition-related costs of $1.6 million after-tax were expensed as incurred during 2015 and recorded in Operating and Maintenance on the Consolidated Statement of Income.

A and W Technologies. On November 1, 2015, U.S. Water Services acquired 100 percent of A and W Technologies, Inc. (AWT). Total consideration for the transaction was $9.2 million, which included payment of $8.2 million in cash and a $1.0 million payment due in April 2016. AWT, similar to U.S. Water Services, is an integrated water management company and was acquired to expand U.S. Water Services' regional footprint in the Southeastern United States.

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 purchase price accounting, which was finalized in 2015, is reflected in the following table. Fair value measurements were valued primarily using the discounted cash flow method.

Millions	
Assets Acquired	
Current Assets	$1.0
Property, Plant and Equipment	0.1
Intangible Assets *(a)*	3.9
Goodwill *(b)*	4.3
Total Assets Acquired	**$9.3**
Liabilities Assumed	
Current Liabilities	$0.1
Total Liabilities Assumed	**$0.1**
Net Identifiable Assets Acquired	**$9.2**

(a) Intangible Assets include customer relationships and non-compete agreements. (See Note 8. Goodwill and Intangible Assets.)
(b) For tax purposes, the purchase price allocation resulted in $4.3 million of deductible goodwill.

Acquisition-related costs were immaterial, expensed as incurred during 2015 and 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 energy facility near Hettinger, North Dakota. ALLETE Clean Energy constructed a 107 MW wind energy facility consisting of 43 turbines, which was approved to be sold to Montana-Dakota Utilities by the NDPSC on June 30, 2015. Construction and sale of the wind energy facility were completed in December 2015 with revenue totaling $197.7 million.

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.

For the year ended December 31, 2015, revenue of $197.7 million and cost of sales of $162.9 million were recognized related to the sale of the wind energy facility to Montana-Dakota Utilities and were reported on the Consolidated Statement of Income as Operating Revenue and Cost of Sales, respectively.

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 Current Liabilities - Other and Prepayments and Other, 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.

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.

NOTE 7. ACQUISITIONS (Continued)
2014 Activity (Continued)

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 related to Lake Benton, Storm Lake II and Condon at fair value using the discounted cash flow method.

Acquisition-related costs of $1.4 million after-tax were expensed as incurred during 2014 and recorded in Operating and Maintenance on the Consolidated Statement of Income.

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 2019.

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 purchase price accounting, which was finalized in 2015, is reflected in the following table. Fair value measurements were valued primarily using the discounted cash flow method.

NOTE 7. ACQUISITIONS (Continued)
2014 Activity (Continued)

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.

Acquisition-related costs were immaterial, expensed as incurred during 2014 and recorded in Operating and Maintenance on the Consolidated Statement of Income.

NOTE 8. GOODWILL AND INTANGIBLE ASSETS

The following table summarizes changes to goodwill by reportable segment for the year ended December 31, 2015:

	ALLETE Clean Energy	U.S. Water Services	Total
Millions			
Balance as of December 31, 2014	$2.9	—	$2.9
Acquired Goodwill	0.4	$127.3	127.7
Balance as of December 31, 2015	$3.3	$127.3	$130.6

Balances of intangible assets, net, excluding goodwill as of December 31, 2015, are as follows:

	December 31, 2014	Additions *(a)*	Amortization	Other *(b)*	December 31, 2015
Millions					
Intangible Assets					
Definite-Lived Intangible Assets					
Customer Relationships	—	$64.0	$(3.2)	—	$60.8
Developed Technology and Other *(c)*	$1.9	6.4	(0.8)	$(0.3)	7.2
Total Definite-Lived Intangible Assets	1.9	70.4	(4.0)	(0.3)	68.0
Indefinite-Lived Intangible Assets					
Trademarks and Trade Names	—	16.6	n/a	—	16.6
Total Intangible Assets	$1.9	$87.0	$(4.0)	$(0.3)	$84.6

(a) Additions are primarily the result of the U.S. Water Services acquisition. (See Note 7. Acquisitions.)
(b) Armenia Mountain was acquired on July 1, 2015, at which time the purchase option intangible asset was reclassified as a component of the acquisition consideration.
(c) Developed Technology and Other includes patents, non-compete agreements, and land easements.

NOTE 8. GOODWILL AND INTANGIBLE ASSETS (Continued)

Customer relationships have a useful life of approximately 22 years and developed technology and other have useful lives ranging from approximately 3 years to approximately 13 years (weighted average of approximately 9 years). The weighted average useful life of all definite-lived intangible assets as of December 31, 2015, is approximately 21 years.

Amortization expense of intangible assets for the year ended December 31, 2015, was $4.0 million. Accumulated amortization was $4.1 million and $0.1 million as of December 31, 2015, and December 31, 2014, respectively. Estimated annual amortization expense for definite-lived intangible assets is $5.1 million in 2016, $5.0 million in 2017, $4.7 million in 2018, $4.4 million in 2019, $4.2 million in 2020, and $44.6 million thereafter.

NOTE 9. INVESTMENTS

Investments. At December 31, 2015, the investment portfolio included the legacy 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 As of December 31	2015	2014
Millions		
ALLETE Properties *(a)*	$50.1	$88.2
Available-for-sale Securities *(b)*	18.5	18.9
Cash Equivalents	2.0	2.9
Other	4.0	4.4
Total Other Investments	$74.6	$114.4

(a) In 2015, ALLETE Properties recorded a $36.3 million non-cash impairment charge related to its real estate assets. (See Note 1. Operations and Significant Accounting Policies.)

(b) As of December 31, 2015, the aggregate amount of available-for-sale corporate debt securities maturing in one year or less was none, in one year to less than three years was $1.0 million, in three years to less than five years was $3.2 million, and in five or more years was $6.7 million.

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 estimated fair value. Land values are reviewed for indicators of impairment on a quarterly basis and a $36.3 million non-cash impairment was recorded for the year ended December 31, 2015 (none for the years ended December 31, 2014 and 2013). (See Note 1. Operations and Significant Accounting Policies.)

Available-for-Sale Investments. We account for our available-for-sale portfolio in accordance with the guidance for certain investments in debt and equity securities. Our available-for-sale securities portfolio consisted primarily of securities held in other postretirement plans to fund employee benefits.

Available-For-Sale Securities

Millions		Gross Unrealized		
As of December 31	**Cost**	**Gain**	**Loss**	**Fair Value**
2015	$20.0	—	$1.5	$18.5
2014	$19.6	$0.2	$0.9	$18.9
2013	$18.3	—	$0.6	$17.7
		Net	**Gross Realized**	
Year Ended December 31		**Proceeds**	**Gain**	**Loss**
2015		$1.7	$0.1	—
2014		$3.6	$0.2	—
2013		$16.1	$2.2	—

NOTE 10. 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). The three levels of the fair value hierarchy are as follows:

Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reported date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. This category includes primarily mutual fund investments held to fund employee benefits.

Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reported date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, such as treasury securities with pricing interpolated from recent trades of similar securities, or priced with models using highly observable inputs, such as commodity options priced using observable forward prices and volatilities. This category includes deferred compensation, fixed income securities, and derivative instruments consisting of cash flow hedges.

Level 3 — Significant inputs that are generally less observable from objective sources. The types of assets and liabilities included in Level 3 are those with inputs requiring significant management judgment or estimation, such as the complex and subjective models and forecasts used to determine the fair value.

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 December 31, 2015 and 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 following tables.

	Fair Value as of December 31, 2015			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Investments *(a)*				
Available-for-sale – Equity Securities	$7.6	—	—	$7.6
Available-for-sale – Corporate Debt Securities	—	$10.9	—	10.9
Cash Equivalents	2.0	—	—	2.0
Total Fair Value of Assets	$9.6	$10.9	—	$20.5
Liabilities: *(b)*				
Deferred Compensation	—	$16.1	—	$16.1
U.S. Water Services Contingent Consideration	—	—	$36.6	36.6
Total Fair Value of Liabilities	—	$16.1	$36.6	$52.7
Total Net Fair Value of Assets (Liabilities)	$9.6	$(5.2)	$(36.6)	$(32.2)

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

NOTE 10. 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 December 31, 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 $36.6 million as of December 31, 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)*	2.4
Changes in Cash Flow Projections	(1.5)
Balance as of December 31, 2015	$36.6

(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.

The Company’s policy is to recognize transfers in and transfers out as of the actual date of the event or change in circumstances that caused the transfer. For the years ended December 31, 2015 and 2014, there were no transfers in or out of Levels 1, 2 or 3.

NOTE 10. 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 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		
December 31, 2015	$1,605.0	$1,676.0
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, ALLETE Transmission Holdings, 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 6. Investment in ATC.) The aggregate carrying amount of the investment was 124.5 million as of December 31, 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 years ended December 31, 2015 and 2014, there were no indicators of impairment.

Goodwill. To align with the annual budgeting and forecasting process, the Company assesses the impairment of goodwill annually in the fourth 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 $130.6 million as of December 31, 2015 and $2.9 million as of December 31, 2014.

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 December 31, 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 fourth 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 $84.6 million as of December 31, 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 December 31, 2015, there have been no events or changes in circumstance which would indicate impairment of our intangible assets.

NOTE 10. FAIR VALUE (Continued)

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 years ended December 31, 2015 and 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. Minnesota Power retired Taconite Harbor Unit 3 and converted Laskin to natural gas in 2015, which were actions included in Minnesota Power's 2013 IRP approved by the MPUC in a November 2013 order. On September 1, 2015, Minnesota Power filed its 2015 IRP with the MPUC. The 2015 IRP contains the next steps for Minnesota Power's *EnergyForward* plan including the economic idling of Taconite Harbor Units 1 and 2 in the fall of 2016 and the ceasing of coal-fired operations at Taconite Harbor in 2020. We do not expect to record any impairment charge as a result of the retirement of Taconite Harbor Unit 3, the ceasing of coal-fired operations at Taconite Harbor Units 1 and 2, or the conversion of Laskin. In addition, we expect to be able to continue depreciating these assets over their established remaining useful lives; however, we are unable to predict the impact of unanticipated regulatory outcomes resulting in changes to their established remaining useful lives. The remaining net book value for Taconite Harbor as of December 31, 2015 was approximately $100 million. We would seek recovery in a general rate case of additional depreciation expense as a result of material changes in useful lives.

NOTE 11. SHORT-TERM AND LONG-TERM DEBT

Short-Term Debt. As of December 31, 2015, total short-term debt outstanding was $37.9 million ($104.4 million as of December 31, 2014) and consisted of long-term debt due within one year and notes payable.

As of December 31, 2015, we had bank lines of credit aggregating $408.4 million ($408.4 million as of December 31, 2014), the majority of which expire in November 2018. We had $12.4 million outstanding in standby letters of credit and $1.6 million outstanding in draws under our lines of credit as of December 31, 2015 ($47.5 million in standby letters of credit and $3.7 million in draws outstanding as of December 31, 2014).

Long-Term Debt. As of December 31, 2015, total long-term debt outstanding was $1,568.7 million ($1,272.8 million as of December 31, 2014). The aggregate amount of long-term debt maturing in 2016 is $36.3 million ($193.6 million in 2017; $64.1 million in 2018; $56.5 million in 2019; $103.0 million in 2020; and $1,151.5 million thereafter). Substantially all of our regulated electric plant is subject to the lien of the mortgage collateralizing outstanding first mortgage bonds. The mortgages contain non-financial covenants customary in utility mortgages, including restrictions on our ability to incur liens, dispose of assets, and merge with other entities.

On July 1, 2015, ALLETE Clean Energy assumed $60.9 million of long-term debt at fair value, including $5.9 million due within one year, in conjunction with ALLETE Clean Energy's acquisition of Armenia Mountain. (See Note 7. Acquisitions.) On November 5, 2015, the assumed debt was refinanced when Armenia Mountain Wind, LLC (Armenia Mountain) entered into a Note Purchase and Guarantee Agreement (NPA) with AMW I Holding, LLC (Guarantor) and the purchasers named therein. Both Armenia Mountain and the Guarantor are wholly owned subsidiaries of ALLETE Clean Energy. Under the NPA, Armenia Mountain issued and sold $84.5 million of its 3.26 percent Senior Secured Notes (Notes) due December 31, 2024, to certain institutional accredited investors in the private placement market. The Notes were issued and 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.

Interest on the Notes is payable semi-annually on June 30 and December 31 of each year, commencing on December 31, 2015. Armenia Mountain has the option to prepay all or a portion of the Notes at its discretion, subject to a make-whole provision; however, the Notes are redeemable at par, including accrued and unpaid interest, three months prior to the maturity date. The Notes are subject to additional terms and conditions which are customary for these types of transactions. Armenia Mountain used a portion of the proceeds to refinance the debt assumed in the Armenia Mountain acquisition and plans to use the remaining proceeds for general corporate purposes. Armenia Mountain's obligations under the Notes are secured by its assets and a pledge by the Guarantor of its equity interests in Armenia Mountain. There is no recourse to ALLETE or any other subsidiary of ALLETE with respect to the Armenia Mountain's obligations under the Notes other than to itself and its direct owner, the Guarantor, which guarantees payment under the Notes.

NOTE 11. SHORT-TERM AND LONG-TERM DEBT (Continued)

On August 25, 2015, the Company entered into a $125.0 million Term Loan Agreement with JPMorgan Chase Bank, N.A., as a lender and administrative agent, and Bank of America, N.A., as a lender (Term Loan). The Term Loan is an unsecured, single-draw loan that is due on August 25, 2017. The interest rate on the Term Loan is equal to LIBOR plus 0.625 percent. Proceeds from the Term Loan will be used for general corporate purposes, including the refinancing of the $75.0 million Term Loan Agreement due August 25, 2015.

The Term Loan contains customary conditions of borrowing, events of default and affirmative and negative covenants. The Term Loan includes a financial covenant to maintain a ratio of total indebtedness to total capitalization (as defined therein) equal to or less than 65 percent. Indebtedness under the Term Loan may be accelerated upon the occurrence of an event of default, including cross-default to other indebtedness in excess of $35.0 million.

On September 24, 2015, we issued $100.0 million of ALLETE first mortgage bonds (Bonds) in the private placement market as shown below:

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

Interest on the Bonds is payable semi-annually on March 15 and September 15 of each year, commencing on March 15, 2016. The Company has 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 is redeemable at par, including accrued and unpaid interest, six months prior to the maturity date. The Bonds are 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. The Bonds were sold in reliance on an exemption from registration under Section 4(a)(2) of the Securities Act of 1933, as amended, to institutional accredited investors.

NOTE 11. SHORT-TERM AND LONG-TERM DEBT (Continued)

Long-Term Debt As of December 31	2015	2014
Millions		
First Mortgage Bonds		
7.70% Series Due 2016	$20.0	$20.0
1.83% Series Due 2018	50.0	50.0
8.17% Series Due 2019	42.0	42.0
5.28% Series Due 2020	35.0	35.0
2.80% Series Due 2020	40.0	—
4.85% Series Due 2021	15.0	15.0
3.02% Series Due 2021	60.0	60.0
3.40% Series Due 2022	75.0	75.0
6.02% Series Due 2023	75.0	75.0
3.69% Series Due 2024	60.0	60.0
4.90% Series Due 2025	30.0	30.0
5.10% Series Due 2025	30.0	30.0
3.20% Series Due 2026	75.0	75.0
5.99% Series Due 2027	60.0	60.0
3.30% Series Due 2028	40.0	40.0
3.74% Series Due 2029	50.0	50.0
3.86% Series Due 2030	60.0	—
5.69% Series Due 2036	50.0	50.0
6.00% Series Due 2040	35.0	35.0
5.82% Series Due 2040	45.0	45.0
4.08% Series Due 2042	85.0	85.0
4.21% Series Due 2043	60.0	60.0
4.95% Series Due 2044	40.0	40.0
5.05% Series Due 2044	40.0	40.0
4.39% Series Due 2044	50.0	50.0
Unsecured Term Loan Variable Rate Due 2015	—	75.0
Unsecured Term Loan Variable Rate Due 2017	125.0	—
Senior Unsecured Notes 5.99% Due 2017	50.0	50.0
Variable Demand Revenue Refunding Bonds Series 1997 A Due 2015 – 2020	13.5	24.6
Industrial Development Variable Rate Demand Refunding Revenue Bonds Series 2006, Due 2025	27.8	27.8
Armenia Mountain Senior Secured Notes 3.26% Due 2024	83.3	—
SWL&P First Mortgage Bonds 4.15% Series Due 2028	15.0	15.0
Other Long-Term Debt, 0.08% – 7.45% Due 2016 – 2037	68.4	59.1
Total Long-Term Debt	1,605.0	1,373.5
Less: Due Within One Year	36.3	100.7
Net Long-Term Debt	$1,568.7	$1,272.8

NOTE 11. 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 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 December 31, 2015, our ratio was approximately 0.47 to 1.00. Failure to meet this covenant would give rise to an event of default if not cured after notice from the lender, in which event ALLETE may need to pursue alternative sources of funding. Some of ALLETE's debt arrangements contain "cross-default" provisions that would result in an event of default if there is a failure under other financing arrangements to meet payment terms or to observe other covenants that would result in an acceleration of payments due. As of December 31, 2015, ALLETE was in compliance with its financial covenants.

NOTE 12. 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 Minnesota Power's 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 its entitlement to Unit output. Minnesota Power's 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 December 31, 2015, Square Butte had total debt outstanding of $376.4 million. Annual debt service for Square Butte is expected to be approximately $45 million in each of the next five years, 2016 through 2020, of which Minnesota Power's obligation is 50 percent. Fuel expenses are recoverable through Minnesota Power's fuel adjustment clause and include the cost of coal purchased from BNI Energy under a long-term contract.

Minnesota Power's cost of power purchased from Square Butte during 2015 was $77.8 million ($70.1 million in 2014; $71.1 million in 2013). 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 $10.1 million in 2015 ($10.5 million in 2014; $10.5 million in 2013). 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. Minnesota Power has a power sales agreement with Minnkota Power, which commenced June 1, 2014. Under the power sales agreement, Minnesota Power is selling a portion of its entitlement 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. Of Minnesota Power's 50 percent output entitlement, it sold to Minnkota Power approximately 28 percent in 2015 (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 Minnesota Power only pays for energy as it is delivered.

Manitoba Hydro PPAs. Minnesota Power has five long-term PPAs with Manitoba Hydro. The first PPA 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. Under the second PPA, Minnesota Power is purchasing 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 a third PPA. This 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. In September 2015, Manitoba Hydro submitted the final preferred route and EIS for the additional transmission capacity in Canada to the Manitoba Conservation and Water Stewardship for regulatory approval. Construction of Manitoba Hydro's hydroelectric generation facility commenced in 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 fourth 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 PPA 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.*)

In October 2015, Minnesota Power and Manitoba Hydro signed a fifth PPA that provides for Minnesota Power to purchase 50 MW of capacity at fixed prices. The PPA begins in June 2017 and expires in May 2020.

Great River Energy PPAs. In August 2014, January 2015 and October 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, 50 MW of capacity only under the second PPA, and 50 MW of capacity only under the third PPA. The first and second PPAs begin in June 2016 and expire in May 2020, and the third PPA begins in June 2017 and expires in May 2020. All of these 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.

TransAlta PPAs. In September 2015, Minnesota Power and TransAlta signed PPAs that provide for Minnesota Power to purchase 50 MW of energy during off-peak hours and 100 MW of energy during on-peak hours beginning in January 2017 and ending in December 2019. The energy prices are fixed throughout the terms of the PPAs.

Basin Power Sales Agreements. Minnesota Power has an agreement to sell 100 MW of capacity and energy to Basin for a ten-year period which expires in April 2020. The capacity charge is based on a fixed monthly schedule with a minimum annual escalation provision. The energy charge is based on a fixed monthly schedule and provides for annual escalation based on the cost of fuel. The agreement allows Minnesota Power to recover a pro rata share of increased costs related to emissions that occur during the last five years of the contract. On July 9, 2015, Minnesota Power entered into an additional agreement to sell 100 MW of capacity only to Basin at fixed rates for a two-year period beginning in June 2016.

Coal, Rail and Shipping Contracts. Minnesota Power has coal supply agreements providing for the purchase of a significant portion of its coal requirements through December 2016 and a portion of its coal requirements through December 2019. Minnesota Power also has coal transportation agreements in place for the delivery of a significant portion of its coal requirements through December 2018. The minimum annual payment obligation under these supply and transportation agreements is $40.7 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.

On January 11, 2016, Arch Coal, Inc. (Arch Coal) elected to file for reorganization under Chapter 11 of the Bankruptcy Code and announced that it reached an agreement with the majority of its senior lenders on the terms of a financial restructuring. The United States Bankruptcy Court for the Eastern District of Missouri authorized Arch Coal to enter into and perform under coal contracts in the ordinary course of business.

NOTE 12. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)

Leasing Agreements. BNI Energy is obligated to make lease payments for a dragline totaling $2.8 million annually for the lease term, which expires in 2027. BNI Energy 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 $14.0 million in 2016, $12.6 million in 2017, $11.1 million in 2018, $9.9 million in 2019, $6.9 million in 2020 and $23.2 million thereafter. Total lease expense was $17.3 million in 2015 ($14.8 million in 2014; $13.8 million in 2013).

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 3, 2016, 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. 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 the existing transmission cost recovery rider. Minnesota Power anticipates including its portion of the investments and expenditures for the GNTL in 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.

On April 2, 2015, the CapX2020 transmission line project from Fargo, North Dakota, to St. Cloud, Minnesota, was completed and placed in service. Minnesota Power previously participated in two additional CapX2020 projects which were completed and placed in 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 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, Minnesota Power's portion of the investments and expenditures for the project are eligible for cost recovery under its existing transmission cost recovery rider and are anticipated to be included in future transmission factor filings. In an order dated December 17, 2015, the FERC approved our request to recover on construction work in progress related to the GNTL from Minnesota Power's wholesale customers. 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 October 30, 2015, the Minnesota Department of Commerce and the U.S. Department of Energy released the final EIS for the GNTL. On January 4, 2016, an administrative law judge recommended approval of the route permit for the GNTL. A final decision on the route permit by the MPUC is expected in the first quarter of 2016. Manitoba Hydro must also obtain regulatory and governmental approvals related to a new transmission line in Canada. In September 2015, Manitoba Hydro submitted the final preferred route and EIS for the transmission line in Canada to the Manitoba Conservation and Water Stewardship for regulatory approval. Construction of Manitoba Hydro's hydroelectric generation facility commenced in 2014. Upon receipt of all applicable permits and approvals, construction of the GNTL is expected to begin by 2017 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.

NOTE 12. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)

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 or have already been promulgated by both the EPA and state authorities. Minnesota Power's facilities are subject to additional regulation under many of these proposals. In preparation and response to these regulations, Minnesota Power is reshaping its generation portfolio over time to reduce its reliance on coal, has installed cost-effective emission control technology, and advocates for sound science and policy during rulemaking implementation.

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. We anticipate that although many of the state and federal environmental regulations have been finalized, or will be finalized in the near future, potential expenditures for future environmental matters may be material and may 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.

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 through existing emission control technology at Boswell. Minnesota Power estimates that if the units are not retired, capital expenditures could range between \$20 million and \$40 million. Minnesota Power's 2015 IRP filed with the MPUC on September 1, 2015, outlined Minnesota Power's preferred option to reroute emissions from Units 1 and 2 through existing emission control technology at Boswell Unit 3. 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 projected CSAPR Phase II allowances not yet issued, we currently expect projected generation levels and emission rates will result 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. Construction on the project to implement the Boswell Unit 4 mercury emissions reduction plan was completed with project costs totaling approximately \$220 million through December 31, 2015. Boswell Unit 3 is also subject to the MATS rule; however, investments and compliance work completed at Boswell Unit 3, including the emission reduction investments completed in 2009, meet the requirements of the MATS rule. The conversion of Laskin Units 1 and 2 to natural gas in June 2015 positioned those units 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. Taconite Harbor Unit 3 was retired in May 2015.

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. On December 15, 2015, the U.S. Court of Appeals for the D.C. Circuit rejected a motion by utilities and states to vacate the MATS rule, ordering the rule stayed while the EPA completes its review. 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 was required to implement a mercury emissions reduction project for Boswell Unit 4 by December 31, 2018. The Boswell Unit 4 environmental upgrade discussed above (see *Mercury and Air Toxics Standards (MATS) Rule*) fulfills 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 MACT became effective in December 2012. Major existing sources had 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.

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 of 75 parts per billion (ppb) and to adopt a secondary standard for the protection of sensitive vegetation from ozone-related damage. On October 26, 2015, the EPA published the final rule in the Federal Register revising the eight-hour ozone standard to 70 ppb with a secondary standard also set at 70 ppb. All areas of Minnesota currently meet the new standard based on the most recent available ambient monitoring data. However, some areas in the metropolitan Twin Cities and southwest portion of the state are close to exceeding the standard, so voluntary efforts to reduce ozone continue in the state. No additional costs for compliance are anticipated at this time.

NOTE 12. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

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 $PM_{2.5}$ 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.

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 is likely in compliance with these standards; however, the one-hour SO_2 NAAQS also requires the EPA to evaluate additional modeling and monitoring considerations 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 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 delayed completing the documents pending EPA guidance to states for preparing the SIP submittal.

In September 2013 the EPA provided guidance to states regarding implementation of the one-hour NO_2 NAAQS and in June 2014, as clarified on February 3, 2015, the MPCA submitted a SIP revision to the EPA addressing the infrastructure requirements of Sections 110(a)(1) and 110(a)(2) of the Clean Air Act in regards to the one-hour NO_2 and SO_2 NAAQS, among other standards. The SIP stated that since the EPA determined in January 2012 that no area in the country is in violation of the one-hour NO_2 NAAQS, there are no nonattainment areas in the country for this pollutant, and therefore Minnesota's NO_2 emissions cannot be significantly contributing to nonattainment in any other state. On October 20, 2015, the EPA published in the Federal Register an approval and partial disapproval of the June 2014 SIP revision. According to the MPCA, the partial disapproval is regarding state delegation of a program unrelated to the one-hour NAAQS for SO_2 and NO_2, and is not expected to require further action. As such, additional compliance costs for the one-hour NO_2 NAAQS are not expected at this time.

On August 10, 2015, the EPA finalized the SO_2 data requirements rule (DRR) for the 2010 one-hour NAAQS to assist the states in implementing the standard. The rule sets emissions thresholds and exemptions for facilities that trigger modeling requirements. Boswell and Taconite Harbor are the only Minnesota Power generating facilities subject to the DRR. The MPCA has informed Minnesota Power that compliant SO_2 modeling recently completed at these facilities should satisfy the DRR obligations, and no further modeling should be required. The MPCA is in discussion with the EPA to confirm its conclusion. The MPCA is required to inform the EPA which sources are subject to the rule by January 15, 2016, and how each source will evaluate air quality by July 1, 2016. As such, additional compliance costs for the one-hour SO_2 NAAQS are not expected at this time.

Class I Air Quality Petitions and Requests. In July 2014, the Fond du Lac Band of Lake Superior Chippewa (Fond du Lac Band) announced its intent 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 extended 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 May 2013, the Bad River Band of Lake Superior Chippewa (Bad River Band) announced its intent to petition the EPA to redesignate its reservation air shed, 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. The Class I analysis report was issued by the Bad River Band in January 2015 which was followed by public hearings in March 2015 and a public comment period ending 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.

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.

NOTE 12. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Environmental Matters (Continued)

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 issued the final CPP on August 3, 2015, together with a proposed federal implementation plan and a model rule for emissions trading. Numerous petitions for review of the rule have been filed with the U.S. Court of Appeals for the District of Columbia Circuit. On February 9, 2016, the U.S. Supreme Court issued an order staying the effectiveness of the rule until after the appellate court process is complete.

The CPP establishes uniform CO_2 emission performance rates for existing fossil fuel-fired and natural gas-fired combined cycle generating units, setting state-specific goals for CO_2 emissions from the power sector. State goals were determined based on CPP source-specific performance emission rates and each state's mix of power plants. 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). BSER is comprised of three 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, and 3) building more zero- and low-emitting power sources, including renewable energy. States may also choose to include avoided CO_2 emissions from customer energy efficiency measures for credit towards meeting state goals.

State goals under the CPP are expressed as both mass-based and rate-based goals, and include interim goals to be met over the years 2022 through 2029, as well as a final goal to be met in 2030 and thereafter. Under the CPP, each state is required to develop a state implementation plan by September 6, 2016, or by September 6, 2018, if granted an extension. If the CPP is upheld at the completion of the appellate court process, all of these deadlines are likely to be reset based on the length of time that the appeals process takes.

In developing its plan, a state may choose to meet either the mass-based or the rate-based goals. Minnesota Power is currently evaluating the CPP as it relates to the State of Minnesota and its potential impact on the Company and is actively discussing potential compliance scenarios with regulatory agencies and in public stakeholder meetings. 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 5. Regulatory Matters.)

We are unable to predict the GHG emission compliance costs we might incur; however, the costs could be material. Minnesota Power 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, the 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.

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. Minnesota Power 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 limit guidelines (ELG) for steam electric power generating stations under the Clean Water Act. The final ELG was issued on September 30, 2015. It sets effluent limits and prescribes BACT for several wastewater streams, including flue gas desulphurization (FGD) water and coal combustion landfill leachate. The ELG rule also prohibits the discharge of bottom and fly ash contact waters. Compliance with the final rule is required between November 1, 2018, and December 31, 2023.

We are reviewing the final rule and evaluating its potential impact on Minnesota Power's operations, primarily at Boswell. Boswell currently discharges bottom ash contact water through its NPDES permit, and also has a closed-loop FGD system that does not currently discharge, but may do so in the future. Under the final ELG rule, bottom ash discharge would not be allowed and bottom ash contact water would either need to be re-used in a closed-loop process, routed to a FGD scrubber, or the bottom ash handling system would need to be converted to a dry process. If the FGD wastewater is discharged in the future, it would require additional wastewater treatment. Efforts have been underway at Boswell for several years to reduce the amount of water discharged and evaluate potential re-use options in its plant processes. Additional efforts are underway to determine if land application of certain wastewater streams under a state disposal system may be feasible.

At this time, we cannot estimate what 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. Minnesota Power 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 or disposes coal ash at five of its 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 and it 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 for Boswell and Laskin are expected to occur primarily over the next 10 years and be between approximately $80 million and $100 million. Minnesota Power has not disposed ash onsite at Taconite Harbor since the effective date of the rule, and therefore, the CCR rule is not applicable to that generating facility. Minnesota Power continues to work on minimizing costs through evaluation of beneficial re-use and recycling of CCR and CCR-related waters. Minnesota Power would seek recovery of any additional costs through a general rate case.

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 7. Acquisitions.)

U.S. Water Services. As of December 31, 2015, U.S. Water Services has $0.8 million outstanding in standby letters of credit.

BNI Energy. As of December 31, 2015, BNI Energy had surety bonds outstanding of $49.9 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 Energy has secured a letter of credit for an additional $0.6 million to provide for BNI Energy's total reclamation liability, which is currently estimated at $47.5 million. BNI Energy does not believe it is likely that any of these outstanding surety bonds or the letter of credit will be drawn upon.

NOTE 12. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)
Other Matters (Continued)

ALLETE Properties. As of December 31, 2015, ALLETE Properties, through its subsidiaries, had surety bonds outstanding and letters of credit to governmental entities totaling $10.3 million primarily related to development and maintenance obligations for various projects. The estimated cost of the remaining development work is approximately $6.3 million. ALLETE Properties does not believe it is likely that any of these outstanding surety bonds or letters of credit will be drawn upon.

Community Development District Obligations. In March 2005, the Town Center District issued $26.4 million of tax-exempt, 6 percent capital improvement revenue bonds and in May 2006, the Palm Coast Park District issued $31.8 million of tax-exempt, 5.7 percent special assessment bonds. The capital improvement revenue bonds and the special assessment bonds are payable over 31 years (by May 1, 2036 and 2037, respectively) and are secured by special assessments on the benefited land. The bond proceeds were used to pay for the construction of a portion of the major infrastructure improvements in each district and to mitigate traffic and environmental impacts. The assessments were billed to the landowners beginning in November 2006 for Town Center and November 2007 for Palm Coast Park. To the extent that we still own land at the time of the assessment, we will incur the cost of our portion of these assessments, based upon our ownership of benefited property. At December 31, 2015, we owned 72 percent of the assessable land in the Town Center District (72 percent at December 31, 2014) and 89 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.

NOTE 13. COMMON STOCK AND EARNINGS PER SHARE

Summary of Common Stock	**Shares Thousands**	**Equity Millions**
Balance as of December 31, 2012	39,377	$784.7
Employee Stock Purchase Program	16	0.7
Invest Direct	395	18.5
Options and Stock Awards	301	17.9
Equity Issuance Program	1,312	63.4
Balance as of December 31, 2013	41,401	885.2
Employee Stock Purchase Program	18	0.8
Invest Direct	378	18.9
Options and Stock Awards	78	8.0
Equity Issuance Program	1,851	90.0
Forward Sale Agreement and Issuance	1,807	85.2
Contribution to Pension	396	19.5
Balance as of December 31, 2014	45,929	1,107.6
Employee Stock Purchase Program	18	0.9
Invest Direct	383	19.0
Options and Stock Awards	43	8.6
Equity Issuance Program	1,289	69.9
Forward Sale Agreement	1,413	65.4
Balance as of December 31, 2015	49,075	$1,271.4

NOTE 13. COMMON STOCK AND EARNINGS PER SHARE (Continued)

Equity Issuance Program. 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 shares remain available for issuance. For the year ended December 31, 2015, 1.3 million shares of common stock were issued under this agreement resulting in net proceeds of $69.9 million (1.9 million shares for net proceeds of $90.0 million for the year ended December 31, 2014; 1.3 million shares for net proceeds of $63.4 million for the year ended December 31, 2013). The shares sold January 1, 2013 through August 1, 2013, were offered and sold pursuant to Registration Statement No. 333-170289. On August 2, 2013, we filed Registration Statement No. 333-190335, pursuant to which the remaining shares will continue to be offered for sale from time to time.

Earnings Per Share. 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). In accordance with accounting standards for earnings per share, no options to purchase shares of common stock were excluded from the computation of diluted earnings per share in 2015, 2014 and 2013.

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 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 year ended December 31, 2015. In 2014, we contributed approximately 0.4 million shares of ALLETE common stock to our pension plan, which had an aggregate value of $19.5 million when contributed; no contributions were made in 2013. 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.

Reconciliation of Basic and Diluted Earnings Per Share Year Ended December 31	Basic	Dilutive Securities	Diluted
Millions Except Per Share Amounts			
2015			
Net Income Attributable to ALLETE	$141.1		$141.1
Average Common Shares	48.3	0.1	48.4
Earnings Per Share	$2.92		$2.92
2014			
Net Income Attributable to ALLETE	$124.8		$124.8
Average Common Shares	42.9	0.2	43.1
Earnings Per Share	$2.91		$2.90
2013			
Net Income Attributable to ALLETE	$104.7		$104.7
Average Common Shares	39.7	0.1	39.8
Earnings Per Share	$2.64		$2.63

NOTE 14. OTHER INCOME

Year Ended December 31	2015	2014	2013
Millions			
AFUDC–Equity	$3.3	$7.8	$4.6
Gain on Sale of Available-for-sale Securities	0.1	0.2	2.2
Investments and Other Income	1.3	0.6	2.5
Total Other Income	$4.7	$8.6	$9.3

NOTE 15. INCOME TAX EXPENSE

Income Tax Expense Year Ended December 31	2015	2014	2013
Millions			
Current Tax Expense			
Federal *(a)*	—	$1.1	—
State *(a)*	$0.2	2.9	$0.1
Total Current Tax Expense	0.2	4.0	0.1
Deferred Tax Expense			
Federal	19.4	25.3	22.9
State	6.5	8.2	6.5
Investment Tax Credit Amortization	(0.8)	(0.8)	(0.8)
Total Deferred Tax Expense	25.1	32.7	28.6
Total Income Tax Expense	$25.3	$36.7	$28.7

(a) For the years ended December 31, 2015, 2014, and 2013, the federal and state current tax expense was minimal due to NOLs which resulted from the bonus depreciation provisions of the Protecting Americans from Tax Hikes Act of 2015, the Tax Increase Prevention Act of 2014 and the American Taxpayer Relief Act of 2012. The federal and state NOLs will be carried forward to offset future taxable income. The year ended December 31, 2014 includes the resolution of an Internal Revenue Service examination for tax years 2005 through 2009 and the impacts of initiatives implemented on the 2013 federal and state tax returns to utilize tax carryforwards that may have expired.

Reconciliation of Taxes from Federal Statutory Rate to Total Income Tax Expense Year Ended December 31	2015	2014	2013
Millions			
Income Before Non-Controlling Interest and Income Taxes	$166.8	$162.2	$133.4
Statutory Federal Income Tax Rate	35%	35%	35%
Income Taxes Computed at 35 percent Statutory Federal Rate	$58.4	$56.8	$46.7
Increase (Decrease) in Tax Due to:			
State Income Taxes – Net of Federal Income Tax Benefit	4.4	7.2	4.3
Regulatory Differences for Utility Plant	(0.6)	(3.5)	(2.2)
Production Tax Credits	(37.0)	(23.7)	(19.2)
Other	0.1	(0.1)	(0.9)
Total Income Tax Expense	$25.3	$36.7	$28.7

The effective tax rate on income was 15.2 percent for 2015 (22.6 percent for 2014; 21.5 percent for 2013). The 2015, 2014, and 2013 effective rates were primarily impacted by production tax credits and by the deduction for AFUDC–Equity (included in Regulatory Differences for Utility Plant in the preceding table).

NOTE 15. INCOME TAX EXPENSE (Continued)

Deferred Tax Assets and Liabilities **As of December 31**	**2015**	**2014**
Millions		
Deferred Tax Assets		
Employee Benefits and Compensation	$105.4	$102.2
Property Related	126.6	102.7
NOL Carryforwards	186.4	156.5
Tax Credit Carryforwards	164.8	95.7
Power Purchase Agreements	73.0	51.8
Other	21.8	17.0
Gross Deferred Tax Assets	678.0	525.9
Deferred Tax Asset Valuation Allowance	(31.6)	(22.1)
Total Deferred Tax Assets	$646.4	$503.8
Deferred Tax Liabilities		
Property Related	$1,053.0	$848.8
Regulatory Asset for Benefit Obligations	89.4	89.9
Unamortized Investment Tax Credits	26.0	10.3
Partnership Basis Differences	47.8	41.9
Other	10.0	16.1
Total Deferred Tax Liabilities	$1,226.2	$1,007.0
Net Deferred Income Taxes	$579.8	$503.2
Recorded as:		
Net Current Deferred Tax Assets *(a)*	—	$7.5
Net Long-Term Deferred Tax Liabilities	$579.8	510.7
Net Deferred Income Taxes	$579.8	$503.2

(a) For discussion of classification of deferred income taxes see Note 1. Operations and Significant Accounting Policies - New Accounting Standards - Balance Sheet Classification of Deferred Taxes.

NOL and Tax Credit Carryforwards **As of December 31**	**2015**	**2014**
Millions		
Federal NOL Carryforwards *(a)*	$493.0	$413.7
Federal Tax Credit Carryforwards	$113.6	$59.3
State NOL Carryforwards *(a)*	$228.6	$184.7
State Tax Credit Carryforwards *(b)*	$20.0	$14.7

(a) Pretax amounts.
(b) Net of a $31.2 million valuation allowance as of December 31, 2015 ($21.7 million as of December 31, 2014).

The federal NOL and tax credit carryforward periods expire between 2030 and 2035. We expect to fully utilize the federal NOL and federal tax credit carryforwards; therefore no federal valuation allowance has been recognized as of December 31, 2015. The state NOL and tax credit carryforward periods expire between 2025 and 2045. We have established a valuation allowance against certain state NOL and tax credits that we do not expect to utilize before their expiration.

Gross Unrecognized Income Tax Benefits	2015	2014	2013
Millions			
Balance at January 1	$2.0	$1.2	$2.7
Additions for Tax Positions Related to the Current Year	0.5	—	0.1
Additions for Tax Positions Related to Prior Years	0.7	1.0	1.3
Reductions for Tax Positions Related to Prior Years	(0.7)	—	—
Reductions for Settlements	—	—	(2.9)
Lapse of Statute	(0.1)	(0.2)	—
Balance as of December 31	$2.4	$2.0	$1.2

Unrecognized tax benefits are the differences between a tax position taken or expected to be taken in a tax return and the benefit recognized and measured pursuant to the "more-likely-than-not" criteria. The unrecognized tax benefit balance includes permanent tax positions which, if recognized would affect the annual effective income tax rate. In addition, the unrecognized tax benefit balance includes temporary tax positions for which the ultimate deductibility is highly certain but for which there is uncertainty about the timing of such deductibility. A change in the period of deductibility would not affect the effective tax rate but would accelerate the payment of cash to the taxing authority to an earlier period.

The gross unrecognized tax benefits as of December 31, 2015, included $0.5 million of net unrecognized tax benefits which, if recognized, would affect the annual effective income tax rate. The decrease in the unrecognized tax benefit balance of $2.9 million in 2013 was due to the removal of our uncertain tax positions for positions effectively settled with the Internal Revenue Service for tax years 2005 through 2009.

As of December 31, 2015, we had no accrued interest (none as of December 31, 2014; $0.5 million as of December 31, 2013) related to unrecognized tax benefits included on our Consolidated Balance Sheet due to our NOL carryforwards. We classify interest related to unrecognized tax benefits as interest expense and tax-related penalties in operating expenses on our Consolidated Statement of Income. Interest expense related to unrecognized tax benefits on our Consolidated Statement of Income was immaterial in 2015 (immaterial in 2014, and in 2013). There were no penalties recognized in 2015, 2014 or 2013. The unrecognized tax benefit amounts have been presented as reductions to the tax benefits associated with NOL and tax credit carryforwards on our Consolidated Balance Sheet.

No material changes to unrecognized tax benefits are expected during the next 12 months.

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 has no open federal or state audits, and is no longer subject to federal examination for years before 2012 or state examination for years before 2011.

NOTE 16. RECLASSIFICATIONS OUT OF ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS)

Changes in Accumulated Other Comprehensive Loss. Comprehensive income (loss) is the change in common shareholders' equity during a period from transactions and events from non-owner sources, including net income. The amounts recorded to accumulated other comprehensive loss include unrealized gains and losses on available-for-sale securities, defined benefit pension and other postretirement items, consisting of deferred actuarial gains or losses and prior service costs or credits, and gains and losses on derivatives accounted for as cash flow hedges.

NOTE 16. RECLASSIFICATIONS OUT OF ACCUMULATED OTHER COMPREHENSIVE INCOME (LOSS) (Continued)

Changes in accumulated other comprehensive loss, net of tax, for the years ended December 31, 2015, 2014 and 2013, were as follows:

Millions	Unrealized Gain (Loss) on Available-for-sale Securities	Defined Benefit Pension, Other Postretirement Items *(a)*	Gain (Loss) on Cash Flow Hedge	Total
Balance as of December 31, 2012	$(0.1)	$(21.5)	$(0.4)	$(22.0)
Other Comprehensive Income Before Reclassifications	1.3	3.2	0.1	4.6
Amounts Reclassified From Accumulated Other Comprehensive Loss	(1.3)	1.6	—	0.3
Net Other Comprehensive Income	—	4.8	0.1	4.9
Balance as of December 31, 2013	(0.1)	(16.7)	(0.3)	(17.1)
Other Comprehensive Income (Loss) Before Reclassifications	(0.3)	(5.2)	0.2	(5.3)
Amounts Reclassified From Accumulated Other Comprehensive Loss	0.1	1.2	—	1.3
Net Other Comprehensive Income (Loss)	(0.2)	(4.0)	0.2	(4.0)
Balance as of December 31, 2014	(0.3)	(20.7)	(0.1)	(21.1)
Other Comprehensive Income (Loss) Before Reclassifications	(0.4)	(4.3)	0.1	(4.6)
Amounts Reclassified From Accumulated Other Comprehensive Loss	(0.1)	1.3	—	1.2
Net Other Comprehensive Income (Loss)	(0.5)	(3.0)	0.1	(3.4)
Balance as of December 31, 2015	$(0.8)	$(23.7)	—	$(24.5)

(a) 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 17. Pension and Other Postretirement Benefit Plans.)

NOTE 17. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS

We have noncontributory union and non-union defined benefit pension plans covering eligible employees. The plans provide defined benefits based on years of service and final average pay. We made no contributions to the plans in 2015 ($19.5 million in 2014; none in 2013). We also have a defined contribution RSOP covering substantially all employees. The 2015 plan year employer contributions, which are made through the employee stock ownership plan portion of the RSOP, totaled $9.0 million ($9.1 million for the 2014 plan year; $8.4 million for the 2013 plan year). (See Note 13. Common Stock and Earnings Per Share and Note 18. Employee Stock and Incentive Plans.)

In 2006, the non-union defined benefit pension plan was amended to suspend further crediting of service to the plan and to close the plan to new participants. In conjunction with those amendments, contributions were increased to the RSOP. In 2010, the Minnesota Power union defined benefit pension plan was amended to close the plan to new participants beginning February 1, 2011.

We have postretirement health care and life insurance plans covering eligible employees. In 2010, our postretirement health plan was amended to close the plan to employees hired after January 31, 2011. The full eligibility requirement was also amended in 2010, to require employees to be at least age 55 with 10 years of participation in the plan. In 2014, our postretirement life plan was amended to close the plan to non-union employees retiring after December 31, 2015. The postretirement health and life plans are contributory with participant contributions adjusted annually. Postretirement health and life benefits are funded through a combination of Voluntary Employee Benefit Association trusts (VEBAs), established under section 501(c)(9) of the Internal Revenue Code, and irrevocable grantor trusts. In 2015, no contributions were made to the VEBAs (none in 2014; $10.8 million in 2013) and no contributions were made to the grantor trusts (none in 2014; $2.0 million in 2013).

NOTE 17. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (Continued)

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 pension plans. Contributions are based on estimates and assumptions which are subject to change. We expect to contribute $2.0 million to the defined benefit pension plan and expect no contributions to the defined benefit postretirement health and life plan in 2016.

Accounting for defined benefit pension and postretirement benefit plans requires that employers recognize on a prospective basis the funded status of their defined benefit pension and other postretirement plans on their balance sheet and recognize as a component of other comprehensive income, net of tax, the gains or losses and prior service costs or credits that arise during the period but are not recognized as components of net periodic benefit cost.

The defined benefit pension and postretirement health and life benefit expense (credit) recognized annually by our regulated utilities are expected to be recovered (refunded) through rates filed with our regulatory jurisdictions. As a result, these amounts that are required to otherwise be recognized in accumulated other comprehensive income have been recognized as a long-term regulatory asset (regulatory liability) on our Consolidated Balance Sheet, in accordance with the accounting standards for the effect of certain types of regulation applicable to our Regulated Operations. The defined benefit pension and postretirement health and life benefit expense (credits) associated with our other operations are recognized in accumulated other comprehensive income.

Pension Obligation and Funded Status **At December 31**	**2015**	**2014**
Millions		
Accumulated Benefit Obligation	$665.0	$661.4
Change in Benefit Obligation		
Obligation, Beginning of Year	$714.5	$622.8
Service Cost	10.1	8.3
Interest Cost	29.9	29.8
Actuarial (Gain) Loss	(31.2)	72.6
Benefits Paid	(40.2)	(36.9)
Participant Contributions	26.7	17.9
Obligation, End of Year	$709.8	$714.5
Change in Plan Assets		
Fair Value, Beginning of Year	$544.2	$501.6
Actual Return on Plan Assets	(10.8)	41.0
Employer Contribution *(a)*	28.1	38.5
Benefits Paid	(40.2)	(36.9)
Fair Value, End of Year	$521.3	$544.2
Funded Status, End of Year	$(188.5)	$(170.3)
Net Pension Amounts Recognized in Consolidated Balance Sheet Consist of:		
Current Liabilities	$(1.3)	$(1.2)
Non-Current Liabilities	$(187.2)	$(169.1)

(a) Includes Participant Contributions noted above.

NOTE 17. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (Continued)

The pension costs that are reported as a component within our Consolidated Balance Sheet, reflected in long-term regulatory assets or liabilities and accumulated other comprehensive income, consist of the following:

Unrecognized Pension Costs **As of December 31**	**2015**	**2014**
Millions		
Net Loss	$252.7	$250.4
Prior Service Cost	—	0.2
Total Unrecognized Pension Costs	$252.7	$250.6

Components of Net Periodic Pension Expense **Year Ended December 31**	**2015**	**2014**	**2013**
Millions			
Service Cost	$10.1	$8.3	$9.9
Interest Cost	29.9	29.8	26.0
Expected Return on Plan Assets	(40.7)	(38.2)	(35.2)
Amortization of Loss	17.9	14.2	21.5
Amortization of Prior Service Cost	0.2	0.3	0.3
Net Pension Expense	$17.4	$14.4	$22.5

Other Changes in Pension Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income and Regulatory Assets or Liabilities **Year Ended December 31**	**2015**	**2014**
Millions		
Net Loss	$20.2	$69.8
Amortization of Prior Service Cost	(0.2)	(0.3)
Amortization of Loss	(17.9)	(14.2)
Total Recognized in Other Comprehensive Income and Regulatory Assets or Liabilities	$2.1	$55.3

Information for Pension Plans with an Accumulated Benefit Obligation in Excess of Plan Assets **As of December 31**	**2015**	**2014**
Millions		
Projected Benefit Obligation	$709.8	$714.5
Accumulated Benefit Obligation	$665.0	$661.4
Fair Value of Plan Assets	$521.3	$544.2

Postretirement Health and Life Obligation and Funded Status **At December 31**	**2015**	**2014**
Millions		
Change in Benefit Obligation		
Obligation, Beginning of Year	$170.9	$151.9
Service Cost	4.3	3.4
Interest Cost	7.2	7.3
Actuarial (Gain) Loss	(14.4)	18.1
Benefits Paid	(10.7)	(8.9)
Participant Contributions	2.9	2.6
Plan Amendments	—	(2.9)
Plan Curtailments	—	(0.6)
Obligation, End of Year	$160.2	$170.9
Change in Plan Assets		
Fair Value, Beginning of Year	$163.2	$157.0
Actual Return on Plan Assets	(3.5)	11.6
Employer Contribution	1.5	1.1
Participant Contributions	2.9	2.6
Benefits Paid	(10.7)	(9.1)
Fair Value, End of Year	$153.4	$163.2
Funded Status, End of Year	$(6.8)	$(7.7)

Net Postretirement Health and Life Amounts Recognized in Consolidated Balance Sheet Consist of:		
Non-Current Assets	$6.4	$6.6
Current Liabilities	$(1.0)	$(0.9)
Non-Current Liabilities	$(12.2)	$(13.4)

According to the accounting standards for retirement benefits, only assets in the VEBAs are treated as plan assets in the above table for the purpose of determining funded status. In addition to the postretirement health and life assets reported in the previous table, we had $17.4 million in irrevocable grantor trusts included in Other Investments on our Consolidated Balance Sheet at December 31, 2015 ($17.9 million at December 31, 2014).

The postretirement health and life costs that are reported as a component within our Consolidated Balance Sheet, reflected in regulatory long-term assets or liabilities and accumulated other comprehensive income, consist of the following:

Unrecognized Postretirement Health and Life Costs **As of December 31**	**2015**	**2014**
Millions		
Net Loss	$6.5	$6.9
Prior Service Credit	(7.6)	(10.6)
Total Unrecognized Postretirement Health and Life Credit	$(1.1)	$(3.7)

NOTE 17. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (Continued)

Components of Net Periodic Postretirement Health and Life Expense Year Ended December 31	2015	2014	2013
Millions			
Service Cost	$4.3	$3.4	$3.9
Interest Cost	7.2	7.3	6.8
Expected Return on Plan Assets	(10.9)	(10.3)	(9.7)
Amortization of Loss	0.4	0.5	1.6
Amortization of Prior Service Credit	(3.0)	(2.5)	(2.5)
Effect of Plan Settlement *(a)*	—	—	(1.6)
Net Postretirement Health and Life Credit	$(2.0)	$(1.6)	$(1.5)

(a) Result of the termination of a legacy benefit plan.

Other Changes in Postretirement Benefit Plan Assets and Benefit Obligations Recognized in Other Comprehensive Income and Regulatory Assets or Liabilities Year Ended December 31	2015	2014
Millions		
Net Loss	—	$16.4
Prior Service Credit Arising During the Period	—	(3.0)
Amortization of Prior Service Credit	$3.0	2.5
Amortization of Loss	(0.4)	(0.5)
Total Recognized in Other Comprehensive Income and Regulatory Assets or Liabilities	$2.6	$15.4

Estimated Future Benefit Payments	Pension	Postretirement Health and Life
Millions		
2016	$39.8	$8.3
2017	$40.6	$8.6
2018	$41.1	$8.8
2019	$41.7	$9.1
2020	$41.8	$9.3
Years 2021 – 2025	$216.2	$48.0

The pension and postretirement health and life costs recorded in regulatory long-term assets or liabilities and accumulated other comprehensive income expected to be recognized as a component of net pension and postretirement benefit costs for the year ending December 31, 2016, are as follows:

	Pension	Postretirement Health and Life
Millions		
Net (Gain) Loss	$(8.4)	$0.2
Prior Service Credit	—	(2.9)
Total Pension and Postretirement Health and Life Credit	$(8.4)	$(2.7)

NOTE 17. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (Continued)

Assumptions Used to Determine Benefit Obligation **As of December 31**	**2015**	**2014**
Discount Rate		
Pension	4.72%	4.30%
Postretirement Health and Life	4.73%	4.33%
Rate of Compensation Increase	3.70 - 4.30%	3.70 - 4.30%
Health Care Trend Rates		
Trend Rate	6.50%	6.75%
Ultimate Trend Rate	5.00%	5.00%
Year Ultimate Trend Rate Effective	2022	2022

Assumptions Used to Determine Net Periodic Benefit Costs **Year Ended December 31**	**2015**	**2014**	**2013**
Discount Rate	4.30 - 4.33%	4.93 - 4.96%	4.10 - 4.13%
Expected Long-Term Return on Plan Assets			
Pension	8.00%	8.00%	8.25%
Postretirement Health and Life	6.40 - 8.00%	6.40 - 8.00%	6.60 - 8.25%
Rate of Compensation Increase	3.70 - 4.30%	3.70 - 4.30%	4.30 - 4.60%

In establishing the expected long-term rate of return on plan assets, we determine the long-term historical performance of each asset class, adjust these for current economic conditions, and utilizing the target allocation of our plan assets, forecast the expected long-term rate of return.

The discount rate is computed using a yield curve adjusted for ALLETE's projected cash flows to match our plan characteristics. The yield curve is determined using high-quality long-term corporate bond rates at the valuation date. We believe the adjusted discount curve used in this comparison does not materially differ in duration and cash flows from our pension obligation.

The Company utilizes actuarial assumptions about mortality to calculate the pension and postretirement health and life benefit obligations. In 2014, revised mortality tables were released, and the Company adopted updated mortality tables as of December 31, 2014.

Sensitivity of a One-Percentage-Point Change in Health Care Trend Rates

	One Percent Increase	**One Percent Decrease**
Millions		
Effect on Total of Postretirement Health and Life Service and Interest Cost	$1.9	$(1.5)
Effect on Postretirement Health and Life Obligation	$19.3	$(15.9)

Actual Plan Asset Allocations	**Pension**		**Postretirement Health and Life *(a)***	
	2015	**2014**	**2015**	**2014**
Equity Securities	47%	48%	57%	58%
Debt Securities	39%	39%	35%	34%
Private Equity	8%	8%	8%	8%
Real Estate	6%	5%	—	—
	100%	100%	100%	100%

(a) Includes VEBAs and irrevocable grantor trusts.

There were no shares of ALLETE common stock included in pension plan equity securities as of December 31, 2015 (no shares as of December 31, 2014).

NOTE 17. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (Continued)

In 2013, the defined benefit pension plan adopted a dynamic asset allocation strategy (glide path) that increases the invested allocation to fixed income assets as the funding level of the plan increases to better match the sensitivity of the plan's assets and liabilities to changes in interest rates. This is expected to reduce the volatility of reported pension plan expenses. The postretirement health and life plans' assets continue to be diversified to achieve strong returns within managed risk. Equity securities are diversified among domestic companies with large, mid and small market capitalizations, as well as investments in international companies. The majority of debt securities are made up of investment grade bonds. Below are the current targeted allocations as of December 31, 2015.

Plan Asset Target Allocations	**Pension**	**Postretirement Health and Life *(a)***
Equity Securities	56%	60%
Debt Securities	35%	37%
Real Estate	9%	3%
	100%	100%

(a) Includes VEBAs and irrevocable grantor trusts.

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). The three levels of the fair value hierarchy are as follows:

Level 1 — Quoted prices are available in active markets for identical assets or liabilities as of the reported date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis. This category includes various U.S. equity securities, public mutual funds, and futures. These instruments are valued using the closing price from the applicable exchange or whose value is quoted and readily traded daily.

Level 2 — Pricing inputs are other than quoted prices in active markets, but are either directly or indirectly observable as of the reported date. The types of assets and liabilities included in Level 2 are typically either comparable to actively traded securities or contracts, such as treasury securities with pricing interpolated from recent trades of similar securities, or priced with models using highly observable inputs. This category includes various bonds and non-public funds whose underlying investments may be Level 1 or Level 2 securities.

Level 3 — Significant inputs that are generally less observable from objective sources. The types of assets and liabilities included in Level 3 are those with inputs requiring significant management judgment or estimation, such as the complex and subjective models and forecasts used to determine the fair value. This category includes private equity funds and real estate valued through external appraisal processes. Valuation methodologies incorporate pricing models, discounted cash flow models, and similar techniques which utilize capitalization rates, discount rates, cash flows and other factors.

NOTE 17. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (Continued)

Pension Fair Value

	Fair Value as of December 31, 2015			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Equity Securities:				
U.S. Large-cap *(a)*	$33.9	$42.1	—	$76.0
U.S. Mid-cap Growth *(a)*	14.2	17.7	—	31.9
U.S. Small-cap *(a)*	14.5	17.9	—	32.4
Mutual Funds	8.4	—	—	8.4
International	44.7	42.0	—	86.7
Debt Securities:				
Mutual Funds	0.1	—	—	0.1
Fixed Income	2.7	185.3	—	188.0
Cash and Cash Equivalents	25.6	—	—	25.6
Other Types of Investments:				
Private Equity Funds	—	—	$43.3	43.3
Real Estate	—	—	28.9	28.9
Total Fair Value of Assets	$144.1	$305.0	$72.2	$521.3

(a) The underlying investments classified under U.S. Equity Securities consist of money market funds (Level 1) and actively-managed funds (Level 2), which are combined with futures, and settle daily, to achieve the returns of the U.S. Equity Securities Large-cap, Mid-cap Growth, and Small-cap funds. Our exposure with respect to these investments includes both the futures and the underlying investments.

Recurring Fair Value Measures **Activity in Level 3**	**Private Equity Funds**	**Real Estate**
Millions		
Balance as of December 31, 2014	$43.3	$28.9
Actual Return on Plan Assets	2.6	2.9
Purchases, Sales, and Settlements – Net	(2.6)	(2.9)
Balance as of December 31, 2015	$43.3	$28.9

NOTE 17. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS (Continued)
Fair Value (Continued)

	Fair Value as of December 31, 2014			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Equity Securities:				
U.S. Large-cap *(a)*	$32.1	$56.4	—	$88.5
U.S. Mid-cap Growth *(a)*	13.6	23.9	—	37.5
U.S. Small-cap *(a)*	13.9	24.4	—	38.3
International	46.1	45.9	—	92.0
Debt Securities:				
Mutual Funds	0.1	—	—	0.1
Fixed Income	2.7	201.0	—	203.7
Cash and Cash Equivalents	11.9	—	—	11.9
Other Types of Investments:				
Private Equity Funds	—	—	$43.3	43.3
Real Estate	—	—	28.9	28.9
Total Fair Value of Assets	$120.4	$351.6	$72.2	$544.2

(a) The underlying investments classified under U.S. Equity Securities consist of money market funds (Level 1) and actively-managed funds (Level 2), which are combined with futures, and settle daily, to achieve the returns of the U.S. Equity Securities Large-cap, Mid-cap Growth, and Small-cap funds. Our exposure with respect to these investments includes both the futures and the underlying investments.

Recurring Fair Value Measures		
Activity in Level 3	**Private Equity Funds**	**Real Estate**
Millions		
Balance as of December 31, 2013	$46.8	$26.5
Actual Return on Plan Assets	1.2	2.8
Purchases, Sales, and Settlements – Net	(4.7)	(0.4)
Balance as of December 31, 2014	$43.3	$28.9

Postretirement Health and Life Fair Value

	Fair Value as of December 31, 2015			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Equity Securities:				
U.S. Large-cap *(a)*	$28.2	—	—	$28.2
U.S. Mid-cap Growth *(a)*	19.1	—	—	19.1
U.S. Small-cap *(a)*	12.1	—	—	12.1
International	26.8	—	—	26.8
Debt Securities:				
Mutual Funds	45.2	—	—	45.2
Fixed Income	—	$8.4	—	8.4
Cash and Cash Equivalents	1.6	—	—	1.6
Other Types of Investments:				
Private Equity Funds	—	—	$12.0	12.0
Total Fair Value of Assets	$133.0	$8.4	$12.0	$153.4

(a) The underlying investments classified under U.S. Equity Securities consist of mutual funds (Level 1).

Recurring Fair Value Measures Activity in Level 3	Private Equity Funds
Millions	
Balance as of December 31, 2014	$12.9
Actual Return on Plan Assets	1.2
Purchases, Sales, and Settlements – Net	(2.1)
Balance as of December 31, 2015	$12.0

	Fair Value as of December 31, 2014			
Recurring Fair Value Measures	**Level 1**	**Level 2**	**Level 3**	**Total**
Millions				
Assets:				
Equity Securities:				
U.S. Large-cap *(a)*	$29.3	—	—	$29.3
U.S. Mid-cap Growth *(a)*	20.0	—	—	20.0
U.S. Small-cap *(a)*	12.6	—	—	12.6
International	30.6	—	—	30.6
Debt Securities:				
Mutual Funds	44.5	—	—	44.5
Fixed Income	—	$9.9	—	9.9
Cash and Cash Equivalents	3.4	—	—	3.4
Other Types of Investments:				
Private Equity Funds	—	—	$12.9	12.9
Total Fair Value of Assets	$140.4	$9.9	$12.9	$163.2

(a) The underlying investments classified under U.S. Equity Securities consist of mutual funds (Level 1).

Recurring Fair Value Measures Activity in Level 3	Private Equity Funds
Millions	
Balance as of December 31, 2013	$13.1
Actual Return on Plan Assets	1.4
Purchases, Sales, and Settlements – Net	(1.6)
Balance as of December 31, 2014	$12.9

Accounting and disclosure requirements for the Medicare Prescription Drug, Improvement and Modernization Act of 2003 (Act) provide guidance for employers that sponsor postretirement health care plans that provide prescription drug benefits. We provide a fully insured postretirement health benefit, including a prescription drug benefit, which qualifies us for a federal subsidy under the Act. The federal subsidy is reflected in the premiums charged to us by the insurance company.

NOTE 18. EMPLOYEE STOCK AND INCENTIVE PLANS

Employee Stock Ownership Plan. We sponsor an ESOP within the RSOP. Eligible employees may contribute to the RSOP plan as of their date of hire. In 1990, the ESOP issued a $75.0 million note (term not to exceed 25 years at 10.25 percent) to use as consideration for 2.8 million shares (1.9 million shares adjusted for stock splits) of our newly issued common stock. The note was refinanced in 2006 at 6 percent and subsequently matured in December 2015. The ESOP shares were initially pledged as collateral for the debt. As the debt was repaid, shares were released from collateral and allocated to participants based on the proportion of debt service paid in the year. As shares were released from collateral, we reported compensation expense equal to the current market price of the shares less dividends on allocated shares. The dividends received by the ESOP are distributed to participants. Dividends on allocated ESOP shares are recorded as a reduction of retained earnings. With the maturity of the note, ESOP employer allocations will be funded with contributions paid in either cash or the issuance of ALLETE common stock at the Company's discretion. ESOP compensation expense was $9.0 million in 2015 ($9.1 million in 2014; $8.4 million in 2013).

According to the accounting standards for stock compensation, unallocated shares of ALLETE common stock held and purchased by the ESOP were treated as unearned ESOP shares and not considered outstanding for earnings per share computations. ESOP shares are included in earnings per share computations after they are allocated to participants.

As of December 31	**2015**	**2014**	**2013**
Millions			
ESOP Shares			
Allocated	1.8	1.9	2.0
Unallocated	—	0.3	0.5
Total	1.8	2.2	2.5
Fair Value of Unallocated Shares	—	$13.2	$24.1

Stock-Based Compensation. *Stock Incentive Plan.* Under our Executive Long-Term Incentive Compensation Plan (Executive Plan), share-based awards may be issued to key employees through a broad range of methods, including non-qualified and incentive stock options, performance shares, performance units, restricted stock, restricted stock units, stock appreciation rights and other awards. There are 1.1 million shares of common stock reserved for issuance under the Executive Plan, with 0.9 million of these shares available for issuance as of December 31, 2015.

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

Non-Qualified Stock Options. These options allow for the purchase of shares of common stock at a price equal to the market value of our common stock at the date of grant. Options become exercisable beginning one year after the grant date, with one-third vesting each year over three years. Options may be exercised up to ten years following the date of grant. In the case of qualified retirement, death or disability, options vest immediately and the period over which the options can be exercised is three years. Employees have up to three months to exercise vested options upon voluntary termination or involuntary termination without cause. All options are canceled upon termination for cause. All options vest immediately upon retirement, death, disability or a change of control, as defined in the award agreement. We determine the fair value of options using the Black-Scholes option-pricing model. The estimated fair value of options, including the effect of estimated forfeitures, is recognized as expense on the straight-line basis over the options' vesting periods, or the accelerated vesting period if the employee is eligible for retirement. Stock options have not been granted since 2008.

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

NOTE 18. EMPLOYEE STOCK AND INCENTIVE PLANS (Continued)

Performance Shares. Under the performance share awards plan, the number of shares earned is contingent upon attaining specific market goals over a three-year performance period. Market goals are measured by total shareholder return relative to a group of peer companies. In the case of qualified retirement, death, or disability during a performance period, a pro rata portion of the award will be earned at the conclusion of the performance period based on the market goals achieved. In the case of termination of employment for any reason other than qualified retirement, death, or disability, no award will be earned. If there is a change in control, a pro rata portion of the award will be paid based on the greater of actual performance up to the date of the change in control or target performance. The fair value of these awards is determined by the probability of meeting the total shareholder return goals. Compensation cost is recognized over the three-year performance period based on our estimate of the number of shares which will be earned by the award recipients.

Restricted Stock Units. Under the restricted stock units plan, shares for participants eligible for retirement vest monthly over a three-year period. For participants not eligible for retirement, shares vest at the end of the three-year period. In the case of qualified retirement, death or disability, a pro rata portion of the award will be earned. In the case of termination of employment for any reason other than qualified retirement, death or disability, no award will be earned. If there is a change in control, a pro rata portion of the award will be earned. The fair value of these awards is equal to the grant date fair value. Compensation cost is recognized over the three-year vesting period based on our estimate of the number of shares which will be earned by the award recipients.

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

RSOP. The RSOP is a contributory defined contribution plan subject to the provisions of the Employee Retirement Income Security Act of 1974, as amended, and qualifies as an employee stock ownership plan and profit sharing plan. The RSOP provides eligible employees an opportunity to save for retirement.

The following share-based compensation expense amounts were recognized in our Consolidated Statement of Income for the periods presented.

Share-Based Compensation Expense **Year Ended December 31**	**2015**	**2014**	**2013**
Millions			
Performance Shares	$1.8	$1.6	$1.7
Restricted Stock Units	0.8	0.7	0.7
Total Share-Based Compensation Expense	$2.6	$2.3	$2.4
Income Tax Benefit	$1.1	$1.0	$1.0

There were no capitalized share-based compensation costs during the years ended December 31, 2015, 2014 or 2013.

As of December 31, 2015, the total unrecognized compensation cost for the performance share awards and restricted stock units not yet recognized in our Consolidated Statements of Income was $1.9 million and $1.1 million, respectively. These amounts are expected to be recognized over a weighted-average period of 1.7 years for performance share awards and 1.9 years for restricted stock units.

NOTE 18. EMPLOYEE STOCK AND INCENTIVE PLANS (Continued)

Non-Qualified Stock Options. The following table presents information regarding our outstanding stock options.

	2015		2014		2013	
	Number of Options	**Weighted-Average Exercise Price**	**Number of Options**	**Weighted-Average Exercise Price**	**Number of Options**	**Weighted-Average Exercise Price**
Outstanding as of January 1	66,279	$44.39	108,299	$44.10	395,678	$42.28
Granted *(a)*	—	—	—	—	—	—
Exercised	(24,456)	$44.52	(42,020)	$43.65	(287,379)	$41.60
Forfeited	(2,169)	$42.93	—	—	—	—
Outstanding as of December 31	39,654	$44.39	66,279	$44.39	108,299	$44.10
Exercisable as of December 31	39,654	$44.39	66,279	$44.39	108,299	$43.17

(a) Stock options have not been granted since 2008. The weighted-average grant-date intrinsic value of options granted in 2008 was $6.18.

Cash received from non-qualified stock options exercised was approximately $1.1 million in 2015. The intrinsic value of a stock award is the amount by which the fair value of the underlying stock exceeds the exercise price of the award. The total intrinsic value of options exercised was $0.2 million during 2015 ($0.4 million in 2014; $2.2 million in 2013).

	Exercise Price		
As of December 31, 2015	**$39.10**	**$44.15**	**$48.65**
Options Outstanding and Exercisable:			
Number Outstanding and Exercisable	16,620	2,306	20,728
Weighted Average Remaining Contractual Life (Years)	2.1	0.1	1.1
Weighted Average Exercise Price	$39.10	$44.15	$48.65
Aggregate Intrinsic Value (Millions)	$0.2	—	$0.1

Performance Shares. The following table presents information regarding our non-vested performance shares.

	2015		2014		2013	
	Number of Shares	**Weighted-Average Grant Date Fair Value**	**Number of Shares**	**Weighted-Average Grant Date Fair Value**	**Number of Shares**	**Weighted-Average Grant Date Fair Value**
Non-vested as of January 1	119,635	$48.26	114,765	$47.02	107,899	$40.73
Granted *(a)*	43,583	$58.95	47,992	$46.47	45,830	$52.15
Awarded	—	—	(36,515)	$42.01	(18,605)	$35.10
Unearned Grant Award	(36,670)	$45.41	—	—	(18,606)	$35.10
Forfeited	(7,008)	$53.49	(6,607)	$48.29	(1,753)	$47.26
Non-vested as of December 31	119,540	$52.72	119,635	$48.26	114,765	$47.02

(a) Shares granted include accrued dividends.

There were 51,586 performance shares granted in January 2016 for the three-year performance period ending in 2018. The ultimate issuance is contingent upon the attainment of certain goals of ALLETE during the performance periods. The grant date fair value of the performance shares granted was $2.7 million.

There were no performance shares awarded in February 2016 for the three-year performance period ending in 2015.

NOTE 18. EMPLOYEE STOCK AND INCENTIVE PLANS (Continued)

Restricted Stock Units. The following table presents information regarding our available restricted stock units.

	2015		2014		2013	
	Number of Shares	Weighted-Average Grant Date Fair Value	Number of Shares	Weighted-Average Grant Date Fair Value	Number of Shares	Weighted-Average Grant Date Fair Value
Available as of January 1	53,888	$44.47	55,982	$40.85	56,415	$36.61
Granted *(a)*	26,702	$54.81	19,645	$48.44	21,440	$43.41
Awarded	(19,464)	$41.44	(18,860)	$37.64	(20,939)	$32.03
Forfeited	(3,432)	$51.52	(2,879)	$45.92	(934)	$41.02
Available as of December 31	57,694	$49.86	53,888	$44.47	55,982	$40.85

(a) Shares granted include accrued dividends.

There were 17,396 restricted stock units granted in January 2016 for the vesting period ending in 2018. The grant date fair value of the restricted stock units granted was $0.9 million.

There were 17,608 restricted stock units awarded in February 2016. The grant date fair value of the shares awarded was $0.8 million.

NOTE 19. QUARTERLY FINANCIAL DATA (UNAUDITED)

Information for any one quarterly period is not necessarily indicative of the results which may be expected for the year.

Quarter Ended	Mar. 31	Jun. 30	Sept. 30	Dec. 31
Millions Except Earnings Per Share				
2015				
Operating Revenue	$320.0	$323.3	$462.5	$380.6
Operating Income	$56.4	$39.5	$85.2	$29.6
Net Income Attributable to ALLETE	$39.9	$22.5	$60.4	$18.3
Earnings Per Share of Common Stock				
Basic	$0.85	$0.46	$1.24	$0.37
Diluted	$0.85	$0.46	$1.23	$0.37
2014				
Operating Revenue	$296.5	$260.7	$288.9	$290.7
Operating Income	$48.3	$28.2	$60.8	$51.5
Net Income Attributable to ALLETE	$33.5	$16.8	$41.6	$32.9
Earnings Per Share of Common Stock				
Basic	$0.81	$0.40	$0.97	$0.73
Diluted	$0.80	$0.40	$0.97	$0.73

Schedule II

ALLETE

Valuation and Qualifying Accounts and Reserves

	Balance at Beginning of Period	Additions		Deductions from Reserves *(a)*	Balance at End of Period
		Charged to Income	Other Charges		
Millions					
Reserve Deducted from Related Assets					
Reserve For Uncollectible Accounts					
2013 Trade Accounts Receivable	$1.0	$1.3	—	$1.2	$1.1
Finance Receivables – Long-Term	$0.6	—	—	—	$0.6
2014 Trade Accounts Receivable	$1.1	$1.8	—	$1.8	$1.1
Finance Receivables – Long-Term	$0.6	—	—	—	$0.6
2015 Trade Accounts Receivable	$1.1	$1.6	—	$1.7	$1.0
Finance Receivables – Long-Term	$0.6	—	—	—	$0.6
Deferred Asset Valuation Allowance					
2013 Deferred Tax Assets	$2.4	$5.6	—	—	$8.0
2014 Deferred Tax Assets	$8.0	$14.1	—	—	$22.1
2015 Deferred Tax Assets	$22.1	$9.5	—	—	$31.6

(a) Includes uncollectible accounts written off.