ALLETE INC
Form 10-Q
August 02, 2018

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

FORM 10-Q
(Mark One)
x Quarterly Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the quarterly period ended June 30, 2018
or
¨ Transition Report Pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from ______________ to ______________
Commission File Number 1-3548
ALLETE, Inc.
(Exact name of registrant as specified in its charter)

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

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

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

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

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

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

Large Accelerated Filer x	Accelerated Filer ¨
Non-Accelerated Filer ¨	Smaller Reporting Company ¨
	Emerging Growth Company ¨

If an emerging growth company, indicate by check mark if the registrant has elected not to use the extended transition period for complying with any new or revised financial accounting standards provided pursuant to Section 13(a) of the

Exchange Act. ¨

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

Common Stock, without par value,
51,360,616 shares outstanding
as of June 30, 2018

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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 regulated 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, Inc.
ATC	American Transmission Company LLC
Bison	Bison Wind Energy Center
BNI Energy	BNI Energy, Inc. and its subsidiary
Boswell	Boswell Energy Center
Camp Ripley	Camp Ripley Solar Array
CO_2	Carbon Dioxide
Company	ALLETE, Inc. and its subsidiaries
CIP	Conservation Improvement Program
Cliffs	Cleveland-Cliffs Inc.
CSAPR	Cross-State Air Pollution Rule
DC	Direct Current
EIS	Environmental Impact Statement
EITE	Energy-Intensive Trade-Exposed
EPA	United States Environmental Protection Agency
ERP Iron Ore	ERP Iron Ore, LLC
ESOP	Employee Stock Ownership Plan
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
Form 10-K	ALLETE Annual Report on Form 10-K
Form 10-Q	ALLETE Quarterly Report on Form 10-Q
GAAP	Generally Accepted Accounting Principles in the United States of America
GHG	Greenhouse Gases
GNTL	Great Northern Transmission Line
Invest Direct	ALLETE's Direct Stock Purchase and Dividend Reinvestment Plan
IRP	Integrated Resource Plan
Item ___	Item ___ of this Form 10-Q
kV	Kilovolt(s)
kW / kWh	Kilowatt(s) / Kilowatt-hour(s)
Laskin	Laskin Energy Center
Magnetation	Magnetation, LLC
Manitoba Hydro	Manitoba Hydro-Electric Board
MATS	Mercury and Air Toxics Standards
Mesabi Metallics	Mesabi Metallics Company, LLC (formerly Essar Steel Minnesota, LLC)
Minnesota Power	An operating division of ALLETE, Inc.
Minnkota Power	Minnkota Power Cooperative, Inc.

MISO	Midcontinent Independent System Operator, Inc.

Abbreviation or Acronym	Term
Montana-Dakota Utilities	Montana-Dakota Utilities Co., a division of MDU Resources Group, 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
NOL	Net Operating Loss
NO_2	Nitrogen Dioxide
NO_X	Nitrogen Oxides
Northern States Power	Northern States Power Company, a subsidiary of Xcel Energy Inc.
Northshore Mining	Northshore Mining Company, a wholly-owned subsidiary of Cleveland-Cliffs Inc.
Note ___	Note ___ to the Consolidated Financial Statements in this Form 10-Q
NPDES	National Pollutant Discharge Elimination System
NTEC	Nemadji Trail Energy Center
Oliver Wind I	Oliver Wind I Energy Center
Oliver Wind II	Oliver Wind II Energy Center
Palm Coast Park District	Palm Coast Park Community Development District in Florida
PolyMet	PolyMet Mining Corp.
PPA / PSA	Power Purchase Agreement / Power Sales Agreement
PPACA	Patient Protection and Affordable Care Act of 2010
PSCW	Public Service Commission of Wisconsin
SEC	Securities and Exchange Commission
Silver Bay Power	Silver Bay Power Company, a wholly-owned subsidiary of Cleveland-Cliffs Inc.
SO_2	Sulfur Dioxide
Square Butte	Square Butte Electric Cooperative, a North Dakota cooperative corporation
SWL&P	Superior Water, Light and Power Company
Taconite Harbor	Taconite Harbor Energy Center
TCJA	Tax Cuts and Job Act of 2017 (Public Law 115-97)
Tenaska	Tenaska Energy, Inc. and Tenaska Energy Holdings, LLC
Tonka Water	Tonka Equipment Company
Town Center District	Town Center at Palm Coast Community Development District in Florida
UPM Blandin	UPM, Blandin Paper Mill owned by UPM-Kymmene Corporation
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
WTG	Wind Turbine Generator

Forward-Looking Statements

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

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

- our ability to successfully implement our strategic objectives;
- global and domestic economic conditions affecting us or our customers;
- 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 cybersecurity 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 GHG;
- 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 our 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, creditworthiness of customers, ability to obtain materials required to perform services, and changing market conditions.

Forward-Looking Statements (Continued)

Additional disclosures regarding factors that could cause our results or performance to differ from those anticipated by this report are discussed in Part I, Item 1A. Risk Factors of ALLETE’s 2017 Form 10-K, and in Part II, Item 1A. Risk Factors in this Form 10 Q. 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-Q and in other reports filed with the SEC that attempt to identify the risks and uncertainties that may affect ALLETE’s business.

PART I. FINANCIAL INFORMATION

ITEM 1. CONSOLIDATED FINANCIAL STATEMENTS

ALLETE
CONSOLIDATED BALANCE SHEET
Unaudited

	June 30, 2018	December 31, 2017
Millions		
Assets		
Current Assets		
Cash and Cash Equivalents	$121.9	$98.9
Accounts Receivable (Less Allowance of $2.3 and $2.1)	132.4	135.1
Inventories – Net	145.4	95.9
Prepayments and Other	24.3	37.6
Total Current Assets	424.0	367.5
Property, Plant and Equipment – Net	3,809.3	3,822.4
Regulatory Assets	374.5	384.7
Investment in ATC	123.6	118.7
Other Investments	52.5	53.1
Goodwill and Intangible Assets – Net	225.8	225.9
Other Non-Current Assets	105.0	107.7
Total Assets	$5,114.7	$5,080.0
Liabilities and Shareholders' Equity		
Liabilities		
Current Liabilities		
Accounts Payable	$105.0	$136.3
Accrued Taxes	42.0	50.0
Accrued Interest	18.0	17.6
Long-Term Debt Due Within One Year	56.7	64.1
Other	128.5	83.2
Total Current Liabilities	350.2	351.2
Long-Term Debt	1,462.2	1,439.2
Deferred Income Taxes	228.5	230.5
Regulatory Liabilities	516.0	532.0
Defined Benefit Pension and Other Postretirement Benefit Plans	175.2	191.8
Other Non-Current Liabilities	274.4	267.1
Total Liabilities	3,006.5	3,011.8
Commitments, Guarantees and Contingencies (Note 13)		
Shareholders' Equity		
Common Stock Without Par Value, 80.0 Shares Authorized, 51.4 and 51.1 Shares Issued and Outstanding	1,415.4	1,401.4
Accumulated Other Comprehensive Loss	(27.6)	(22.6)
Retained Earnings	720.4	689.4
Total Shareholders' Equity	2,108.2	2,068.2
Total Liabilities and Shareholders' Equity	$5,114.7	$5,080.0

The accompanying notes are an integral part of these statements.

ALLETE
CONSOLIDATED STATEMENT OF INCOME
Unaudited

	Quarter Ended		Six Months Ended	
	June 30,		June 30,	
	2018	2017	2018	2017
Millions Except Per Share Amounts				
Operating Revenue				
Contracts with Customers – Utility	$257.8	$264.9	$528.0	$546.5
Contracts with Customers – Non-utility	80.4	82.5	162.4	160.6
Other – Non-utility	5.9	5.9	11.9	11.8
Total Operating Revenue	344.1	353.3	702.3	718.9
Operating Expenses				
Fuel, Purchased Power and Gas – Utility	96.5	93.1	197.4	189.7
Transmission Services – Utility	16.8	17.6	35.2	34.2
Cost of Sales – Non-utility	37.0	38.4	69.9	69.9
Operating and Maintenance	86.8	85.9	173.3	170.3
Depreciation and Amortization	56.1	50.1	101.9	100.6
Taxes Other than Income Taxes	14.4	14.2	30.7	28.6
Total Operating Expenses	307.6	299.3	608.4	593.3
Operating Income	36.5	54.0	93.9	125.6
Other Income (Expense)				
Interest Expense	(17.1)	(16.7)	(34.0)	(33.9)
Equity Earnings in ATC	4.3	5.3	9.0	11.4
Other	2.2	1.6	4.3	3.2
Total Other Expense	(10.6)	(9.8)	(20.7)	(19.3)
Income Before Income Taxes	25.9	44.2	73.2	106.3
Income Tax Expense (Benefit)	(5.4)	7.3	(9.1)	20.4
Net Income	$31.3	$36.9	$82.3	$85.9
Average Shares of Common Stock				
Basic	51.3	50.9	51.2	50.5
Diluted	51.5	51.1	51.4	50.7
Basic Earnings Per Share of Common Stock	$0.61	$0.73	$1.61	$1.70
Diluted Earnings Per Share of Common Stock	$0.61	$0.72	$1.60	$1.69
Dividends Per Share of Common Stock	$0.56	$0.535	$1.12	$1.07

The accompanying notes are an integral part of these statements.

ALLETE
CONSOLIDATED STATEMENT OF COMPREHENSIVE INCOME
Unaudited

	Quarter Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Millions				
Net Income	$31.3	$36.9	$82.3	$85.9
Other Comprehensive Income (Loss)				
Currency Translation Adjustments	—	(0.2)	—	(0.2)
Unrealized Gain (Loss) on Securities				
Net of Income Tax Expense of $–, $0.2, $– and $0.5	—	0.4	(0.1)	0.7
Defined Benefit Pension and Other Postretirement Benefit Plans				
Net of Income Tax Expense of $0.1, $0.2, $0.2 and $0.3	0.3	0.2	0.7	0.4
Total Other Comprehensive Income	0.3	0.4	0.6	0.9
Total Comprehensive Income	$31.6	$37.3	$82.9	$86.8

The accompanying notes are an integral part of these statements.

ALLETE
CONSOLIDATED STATEMENT OF CASH FLOWS
Unaudited

	Six Months Ended June 30,	
	2018	2017
Millions		
Operating Activities		
Net Income	$82.3	$85.9
AFUDC – Equity	(0.5)	(0.4)
Income from Equity Investments – Net of Dividends	(0.4)	(2.5)
Change in Fair Value of Contingent Consideration	—	(0.4)
Depreciation Expense	99.2	97.9
Amortization of PSAs	(11.9)	(11.8)
Amortization of Other Intangible Assets and Other Assets	5.0	5.3
Deferred Income Tax Expense	(9.5)	20.2
Share-Based and ESOP Compensation Expense	3.3	3.3
Defined Benefit Pension and Postretirement Benefit Expense	4.3	5.0
Provision for Interim Rate Refund	8.8	—
Provision for Tax Reform Refund	6.7	—
Bad Debt Expense	0.7	—
Changes in Operating Assets and Liabilities		
Accounts Receivable	1.7	2.4
Inventories	(3.2)	0.8
Prepayments and Other	2.8	4.3
Accounts Payable	8.1	(12.6)
Other Current Liabilities	(1.3)	(12.8)
Cash Contributions to Defined Benefit Pension Plans	(15.0)	(1.7)
Changes in Regulatory and Other Non-Current Assets	5.8	6.7
Changes in Regulatory and Other Non-Current Liabilities	7.5	(5.2)
Cash from Operating Activities	194.4	184.4
Investing Activities		
Proceeds from Sale of Available-for-sale Securities	7.2	1.0
Payments for Purchase of Available-for-sale Securities	(9.8)	(1.6)
Investment in ATC	(3.9)	(5.0)
Additions to Property, Plant and Equipment	(133.4)	(81.1)
Other Investing Activities	1.4	2.0
Cash for Investing Activities	(138.5)	(84.7)
Financing Activities		
Proceeds from Issuance of Common Stock	10.7	74.4
Proceeds from Issuance of Long-Term Debt	72.0	86.2
Repayments of Long-Term Debt	(57.9)	(127.0)
Acquisition-Related Contingent Consideration Payments	—	(19.7)
Dividends on Common Stock	(57.4)	(54.0)
Other Financing Activities	(0.6)	(1.4)
Cash for Financing Activities	(33.2)	(41.5)
Change in Cash, Cash Equivalents and Restricted Cash	22.7	58.2

Cash, Cash Equivalents and Restricted Cash at Beginning of Period	110.1	38.3
Cash, Cash Equivalents and Restricted Cash at End of Period	$132.8	$96.5

The accompanying notes are an integral part of these statements.

ALLETE
CONSOLIDATED STATEMENT OF SHAREHOLDERS' EQUITY
Unaudited

Millions	Total Shareholders' Equity	Retained Earnings	Accumulated Other Comprehensive Loss	Common Stock
Balance as of December 31, 2017	$2,068.2	$689.4	$(22.6)	$1,401.4
Adjustments to Opening Balance – Net of Income Taxes (a)	0.5	6.1	(5.6)	—
Balance as of January 1, 2018	2,068.7	695.5	(28.2)	1,401.4
Comprehensive Income				
Net Income	82.3	82.3	—	—
Other Comprehensive Income – Net of Income Taxes				
Unrealized Loss on Debt Securities	(0.1)	—	(0.1)	—
Defined Benefit Pension and Other Postretirement Plans	0.7	—	0.7	—
Total Comprehensive Income	82.9			
Common Stock Issued	14.0	—	—	14.0
Dividends Declared	(57.4)	(57.4)	—	—
Balance as of June 30, 2018	$2,108.2	$720.4	$(27.6)	$1,415.4

(a) Reflects the impacts associated with the adoption of accounting standards concerning Financial Instruments, Revenue from Contracts with Customers and the Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income. (See Note 1. Operations and Significant Accounting Policies.)

The accompanying notes are an integral part of these statements.

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS – UNAUDITED

The accompanying unaudited Consolidated Financial Statements have been prepared in accordance with the instructions to Form 10-Q and Rule 10-01 of Regulation S-X, and do not include all of the information and notes required by GAAP for complete financial statements. Similarly, the December 31, 2017, Consolidated Balance Sheet was derived from audited financial statements, but does not include all disclosures required by GAAP. In management's opinion, these unaudited financial statements include all adjustments necessary for a fair statement of financial results. All adjustments are of a normal, recurring nature, except as otherwise disclosed. Operating results for the six months ended June 30, 2018, are not necessarily indicative of results that may be expected for any other interim period or for the year ending December 31, 2018. For further information, refer to the Consolidated Financial Statements and notes included in our 2017 Form 10-K.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES

Cash, Cash Equivalents and Restricted Cash. We consider all investments purchased with original maturities of three months or less to be cash equivalents. Restricted cash amounts included in Prepayments and Other on the Consolidated Balance Sheet include collateral deposits required under an ALLETE Clean Energy loan agreement and U.S. Water Service's standby letters of credit. The restricted cash amounts included in Other Non-Current Assets represent collateral deposits required under an ALLETE Clean Energy loan agreement and PSAs, and deposits from a SWL&P customer in aid of future capital expenditures. The following table provides a reconciliation of cash, cash equivalents and restricted cash reported within the Consolidated Balance Sheet that aggregate to the amount presented in the Consolidated Statement of Cash Flows. During the first quarter of 2018, the Company updated the presentation of its Consolidated Statement of Cash Flows to include restricted cash with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the Consolidated Statement of Cash Flows. (See Recently Adopted Pronouncements - Statement of Cash Flows: Restricted Cash.)

Cash, Cash Equivalents and Restricted Cash	June 30, 2018	December 31, 2017	June 30, 2017	December 31, 2016
Millions				
Cash and Cash Equivalents	$121.9	$98.9	$84.2	$27.5
Restricted Cash included in Prepayments and Other	2.3	2.6	3.7	2.2
Restricted Cash included in Other Non-Current Assets	8.6	8.6	8.6	8.6
Cash, Cash Equivalents and Restricted Cash on the Consolidated Statement of Cash Flows	$132.8	$110.1	$96.5	$38.3

Inventories – Net. Inventories are stated at the lower of cost or net realizable value. Inventories in our Regulated Operations segment are carried at an average cost or first-in, first-out basis. Inventories in our U.S. Water Services and ALLETE Clean Energy segments, and Corporate and Other businesses are carried at an average cost, first-in, first-out or specific identification basis.

Inventories – Net	June 30, 2018	December 31, 2017
Millions		
Fuel (a)	$31.4	$34.8
Materials and Supplies	44.3	46.5
Construction of Wind Energy Facility (b)	54.1	—
Raw Materials	3.0	2.8
Work in Progress	4.4	4.2
Finished Goods	9.1	8.3
Reserve for Obsolescence	(0.9)	(0.7)

Total Inventories – Net	$145.4	$95.9

(a) Fuel consists primarily of coal inventory at Minnesota Power.

(b) On February 28, 2018, Montana-Dakota Utilities exercised its option to purchase the Thunder Spirit II wind energy facility upon completion, resulting in a reclassification of the project costs from Property, Plant and Equipment – Net to Inventories – Net as ALLETE Clean Energy will not own the facility upon completion.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Other Non-Current Assets	June 30, 2018	December 31, 2017
Millions		
Contract Assets (a)	$30.9	$31.6
Finance Receivable	10.9	11.0
Other	63.2	65.1
Total Other Non-Current Assets	$105.0	$107.7

(a) Contract Assets include payments made to customers as an incentive to execute or extend service agreements. The contract payments are being amortized over the term of the respective agreements as a reduction to revenue.

Other Current Liabilities	June 30, 2018	December 31, 2017
Millions		
Provision for Interim Rate Refund (a)	$32.5	—
Contract Liabilities (b)	24.3	$8.7
PSAs	18.4	24.5
Provision for Tax Reform Refund (c)	6.7	—
Contingent Consideration (d)	5.6	—
Other	41.0	50.0
Total Other Current Liabilities	$128.5	$83.2

(a) Provision for Interim Rate Refund is expected to be refunded to Minnesota Power’s regulated retail customers in the first quarter of 2019 and includes $16.7 million of discounts provided to EITE customers that will be offset against interim rate refunds as of June 30, 2018 ($8.6 million as of December 31, 2017). (See Note 6. Regulatory Matters.)

(b) Contract Liabilities include deposits received as a result of entering into contracts with our customers prior to completing our performance obligations.

(c) Provision for Tax Reform Refund is deferred as a regulatory liability pending the outcome of regulatory proceedings with the MPUC and PSCW. (See Note 6. Regulatory Matters.)

(d) Contingent Consideration relates to the estimated fair value of the earnings-based payment resulting from the U.S. Water Services acquisition. (See Note 5. Fair Value.)

Other Non-Current Liabilities	June 30, 2018	December 31, 2017
Millions		
Asset Retirement Obligation	$143.2	$122.7
PSAs	83.1	89.5
Contingent Consideration (a)	—	5.4
Other	48.1	49.5
Total Other Non-Current Liabilities	$274.4	$267.1

(a) Contingent Consideration relates to the estimated fair value of the earnings-based payment resulting from the U.S. Water Services acquisition. (See Note 5. Fair Value.)

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Supplemental Statement of Cash Flows Information.

Six Months Ended June 30,	2018	2017
Millions		
Cash Paid for Interest – Net of Amounts Capitalized	$33.0	$32.5
Noncash Investing and Financing Activities		
Decrease in Accounts Payable for Capital Additions to Property, Plant and Equipment	$(39.4)	$(0.4)
Reclassification of Property, Plant and Equipment to Inventory (a)	$46.3	—
Capitalized Asset Retirement Costs	$20.8	$19.7
AFUDC–Equity	$0.5	$0.4
ALLETE Common Stock Contributed to the Pension Plans	—	$13.5

(a) On February 28, 2018, Montana-Dakota Utilities exercised its option to purchase the Thunder Spirit II wind energy facility upon completion, resulting in a reclassification of the project costs from Property, Plant and Equipment – Net to Inventories – Net as ALLETE Clean Energy will not own the facility upon completion.

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

Revenue.

Contracts with Customers – Utility includes sales from our regulated operations for generation, transmission and distribution of electric service, and distribution of water and gas services to our customers. Also included is an immaterial amount of regulated steam generation that is used by customers in the production of paper and pulp.

Contracts with Customers – Non-utility includes sales of goods and services to customers from ALLETE Clean Energy, U.S. Water Services and our Corporate and Other businesses.

Other – Non-utility is the non-cash adjustments to revenue recognized by ALLETE Clean Energy for the amortization of differences between contract prices and estimated market prices for PSAs that were assumed during the acquisition of various wind energy facilities.

Revenue Recognition

Revenue is recognized upon transfer of control of promised goods or services to our customers in an amount that reflects the consideration we expect to receive in exchange for those products or services. Revenue is recognized net of allowance for returns and any taxes collected from customers, which are subsequently remitted to the appropriate governmental authorities. We account for shipping and handling activities that occur after the customer obtains control of goods as a cost rather than an additional performance obligation thereby recognizing revenue at time of shipment and accruing shipping and handling costs when control transfers to our customers. We have a right to consideration from our customers in an amount that corresponds directly with the value to the customer for our performance completed to date; therefore, we may recognize revenue in the amount to which we have a right to invoice.

Nature of Revenue Streams

Utility

Residential and Commercial includes sales for electric, gas or water service to customers, who have implied contracts with the utility, under rates governed by the MPUC, PSCW or FERC. Customers are billed on a monthly cycle basis and revenue is recognized for electric, gas or water service delivered during the billing period. Revenue is accrued for service provided but not yet billed at period end. Performance obligations with these customers are satisfied at time of delivery to customer meters and simultaneously consumed.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)
Revenue (Continued)

Municipal includes sales to 16 non-affiliated municipal customers in Minnesota under long-term wholesale electric contracts. All wholesale electric contracts include a termination clause requiring a three-year notice to terminate. These contracts have termination dates ranging from 2019 through at least 2032, with a majority of contracts effective through at least 2024. Performance obligations with these customers are satisfied at the time energy is delivered to an agreed upon municipal substation or meter.

Industrial includes sales recognized from contracts with customers in the taconite mining, iron concentrate, paper, pulp and secondary wood products, pipeline and other industries. Industrial sales accounted for approximately 49 percent of total regulated utility kWh sales for the six months ended June 30, 2018. Within industrial revenue, Minnesota Power has 9 Large Power Customer contracts, each serving requirements of 10 MW or more of customer load. These contracts automatically renew past the contract term unless a four-year advanced written notice is given. Large Power Customer contracts have earliest termination dates ranging from 2022 through 2026. We satisfy our performance obligations for these customers at the time energy is delivered to an agreed upon customer substation. Revenue is accrued for energy provided but not yet billed at period end. Based on current contracts with industrial customers, we expect to recognize minimum revenue for the fixed contract components of approximately $70 million per annum through 2019, $50 million in 2020 and 2021, $30 million in 2022 and $30 million for aggregate years thereafter, which reflects the termination notice period in these contracts. When determining minimum revenue, we assume that customer contracts will continue under the contract renewal provision; however, if long-term contracts are renegotiated and subsequently approved by the MPUC or there are changes within our industrial customer class, these amounts may be impacted. Contracts with customers that contain variable pricing or quantity components are excluded from the expected minimum revenue amounts.

Other Power Suppliers includes the sale of energy under long-term PSAs with two customers as well as MISO market and liquidation sales. Expiration dates of these PSAs range from 2020 through 2026. Performance obligations with these customers are satisfied at the time energy is delivered to an agreed upon delivery point defined in the contract (generally the MISO pricing node). Based on current contracts with two customers, we expect to recognize minimum revenue for fixed contract components of approximately $10 million per annum through 2019. Other power supplier contracts that extend beyond 2020 contain variable pricing components that prevent us from estimating future minimum revenue, and therefore are not included.

Other Revenue includes all remaining individually immaterial revenue streams for Minnesota Power and SWL&P, and is comprised of steam sales to paper and pulp mills, wheeling revenue and other sources. Revenue for steam sales to customers is recognized at the time steam is delivered and simultaneously consumed. Revenue is recognized at the time each performance obligation is satisfied.

Alternative Programs includes revenue that is driven by factors outside of our regulated entities’ control or as a result of the achievement of certain objectives, such as CIP financial incentives. This revenue is accounted for in accordance with the accounting standards for alternative revenue programs which allow for the recognition of revenue under an alternative revenue program if the program is established by an order from the utility’s regulatory commission, the order allows for automatic adjustment of future rates, the amount of 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. CIP financial incentives are recognized in the period in which the MPUC approves the filing, which is typically mid-year.

Non-utility

ALLETE Clean Energy

Long-term PSA revenue includes all sales recognized under long-term contracts for production, curtailment, capacity and associated renewable energy credits from ALLETE Clean Energy wind energy facilities. Expiration dates of these PSAs range from 2018 through 2032. Performance obligations for these contracts are satisfied at the time energy is delivered to an agreed upon point, or production is curtailed at the request of the customer, at specified prices. Revenue from the sale of renewable energy credits is recognized at the same time the related energy is delivered to the customer when sold to the same party.

Other is the non-cash adjustments to revenue recognized by ALLETE Clean Energy for the amortization of differences between contract prices and estimated market prices on assumed PSAs. As part of wind energy facility acquisitions, ALLETE Clean Energy assumed various PSAs that were above or below estimated market prices at the time of acquisition; the resulting differences between contract prices and estimated market prices are amortized to revenue over the remaining PSA term.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)
Revenue (Continued)

U.S. Water Services

Point-in-time revenue is recognized for purchases by customers for chemicals, consumable equipment (e.g. filters, pumps and valves) or related maintenance and repair services as the customer's usage and needs change over time. These goods and services are purchased on an as-needed basis by the customers and therefore revenue can be variable. Products are shipped to the customer in accordance with the terms of the purchase order, and performance obligations are satisfied at the time of shipment of goods or when services are rendered to the customer.

Contract includes monthly revenue from contracts with customers to provide chemicals, consumable equipment and services to meet customer needs during the contract period. As agreed with the customer, a fixed amount is invoiced based on the goods and services to be provided under the contract. The duration of these contracts generally range in length from three months to five years and automatically renew. A 30-day notice is required to terminate such contracts without penalty after contract execution. Performance obligations are satisfied during the period as goods and service are delivered in accordance with the terms of the contract.

Capital Project includes the sale of equipment and other components assembled to create a water treatment system for the customer. These projects are provided under contracts at an agreed upon price to meet a customer's specifications and typically take less than one year to complete. In general, progress payments are received throughout the project period and are recorded as contract liabilities until performance obligations are satisfied at the time the equipment and other components are delivered to the customer's site.

Corporate and Other

Long-term Contract encompasses the sale and delivery of coal to customer generation facilities. Revenue is recognized on a monthly basis at the cost of production plus a specified profit per ton of coal delivered to the customer. Coal sales are secured under long-term coal supply agreements extending through 2037. Performance obligations are satisfied during the period as coal is delivered to customer generation facilities.

Other primarily includes revenue from BNI Energy unrelated to coal, the sale of real estate from ALLETE Properties, and non rate base steam generation that is sold for use during production of paper and pulp. Performance obligations are satisfied when control transfers to the customer.

Payment Terms

Payment terms and conditions vary across our businesses. Aside from taconite-producing Large Power Customers, payment terms generally require payment to be made within 15 to 30 days from the end of the period that the service has been rendered or goods provided. In the case of its taconite-producing Large Power Customers, as permitted by the MPUC, Minnesota Power requires weekly payments for electric usage based on monthly energy usage estimates. These customers receive estimated bills based on Minnesota Power's estimate of the customers' energy usage, forecasted energy prices and fuel adjustment clause estimates. Minnesota Power's taconite-producing Large Power Customers have generally predictable energy usage on a weekly basis and any differences that occur are trued-up the following month. Due to the timing difference of revenue recognition from the timing of invoicing and payment, the customer receives credit for the time value of money; however, we have determined that our contracts do not include a significant financing component as the period between when we transfer the service to the customer and when they pay for such service is minimal.

Assets Recognized From the Costs to Obtain a Contract with a Customer

We recognize as an asset the incremental costs of obtaining a contract with a customer if we expect the benefit of those costs to be longer than one year. We expense incremental costs when the asset that would have resulted from capitalizing these costs would have been amortized in one year or less. As of June 30, 2018, we have $30.9 million of assets recognized for costs incurred to obtain contracts with our customers ($31.6 million as of December 31, 2017). Management determined the amount of costs to be recognized as assets based on actual costs incurred and paid to obtain and fulfill these contracts to provide goods and services to our customers. Assets recognized to obtain contracts are amortized on a straight-line basis over the contract term as a non-cash reduction to revenue. For the six months ended June 30, 2018, and 2017, we recognized $1.3 million of non-cash amortization.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

New Accounting Pronouncements.

Recently Adopted Pronouncements

Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income. In February 2018, the FASB issued an update allowing for a one-time reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the enactment of the TCJA. With the enactment of the new federal tax rates in 2017, entities were required to adjust deferred tax assets and liabilities to reflect the lower federal rate with the effect of this reduction impacting income from continuing operations in the period of enactment, even in instances where the related income tax effects of items were originally recognized in other comprehensive income. As such, companies were left with stranded tax effects in accumulated other comprehensive income that did not reflect the appropriate tax rate. This guidance is effective in the first quarter of 2019 with early adoption permitted. The Company elected to early adopt this guidance in the first quarter of 2018 which resulted in a reduction of $5.7 million to Accumulated Other Comprehensive Loss and a corresponding increase to Retained Earnings for the reclassification of the stranded income tax effects.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost. In March 2017, the FASB issued an accounting standard update to improve the presentation of net periodic pension and postretirement benefit costs. Under the guidance, an entity is required to present the service cost component of the net periodic benefit cost in the same income statement line as other employee compensation costs arising from services rendered during the period. The guidance also allows only the service cost component of the periodic cost to be eligible for capitalization on a prospective basis. The other components of net periodic expense must be presented separately from the line item that includes the service cost and must be excluded from the operating income subtotal. The Company adopted the guidance in the first quarter of 2018 and retrospectively adjusted the presentation of the service cost component and the other components of net periodic costs in the Consolidated Statement of Income. The retrospective adjustments for the quarter and six months ended June 30, 2017, were as follows: Operating and Maintenance increased $1.0 million and $2.1 million, respectively, Cost of Sales – Non-utility remained unchanged and decreased $0.1 million, respectively, resulting in an increase of $1.0 million and $2.0 million, respectively to Other Income (Expense) – Other. There was no impact to net income as a result of adoption.

Financial Instruments. In 2016, the FASB issued an accounting standard update which requires entities to measure equity investments at fair value and recognize any changes in fair value in net income unless the investments qualify for the practicability exception. The practicability exception will be available for equity investments that do not have readily determinable fair values. The update was adopted by the Company in the first quarter of 2018 which resulted in a cumulative-effect transition adjustment reducing Retained Earnings by $0.1 million, including the tax effect, for the previously unrealized loss on available-for-sale equity securities in Accumulated Other Comprehensive Loss as of December 31, 2017.

Classification of Certain Cash Receipts and Cash Payments. In 2016, the FASB issued an accounting standard update which addressed the following eight specific cash flow issues: debt prepayment or debt extinguishment costs; settlement of zero coupon debt instruments or other debt instruments with coupon interest rates that are insignificant in relation to the effective interest rate of the borrowing; contingent consideration payments made after a business combination; proceeds from the settlement of insurance claims; proceeds from the settlement of corporate-owned life insurance policies (including bank-owned life insurance policies); distributions received from equity method investees; beneficial interests in securitization transactions; and separately identifiable cash flows and application of the predominance principle. The amendments of this update were adopted by the Company in the first quarter of 2018.

There was no impact to the Consolidated Statement of Cash Flows as a result of adoption.

Statement of Cash Flows: Restricted Cash. In 2016, the FASB issued an accounting standard update related to the presentation of restricted cash in the Company's Consolidated Statement of Cash Flows. The update requires that the Consolidated Statement of Cash Flows explain the change during the period in cash, cash equivalents and restricted cash. Restricted cash should be included with cash and cash equivalents when reconciling the beginning-of-period and end-of-period total amounts shown on the Consolidated Statement of Cash Flows. This guidance update was adopted by the Company in the first quarter of 2018 and was applied retrospectively to the periods presented in the Consolidated Statement of Cash Flows which resulted in a net increase in cash from financing activities of $1.5 million for the six months ended June 30, 2017. Additional disclosure, including a reconciliation of the beginning-of-period and end-of-period cash on hand to the statement of cash flows, is included in this note. (See Cash, Cash Equivalents and Restricted Cash.)

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)
New Accounting Pronouncements (Continued)

Revenue from Contracts with Customers. In 2014, the FASB issued amended revenue recognition guidance that clarifies the principles for recognizing revenue from contracts with customers by providing a single comprehensive model to determine the measurement of revenue and timing of recognition. The guidance requires an entity to recognize revenue in a manner that depicts the transfer of goods or services to customers in an amount that reflects the consideration to which an entity expects to be entitled to in exchange for those goods or services. The guidance 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 regarding customer contracts, significant judgments and changes in those judgments, and the assets recognized from the costs to obtain or fulfill a contract are required. The Company adopted this accounting guidance in the first quarter of 2018 and elected to apply the modified retrospective method of adoption to all contracts as of the date of initial application. The financial impact to the consolidated financial statements as a result of adoption of the new standard is immaterial. Based on the nature of the contracts with our customers and our related performance obligations which transfer control, a $0.5 million after-tax cumulative effect transition adjustment was made to increase the opening balance of Retained Earnings. We have included additional disclosures in the notes to the consolidated financial statements including additional information on the Company's revenue streams and related performance obligations required to be satisfied in order to recognize revenue. (See Revenue Recognition.)

Practical Expedients

The following practical expedients were used by the Company as part of the adoption of the new revenue recognition guidance:

- We have a right to consideration from our customers in an amount that corresponds directly with the value to such customer for performance completed to date; therefore, we may recognize revenue in the amount to which we have a right to invoice.
- We do not adjust the promised amount of consideration for the effects of a significant financing component as at contract inception we expect that the period between when we transfer a promised good or service to a customer and when the customer pays for that good or service will be one year or less.
- Where applicable, we adopted this guidance using the portfolio approach in which contracts that have similar characteristics were reviewed as a portfolio. The effects on the financial statements of applying this guidance to the portfolio would not differ materially from applying the guidance to each individual contract.
- We recognize the incremental costs of obtaining a contract as an expense when incurred if the amortization period of the asset that would otherwise have been recognized is one year or less.

Recently Issued Pronouncements

Simplifying the Test for Goodwill Impairment. In January 2017, the FASB issued updated guidance which simplifies the measurement of goodwill impairment by removing step two of the goodwill impairment test that requires the determination of the fair value of individual assets and liabilities of a reporting unit. The updated guidance requires goodwill impairment to be measured as the amount by which a reporting unit's carrying value exceeds its fair value; however, the loss recognized should not exceed the total amount of goodwill allocated to that reporting unit. This guidance is effective for the Company beginning in the first quarter of 2020, with early adoption permitted on a prospective basis.

Leases. In 2016, the FASB issued an accounting standard update which revises the existing guidance for leases. Under the revised guidance, lessees will be required to recognize a "right-of-use" asset and a lease liability for all leases with a term greater than 12 months. The new standard also requires additional quantitative and qualitative disclosures by lessees and lessors to enable users of the financial statements to assess the amount, timing and uncertainty of cash flows arising from leases. The accounting for leases by lessors and the recognition, measurement, and presentation of expenses and cash flows from leases are not expected to significantly change as a result of the new guidance. We expect to make approximately $80 million in minimum lease payments due in future years (undiscounted). The revised guidance is effective for the Company beginning in the first quarter of 2019 with early adoption permitted. We are currently evaluating the impact of the revised lease guidance on our Consolidated Financial Statements.

NOTE 1. OPERATIONS AND SIGNIFICANT ACCOUNTING POLICIES (Continued)

Income Taxes. Under SEC Staff Accounting Bulletin 118 (SAB 118), which was issued in December 2017, companies are allowed up to one year to complete the required analyses and accounting for the TCJA. SAB 118 requires companies to disclose which tax positions are considered complete, which tax positions are considered provisional and which tax provisions reflect prior law. At December 31, 2017, we were reasonably able to estimate the effects of the TCJA, and therefore recorded provisional amounts associated with the changes under the TCJA. The provisional amounts incorporate assumptions made based upon the Company's interpretation of the TCJA, and may change as the Company receives additional clarification and implementation guidance. We have not made any adjustments to our accounting to date, although the accounting is still considered provisional while we complete our analysis. Any adjustments recorded to the provisional amounts in 2018 will be included in income from operations as an adjustment to income tax expense.

NOTE 2. INVESTMENTS

Investments. As of June 30, 2018, 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	June 30, 2018	December 31, 2017
Millions		
ALLETE Properties	$25.9	$26.4
Available-for-sale Securities (a)	21.4	19.1
Cash Equivalents	1.5	3.8
Other	3.7	3.8
Total Other Investments	$52.5	$53.1

(a) As of June 30, 2018, the aggregate amount of available-for-sale corporate and governmental debt securities maturing in one year or less was $1.1 million, in one year to less than three years was $3.9 million, in three years to less than five years was $2.5 million and in five or more years was $1.1 million.

Available-for-Sale Securities. We account for our available-for-sale securities 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. Gross realized and unrealized gains and losses on our available-for-sale securities were immaterial for the quarter and six months ended June 30, 2018, and 2017.

NOTE 3. ACQUISITIONS

The following acquisition is consistent with ALLETE's stated strategy of investing in energy infrastructure and related services businesses to complement its regulated businesses, balance exposure to business cycles and changing demand, and provide potential long-term earnings growth. The pro forma impact of the following acquisitions was not significant, either individually or in the aggregate, to the results of the Company for the six months ended June 30, 2018, and 2017.

2017 Activity.

Tonka Water. In September 2017, U.S. Water Services acquired 100 percent of Tonka Water. Total consideration for the transaction was $19.2 million, including a working capital adjustment. Consideration of $19.0 million was paid in cash on the acquisition date and a working capital adjustment of $0.2 million was paid in the fourth quarter of 2017. Tonka Water is a supplier of municipal and industrial water treatment systems and will expand U.S. Water Services' geographic and customer markets.

NOTE 3. ACQUISITIONS (Continued)
2017 Activity (Continued)

The acquisition was accounted for as a business combination and the purchase price was allocated based on the estimated fair values of the assets acquired and the liabilities assumed at the date of acquisition. The purchase price accounting, which was finalized in 2018, is reflected in the following table. Fair value measurements were valued primarily using the discounted cash flow method and replacement cost basis.

Millions	
Assets Acquired	
Accounts Receivable	$5.1
Other Current Assets	5.1
Trade Names (a)	0.9
Goodwill (a)(b)	16.9
Other Non-Current Assets	0.2
Total Assets Acquired	$28.2
Liabilities Assumed	
Current Liabilities	$9.0
Total Liabilities Assumed	$9.0
Net Identifiable Assets Acquired	$19.2

(a) Presented within Goodwill and Intangible Assets – Net on the Consolidated Balance Sheet. (See Note 4. Goodwill and Intangible Assets.)

(b) Recognized goodwill is attributable to the assembled workforce and anticipated synergies. For tax purposes, the purchase price allocation resulted in $4.1 million of deductible goodwill.

Acquisition-related costs were immaterial, expensed as incurred during 2017 and recorded in Operating and Maintenance on the Consolidated Statement of Income.

NOTE 4. GOODWILL AND INTANGIBLE ASSETS

The aggregate carrying amount of goodwill was $148.5 million as of June 30, 2018, and $148.3 million as of December 31, 2017.

Balances of intangible assets, net, excluding goodwill as of June 30, 2018, are as follows:

	December 31, 2017	Additions	Amortization	June 30, 2018
Millions				
Intangible Assets				
Definite-Lived Intangible Assets				
Customer Relationships	$54.7	$0.2	$(2.1)	$52.8
Developed Technology and Other (a)	6.3	2.2	(0.6)	7.9
Total Definite-Lived Intangible Assets	61.0	2.4	(2.7)	60.7
Indefinite-Lived Intangible Assets				
Trademarks and Trade Names	16.6	—	n/a	16.6
Total Intangible Assets	$77.6	$2.4	$(2.7)	$77.3

(a) Developed Technology and Other includes patents, non-compete agreements, land easements and trade names with finite lives.

Customer relationships have a remaining useful life of approximately 20 years, and developed technology and other have remaining useful lives ranging from approximately 1 year to approximately 11 years (weighted average of approximately 6 years). The weighted average remaining useful life of all definite-lived intangible assets as of June 30, 2018, is approximately 18 years.

NOTE 4. GOODWILL AND INTANGIBLE ASSETS (Continued)

Amortization expense for intangible assets was $1.3 million and $2.7 million for the quarter and six months ended June 30, 2018, respectively ($1.4 million and $2.8 million for the quarter and six months ended June 30, 2017, respectively). Accumulated amortization was $17.5 million as of June 30, 2018 ($14.8 million as of December 31, 2017). The estimated amortization expense for definite-lived intangible assets for the remainder of 2018 is $2.8 million. Estimated annual amortization expense for definite lived intangible assets is $5.2 million in 2019, $5.0 million in 2020, $4.9 million in 2021, $4.6 million in 2022 and $38.2 million thereafter.

NOTE 5. FAIR VALUE

Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price). We utilize market data or assumptions that market participants would use in pricing the asset or liability, including assumptions about risk and the risks inherent in the inputs to the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. We primarily apply the market approach for recurring fair value measurements and endeavor to utilize the best available information. Accordingly, we utilize valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs. These inputs, which are used to measure fair value, are prioritized through the fair value hierarchy. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). Descriptions of the three levels of the fair value hierarchy are discussed in Note 9. Fair Value to the Consolidated Financial Statements in our 2017 Form 10-K.

The following tables set forth by level within the fair value hierarchy our assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2018, and December 31, 2017. 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 June 30, 2018			
Recurring Fair Value Measures	Level 1	Level 2	Level 3	Total
Millions				
Assets				
Investments (a)				
Available-for-sale – Equity Securities	$12.8	—	—	$12.8
Available-for-sale – Corporate and Governmental Debt Securities	—	$8.6	—	8.6
Cash Equivalents	1.5	—	—	1.5
Total Fair Value of Assets	$14.3	$8.6	—	$22.9
Liabilities				
Deferred Compensation (b)	—	$20.5	—	$20.5
U.S. Water Services Contingent Consideration (c)	—	—	$5.6	5.6
Total Fair Value of Liabilities	—	$20.5	$5.6	$26.1
Total Net Fair Value of Assets (Liabilities)	$14.3	$(11.9)	$(5.6)	$(3.2)

(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 Other Current Liabilities on the Consolidated Balance Sheet.

NOTE 5. FAIR VALUE (Continued)

Recurring Fair Value Measures	Fair Value as of December 31, 2017			
	Level 1	Level 2	Level 3	Total
Millions				
Assets				
Investments (a)				
Available-for-sale – Equity Securities	$10.2	—	—	$10.2
Available-for-sale – Corporate and Governmental Debt Securities	—	$8.9	—	8.9
Cash Equivalents	3.8	—	—	3.8
Total Fair Value of Assets	$14.0	$8.9	—	$22.9
Liabilities (b)				
Deferred Compensation	—	$18.2	—	$18.2
U.S. Water Services Contingent Consideration	—	—	$5.4	5.4
Total Fair Value of Liabilities	—	$18.2	$5.4	$23.6
Total Net Fair Value of Assets (Liabilities)	$14.0	$(9.3)	$(5.4)	$(0.7)

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

The Level 3 liability in the preceding tables is the result of the 2015 acquisition of U.S. Water Services. Changes in the U.S. Water Services Contingent Consideration can result from modifications to the shareholder agreement, changes in discount rates, timing of milestones that trigger payment, or the timing and amount of earnings estimates. The following table provides a reconciliation of the beginning and ending balances of the U.S. Water Services Contingent Consideration measured at fair value using Level 3 measurements as of June 30, 2018. Management analyzes the fair value of the contingent liability on a quarterly basis and makes adjustments as appropriate.

Recurring Fair Value Measures	
Activity in Level 3	
Millions	
Balance as of December 31, 2017	$5.4
Accretion	0.2
Balance as of June 30, 2018	$5.6

For the six months ended June 30, 2018, and the year ended December 31, 2017, there were no transfers in or out of Levels 1, 2 or 3.

Fair Value of Financial Instruments. With the exception of the item listed in the following table, the estimated fair value of all financial instruments approximates the carrying amount. The fair value for the item listed in the following table 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 Long-Term Debt Due Within One Year		
June 30, 2018	$1,528.8	$1,572.8
December 31, 2017	$1,513.3	$1,627.6

Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis. Non-financial assets such as equity method investments, goodwill, intangible assets, land inventory, 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. For the quarter and six months ended June 30, 2018, and the year ended December 31, 2017, there were no triggering events or indicators of impairment for these non-financial assets.

NOTE 6. REGULATORY MATTERS

Regulatory matters are summarized in Note 4. Regulatory Matters to our Consolidated Financial Statements in our 2017 Form 10 K, with additional disclosure provided in the following paragraphs.

Electric Rates. Entities within our Regulated Operations segment file for periodic rate revisions with the MPUC, PSCW or FERC. As authorized by the MPUC, Minnesota Power also recognizes revenue under cost recovery riders for transmission, renewable, and environmental investments and expenditures. (See Transmission Cost Recovery Rider, Renewable Cost Recovery Rider and Environmental Improvement Rider.) Revenue from cost recovery riders was \$28.0 million and \$52.1 million for the quarter and six months ended June 30, 2018, respectively (\$24.4 million and \$48.6 million for the quarter and six months ended June 30, 2017, respectively).

2016 Minnesota General Rate Case. In November 2016, Minnesota Power filed a retail rate increase request with the MPUC which sought an average increase of approximately 9 percent for retail customers. The rate filing sought a return on equity of 10.25 percent and a 53.81 percent equity ratio. On an annualized basis, the requested final rate increase would have generated approximately \$55 million in additional revenue. In December 2016, Minnesota Power filed a request to modify its original interim rate proposal, reducing its requested interim rate increase to \$34.7 million from the original request of approximately \$49 million due to a change in its electric sales forecast. In December 2016 orders, the MPUC accepted the November 2016 filing as complete and authorized an annual interim rate increase of \$34.7 million beginning in January 2017.

In February 2017, Minnesota Power filed an additional request to further reduce its requested interim rate increase. In an April 2017 order, the MPUC approved Minnesota Power's updated retail rate request resulting in a reduction in the annual interim rate increase to \$32.2 million beginning in May 2017. As a result of working with intervenors and further developments as the rate review progressed, Minnesota Power's final rate request was adjusted to approximately \$49 million on an annualized basis. In an order dated March 12, 2018, the MPUC affirmed determinations made at a hearing on January 18, 2018, regarding Minnesota Power's general rate case including allowing a return on common equity of 9.25 percent and a 53.81 percent equity ratio. Upon commencement of final rates, we expect additional revenue of approximately \$13 million on an annualized basis. Final rates are expected to commence in the fourth quarter of 2018; interim rates will be collected through this period which are fully offset by the recognition of a corresponding reserve. Minnesota Power has recorded a reserve for an interim rate refund of \$49.2 million as of June 30, 2018 (\$32.3 million as of December 31, 2017). The MPUC also disallowed Minnesota Power's regulatory asset for deferred fuel adjustment clause costs due to the anticipated adoption of a forward-looking fuel adjustment clause methodology resulting in a \$19.5 million pre-tax charge to Fuel, Purchased Power and Gas – Utility in the fourth quarter of 2017.

As part of its decision in Minnesota Power's 2016 general rate case, the MPUC extended the depreciable lives of Boswell Unit 3, Unit 4 and common facilities to 2050 primarily to mitigate rate increases for our customers, and shortened the depreciable lives of Boswell Unit 1 and Unit 2 to 2022, resulting in a net decrease to depreciation expense of approximately \$25 million in the fourth quarter of 2017.

On April 2, 2018, Minnesota Power filed a petition with the MPUC requesting reconsideration of certain decisions in the MPUC's order dated March 12, 2018, collectively representing approximately \$20 million to \$25 million in additional revenue on an annualized basis. Minnesota Power's petition included requesting reconsideration of the allowed return on common equity, recovery of the prepaid pension asset in rate base, certain disallowed expenses, and certain transmission revenue adjustments. In an order dated May 29, 2018, the MPUC denied Minnesota Power's petition for reconsideration and accepted a Minnesota Department of Commerce request for reconsideration reducing the depreciable lives of Boswell Unit 3, Unit 4 and common facilities to 2035 while utilizing the benefits of the lower federal income tax rate enacted as part of the TCJA to mitigate the impact on customer rates.

Energy-Intensive Trade-Exposed Customer Rates. An EITE customer ratemaking law was enacted in 2015, which established a Minnesota energy policy to have competitive rates for certain industries such as mining and forest products. In 2015, Minnesota Power filed a rate schedule petition with the MPUC for EITE customers and a corresponding rider for EITE cost recovery. In a March 2016 order, the MPUC dismissed the petition without prejudice. In June 2016, Minnesota Power filed a revised EITE petition with the MPUC which included additional information on the net benefits analysis, limits on eligible customers and term lengths for the EITE discount. The rate adjustments were intended to be revenue and cash flow neutral to Minnesota Power. The MPUC approved a reduction in rates for EITE customers in a December 2016 order and subsequently approved cost recovery in an April 2017 order; collection of the discount was subject to the MPUC's review of Minnesota Power's compliance filing implementing approval of a recovery mechanism, with the subsequent order issued in October 2017 that modified the April 2017 order. During 2017, Minnesota Power provided discounts of $8.6 million that were recorded as a regulatory asset.

NOTE 6. REGULATORY MATTERS (Continued)
Electric Rates (Continued)

In September 2017, Minnesota Power informed its EITE customers that it had suspended the EITE discount due to a concern that it was not revenue and cash flow neutral to Minnesota Power based on an MPUC decision at a hearing in September 2017, as well as the interim rate reduction and decisions in its 2016 general rate case. Based on the MPUC's decisions at a hearing on January 18, 2018, as part of Minnesota Power's 2016 general rate case, Minnesota Power reinstated the EITE discount effective January 1, 2018. Minnesota Power expects the discount to EITE customers to be approximately $15 million annually based on EITE customer current operating levels. While interim rates are in effect for Minnesota Power's 2016 general rate case, discounts provided to EITE customers will offset interim rate refund reserves for non-EITE customers. Minnesota Power provided $3.8 million and $8.1 million of discounts to EITE customers during the quarter and six months ended June 30, 2018, respectively ($3.6 million and $5.9 million for the quarter and six months ended June 30, 2017, respectively).

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. All wholesale contracts include a termination clause requiring a three-year notice to terminate.

Minnesota Power's wholesale electric contract with the Nashwauk Public Utilities Commission is effective through at least December 31, 2032. No termination notice may be given for this contract prior to July 1, 2029. The wholesale electric service contracts with SWL&P and another municipal customer are effective through at least August 31, 2021, and through June 30, 2019, respectively. Under the agreement with SWL&P, no termination notice has been given. The other municipal customer provided termination notice for its contract in 2016. Minnesota Power currently provides approximately 29 MW of average monthly demand to this customer. The rates included in these three 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. The formula-based rate methodology also provides for a yearly true-up calculation for actual costs incurred.

Minnesota Power's wholesale electric contracts with 14 municipal customers are effective through varying dates ranging from 2024 through 2029 with a majority effective through at least December 31, 2024. No termination notices may be given prior to three years before maturity. These contracts include fixed capacity charges through 2018; beginning in 2019, the capacity charge will be determined using a cost-based formula methodology with limits on the annual change from the previous year's capacity charge. The base energy charge for each year of the contract term will be set each January 1, subject to monthly adjustment, and will also be determined using a cost-based formula methodology.

Transmission Cost Recovery Rider. Minnesota Power has an approved cost recovery rider for certain transmission investments and expenditures. In a 2016 order, the MPUC approved Minnesota Power's updated customer billing rates allowing 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 in 2015, the project is eligible for cost recovery under the existing transmission cost recovery rider. Minnesota Power is funding the construction of the GNTL with a subsidiary of Manitoba Hydro (see Great Northern Transmission Line), and anticipates including its portion of the investments and expenditures for the GNTL in future transmission bill factor filings.

Renewable Cost Recovery Rider. Minnesota Power has an approved cost recovery rider for investments and expenditures related to Bison. The cost recovery rider allows Minnesota Power to charge retail customers on a current basis for the costs of certain renewable investments plus a return on the capital invested. Updated customer billing rates for the renewable cost recovery rider were approved by the MPUC in a November 2017 order. On June 5, 2018, Minnesota Power made a renewable resources factor filing. Upon approval of the filing, Minnesota Power will be authorized to include updated billing rates on customer bills.

Minnesota Power also has approval for current cost recovery of investments and expenditures related to compliance with the Minnesota Solar Energy Standard. (See Minnesota Solar Energy Standard.) Currently, there is no approved customer billing rate for solar costs.

Environmental Improvement Rider. Minnesota Power has an approved environmental improvement rider for investments and expenditures related to the implementation of the Boswell Unit 4 mercury emissions reduction plan completed in 2015. Updated customer billing rates for the environmental improvement rider were provisionally approved by the MPUC in an order dated June 20, 2018, subject to further review by the MPUC.

NOTE 6. REGULATORY MATTERS (Continued)
Electric Rates (Continued)

Fuel Adjustment Clause Reform. In a December 2017 order, the MPUC adopted a three-year program to implement certain procedural reforms to the Minnesota utilities' automatic fuel adjustment clause (FAC) for fuel and purchased power. The order will change the method of accounting for all Minnesota electric utilities to a monthly budgeted, forward-looking FAC with an annual prudence review and true-up to actual allowed costs. The MPUC is seeking input from Minnesota electric utilities and other stakeholders on the implementation and transition accounting needed to adopt the change. The three-year program is expected to begin in 2019.

Tax Cuts and Jobs Act of 2017. In December 2017, the MPUC opened a docket to review the effects of the TCJA on electric and natural gas rates and services in Minnesota, including the legislation's impact on tax rates and utilities' deferred income tax assets and liabilities. On March 2, 2018, Minnesota Power submitted an initial filing to the MPUC regarding the impacts of the TCJA on Minnesota Power. As part of Minnesota Power's rate case, in an order dated May 29, 2018, the MPUC directed Minnesota Power to utilize the benefits of lower federal income tax rates enacted as part of the TCJA to offset a reduction in the depreciable lives of Boswell Unit 3, Unit 4 and common facilities to 2035 that would have otherwise resulted in an increase in customer rates. The treatment of the impact of the TCJA on Minnesota Power's deferred income tax assets and liabilities is still subject to this regulatory proceeding.

On January 10, 2018, the PSCW opened a docket to review the effects of the TCJA and directed Wisconsin utilities to defer its impacts until further direction was provided by the PSCW. On February 9, 2018, SWL&P filed comments with the PSCW regarding the impacts of the TCJA on SWL&P. In this filing, SWL&P proposed deferring the benefits of the TCJA and incorporating any deferred refunds or credits into its next general rate case. In an order dated May 24, 2018, the PSCW directed SWL&P to refund the benefits of the lower federal income tax rates enacted as part of the TCJA on customer bills beginning in July 2018. Any changes in deferred income taxes will be adjusted as part of SWL&P's rate filing. (See 2018 Wisconsin General Rate Case.)

We have recorded the impact of the remeasurement of deferred income tax assets and liabilities in 2017 resulting from the TCJA for Minnesota Power and SWL&P as regulatory assets and liabilities as the benefits are deferred pending the outcome of regulatory proceedings. Most of the benefits for Minnesota Power and SWL&P are expected to be passed back to customers over time primarily based upon the normalization provisions of the U.S. Internal Revenue Code over the life of the related property, plant and equipment with the remainder expected to be passed back based upon the outcome of regulatory proceedings. We are unable to predict the outcome of these regulatory proceedings.

2016 Wisconsin General Rate Case. SWL&P's current retail rates are based on a 2017 PSCW retail rate order effective since August 2017 that allows for a 10.5 percent return on common equity and a 55 percent equity ratio. SWL&P's retail rates prior to August 2017 were based on a 2012 PSCW retail rate order that provided for a 10.9 percent return on equity. On an annualized basis, SWL&P expects to collect additional revenue of $2.5 million under the 2017 PSCW retail rate order.

2018 Wisconsin General Rate Case. On May 25, 2018, SWL&P filed a rate increase request with the PSCW requesting an average increase of 2.7 percent for retail customers (2.0 percent increase in electric rates; 2.3 percent increase in natural gas rates; and 8.3 percent increase in water rates). The filing seeks an overall return on equity of 10.5 percent and a 55.41 percent equity ratio. On an annualized basis, this filing is expected to result in additional revenue of approximately $2.4 million.

Integrated Resource Plan. In 2015, Minnesota Power filed its 2015 IRP with the MPUC, which included 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 contained steps in Minnesota Power’s EnergyForward strategic plan including the economic idling of Taconite Harbor Units 1 and 2 which occurred in 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. In a 2016 order, the MPUC approved Minnesota Power’s 2015 IRP with modifications. The order accepted Minnesota Power’s plans for Taconite Harbor, directed Minnesota Power to retire Boswell Units 1 and 2 no later than 2022, required an analysis of generation and demand response alternatives to be filed with a natural gas resource proposal, and required Minnesota Power to conduct request for proposals for additional wind, solar and demand response resource additions subject to further MPUC approvals. In 2016, Minnesota Power announced Boswell Units 1 and 2 will be retired, which is expected to occur in the fourth quarter of 2018.

NOTE 6. REGULATORY MATTERS (Continued)
Integrated Resource Plan (Continued)

In July 2017, Minnesota Power submitted a resource package to the MPUC requesting approval of PPAs for the output of a 250 MW wind energy facility and a 10 MW solar energy facility as well as approval of a 250 MW natural gas energy PPA. These agreements are subject to MPUC approval of the construction of NTEC, a 525 MW to 550 MW combined cycle natural gas fired generating facility which will be jointly owned by Dairyland Power Cooperative and a subsidiary of ALLETE. Minnesota Power would purchase approximately 50 percent of the facility's output starting in 2025. In a September 2017 order, the MPUC approved Minnesota Power’s request to extend the next IRP filing deadline until October 1, 2019, and Minnesota Power’s request that approval for the natural gas energy PPA be decided through a contested case process. On July 2, 2018, an administrative law judge issued a recommendation that the MPUC deny approval of the NTEC agreements; the recommendation is not binding on the MPUC. On July 23, 2018, Minnesota Power filed exceptions to the administrative law judge’s recommendation. The MPUC is expected to hold a hearing in the fourth quarter of 2018 on NTEC. On June 18, 2018, Minnesota Power filed a separate petition for approval of the PPA for the output of a 10 MW solar energy facility located in central Minnesota. The MPUC has not taken any action regarding the wind energy PPA which will be refiled separately from the natural gas energy PPA.

Great Northern Transmission Line. Minnesota Power is constructing the GNTL, an approximately 220-mile 500-kV transmission line between Manitoba and Minnesota’s Iron Range that was proposed by Minnesota Power and Manitoba Hydro. In 2015, a certificate of need was approved by the MPUC. Based on this approval, 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 cost recovery filings. (See Transmission Cost Recovery Rider.) Also in 2015, the FERC approved our request to recover on construction work in progress related to the GNTL from Minnesota Power’s wholesale customers. In a 2016 order, the MPUC approved the route permit for the GNTL which largely follows Minnesota Power’s preferred route, including the international border crossing, and in 2016, the U.S. Department of Energy issued a presidential permit to cross the U.S.-Canadian border, which was the final major regulatory approval needed before construction in the U.S. could begin. Site clearing and pre construction activities commenced in the first quarter of 2017 with construction expected to be completed in 2020. To date, most of the right-of-way has been cleared while foundation installation and transmission tower construction have commenced. The total project cost in the U.S., including substation work, is estimated to be between $560 million and $710 million, of which Minnesota Power’s portion is expected to be between $300 million and $350 million; the difference will be recovered from a subsidiary of Manitoba Hydro as non-shareholder contributions to capital. Total project costs of $248.8 million have been incurred through June 30, 2018, of which $129.2 million has been recovered from a subsidiary of Manitoba Hydro.

Manitoba Hydro must obtain regulatory and governmental approvals related to a new transmission line in Canada known as the Manitoba-Minnesota Transmission Project (MMTP) that will connect with the GNTL. In 2015, Manitoba Hydro submitted the final preferred route and EIS for the MMTP to the Manitoba Conservation and Water Stewardship for siting and environmental approval, which remains pending. In 2016, Manitoba Hydro filed an application with the Canadian National Energy Board (NEB) requesting authorization to construct and operate the MMTP. The NEB determined that Manitoba Hydro’s application was complete in December 2017, and held public hearings in June 2018. The NEB is required to make a decision on the MMTP by March 2019, but is not precluded from making a decision prior to that date. Approval of the Canadian federal cabinet is also required.

The MMTP is subject to legal and regulatory challenges which Minnesota Power is actively monitoring. Manitoba Hydro has informed Minnesota Power that it continues to work towards completing the MMTP on schedule. In order to meet the transmission in service requirements in PPAs with Minnesota Power, Manitoba Hydro has indicated that it would need to start construction of the MMTP in December 2018. We are unable to predict the outcome of the

Canadian regulatory review process, including the timing thereof or whether any onerous conditions may be imposed, or the timing of the completion of the MMTP, including the impact of any delays that may result in construction schedule adjustments. Any significant delays in the MMTP construction schedule may result in Minnesota Power adjusting the GNTL construction schedule and impact the timing of capital expenditures and associated cost recovery under our transmission cost recovery rider.

Construction of Manitoba Hydro's Keeyask hydroelectric generation facility, which will provide the power to be sold under PPAs with Minnesota Power and transmitted on the MMTP and the GNTL, commenced in 2014 and is anticipated to be in service by early 2021.

NOTE 6. REGULATORY MATTERS (Continued)

Conservation Improvement Program. Minnesota requires electric utilities to spend a minimum of 1.5 percent of gross operating revenues, excluding revenue received from exempt customers, from service provided in the state on energy CIPs each year. On April 2, 2018, Minnesota Power submitted its 2017 CIP consolidated filing, which detailed Minnesota Power's CIP program results and requested a CIP financial incentive of $3.3 million based upon MPUC procedures. In 2017, the CIP financial incentive of $5.5 million was recognized in the second quarter upon approval by the MPUC of Minnesota Power's 2016 CIP consolidated filing in a June 2017 order. Approval of Minnesota Power's 2017 CIP consolidated filing and related financial incentive is expected in the third quarter of 2018. CIP financial incentives are recognized in the period in which the MPUC approves the filing.

MISO Return on Equity Complaints. MISO transmission owners, including ALLETE and ATC, have an authorized return on equity of 10.32 percent, or 10.82 percent including an incentive adder for participation in a regional transmission organization.

In 2016, a federal administrative law judge ruled on a complaint proposing a reduction in the base return on equity to 9.70 percent, or 10.20 percent including an incentive adder for participation in a regional transmission organization, subject to approval or adjustment by the FERC. A final decision from the FERC on the administrative law judge's recommendation is pending, which is not expected to have a material impact on our Consolidated Financial Statements.

Minnesota Solar Energy Standard. Minnesota law requires at least 1.5 percent of total retail electric sales, excluding sales to certain 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 40 kW or less and community solar garden subscriptions. In a 2016 order, the MPUC approved Camp Ripley, a 10 MW utility scale solar project at the Camp Ripley Minnesota Army National Guard base and training facility near Little Falls, Minnesota, as eligible to meet the solar energy standard and for current cost recovery. Camp Ripley was completed in the fourth quarter of 2016. In a 2016 order, the MPUC approved a community solar garden project in northeastern Minnesota, which is comprised of a 1 MW solar array owned and operated by a third party with the output purchased by Minnesota Power and a 40 kW solar array that is owned and operated by Minnesota Power. Minnesota Power believes Camp Ripley and the community solar garden arrays will meet approximately one third of the overall mandate. Additionally, in a February 2017 order, the MPUC approved Minnesota Power's proposal to increase the amount of solar rebates available for customer-sited solar installations and recover costs of the program through Minnesota Power's renewable cost recovery rider. The proposal to incentivize customer sited solar installations and community solar garden subscriptions is expected to meet a portion of the required small scale solar mandate.

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

NOTE 6. REGULATORY MATTERS (Continued)

Regulatory Assets and Liabilities	June 30, 2018	December 31, 2017
Millions		
Non-Current Regulatory Assets		
Defined Benefit Pension and Other Postretirement Benefit Plans	$216.7	$220.3
Income Taxes	109.3	112.8
Asset Retirement Obligations	31.0	29.6
Manufactured Gas Plant	8.0	8.1
PPACA Income Tax Deferral	5.0	5.0
Conservation Improvement Program	—	3.3
Other	4.5	5.6
Total Non-Current Regulatory Assets	$374.5	$384.7
Current Regulatory Liabilities (a)		
Provision for Interim Rate Refund (b)	$32.5	—
Provision for Tax Reform Refund (c)	6.7	—
Total Current Regulatory Liabilities	39.2	—
Non-Current Regulatory Liabilities		
Income Taxes	401.4	$411.2
Wholesale and Retail Contra AFUDC	60.2	57.9
Plant Removal Obligations	23.0	20.3
Cost Recovery Riders	16.8	2.2
North Dakota Investment Tax Credits	14.4	14.1
Provision for Interim Rate Refund (b)	—	23.7
Other	0.2	2.6
Total Non-Current Regulatory Liabilities	516.0	532.0
Total Regulatory Liabilities	$555.2	$532.0

(a) Current regulatory liabilities are presented within Other Current Liabilities on the Consolidated Balance Sheet.

(b) This amount is expected to be refunded to Minnesota Power's regulated retail customers in the first quarter of 2019 and includes $16.7 million of discounts provided to EITE customers that will be offset against interim rate refunds as of June 30, 2018 ($8.6 million as of December 31, 2017). (See 2016 Minnesota General Rate Case and Energy-Intensive Trade Exposed Customer Rates.)

(c) We have recorded the impact of income tax changes for Minnesota Power and SWL&P resulting from the TCJA in 2018 as regulatory liabilities and a reduction in revenue as the benefits are deferred pending the outcome of regulatory proceedings with the MPUC and PSCW. (See Tax Cuts and Jobs Act of 2017.)

NOTE 7. 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 portions of Wisconsin, Michigan, Minnesota and Illinois. We account for our investment in ATC under the equity method of accounting. As of June 30, 2018, our equity investment in ATC was $123.6 million ($118.7 million at December 31, 2017). In the first six months of 2018, we invested $3.9 million in ATC, and on July 31, 2018, we invested an additional $1.2 million. We expect to make additional investments of $1.3 million in 2018.

ALLETE's Investment in ATC

Millions

Equity Investment Balance as of December 31, 2017	$118.7
Cash Investments	3.9
Equity in ATC Earnings	9.0
Distributed ATC Earnings	(8.6)
Amortization of the Remeasurement of Deferred Income Taxes (a)	0.6
Equity Investment Balance as of June 30, 2018	$123.6

(a) Amortization related to the impact of the remeasurement of deferred income tax assets and liabilities resulting from the TCJA.

NOTE 7. INVESTMENT IN ATC (Continued)

ATC’s authorized return on equity is 10.32 percent, or 10.82 percent including an incentive adder for participation in a regional transmission organization.

In 2016, a federal administrative law judge ruled on a complaint proposing a reduction in the base return on equity to 9.70 percent, or 10.20 percent including an incentive adder for participation in a regional transmission organization, subject to approval or adjustment by the FERC. A final decision from the FERC on the administrative law judge’s recommendation is pending.

NOTE 8. SHORT-TERM AND LONG-TERM DEBT

The following tables present the Company’s short-term and long-term debt as of June 30, 2018, and December 31, 2017:

June 30, 2018	Principal	Unamortized Debt Issuance Costs	Total
Millions			
Short-Term Debt	$57.1	$(0.4)	$56.7
Long-Term Debt	1,471.7	(9.5)	1,462.2
Total Debt	$1,528.8	$(9.9)	$1,518.9

December 31, 2017	Principal	Unamortized Debt Issuance Costs	Total
Millions			
Short-Term Debt	$64.6	$(0.5)	$64.1
Long-Term Debt	1,448.7	(9.5)	1,439.2
Total Debt	$1,513.3	$(10.0)	$1,503.3

On April 16, 2018, ALLETE issued and sold $60.0 million of its First Mortgage Bonds (the Bonds) that bear interest at 4.07 percent. The Bonds will mature in April 2048 and pay interest semi-annually in April and October of each year, commencing on October 16, 2018. ALLETE has the option to prepay all or a portion of the Bonds at its discretion, subject to a make-whole provision. The Bonds are subject to additional terms and conditions which are customary for these types of transactions. ALLETE intends to use the proceeds from the sale of the Bonds to fund utility capital investment and 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.

Financial Covenants. Our long-term debt arrangements contain customary covenants. In addition, our lines of credit and letters of credit supporting certain long-term debt arrangements contain financial covenants. Our compliance with financial covenants is not dependent on debt ratings. The most restrictive financial covenant requires ALLETE to maintain a ratio of indebtedness to total capitalization (as the amounts are calculated in accordance with the respective long-term debt arrangements) of less than or equal to 0.65 to 1.00, measured quarterly. As of June 30, 2018, our ratio was approximately 0.42 to 1.00. Failure to meet this covenant would give rise to an event of default if not cured after notice from the lender, in which event ALLETE may need to pursue alternative sources of funding. Some of ALLETE’s debt arrangements contain “cross-default” provisions that would result in an event of default if there is a failure under other financing arrangements to meet payment terms or to observe other covenants that would result in an acceleration of payments due. ALLETE has no significant restrictions on its ability to pay dividends from retained earnings or net income. As of June 30, 2018, ALLETE was in compliance with its financial covenants.

NOTE 9. INCOME TAX EXPENSE

	Quarter Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Millions				
Current Income Tax Expense (Benefit) (a)				
Federal	—	—	—	—
State	$(0.3)	$0.1	$0.4	$0.2
Total Current Income Tax Expense (Benefit)	$(0.3)	$0.1	$0.4	$0.2
Deferred Income Tax Expense (Benefit)				
Federal (b)	$(7.4)	$3.8	$(14.2)	$11.1
State	2.4	3.6	5.0	9.5
Investment Tax Credit Amortization	(0.1)	(0.2)	(0.3)	(0.4)
Total Deferred Income Tax Expense (Benefit)	$(5.1)	$7.2	$(9.5)	$20.2
Total Income Tax Expense (Benefit)	$(5.4)	$7.3	$(9.1)	$20.4

(a) For the quarter and six months ended June 30, 2018, and 2017, 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.

(b) For the quarter and six months ended June 30, 2018, the federal tax benefit is primarily due to the reduction of the federal statutory tax rate from 35 percent to 21 percent enacted as part of the TCJA, and production tax credits.

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

Reconciliation of Taxes from Federal Statutory Rate to Total Income Tax Expense	Quarter Ended June 30,		Six Months Ended June 30,	
	2018	2017	2018	2017
Millions				
Income Before Non-Controlling Interest and Income Taxes	$25.9	$44.2	$73.2	$106.3
Statutory Federal Income Tax Rate	21 %	35 %	21 %	35 %
Income Taxes Computed at Statutory Federal Rate	$5.4	$15.5	$15.4	$37.2
Increase (Decrease) in Income Tax Due to:				
State Income Taxes – Net of Federal Income Tax Benefit	1.6	2.4	4.2	6.3
Production Tax Credits	(11.2)	(10.0)	(25.6)	(23.0)
Other	(1.2)	(0.6)	(3.1)	(0.1)
Total Income Tax Expense (Benefit)	$(5.4)	$7.3	$(9.1)	$20.4

For the six months ended June 30, 2018, the effective tax rate was a benefit of 12.4 percent (expense of 19.2 percent for the six months ended June 30, 2017).

Uncertain Tax Positions. As of June 30, 2018, we had gross unrecognized tax benefits of $1.7 million ($1.7 million as of December 31, 2017). Of the total gross unrecognized tax benefits, $0.8 million represents the amount of unrecognized tax benefits included on the Consolidated Balance Sheet that, if recognized, would favorably impact the effective income tax rate. The unrecognized tax benefit amounts have been presented as reductions to the tax benefits associated with NOL and tax credit carryforwards on the Consolidated Balance Sheet.

ALLETE and its subsidiaries file a consolidated federal income tax return as well as combined and separate state income tax returns in various jurisdictions. ALLETE has no open federal or state audits, and is no longer subject to federal examination for years before 2014, or state examination for years before 2013.

NOTE 10. RECLASSIFICATIONS OUT OF ACCUMULATED OTHER COMPREHENSIVE LOSS

Changes in Accumulated Other Comprehensive Loss. Comprehensive income (loss) is the change in 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 debt securities and defined benefit pension and other postretirement items, consisting of deferred actuarial gains or losses and prior service costs or credits.

For the quarter and six months ended June 30, 2018, and 2017, reclassifications out of accumulated other comprehensive loss for the Company were not material. Changes in accumulated other comprehensive loss for the six months ended June 30, 2018, are presented on the Consolidated Statement of Shareholders' Equity.

NOTE 11. EARNINGS PER SHARE AND COMMON STOCK

We compute basic earnings per share using the weighted average number of shares of common stock outstanding during each period. The difference between basic and diluted earnings per share, if any, arises from outstanding stock options, non-vested restricted stock units and performance share awards granted under our Executive Long-Term Incentive Compensation Plan. For the quarter and six months ended June 30, 2018, and 2017, no options to purchase shares of ALLETE common stock were excluded from the computation of diluted earnings per share.

Reconciliation of Basic and Diluted Earnings Per Share	2018			2017		
Millions Except Per Share Amounts	Basic	Dilutive Securities	Diluted	Basic	Dilutive Securities	Diluted
Quarter ended June 30,						
Net Income	$31.3		$31.3	$36.9		$36.9
Average Common Shares	51.3	0.2	51.5	50.9	0.2	51.1
Earnings Per Share	$0.61		$0.61	$0.73		$0.72
Six Months Ended June 30,						
Net Income	$82.3		$82.3	$85.9		$85.9
Average Common Shares	51.2	0.2	51.4	50.5	0.2	50.7
Earnings Per Share	$1.61		$1.60	$1.70		$1.69

NOTE 12. PENSION AND OTHER POSTRETIREMENT BENEFIT PLANS

	Pension		Other Postretirement	
Components of Net Periodic Benefit Cost	2018	2017	2018	2017
Millions				
Quarter Ended June 30,				
Service Cost	$2.8	$2.6	$1.3	$1.1
Non-Service Cost Components (a)				
Interest Cost	7.4	8.2	1.8	1.9
Expected Return on Plan Assets	(11.1)	(10.6)	(2.8)	(2.7)
Amortization of Prior Service Credits	—	—	(0.5)	(0.5)
Amortization of Net Loss	3.0	2.4	0.2	0.1
Net Periodic Benefit Cost (Income)	$2.1	$2.6	—	$(0.1)

Six Months Ended June 30,				
Service Cost	$5.5	$5.1	$2.5	$2.2
Non-Service Cost Components (a)				
Interest Cost	14.8	16.3	3.6	3.8
Expected Return on Plan Assets	(22.1)	(21.2)	(5.5)	(5.3)
Amortization of Prior Service Credits	—	—	(0.9)	(1.0)
Amortization of Net Loss	6.0	4.9	0.4	0.2
Net Periodic Benefit Cost (Income)	$4.2	$5.1	$0.1	$(0.1)

(a) These components of net periodic benefit cost are included in the line item "Other" under Other Income (Expense) on the Consolidated Statement of Income.

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

Employer Contributions. For the six months ended June 30, 2018, we contributed $15.0 million in cash to the defined benefit pension plans ($1.7 million in cash and $13.5 million in ALLETE common stock for the six months ended June 30, 2017); we do not expect to make additional contributions to our defined benefit pension plans in 2018. For the six months ended June 30, 2018, and 2017, we made no contributions to our other postretirement benefit plans; we do not expect to make any contributions to our other postretirement benefit plans in 2018.

NOTE 13. COMMITMENTS, GUARANTEES AND CONTINGENCIES

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

Our PPAs are summarized in Note 11. Commitments, Guarantees and Contingencies to our Consolidated Financial Statements in our 2017 Form 10-K, with additional disclosure provided in the following paragraphs.

Square Butte PPA. Minnesota Power has a PPA with Square Butte that extends through 2026 (Agreement). Minnesota Power is obligated to pay its pro rata share of Square Butte’s costs based on its entitlement to the output of Square Butte’s 455 MW coal fired generating unit. 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 PSA. (See Minnkota Power PSA.) Square Butte’s costs consist primarily of debt service, operating and maintenance, depreciation and fuel expenses. As of June 30, 2018, Square Butte had total debt outstanding of $311.4 million. 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 the six months ended June 30, 2018, was $37.7 million ($40.7 million for the six months ended June 30, 2017). 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 $4.6 million ($4.7 million for the same period in 2017). 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 PSA. Minnesota Power has a PSA with Minnkota Power, which commenced in 2014. Under the PSA, 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 2018 and in 2017.

Oconto Electric Cooperative PSA. On March 6, 2018, Minnesota Power entered into a PSA with Oconto Electric Cooperative. The contract begins in January 2019 and is effective through May 2026. Under the PSA, Minnesota Power expects to provide approximately 25 MW of energy and capacity at fixed prices.

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 2018 and a portion of its coal requirements through December 2021. Minnesota Power also has coal transportation agreements in place for the delivery of a significant portion of its coal requirements through December 2018. The estimated minimum payments under these supply and transportation agreements is $16.7 million for the remainder of 2018, $1.7 million in 2019, and none thereafter. The costs of fuel and related transportation costs for Minnesota Power's generation are recoverable from Minnesota Power's utility customers through the fuel adjustment clause.

Leasing Agreements. BNI Energy is obligated to make lease payments for a dragline totaling $2.8 million annually during 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 a majority of terms expiring by 2024. The aggregate amount of minimum lease payments for all operating leases is $7.1 million for the remainder of 2018, $12.8 million in 2019, $9.5 million in 2020, $7.3 million in 2021, $6.1 million in 2022 and $30.0 million thereafter.

NOTE 13. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)

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, investments to enhance our own transmission facilities, investments in other transmission assets (individually or in combination with others) and our investment in ATC.

Great Northern Transmission Line. As a condition of the 250-MW long-term PPA entered into with Manitoba Hydro, construction of additional transmission capacity is required. As a result, Minnesota Power is constructing the GNTL, an approximately 220 mile 500-kV transmission line between Manitoba and Minnesota's Iron Range that was proposed by Minnesota Power and Manitoba Hydro in order to strengthen the electric grid, enhance regional reliability and promote a greater exchange of sustainable energy.

In 2015, a certificate of need was approved by the MPUC. Based on this approval, 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 cost recovery filings. (See Note 6. Regulatory Matters.) Also in 2015, the FERC approved our request to recover on construction work in progress related to the GNTL from Minnesota Power's wholesale customers. In a 2016 order, the MPUC approved the route permit for the GNTL which largely follows Minnesota Power's preferred route, including the international border crossing, and in 2016, the U.S. Department of Energy issued a presidential permit to cross the U.S. Canadian border, which was the final major regulatory approval needed before construction in the U.S. could begin. Site clearing and pre construction activities commenced in the first quarter of 2017 with construction expected to be completed in 2020. To date, most of the right-of-way has been cleared while foundation installation and transmission tower construction have commenced. The total project cost in the U.S., including substation work, is estimated to be between $560 million and $710 million, of which Minnesota Power's portion is expected to be between $300 million and $350 million; the difference will be recovered from a subsidiary of Manitoba Hydro as non-shareholder contributions to capital. Total project costs of $248.8 million have been incurred through June 30, 2018, of which $129.2 million has been recovered from a subsidiary of Manitoba Hydro.

Manitoba Hydro must obtain regulatory and governmental approvals related to a new transmission line in Canada known as the Manitoba-Minnesota Transmission Project (MMTP) that will connect with the GNTL. In 2015, Manitoba Hydro submitted the final preferred route and EIS for the MMTP to the Manitoba Conservation and Water Stewardship for siting and environmental approval, which remains pending. In 2016, Manitoba Hydro filed an application with the Canadian National Energy Board (NEB) requesting authorization to construct and operate the MMTP. The NEB determined that Manitoba Hydro's application was complete in December 2017, and held public hearings in June 2018. The NEB is required to make a decision on the MMTP by March 2019, but is not precluded from making a decision prior to that date. Approval of the Canadian federal cabinet is also required.

The MMTP is subject to legal and regulatory challenges which Minnesota Power is actively monitoring. Manitoba Hydro has informed Minnesota Power that it continues to work towards completing the MMTP on schedule. In order to meet the transmission in service requirements in PPAs with Minnesota Power, Manitoba Hydro has indicated that it would need to start construction of the MMTP in December 2018. We are unable to predict the outcome of the Canadian regulatory review process, including the timing thereof or whether any onerous conditions may be imposed, or the timing of the completion of the MMTP, including the impact of any delays that may result in construction schedule adjustments. Any significant delays in the MMTP construction schedule may result in Minnesota Power adjusting the GNTL construction schedule and impact the timing of capital expenditures and associated cost recovery under our transmission cost recovery rider.

Construction of Manitoba Hydro’s Keeyask hydroelectric generation facility, which will provide the power to be sold under PPAs with Minnesota Power and transmitted on the MMTP and the GNTL, commenced in 2014 and is anticipated to be in service by early 2021.

Environmental Matters.

Our businesses are subject to regulation of environmental matters by various federal, state and local authorities. A number of regulatory changes to the Clean Air Act, the Clean Water Act and various waste management requirements have been promulgated by both the EPA and state authorities over the past several years. Minnesota Power’s facilities are subject to additional requirements under many of 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.

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

We consider our businesses to be in substantial compliance with currently applicable environmental regulations and believe all necessary permits have been obtained. We anticipate that with many state and federal environmental regulations and requirements finalized, or to be finalized in the near future, potential expenditures for future environmental matters may be material and require significant capital investments. Minnesota Power has evaluated various environmental compliance scenarios using possible outcomes of 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 expensed 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 emission requirements.

New Source Review (NSR). In 2014, Minnesota Power reached a settlement with the EPA and entered into a Consent Decree regarding certain Notices of Violation received in 2008 and 2011 that asserted violations of the NSR requirements of the Clean Air Act, which was approved by the U.S. District Court for the District of Minnesota. The Consent Decree provided for, among other requirements, more stringent emissions limits at all affected units, the option of refueling, retrofitting or retiring 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. In 2016, Minnesota Power announced that Boswell Units 1 and 2 will be retired in 2018 as part of its EnergyForward strategic plan. We believe that costs to retire Boswell Units 1 and 2 will be eligible for recovery in rates over time, subject to regulatory approval in a rate proceeding.

Cross-State Air Pollution Rule (CSAPR). The CSAPR requires certain states in the eastern half of the U.S., including Minnesota, to reduce power plant emissions that contribute to ozone or fine particulate pollution in other states. The CSAPR does not require installation of controls but does require 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. Based on our review of the NO_x and SO_2 allowances issued and pending issuance, we currently expect generation levels and emission rates will result in continued compliance with the CSAPR.

Mercury and Air Toxics Standards (MATS) 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 final MATS rule addressed such emissions from coal-fired utility units greater than 25 MW and established categories of HAPs, including mercury, trace metals other than mercury, and acid gases. The EPA established emission limits for these categories of HAPs and work practice standards for the remaining categories. Construction on the project to implement the Boswell Unit 4 mercury emissions reduction plan to position the unit for MATS compliance was completed in 2015.

Investments and compliance work previously completed at Boswell Unit 3, including emission reduction investments completed in 2009, meet the requirements of the MATS rule. The conversion of Laskin Units 1 and 2 to operate on natural gas in 2015 positioned those units for MATS compliance.

Minnesota Mercury Emissions Reduction Act/Rule. 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.

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

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. Four NAAQS have either recently been revised or are currently proposed for revision, as described below.

- Ozone NAAQS. 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. As a result, voluntary efforts to reduce ground-level ozone continue in the state. No additional costs for compliance are anticipated at this time.

- Particulate Matter NAAQS. The EPA has 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. In 2016, environmental groups filed a lawsuit against the EPA in the U.S. District Court for the Northern District of California alleging the EPA had failed to fully implement the $PM_{2.5}$ standards in certain states, including Minnesota, by not enforcing states' submittals of required infrastructure implementation plans for the 2012 $PM_{2.5}$ NAAQS. The outcome of this litigation is uncertain, and as such, any costs for complying with the final Particulate Matter NAAQS cannot be estimated at this time.

- NO_2 NAAQS. Ambient monitoring data indicates that Minnesota is likely in compliance with the one-hour NAAQS standard for NO_2. In July 2017, the EPA proposed retaining the current one-hour and annual NO_2 NAAQS. Additional compliance costs for the one-hour NO_2 NAAQS are not expected at this time.

- SO_2 NAAQS. In 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 MPCA initially informed Minnesota Power that compliant SO_2 modeling completed at Minnesota Power's Boswell and Taconite Harbor facilities would satisfy the DRR obligations and no further modeling would be required; however, the DRR also required facilities have federally-enforceable permit limits at which the one-hour SO_2 NAAQS compliance was modeled by January 2017. Taconite Harbor was issued an amended air permit in 2016, containing the new modeling limits at that facility. The MPCA did not meet the January 2017, deadline to amend the Boswell permit. The MPCA is in discussions with the EPA on alternate compliance pathways to use existing completed modeling at current limits. On June 8, 2018, the EPA formally proposed in the Federal Register to retain the current primary SO_2 one-hour NAAQS. Compliance costs for the one-hour SO_2 NAAQS are not expected to be material.

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 power supply;
- Providing energy conservation initiatives for our customers and engaging in other demand side management efforts;
- Improving efficiency of our generating facilities;
- Supporting research of technologies to reduce carbon emissions from generating facilities and carbon sequestration efforts; and

- Evaluating and developing less carbon intensive future generating assets such as efficient and flexible natural gas-fired generating facilities.

EPA Regulation of GHG Emissions. In 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 may be added to our existing Title V operating permits by the MPCA as these permits are renewed or amended.

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

In 2014, the U.S. Supreme Court invalidated the aspect of the Tailoring Rule that established higher permitting thresholds for GHG than for other pollutants subject to PSD; however, the court also upheld the EPA's ability to require best available control technology (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.

In 2016, the EPA published a proposed rule in the Federal Register to revise its PSD and Title V regulatory provisions concerning GHG emissions. In this proposed rule, the EPA proposes to amend its regulations to clarify that a source's obligation to obtain a PSD or Title V permit is triggered only by non-GHG pollutants. If the PSD or Title V permitting requirements are triggered by non-GHG, NSR pollutants, then these programs will also apply to the source's GHG emissions. The proposed rule, as currently written, is not expected to have a material impact on the Title V permitting for current operations.

In 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", also referred to as the Clean Power Plan (CPP). The EPA issued the final CPP in 2015, together with a proposed federal implementation plan and a model rule for emissions trading. In 2016, the U.S. Supreme Court issued an order staying the effectiveness of the rule until after the appellate court process is complete. In 2016, the U.S. Court of Appeals for the District of Columbia heard oral arguments and is currently deliberating. If the CPP is upheld at the completion of the appellate process, all of the CPP regulatory deadlines are expected to be reset based on the length of time that the appeals process takes. The EPA is precluded from enforcing the CPP while the U.S. Supreme Court stay is in force; however, the MPCA has been holding a series of meetings on the CPP for educational and planning purposes in the interim. Minnesota Power has been actively involved in these MPCA meetings, and is closely monitoring the appeals process.

If upheld, the CPP would establish 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 filed a motion with the U.S. Court of Appeals for the District of Columbia Circuit to hold CPP-related litigation in suspension while the EPA is reviewing the rule. In October 2017, the EPA issued a notice of proposed rulemaking, proposing to repeal the CPP. In December 2017, an Advanced Notice of Proposed Rulemaking for a CPP replacement rule was published in the Federal Register.

Minnesota Power is currently evaluating the CPP rescission and recent proposal for a CPP replacement rule as it relates to the state of Minnesota as well as its potential impact on the Company. Minnesota has already initiated several measures consistent with those called for under the 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 6. 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 additional costs through a rate proceeding.

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 2014, EPA regulations under Section 316(b) of the Clean Water Act setting standards applicable to cooling water intake structures for the protection of aquatic organisms became effective. The regulations apply to the following facilities: Boswell, Taconite Harbor, Laskin, Rapids Energy Center, Hibbard Renewable Energy Center and portions of the DC transmission line that runs from Center, North Dakota, to Duluth, Minnesota. The Section 316(b) rule will be implemented through NPDES permits issued to covered facilities. No NPDES permits for Minnesota Power facilities have been re-issued containing Section 316(b) requirements since the final rule became effective. Should the MPCA require significant modifications to Minnesota Power's intake structures, a preliminary assessment indicates that Minnesota Power could incur costs of compliance up to $15 million over the next five years. Minnesota Power would seek recovery of additional costs through a rate proceeding.

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

Steam Electric Power Generating Effluent Guidelines. In 2015, the EPA issued revised federal effluent limit guidelines (ELG) for steam electric power generating stations under the Clean Water Act. It set effluent limits and prescribed BACT for several wastewater streams, including flue gas desulphurization (FGD) water, bottom ash transport water and coal combustion landfill leachate. In September 2017, the EPA announced a two-year postponement of the ELG compliance date of November 1, 2018, to November 1, 2020, while the agency reconsiders the bottom ash transport water and FGD wastewater provisions.

The final ELG rule’s potential impact on Minnesota Power operations is 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 discharge, but may do so in the future. Under the existing ELG rule, bottom ash transport water discharge must cease no later than December 31, 2023. Bottom ash contact water will either need to be re-used in a closed-loop process, routed to a FGD scrubber, or the bottom ash handling system will need to be converted to a dry process. If FGD wastewater is discharged in the future, it will require additional wastewater treatment. The ELG rule provision regarding these two waste-streams are being reconsidered and may change prior to November 1, 2020. Efforts have been underway at Boswell to reduce the amount of water discharged and evaluate potential re use options in its plant processes.

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 re-use. Minnesota Power would seek recovery of additional costs through a rate proceeding.

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 reports to the EPA.

Coal Ash Management Facilities. Minnesota Power stores or disposes coal ash at four of its electric generating facilities by the following methods: storing ash in lined onsite impoundments (ash ponds), disposing of dry ash in a lined dry ash landfill, applying ash to land as an approved beneficial use and trucking ash to state permitted landfills.

Coal Combustion Residuals from Electric Utilities (CCR). In 2015, the EPA published the final rule regulating CCR as nonhazardous waste under Subtitle D of the Resource Conservation and Recovery Act (RCRA) in the Federal Register. The rule includes additional requirements for new landfill and impoundment construction as well as closure activities related to certain existing impoundments. Costs of compliance for Boswell and Laskin are expected to occur primarily over the next 15 years and be between approximately $65 million and $100 million. The EPA has indicated to Minnesota Power that the Taconite Harbor landfill, which has been idled and has a temporary landfill cover in place, is a CCR unit, based on the EPA’s interpretation of the CCR rule language. Minnesota Power has agreed to post the required CCR information for the Taconite Harbor landfill on Minnesota Power’s website while the CCR issue is resolved. Compliance costs, if any, for CCR at Taconite Harbor cannot be estimated at this time. Minnesota Power would seek recovery of additional costs through a rate proceeding.

Minnesota Power continues to work on minimizing costs through evaluation of beneficial re-use and recycling of CCR and CCR related waters. In September 2017, the EPA announced its intention to formally reconsider the CCR rule under Subtitle D of the RCRA and on March 15, 2018, published the first phase of the proposed rule revisions in the Federal Register. On July 17, 2018, the EPA finalized revisions to elements of the CCR rule, including extending certain deadlines by two years, the establishment of alternative groundwater protection standards for certain constituents and the potential for risk based management options at facilities based on site characteristics.

Other Environmental Matters

Manufactured Gas Plant Site. We are reviewing and addressing environmental conditions at a former manufactured gas plant site located in Superior, Wisconsin, and formerly operated by SWL&P. SWL&P has been working with the Wisconsin Department of Natural Resources (WDNR) in determining the extent and location of contamination at the site and surrounding properties. In December 2017, the WDNR authorized SWL&P to transition from site investigation into the remedial design process. As of June 30, 2018, we have recorded a liability of approximately $7 million for remediation costs at this site (approximately $8 million as of December 31, 2017), and an associated regulatory asset as we expect recovery of these remediation costs to be allowed by the PSCW. We expect to incur these costs over the next four years.

NOTE 13. COMMITMENTS, GUARANTEES AND CONTINGENCIES (Continued)

Other Matters.

ALLETE Clean Energy. ALLETE Clean Energy's wind energy facilities have PSAs in place for their entire output and expire in various years between 2018 and 2032. As of June 30, 2018, ALLETE Clean Energy has $16.2 million outstanding in standby letters of credit.

U.S. Water Services. As of June 30, 2018, U.S. Water Services has no outstanding standby letters of credit.

BNI Energy. As of June 30, 2018, BNI Energy had surety bonds outstanding of $49.9 million and a letter of credit for an additional $0.6 million related to the reclamation liability for closing costs associated with its mine and mine facilities. Although its coal supply agreements obligate the customers to provide for the closing costs, additional assurance is required by federal and state regulations. BNI Energy's total reclamation liability 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.

ALLETE Properties. As of June 30, 2018, ALLETE Properties had surety bonds outstanding and letters of credit to governmental entities totaling $8.6 million primarily related to development and maintenance obligations for various projects. The estimated cost of the remaining development work is $6.1 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. As of June 30, 2018, we owned 70 percent of the assessable land in the Town Center District (70 percent as of December 31, 2017) and 27 percent of the assessable land in the Palm Coast Park District (33 percent as of December 31, 2017). As of June 30, 2018, ownership levels, our annual assessments related to capital improvement and special assessment bonds for the ALLETE Properties projects within these districts are approximately $1.4 million for Town Center at Palm Coast and $0.6 million for Palm Coast Park. As we sell property at these projects, 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.

U.S. Water Services is involved in on-going patent defense litigation it brought against a company for infringement of two patents held by U.S. Water Services. As of June 30, 2018, U.S. Water Services has recognized approximately $2 million of patent defense costs as an intangible asset. Management expects that U.S. Water Services will prevail, but in the event of an unfavorable outcome, the patent defense costs would be recognized as an expense in the period of resolution.

NOTE 14. BUSINESS SEGMENTS

We present three reportable segments: Regulated Operations, ALLETE Clean Energy and U.S. Water Services. We measure performance of our operations through budgeting and monitoring of contributions to consolidated net income by each business segment.

Regulated Operations includes three operating segments which consist of our regulated utilities, Minnesota Power and SWL&P, as well as our investment in ATC. ALLETE Clean Energy is our business focused on developing, acquiring and operating clean and renewable energy projects. U.S. Water Services is our integrated water management company. 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 4,000 acres of land in Minnesota, and earnings on cash and investments.

NOTE 14. BUSINESS SEGMENTS (Continued)

	Quarter Ended		Six Months Ended	
	June 30,		June 30,	
	2018	2017	2018	2017
Millions				
Operating Revenue (a)				
Regulated Operations				
Residential	$30.7	$27.6	$71.4	$67.1
Commercial	36.2	33.7	72.8	71.9
Municipal	13.7	12.3	27.7	30.5
Industrial	115.3	121.6	230.2	243.3
Other Power Suppliers	42.7	41.7	86.4	82.9
CIP Financial Incentive (b)	—	5.5	—	5.5
Other	19.2	22.5	39.5	45.3
Total Regulated Operations	257.8	264.9	528.0	546.5
Energy Infrastructure and Related Services				
ALLETE Clean Energy				
Long-term PSA	12.4	13.7	31.0	31.5
Other	5.9	5.9	11.9	11.8
Total ALLETE Clean Energy	18.3	19.6	42.9	43.3
U.S. Water Services				
Point-in-Time	25.7	23.9	48.0	45.7
Contract	9.5	8.8	19.0	17.7
Capital Project	6.3	5.7	12.7	7.1
Total U.S. Water Services	41.5	38.4	79.7	70.5
Corporate and Other				
Long-term Contract	22.7	23.2	42.7	45.3
Other	3.8	7.2	9.0	13.3
Total Corporate and Other	26.5	30.4	51.7	58.6
Total Operating Revenue	$344.1	$353.3	$702.3	$718.9
Net Income (Loss)				
Regulated Operations	$26.0	$32.4	$69.9	$75.9
Energy Infrastructure and Related Services				
ALLETE Clean Energy	6.8	3.8	14.9	10.5
U.S. Water Services	0.2	0.6	(1.2)	0.3
Corporate and Other	(1.7)	0.1	(1.3)	(0.8)
Total Net Income	$31.3	$36.9	$82.3	$85.9

(a) With the adoption of new revenue recognition guidance, the Company has enhanced the presentation of business segment Operating Revenue. (See Note 1. Operations and Significant Accounting Policies.)

(b) See Note 6. Regulatory Matters.

NOTE 14. BUSINESS SEGMENTS (Continued)

Millions	June 30, 2018	December 31, 2017
Assets		
Regulated Operations	$3,898.2	$3,886.6
Energy Infrastructure and Related Services		
ALLETE Clean Energy	620.2	600.5
U.S. Water Services	291.8	292.4
Corporate and Other	304.5	300.5
Total Assets	$5,114.7	$5,080.0

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

OVERVIEW

The following discussion should be read in conjunction with our Consolidated Financial Statements and notes to those statements, Management's Discussion and Analysis of Financial Condition and Results of Operations from the 2017 Form 10-K, and the other financial information appearing elsewhere in this report. In addition to historical information, the following discussion and other parts of this Form 10-Q contain forward-looking information that involves risks and uncertainties. Readers are cautioned that forward-looking statements should be read in conjunction with our disclosures in this Form 10-Q and our 2017 Form 10-K under the headings: "Forward-Looking Statements" located on page 6 and "Risk Factors" located in Part I, Item 1A, beginning on page 25 of our 2017 Form 10-K. The risks and uncertainties described in this Form 10-Q and our 2017 Form 10-K are not the only risks facing our Company. Additional risks and uncertainties that we are not presently aware of, or that we currently consider immaterial, may also affect our business operations. Our business, financial condition or results of operations could suffer if the risks are realized.

Regulated Operations includes our regulated utilities, Minnesota Power and SWL&P, as well as our investment in ATC, a Wisconsin-based regulated utility that owns and maintains electric transmission assets in portions 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 utility 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 Note 6. Regulatory Matters.)

ALLETE Clean Energy 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 is contracted under PSAs of various durations. ALLETE Clean Energy also engages in the development of wind energy facilities to operate under long-term PSAs or for sale to others upon completion.

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.

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 4,000 acres of land in Minnesota, and earnings on cash and investments.

ALLETE is incorporated under the laws of Minnesota. Our corporate headquarters are in Duluth, Minnesota. Statistical information is presented as of June 30, 2018, 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.

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

Financial Overview

The following net income discussion summarizes a comparison of the six months ended June 30, 2018, to the six months ended June 30, 2017.

Net income for the six months ended June 30, 2018, was $82.3 million, or $1.60 per diluted share, compared to $85.9 million, or $1.69 per diluted share, for the same period in 2017. Earnings per share dilution was $0.02 due to additional shares of common stock outstanding as of June 30, 2018.

Regulated Operations net income was $69.9 million for the six months ended June 30, 2018, compared to $75.9 million for the same period in 2017. Net income at Minnesota Power was lower than 2017 primarily due to reserves for an interim rate refund, lower transmission revenue, the timing of financial incentives under the Minnesota conservation improvement program and higher property taxes. These decreases were partially offset by lower operating and maintenance expense, higher sales to residential customers due to more favorable weather conditions, and higher sales to industrial customers due to the start-up of Keetac in March 2017. Net income at SWL&P was higher than 2017 due to the implementation of updated rates in August 2017 and more favorable weather conditions in 2018. Our after-tax equity earnings in ATC for the six months ended June 30, 2018, were consistent with 2017.

ALLETE Clean Energy net income was $14.9 million for the six months ended June 30, 2018, compared to $10.5 million for the same period in 2017. Net income in 2018 included $4.5 million after tax of additional production tax credits generated as ALLETE Clean Energy continues to execute its refurbishment strategy and a lower federal income tax rate due to the TCJA. Of the $4.5 million after-tax in additional production tax credits, $2.6 million resulted from the retrospective qualification of additional WTGs in 2016 and 2017. These increases were partially offset by higher operating and maintenance expenses, and lower revenue resulting from lower wind resources.

U.S. Water Services net loss was $1.2 million for the six months ended June 30, 2018, compared to a net income of $0.3 million for the same period in 2017. The net loss in 2018 includes higher operating expenses, partially offset by increased revenue primarily resulting from the September 2017 acquisition of Tonka Water. The first six months of 2018 were also impacted by the timing of capital project sales and unfavorable weather conditions reducing chemical sales. The net loss in 2018 also included $0.5 million of after-tax expense recognized as cost of sales related to purchase accounting for sales backlog.

Corporate and Other net loss was $1.3 million for the six months ended June 30, 2018, compared to a net loss of $0.8 million for the same period in 2017. Results in 2018 decreased primarily due to additional income tax expense recorded in 2018 as GAAP requires the recognition of quarterly income tax expense at the estimated annual effective tax rate, partially offset by lower operating and maintenance expenses at ALLETE Properties.

COMPARISON OF THE QUARTERS ENDED JUNE 30, 2018 AND 2017

(See Note 14. Business Segments for financial results by segment.)

Regulated Operations

Quarter Ended June 30,	2018	2017
Millions		
Operating Revenue – Utility	$257.8	$264.9
Fuel, Purchased Power and Gas – Utility	96.5	93.1
Transmission Services – Utility	16.8	17.6
Operating and Maintenance	54.9	57.3
Depreciation and Amortization	44.5	39.0
Taxes Other than Income Taxes	13.0	12.7
Operating Income	32.1	45.2
Interest Expense	(15.1)	(14.5)
Equity Earnings in ATC	4.3	5.3
Other Income	1.0	1.2
Income Before Income Taxes	22.3	37.2
Income Tax Expense (Benefit)	(3.7)	4.8
Net Income	$26.0	$32.4

Operating Revenue – Utility decreased $7.1 million, or 3 percent, from 2017 reflecting interim retail rate refund reserves, lower financial incentives under the Minnesota conservation improvement program and lower transmission revenue, partially offset by higher revenue from kWh sales, cost recovery rider revenue, conservation improvement program recoveries and fuel clause adjustment recoveries.

Interim rates, net of reserves, decreased $7.8 million from 2017 as interim rate refund reserves were recognized during 2018 due to the regulatory outcome of the MPUC's decisions in Minnesota Power's 2016 general rate case. (See Note 6. Regulatory Matters.)

Financial incentives under the Minnesota conservation improvement program were lower $5.5 million from 2017 due to the timing of MPUC approval. The conservation improvement program financial incentive was recognized in the second quarter of 2017 upon approval by the MPUC of Minnesota Power's 2016 CIP consolidated filing in a June 2017 order. Approval of Minnesota Power's 2017 CIP consolidated filing is expected in the third quarter of 2018.

Transmission revenue decreased $4.4 million primarily due to lower MISO-related revenue. (See Operating Expenses - Transmission Services – Utility.)

Revenue from kWh sales increased $4.4 million from 2017 primarily due to higher sales to Residential, Commercial and Municipal customers in 2018. Sales to Residential, Commercial and Municipal customers increased from 2017 primarily due to more favorable weather conditions in 2018. Sales to Industrial customers decreased 1.9 percent primarily due to lower sales to paper, pulp and secondary wood product customers as a result of the closure of the smaller of UPM Blandin's two paper machines in the fourth quarter of 2017. Sales to Other Power Suppliers were comparable to 2017, while revenue increased due to higher pricing. 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.

COMPARISON OF THE QUARTERS ENDED JUNE 30, 2018 AND 2017 (Continued)
Regulated Operations (Continued)

Kilowatt-hours Sold Quarter Ended June 30, Millions	2018	2017	Quantity Variance	% Variance
Regulated Utility				
Retail and Municipal				
Residential	243	229	14	6.1 %
Commercial	339	328	11	3.4 %
Industrial	1,781	1,816	(35)	(1.9)%
Municipal	188	181	7	3.9 %
Total Retail and Municipal	2,551	2,554	(3)	(0.1)%
Other Power Suppliers	1,005	1,004	1	0.1 %
Total Regulated Utility Kilowatt-hours Sold	3,556	3,558	(2)	(0.1)%

Revenue from electric sales to taconite and iron concentrate customers accounted for 22 percent of consolidated operating revenue in 2018 (22 percent in 2017). Revenue from electric sales to paper, pulp and secondary wood product customers accounted for 5 percent of consolidated operating revenue in 2018 (5 percent in 2017). Revenue from electric sales to pipelines and other industrial customers accounted for 6 percent of consolidated operating revenue in 2018 (7 percent in 2017).

Cost recovery rider revenue increased $3.6 million primarily due to higher expenditures related to the construction of the GNTL.

Conservation improvement program recoveries increased $1.9 million from 2017 primarily due to an increase in related expenditures. (See Operating Expenses - Operating and Maintenance.)

Fuel adjustment clause recoveries increased $1.6 million due to higher fuel and purchased power costs attributable to retail and municipal customers.

Operating Expenses increased $6.0 million, or 3 percent, from 2017.

Fuel, Purchased Power and Gas – Utility expense increased $3.4 million, or 4 percent, from 2017 primarily due to higher purchased power prices, partially offset by lower fuel costs. Fuel and purchased power expense related to our retail and municipal customers is recovered through the fuel adjustment clause.

Transmission Services – Utility expense decreased $0.8 million, or 5 percent, from 2017 primarily due to lower MISO related expense. (See Operating Revenue – Utility.)

Operating and Maintenance expense decreased $2.4 million, or 4 percent, from 2017 primarily due to lower salary and benefit expenses, partially offset by a $1.9 million increase in conservation improvement program expenses in 2018. Conservation improvement program expenses are recovered from certain retail customers. (See Operating Revenue – Utility.)

Depreciation and Amortization expense increased $5.5 million, or 14 percent, from 2017 primarily due to modifications of the depreciable lives for Boswell as part of Minnesota Power’s general rate case. As part of its order dated March 12, 2018, affirming determinations made at a hearing on January 18, 2018, the MPUC extended the depreciable lives of Boswell Unit 3, Unit 4 and common facilities to 2050, and shortened the depreciable lives of

Boswell Unit 1 and Unit 2 to 2022, resulting in a net decrease to depreciation expense in the first quarter of 2018. Subsequently, in an order dated May 29, 2018, the MPUC modified its March 12, 2018 order, reducing the depreciable lives of Boswell Unit 3, Unit 4 and common facilities to 2035 resulting in an increase to depreciation expense in the second quarter of 2018. (See Note 6. Regulatory Matters.)

Equity Earnings in ATC decreased $1.0 million, or 19 percent, from 2017 primarily due to the federal income tax rate change due to the TCJA, partially offset by additional investments in ATC. (See Note 7. Investment in ATC.)

COMPARISON OF THE QUARTERS ENDED JUNE 30, 2018 AND 2017 (Continued)
Regulated Operations (Continued)

Income Tax Expense decreased $8.5 million from 2017 primarily due to the reduction of the federal income tax rate from 35 percent to 21 percent enacted as part of the TCJA, and lower pre-tax income. (See Note 6. Regulatory Matters.)

We expect our annual effective tax rate in 2018 to be lower than 2017 due to the reduction of the federal income tax rate from 35 percent to 21 percent enacted as part of the TCJA, and lower pre-tax income.

ALLETE Clean Energy

Quarter Ended June 30,	2018	2017
Millions		
Operating Revenue	$18.3	$19.6
Net Income	$6.8	$3.8

Operating Revenue decreased $1.3 million, or 7 percent, from 2017 primarily due to lower kWh sales at most of ALLETE Clean Energy's wind energy facilities resulting from lower wind resources.

	Quarter Ended June 30,			
	2018		2017	
Production and Operating Revenue	kWh	Revenue	kWh	Revenue
Millions				
Wind Energy Facilities				
Lake Benton	49.0	$2.8	58.4	$3.1
Storm Lake II	31.7	2.3	35.0	2.3
Condon	24.0	1.9	20.6	1.7
Storm Lake I	41.3	2.9	49.4	3.0
Chanarambie/Viking	59.4	3.3	64.6	3.5
Armenia Mountain	55.5	5.1	62.5	6.0
Total Production and Operating Revenue	260.9	$18.3	290.5	$19.6

Net Income increased $3.0 million, or 79 percent, from 2017. Net income in 2018 included $3.9 million after-tax of additional production tax credits generated as ALLETE Clean Energy continues to execute its refurbishment strategy and a lower federal income tax rate due to the TCJA. Of the $3.9 million after-tax in additional production tax credits, $2.6 million resulted from the retrospective qualification of additional WTGs in 2016 and 2017 and $0.6 million resulted from the qualification of additional WTGs in the first quarter of 2018. These increases were partially offset by higher operating and maintenance expenses, and lower revenue resulting from lower wind resources.

U.S. Water Services

Quarter Ended June 30,	2018	2017
Millions		
Operating Revenue	$41.5	$38.4
Net Income	$0.2	$0.6

Operating Revenue increased $3.1 million, or 8 percent, from 2017 primarily due to the acquisition of Tonka Water in September 2017. Revenue from chemical sales and related services was $35.2 million in 2018 compared to $32.7 million in 2017. Revenue from capital projects was $6.3 million for 2018 compared to $5.7 million in 2017; capital project sales can significantly fluctuate from period to period.

Net Income decreased $0.4 million from 2017. Net income in 2018 included higher operating expenses, partially offset by increased revenue primarily resulting from the September 2017 acquisition of Tonka Water. The second quarter of 2018 was also negatively impacted by the timing of capital project sales. Net income in 2018 also included $0.2 million of after-tax expense recognized as cost of sales related to purchase accounting for sales backlog.

COMPARISON OF THE QUARTERS ENDED JUNE 30, 2018 AND 2017 (Continued)

Corporate and Other

Operating Revenue decreased $3.9 million, or 13 percent, from 2017 primarily due to lower land sales at ALLETE Properties and lower revenue at BNI Energy, which operates under cost-plus fixed fee contracts, as a result of lower expenses in 2018 compared to 2017.

Net Loss was $1.7 million in 2018 compared to net income of $0.1 million in 2017. Results in 2018 decreased primarily due to additional income tax expense recorded in 2018 as GAAP requires the recognition of quarterly income tax expense at the estimated annual effective tax rate. The estimated annual effective tax rate can differ from what a quarterly effective tax rate would otherwise be on a stand-alone basis, and this may cause quarter to quarter differences in the timing of income taxes. Results in 2018 also included lower revenue at ALLETE Properties. The net loss at ALLETE Properties was $0.7 million in 2018 compared to a net loss of $0.4 million in 2017. Net income at BNI Energy was $1.8 million in 2018 compared to net income of $2.0 million in 2017.

Income Taxes – Consolidated

For the quarter ended June 30, 2018, the effective tax rate was a benefit of 20.8 percent (expense of 16.5 percent for the quarter ended June 30, 2017). The decrease from 2017 was primarily due to the reduction of the federal income tax rate from 35 percent to 21 percent enacted as part of the TCJA and lower pre-tax income. (See Regulated Operations - Income Tax Expense.)

We expect our annual effective tax rate in 2018 to be lower than 2017 due to a reduction of the federal income tax rate as part of the TCJA, and lower pre-tax income. The effective rate deviated from the combined statutory rate of approximately 28 percent primarily due to production tax credits. (See Note 9. Income Tax Expense.) The estimated annual effective tax rate can differ from what a quarterly effective tax rate would otherwise be on a stand-alone basis, and this may cause quarter to quarter differences in the timing of income taxes.

COMPARISON OF THE SIX MONTHS ENDED JUNE 30, 2018 AND 2017

(See Note 14. Business Segments for financial results by segment.)

Regulated Operations

Six Months Ended June 30,	2018	2017
Millions		
Operating Revenue – Utility	$528.0	$546.5
Fuel, Purchased Power and Gas – Utility	197.4	189.7
Transmission Services – Utility	35.2	34.2
Operating and Maintenance	110.4	113.4
Depreciation and Amortization	78.8	78.7
Taxes Other than Income Taxes	28.1	25.9
Operating Income	78.1	104.6
Interest Expense	(30.0)	(28.5)
Equity Earnings in ATC	9.0	11.4
Other Income	2.6	2.5
Income Before Income Taxes	59.7	90.0

Income Tax Expense (Benefit)	(10.2)	14.1
Net Income	$69.9	$75.9

Operating Revenue – Utility decreased $18.5 million, or 3 percent, from 2017 reflecting interim retail rate refund reserves, lower transmission revenue, provision for tax reform refund related to income tax changes resulting from the TCJA, lower financial incentives under the Minnesota conservation improvement program and lower FERC formula based rates, partially offset by higher revenue from kWh sales, conservation improvement program recoveries and cost recovery rider revenue.

COMPARISON OF THE SIX MONTHS ENDED JUNE 30, 2018 AND 2017 (Continued)
Regulated Operations (Continued)

Interim rates, net of reserves, decreased $16.6 million from 2017 as interim rate refund reserves were recognized during 2018 due to the regulatory outcome of the MPUC's decisions in Minnesota Power's 2016 general rate case. (See Note 6. Regulatory Matters.)

Transmission revenue decreased $7.0 million primarily due to lower MISO-related revenue. (See Operating Expenses - Transmission Services – Utility.)

Provision for tax reform refund of $6.7 million related to income tax changes resulting from the TCJA was recognized during 2018. We have recorded the impact of these income tax changes for Minnesota Power and SWL&P as regulatory liabilities pending the outcome of regulatory proceedings with the MPUC and PSCW. (See Note 6. Regulatory Matters.)

Financial incentives under the Minnesota conservation improvement program were lower by $5.5 million from 2017 due to the timing of MPUC approval. The conservation improvement program financial incentive was recognized in the second quarter of 2017 upon approval by the MPUC of Minnesota Power's 2016 CIP consolidated filing in a June 2017 order. Approval of Minnesota Power's 2017 CIP consolidated filing and related financial incentive is expected in the third quarter of 2018.

Revenue from wholesale customers under FERC formula-based rates decreased $1.6 million from 2017 primarily due to lower rates.

Revenue from kWh sales increased $10.1 million from 2017 primarily due to higher sales to Residential, Commercial, Industrial and Municipal customers in 2018. Sales to Industrial customers increased 1.3 percent primarily due to increased taconite production. USS Corporation restarted production at its Keetac plant in March 2017. Sales to Residential, Commercial and Municipal customers increased in 2018 primarily due to more favorable weather conditions in 2018 compared to 2017. Sales to Other Power Suppliers decreased 1.8 percent from 2017 as a result of increased sales to Industrial customers, which was more than offset by higher pricing on PSAs with these customers. 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.

Kilowatt-hours Sold Six Months Ended June 30,	2018	2017	Quantity Variance	% Variance
Millions				
Regulated Utility				
Retail and Municipal				
Residential	585	552	33	6.0 %
Commercial	706	697	9	1.3 %
Industrial	3,624	3,578	46	1.3 %
Municipal	407	396	11	2.8 %
Total Retail and Municipal	5,322	5,223	99	1.9 %
Other Power Suppliers	2,008	2,045	(37)	(1.8)%
Total Regulated Utility Kilowatt-hours Sold	7,330	7,268	62	0.9 %

Revenue from electric sales to taconite and iron concentrate customers accounted for 21 percent of consolidated operating revenue in 2018 (22 percent in 2017). Revenue from electric sales to paper, pulp and secondary wood product customers accounted for 5 percent of consolidated operating revenue in 2018 (5 percent in 2017). Revenue from electric sales to pipelines and other industrial customers accounted for 7 percent of consolidated operating revenue in 2018 (7 percent in 2017).

Conservation improvement program recoveries increased $4.2 million from 2017 primarily due to an increase in related expenditures. (See Operating Expenses - Operating and Maintenance.)

Cost recovery rider revenue increased $2.6 million primarily due to higher expenditures related to the construction of the GNTL.

COMPARISON OF THE SIX MONTHS ENDED JUNE 30, 2018 AND 2017 (Continued)
Regulated Operations (Continued)

Operating Expenses increased $8.0 million or 2 percent from 2017.

Fuel, Purchased Power and Gas – Utility expense increased $7.7 million, or 4 percent, from 2017 primarily due to increased kWh sales and higher purchased power prices, partially offset by lower fuel costs. Fuel and purchased power expense related to our retail and municipal customers is recovered through the fuel adjustment clause.

Transmission Services – Utility expense increased $1.0 million, or 3 percent, from 2017 primarily due to higher MISO related expense. (See Operating Revenue – Utility.)

Operating and Maintenance expense decreased $3.0 million, or 3 percent, from 2017 primarily due to lower salary and benefit expenses, and lower materials purchased for generation facilities, partially offset by a $4.2 million increase in conservation improvement program expenses in 2018. Conservation improvement program expenses are recovered from certain retail customers. (See Operating Revenue – Utility.)

Taxes Other than Income Taxes increased $2.2 million, or 8 percent, from 2017 primarily due to higher property tax expenses resulting from higher taxable plant.

Interest Expense increased $1.5 million, or 5 percent, from 2017 primarily due to higher average long-term debt balances and interest rates. We record interest expense for Regulated Operations primarily based on rate base and authorized capital structure, and allocate the balance to Corporate and Other.

Equity Earnings in ATC decreased $2.4 million, or 21 percent, from 2017 primarily due to the federal income tax rate change due to the TCJA, partially offset by additional investments in ATC. (See Note 7. Investment in ATC.)

Income Tax Expense decreased $24.3 million from 2017 primarily due to the reduction of the federal income tax rate from 35 percent to 21 percent enacted as part of the TCJA, and lower pre-tax income. (See Note 6. Regulatory Matters.)

We expect our annual effective tax rate in 2018 to be lower than 2017 due to the reduction of the federal income tax rate from 35 percent to 21 percent enacted as part of the TCJA, and lower pre-tax income.

ALLETE Clean Energy

Six Months Ended June 30,	2018	2017
Millions		
Operating Revenue	$42.9	$43.3
Net Income	$14.9	$10.5

Operating Revenue decreased $0.4 million, or 1 percent, from 2017 primarily due to lower kWh sales at most of ALLETE Clean Energy's wind energy facilities resulting from lower wind resources.

	Six Months Ended June 30,			
	2018		2017	
Production and Operating Revenue	kWh	Revenue	kWh	Revenue
Millions				
Wind Energy Facilities				
Lake Benton	119.4	$6.2	134.2	$6.6

Storm Lake II	79.6	5.2	83.2	5.2
Condon	58.3	4.7	44.8	3.7
Storm Lake I	103.8	6.2	119.1	6.4
Chanarambie/Viking	138.1	7.2	145.5	7.4
Armenia Mountain	147.0	13.4	150.2	14.0
Total Production and Operating Revenue	646.2	$42.9	677.0	$43.3

COMPARISON OF THE SIX MONTHS ENDED JUNE 30, 2018 AND 2017 (Continued)
ALLETE Clean Energy (Continued)

Net Income increased $4.4 million, or 42 percent, from 2017. Net income in 2018 included $4.5 million after-tax of additional production tax credits generated as ALLETE Clean Energy continues to execute its refurbishment strategy and a lower federal income tax rate due to the TCJA. Of the $4.5 million after-tax in additional production tax credits, $2.6 million resulted from the retrospective qualification of additional WTGs in 2016 and 2017. These increases were partially offset by higher operating and maintenance expenses, and lower revenue resulting from lower wind resources.

U.S. Water Services

Six Months Ended June 30,	2018	2017
Millions		
Operating Revenue	$79.7	$70.5
Net Income (Loss)	$(1.2)	$0.3

Operating Revenue increased $9.2 million, or 13 percent, from 2017 primarily due to the acquisition of Tonka Water in September 2017. Revenue from chemical sales and related services was $67.0 million in 2018 compared to $63.4 million in 2017. Revenue from capital projects was $12.7 million for 2018 compared to $7.1 million in 2017; capital project sales can significantly fluctuate from period to period.

Net Loss was $1.2 million in 2018 compared to net income of $0.3 million in 2017. The net loss in 2018 includes higher operating expenses, partially offset by increased revenue primarily resulting from the September 2017 acquisition of Tonka Water. The first six months of 2018 were also impacted by the timing of capital project sales and unfavorable weather conditions reducing chemical sales. The net loss in 2018 also included $0.5 million of after-tax expense recognized as cost of sales related to purchase accounting for sales backlog.

Corporate and Other

Operating Revenue decreased $6.9 million, or 12 percent, from 2017 primarily due to a decrease in revenue at BNI Energy, which operates under cost-plus fixed fee contracts, as a result of lower expenses in 2018 compared to 2017 and lower land sales at ALLETE Properties.

Net Loss was $1.3 million in 2018 compared to a net loss of $0.8 million in 2017. Results in 2018 decreased primarily due to additional income tax expense recorded in 2018 as GAAP requires the recognition of quarterly income tax expense at the estimated annual effective tax rate. The estimated annual effective tax rate can differ from what a quarterly effective tax rate would otherwise be on a stand-alone basis, and this may cause quarter to quarter differences in the timing of income taxes. This decrease was partially offset by lower operating and maintenance expenses at ALLETE Properties. Net income at BNI Energy was $3.6 million in 2018 compared to net income of $3.8 million in 2017. The net loss at ALLETE Properties was $1.1 million in 2018 compared to a net loss of $1.6 million in 2017.

Income Taxes – Consolidated

For the six months ended June 30, 2018, the effective tax rate was a benefit of 12.4 percent (expense of 19.2 percent for the six months ended June 30, 2017). The decrease from 2017 was primarily due to the reduction of the federal income tax rate from 35 percent to 21 percent enacted as part of the TCJA, and lower pre-tax income. (See Regulated Operations - Income Tax Expense.)

We expect our annual effective tax rate in 2018 to be lower than 2017 due to the reduction of the federal income tax rate as part of the TCJA, and lower pre-tax income. The effective rate deviated from the combined statutory rate of approximately 28 percent primarily due to production tax credits. (See Note 9. Income Tax Expense.)

CRITICAL ACCOUNTING POLICIES

Certain accounting measurements under GAAP involve management’s judgment about subjective factors and estimates, the effects of which are inherently uncertain. Accounting measurements that we believe are most critical to our reported results of operations and financial condition include: regulatory accounting, pension and postretirement health and life actuarial assumptions, impairment of long-lived assets, taxation, and valuation of goodwill and intangible assets. These policies are reviewed with the Audit Committee of our Board of Directors on a regular basis and summarized in Part II, Item 7. Management’s Discussion and Analysis of Financial Condition and Results of Operations of our 2017 Form 10-K.

Valuation of Goodwill and Intangible Assets.

Goodwill. Our 2017 annual testing of U.S. Water Services’ goodwill for impairment indicated the calculated fair value of equity for the reporting unit exceeded carrying value. Significant assumptions utilized in the fair value calculation included a discount rate of 10.75 percent, cash flow forecasts through 2022, annual revenue growth rates ranging from 7 percent to 9 percent, excluding 13 percent of revenue growth in 2018 related to the year over year impact of the acquisition of Tonka Water, and a terminal growth rate of 4.0 percent. If U.S. Water Services fails to meet expected cash flow forecasts by a nominal margin or there is an increase in interest rates that has a negative impact on the discount rate used in the Company’s valuation under the income approach, the results of our future tests could result in an impairment of goodwill; our next annual impairment test will occur in the fourth quarter of 2018. Subsequent to our 2017 annual impairment test, there have been no triggering events or indicators of impairment of goodwill.

OUTLOOK

For additional information see our 2017 Form 10-K.

ALLETE is an energy company committed to earning a financial return that rewards our shareholders, allows for reinvestment in our businesses and sustains growth. The Company has long-term objectives of achieving average annual earnings per share growth of 5 percent to 7 percent, and providing a dividend payout competitive with our industry. Regulated Operations is projected to have average annual earnings growth of 3 percent to 4 percent and our Energy Infrastructure and Related Services businesses are projected to have average annual earnings growth of 15 percent.

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 80 percent of total consolidated net income in 2018. 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.

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 approvals for transmission, renewable and environmental investments, as well as work with regulators to earn a fair rate of return.

OUTLOOK (Continued)

Regulatory Matters. Entities within our Regulated Operations segment are under the jurisdiction of the MPUC, FERC, PSCW and NDPSC. See Note 6. Regulatory Matters for discussion of regulatory matters within these jurisdictions.

2016 Minnesota General Rate Case. In November 2016, Minnesota Power filed a retail rate increase request with the MPUC which sought an average increase of approximately 9 percent for retail customers. The rate filing sought a return on equity of 10.25 percent and a 53.81 percent equity ratio. On an annualized basis, the requested final rate increase would have generated approximately $55 million in additional revenue. In December 2016, Minnesota Power filed a request to modify its original interim rate proposal, reducing its requested interim rate increase to $34.7 million from the original request of approximately $49 million due to a change in its electric sales forecast. In December 2016 orders, the MPUC accepted the November 2016 filing as complete and authorized an annual interim rate increase of $34.7 million beginning in January 2017.

In February 2017, Minnesota Power filed an additional request to further reduce its requested interim rate increase. In an April 2017 order, the MPUC approved Minnesota Power’s updated retail rate request resulting in a reduction in the annual interim rate increase to $32.2 million beginning in May 2017. As a result of working with intervenors and further developments as the rate review progressed, Minnesota Power’s final rate request was adjusted to approximately $49 million on an annualized basis. In an order dated March 12, 2018, the MPUC affirmed determinations made at a hearing on January 18, 2018, regarding Minnesota Power’s general rate case including allowing a return on common equity of 9.25 percent and a 53.81 percent equity ratio. Upon commencement of final rates, we expect additional revenue of approximately $13 million on an annualized basis. Final rates are expected to commence in the fourth quarter of 2018; interim rates will be collected through this period which are fully offset by the recognition of a corresponding reserve. Minnesota Power has recorded a reserve for an interim rate refund of $49.2 million as of June 30, 2018 ($32.3 million as of December 31, 2017). The MPUC also disallowed Minnesota Power’s regulatory asset for deferred fuel adjustment clause costs due to the anticipated adoption of a forward-looking fuel adjustment clause methodology resulting in a $19.5 million pre-tax charge to Fuel, Purchased Power and Gas – Utility in the fourth quarter of 2017.

As part of its decision in Minnesota Power’s 2016 general rate case, the MPUC extended the depreciable lives of Boswell Unit 3, Unit 4 and common facilities to 2050 primarily to mitigate rate increases for our customers, and shortened the depreciable lives of Boswell Unit 1 and Unit 2 to 2022, resulting in a net decrease to depreciation expense of approximately $25 million in the fourth quarter of 2017.

On April 2, 2018, Minnesota Power filed a petition with the MPUC requesting reconsideration of certain decisions in the MPUC’s order dated March 12, 2018, collectively representing approximately $20 million to $25 million in additional revenue on an annualized basis. Minnesota Power’s petition included requesting reconsideration of the allowed return on common equity, recovery of the prepaid pension asset in rate base, certain disallowed expenses, and certain transmission revenue adjustments. In an order dated May 29, 2018, the MPUC denied Minnesota Power’s petition for reconsideration and accepted a Minnesota Department of Commerce request for reconsideration reducing the depreciable lives of Boswell Unit 3, Unit 4 and common facilities to 2035 while utilizing the benefits of the lower federal income tax rate enacted as part of the TCJA to mitigate the impact on customer rates.

Energy-Intensive Trade-Exposed Customer Rates. An EITE customer ratemaking law was enacted in 2015, which established a Minnesota energy policy to have competitive rates for certain industries such as mining and forest products. In 2015, Minnesota Power filed a rate schedule petition with the MPUC for EITE customers and a corresponding rider for EITE cost recovery. In a March 2016 order, the MPUC dismissed the petition without prejudice. In June 2016, Minnesota Power filed a revised EITE petition with the MPUC which included additional information on the net benefits analysis, limits on eligible customers and term lengths for the EITE discount. The rate adjustments were intended to be revenue and cash flow neutral to Minnesota Power. The MPUC approved a reduction in rates for EITE customers in a December 2016 order and subsequently approved cost recovery in an April 2017 order; collection of the discount was subject to the MPUC’s review of Minnesota Power’s compliance filing implementing approval of a recovery mechanism, with the subsequent order issued in October 2017 that modified the April 2017 order. During 2017, Minnesota Power provided discounts of $8.6 million that were recorded as a regulatory asset.

OUTLOOK (Continued)
Regulatory Matters (Continued)

In September 2017, Minnesota Power informed its EITE customers that it had suspended the EITE discount due to a concern that it was not revenue and cash flow neutral to Minnesota Power based on an MPUC decision at a hearing in September 2017, as well as the interim rate reduction and decisions in its 2016 general rate case. Based on the MPUC's decisions at a hearing on January 18, 2018, as part of Minnesota Power's 2016 general rate case, Minnesota Power reinstated the EITE discount effective January 1, 2018. Minnesota Power expects the discount to EITE customers to be approximately $15 million annually based on EITE customer current operating levels. While interim rates are in effect for Minnesota Power's 2016 general rate case, discounts provided to EITE customers will offset interim rate refund reserves for non-EITE customers. Minnesota Power provided $3.8 million and $8.1 million of discounts to EITE customers during the quarter and six months ended June 30, 2018, respectively ($3.6 million and $5.9 million for the quarter and six months ended June 30, 2017, respectively).

2016 Wisconsin General Rate Case. SWL&P's current retail rates are based on a 2017 PSCW retail rate order effective since August 2017 that allows for a 10.5 percent return on common equity and a 55 percent equity ratio. SWL&P's retail rates prior to August 2017 were based on a 2012 PSCW retail rate order that provided for a 10.9 percent return on equity. On an annualized basis, SWL&P expects to collect additional revenue of $2.5 million under the 2017 PSCW retail rate order.

2018 Wisconsin General Rate Case. On May 25, 2018, SWL&P filed a rate increase request with the PSCW requesting an average increase of 2.7 percent for retail customers (2.0 percent increase in electric rates; 2.3 percent increase in natural gas rates; and 8.3 percent increase in water rates). The filing seeks an overall return on equity of 10.5 percent and a 55.41 percent equity ratio. On an annualized basis, this filing is expected to result in additional revenue of approximately $2.4 million.

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, pipeline and other industries. Approximately 49 percent of our regulated utility kWh sales in the six months ended June 30, 2018, were made to our industrial customers (49 percent in the six months ended June 30, 2017).

Taconite and Iron Concentrate. Minnesota Power's taconite customers are capable of producing up to approximately 41 million tons of taconite pellets annually. Taconite pellets produced in Minnesota are primarily shipped to North American steel making facilities that are part of the integrated steel industry. Steel produced from these North American facilities is used primarily in the manufacture of automobiles, appliances, pipe and tube products for the gas and oil industry, and in the construction industry. Historically, less than five percent of Minnesota taconite production has been exported outside of North America. Minnesota Power also has provided 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. These facilities have been idled since at least 2016. On July 17, 2018, ERP Iron Ore announced it would no longer seek to restart its operations within Minnesota Power's service territory. (See ERP Iron Ore / Magnetation.)

There has been a general historical correlation between U.S. steel production and Minnesota taconite production. The American Iron and Steel Institute, an association of North American steel producers, reported that U.S. raw steel production operated at approximately 76 percent of capacity during the first six months of 2018 compared to 74 percent in the first six months of 2017. The World Steel Association, an association of over 160 steel producers, national and regional steel industry associations, and steel research institutes representing approximately 85 percent of world steel production, projected U.S. steel consumption in 2018 will increase by approximately 3 percent compared to 2017.

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 $0.04, net of expected power marketing sales at current prices. Changes in wholesale electric prices or customer contractual demand nominations could impact this estimate. Minnesota Power proactively sells power in the wholesale power markets that is temporarily not required by industrial customers to optimize the value of its generating facilities. Long-term reductions in taconite production or a permanent shut down of a taconite customer may lead Minnesota Power to file a general rate case to recover lost revenue.

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

USS Corporation. In 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. USS Corporation returned its Minntac plant to full production in 2015, and in the first quarter of 2017, USS Corporation restarted its Keetac plant. 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.

United Taconite. In May 2017, Cliffs announced that production of a fully fluxed taconite pellet had started at its United Taconite facility. The product replaced a flux pellet previously made at Cliffs' indefinitely idled Empire operation in Michigan. United Taconite has the capability to produce approximately 5 million tons of taconite annually.

Northshore Mining. Cliffs has announced that it is investing further in Minnesota ore operations, specifically planning to invest approximately $80 million through 2020 to expand capacity for producing direct reduced-grade pellets at Northshore Mining. The additional direct reduced-grade pellets could be sold commercially or used to supply Cliff's planned hot briquetted iron production plant in Toledo, Ohio. Minnesota Power has a long-term PSA through 2031 with Silver Bay Power, which provides the majority of the electric service requirements for Northshore Mining. (See Silver Bay Power.)

Silver Bay Power. In 2016, Minnesota Power and Silver Bay Power entered into a long-term PSA through 2031. Silver Bay Power supplies approximately 90 MW of load to Northshore Mining, an affiliate of Silver Bay Power, which has been served predominately through self-generation by Silver Bay Power. Through 2019, Minnesota Power will supply Silver Bay Power with at least 50 MW of energy and Silver Bay Power has the option to purchase additional energy from Minnesota Power as it transitions away from self-generation. On December 31, 2019, Silver Bay Power will cease self-generation and Minnesota Power will supply the energy requirements for Silver Bay Power.

ERP Iron Ore / Magnetation. In 2015, Magnetation announced that it had filed voluntary petitions for reorganization under Chapter 11 of the Bankruptcy Code in the U.S. Bankruptcy Court for the District of Minnesota, citing the significant decrease in global iron ore prices and its existing capital structure. In 2016, Magnetation idled its Plant 2 facility in Bovey, Minnesota. In 2016, the bankruptcy court approved plans to idle Magnetation's Plant 4 facility near Grand Rapids, Minnesota, and its pellet plant in Reynolds, Indiana, as well as terminate Magnetation's pellet purchase agreement with AK Steel Corporation. Magnetation subsequently idled the facilities.

In January 2017, ERP Iron Ore purchased substantially all of Magnetation's assets pursuant to an asset purchase agreement approved by the bankruptcy court. On July 17, 2018, ERP Iron Ore filed voluntary petitions for reorganization under Chapter 11 of the Bankruptcy Code in the U.S. Bankruptcy Court for the District of Minnesota and announced that it would no longer seek to restart its operations within Minnesota Power's service territory. Minnesota Power has reserved for all receivables due from ERP Iron Ore.

Paper, Pulp and Secondary Wood Products. 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 2017. Lower levels of production are expected in 2018 as a result of the closure of the smaller of the two paper machines located at UPM Blandin in the fourth quarter of 2017. (See UPM Blandin.)

UPM Blandin. In October 2017, UPM-Kymmene Corporation announced that in light of the global market situation for graphic papers, and to sustain its competitiveness and leading position in the market, it planned to permanently close the smaller of UPM Blandin's two paper machines located in Grand Rapids, Minnesota; the closure was completed in the fourth quarter of 2017. Paper production related to the other paper machine is planned to continue at UPM Blandin. Minnesota Power provides electric and steam service to UPM Blandin.

Pipeline and Other Industries.

Husky Energy. On April 26, 2018, a fire at Husky Energy Inc.'s (Husky Energy) refinery in Superior, Wisconsin disrupted operations at the facility. Under normal operating conditions, SWL&P provides approximately 14 MW of average monthly demand to Husky Energy in addition to water service. The facility remains at minimal operations, and the refinery is not expected to resume normal operations for at least 18 to 24 months.

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

Prospective Additional Load. Minnesota Power is pursuing new wholesale and retail loads in and around its service territory. Currently, several companies in northeastern Minnesota continue to progress in the development of natural resource-based projects that represent long-term growth potential and load diversity for Minnesota Power. We cannot predict the outcome of these projects.

Nashwauk Public Utilities Commission. Mesabi Metallics is a retail customer of the Nashwauk Public Utilities Commission, and Minnesota Power has a wholesale electric contract with the Nashwauk Public Utilities Commission for electric service through at least December 2032. Mesabi Metallics filed for bankruptcy protection in 2016, under Chapter 11 of the Bankruptcy Code in the U.S. Bankruptcy Court for the District of Delaware. In June 2017, the bankruptcy court approved a settlement plan for a consortium led by Chippewa Capital Partners LLC to take control of the project, subject to certain stipulations. In December 2017, Mesabi Metallics emerged from bankruptcy under the ownership of Chippewa Capital Partners LLC.

PolyMet. PolyMet is planning to start a new copper-nickel and precious metal (non-ferrous) mining operation in northeastern Minnesota. In 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 Minnesota Department of Natural Resources (DNR) issued its Record of Decision in 2016, finding the final EIS adequate. The final EIS also requires Records of Decision by the federal agencies, which are expected in 2018, before final action can be taken on the required federal permits to construct and operate the mining operation.

In 2016, PolyMet submitted applications for water-related permits with the DNR and MPCA, an air quality permit with the MPCA, and a state permit to mine application with the DNR detailing its operational plans for the mine. On January 5, 2018, the DNR released PolyMet’s draft permit to mine and opened a public comment period through March 6, 2018. Public hearings were held in February 2018 to review the draft permit to mine, as well as the MPCA’s recently released draft water quality permit, draft air quality permit and draft water quality certification. On June 28, 2018, the U.S. Forest Service and PolyMet closed on a land exchange, which resulted in PolyMet obtaining surface rights to land needed to develop its mining operation. Minnesota Power could supply between 45 MW and 50 MW of load under a 10-year power supply contract with PolyMet that would begin upon start-up of operations.

EnergyForward. Minnesota Power is executing EnergyForward, a strategic plan for assuring reliability, protecting affordability and further improving environmental performance. The plan includes completed and planned investments in wind, solar, natural gas and hydroelectric power, construction of additional transmission capacity, the installation of emissions control technology and the idling of certain coal-fired generating facilities.

In July 2017, Minnesota Power submitted a resource package to the MPUC requesting approval of PPAs for the output of a 250 MW wind energy facility and a 10 MW solar energy facility as well as approval of a 250 MW natural gas energy PPA. These agreements are subject to MPUC approval of the construction of NTEC, a 525 MW to 550 MW combined cycle natural gas fired generating facility which will be jointly owned by Dairyland Power Cooperative and a subsidiary of ALLETE. Minnesota Power would purchase approximately 50 percent of the facility's output starting in 2025. In a September 2017 order, the MPUC approved Minnesota Power’s request to extend the next IRP filing deadline until October 1, 2019, and Minnesota Power’s request that approval for the natural gas energy PPA be decided through a contested case process. On July 2, 2018, an administrative law judge issued a recommendation that the MPUC deny approval of the NTEC agreements; the recommendation is not binding on the MPUC. On July 23, 2018, Minnesota Power filed exceptions to the administrative law judge’s recommendation. The MPUC is expected to hold a hearing in the fourth quarter of 2018 on NTEC. On June 18, 2018, Minnesota Power filed a separate petition for approval of the PPA for the output of a 10 MW solar energy facility located in central Minnesota. The MPUC has not taken any action regarding the wind energy PPA which will be refiled separately from the natural gas energy PPA.

Integrated Resource Plan. In 2015, Minnesota Power filed its 2015 IRP with the MPUC, which included 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 contained steps in Minnesota Power's EnergyForward strategic plan including the economic idling of Taconite Harbor Units 1 and 2 which occurred in 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. In a 2016 order, the MPUC approved Minnesota Power's 2015 IRP with modifications. The order accepted Minnesota Power's plans for Taconite Harbor, directed Minnesota Power to retire Boswell Units 1 and 2 no later than 2022, required an analysis of generation and demand response alternatives to be filed with a natural gas resource proposal, and required Minnesota Power to conduct request for proposals for additional wind, solar and demand response resource additions subject to further MPUC approvals. In 2016, Minnesota Power announced Boswell Units 1 and 2 will be retired, which is expected to occur in the fourth quarter of 2018. (See Note 6. Regulatory Matters.)

OUTLOOK (Continued)
EnergyForward (Continued)

Renewable Energy. Minnesota Power's 2015 IRP includes an update on its plans and progress in meeting the Minnesota renewable energy milestones through 2025. Minnesota Power continues to execute its renewable energy strategy through 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 and expects between 25 percent and 30 percent of its applicable retail and municipal energy sales will be supplied by renewable energy sources in 2018.

Minnesota Solar Energy Standard. Minnesota law requires at least 1.5 percent of total retail electric sales, excluding sales to certain 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 40 kW or less and community solar garden subscriptions.

Minnesota Power's solar energy supply consists of Camp Ripley, a 10 MW utility scale solar project at the Camp Ripley Minnesota Army National Guard base and training facility near Little Falls, Minnesota, and a community solar garden project in northeastern Minnesota, which is comprised of a 1 MW solar array owned and operated by a third party with the output purchased by Minnesota Power and a 40 kW solar array that is owned and operated by Minnesota Power. Minnesota Power believes Camp Ripley and the community solar garden arrays will meet approximately one third of the overall mandate with an increase in solar rebates and community solar garden subscriptions expected to meet a portion of the required small scale solar mandate. On June 18, 2018, Minnesota Power filed a petition for approval of a PPA for the output of a 10 MW solar energy facility located in central Minnesota.

Minnesota Power has approval for current cost recovery of investments and expenditures related to compliance with the Minnesota Solar Energy Standard. Currently, there is no approved customer billing rate for solar costs.

Wind Energy. Minnesota Power's wind energy facilities consist of Bison (497 MW) located in North Dakota, and Taconite Ridge (25 MW) located in northeastern Minnesota. Minnesota Power also has two long-term wind energy 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.

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.

Updated customer billing rates for the renewable cost recovery rider, which includes investments and expenditures related to Bison, were approved by the MPUC in a November 2017 order, which allows Minnesota Power to charge retail customers on a current basis for the costs of certain renewable investments plus a return on the capital invested. On June 5, 2018, Minnesota Power filed a renewable resources factor filing. Upon approval of the filing, Minnesota Power will be authorized to include updated billing rates on customer bills.

Tenaska PPA. In May 2017, Minnesota Power and an affiliate of Tenaska signed a long-term PPA that provides for Minnesota Power to purchase the energy and associated capacity from a 250 MW wind energy facility in southwest Minnesota for a 20-year period beginning in 2020. The agreement provides for the purchase of output from the facility at fixed energy prices. There are no fixed capacity charges, and Minnesota Power will only pay for energy as it is delivered. This agreement is subject to MPUC approval and construction of the wind energy facility.

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.

The third 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. 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.

OUTLOOK (Continued)
EnergyForward (Continued)

The fourth PPA 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 is subject to the construction of the GNTL. (See Great Northern Transmission Line.)

The fifth PPA provides for Minnesota Power to purchase 50 MW of capacity from Manitoba Hydro at fixed prices. The PPA began in June 2017 and expires in May 2020.

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, investments to enhance our own transmission facilities, investments in other transmission assets (individually or in combination with others) and our investment in ATC.

Great Northern Transmission Line. As a condition of the 250-MW long-term PPA entered into with Manitoba Hydro, construction of additional transmission capacity is required. As a result, Minnesota Power is constructing the GNTL, an approximately 220 mile 500-kV transmission line between Manitoba and Minnesota's Iron Range that was proposed by Minnesota Power and Manitoba Hydro in order to strengthen the electric grid, enhance regional reliability and promote a greater exchange of sustainable energy.

In 2015, a certificate of need was approved by the MPUC. Based on this approval, 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 cost recovery filings. (See Note 6. Regulatory Matters.) Also in 2015, the FERC approved our request to recover on construction work in progress related to the GNTL from Minnesota Power's wholesale customers. In a 2016 order, the MPUC approved the route permit for the GNTL which largely follows Minnesota Power's preferred route, including the international border crossing, and in 2016, the U.S. Department of Energy issued a presidential permit to cross the U.S. Canadian border, which was the final major regulatory approval needed before construction in the U.S. could begin. Site clearing and pre construction activities commenced in the first quarter of 2017 with construction expected to be completed in 2020. To date, most of the right-of-way has been cleared while foundation installation and transmission tower construction have commenced. The total project cost in the U.S., including substation work, is estimated to be between $560 million and $710 million, of which Minnesota Power's portion is expected to be between $300 million and $350 million; the difference will be recovered from a subsidiary of Manitoba Hydro as non-shareholder contributions to capital. Total project costs of $248.8 million have been incurred through June 30, 2018, of which $129.2 million has been recovered from a subsidiary of Manitoba Hydro.

Manitoba Hydro must obtain regulatory and governmental approvals related to a new transmission line in Canada known as the Manitoba-Minnesota Transmission Project (MMTP) that will connect with the GNTL. In 2015, Manitoba Hydro submitted the final preferred route and EIS for the MMTP to the Manitoba Conservation and Water Stewardship for siting and environmental approval, which remains pending. In 2016, Manitoba Hydro filed an application with the Canadian National Energy Board (NEB) requesting authorization to construct and operate the MMTP. The NEB determined that Manitoba Hydro's application was complete in December 2017, and held public hearings in June 2018. The NEB is required to make a decision on the MMTP by March 2019, but is not precluded from making a decision prior to that date. Approval of the Canadian federal cabinet is also required.

The MMTP is subject to legal and regulatory challenges which Minnesota Power is actively monitoring. Manitoba Hydro has informed Minnesota Power that it continues to work towards completing the MMTP on schedule. In order to meet the transmission in service requirements in PPAs with Minnesota Power, Manitoba Hydro has indicated that it would need to start construction of the MMTP in December 2018. We are unable to predict the outcome of the Canadian regulatory review process, including the timing thereof or whether any onerous conditions may be imposed, or the timing of the completion of the MMTP, including the impact of any delays that may result in construction schedule adjustments. Any significant delays in the MMTP construction schedule may result in Minnesota Power adjusting the GNTL construction schedule and impact the timing of capital expenditures and associated cost recovery under our transmission cost recovery rider.

Construction of Manitoba Hydro's Keeyask hydroelectric generation facility, which will provide the power to be sold under PPAs with Minnesota Power and transmitted on the MMTP and the GNTL, commenced in 2014 and is anticipated to be in service by early 2021.

OUTLOOK (Continued)
Transmission (Continued)

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 portions of Wisconsin, Michigan, Minnesota and Illinois. As of June 30, 2018, our equity investment in ATC was $123.6 million ($118.7 million as of December 31, 2017). In the first six months of 2018, we invested $3.9 million in ATC, and on July 31, 2018, we invested an additional $1.2 million. We expect to make additional investments of $1.3 million in 2018. (See Note 7. Investment in ATC.)

ATC's authorized return on equity is 10.32 percent, or 10.82 percent including an incentive adder for participation in a regional transmission organization. In 2016, a federal administrative law judge ruled on a complaint proposing a reduction in the base return on equity to 9.70 percent, or 10.20 percent including an incentive adder for participation in a regional transmission organization, subject to approval or adjustment by the FERC. A final decision from the FERC on the administrative law judge's recommendation is pending.

ATC's 10-year transmission assessment, which covers the years 2017 through 2026, identifies a need for between $2.8 billion and $3.6 billion in transmission system investments. These investments by ATC, if undertaken, 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.

Energy Infrastructure and Related Services.

ALLETE Clean Energy.

ALLETE Clean Energy 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 is contracted under PSAs of various durations. ALLETE Clean Energy also engages in the development of wind energy facilities to operate under long-term PSAs or for sale to others upon completion.

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. State renewable portfolio standards, and state or federal regulations to limit GHG emissions are examples of environmental regulation or public policy 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. ALLETE Clean Energy generally acquires facilities in liquid power markets and its strategy includes the exploration of PSA extensions upon expiration of existing contracts.

ALLETE Clean Energy will pursue growth through acquisitions or project development for others. ALLETE Clean Energy is targeting acquisitions of existing facilities up to 200 MW each, which have long-term PSAs in place for the facilities' output. At this time, ALLETE Clean Energy expects acquisitions or development of new facilities will be primarily wind or solar facilities in North America. ALLETE Clean Energy is also targeting the development of new facilities up to 200 MW each, which will have long-term PSAs in place for the output or may be sold upon completion.

Federal production tax credit qualification is important to the economics of project development, and in late 2016 and late 2017, ALLETE Clean Energy invested in equipment to meet production tax credit safe harbor provisions which provides an opportunity to seek development of up to approximately 1,500 MW of production tax credit qualified wind projects through 2021. ALLETE Clean Energy will also invest approximately $80 million through 2020 for production tax credit requalification of up to 385 WTGs at its Storm Lake I, Storm Lake II and Lake Benton wind energy facilities. We anticipate annual production tax credits relating to these projects of approximately $5 million in 2018, $10 million in 2019, and $15 million to $20 million annually in 2020 through 2027 and decreasing thereafter through 2030.

In January 2017, ALLETE Clean Energy announced that it will develop a wind energy facility of up to 50 MW which will be sold to Montana-Dakota Utilities; construction and sale is expected to be completed in the second half of 2018. Revenue is expected to be recognized upon completion; if the wind energy facility is not completed and sold in 2018, revenue and related margins would be recognized in 2019. ALLETE Clean Energy constructed and sold a 107 MW wind energy facility to Montana-Dakota Utilities in 2015.

OUTLOOK (Continued)
ALLETE Clean Energy (Continued)

In March 2017, ALLETE Clean Energy announced it will build, own and operate a 100 MW wind energy facility pursuant to a 20-year PSA with Northern States Power; construction is expected to be completed in 2019. On March 15, 2018, ALLETE Clean Energy announced that it will build, own and operate an 80 MW wind energy facility pursuant to a 15-year PSA with NorthWestern Corporation; construction is expected to be completed in 2019.

ALLETE Clean Energy manages risk by having a diverse portfolio of assets, which includes PSA expiration, technology and geographic diversity. The current portfolio of approximately 535 MW is subject to typical variations in seasonal wind with higher wind resources typically available in the winter months. The majority of its planned maintenance leverages this seasonality and is performed during lower wind periods. The current mix of PSA expiration and geographic location for existing facilities is as follows:

Wind Energy Facility	Location	Capacity MW	PSA MW %	PSA Expiration
Armenia Mountain	Pennsylvania	100.5	100%	2024
Chanarambie/Viking	Minnesota	97.5		
PSA 1			12%	2018
PSA 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		
PSA 1			90%	2019
PSA 2			10%	2032

U.S. Water Services.

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 has a presence in 49 states and Canada, and has an established base of approximately 4,900 customers. U.S. Water Services differentiates itself from the competition by developing synergies between solutions in engineering, equipment and chemical water treatment, which helps 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 commercial and institutional markets, food and beverage, light manufacturing, power generation, and midstream oil and gas industries, among others. U.S. Water Services principally relies upon recurring revenues from a diverse mix of industrial customers. U.S. Water Services sells certain products which are seasonal in nature, with higher demand typically realized in warmer months; generally, lower sales occur in the first quarter of each year.

Our strategy is to grow U.S. Water Services' presence in North America by adding customers, products, markets 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 purchase prices between $10 million and $50 million. Priority will be given to acquisitions which expand its geographic reach, add new technology, or deepen its capabilities to serve its expanding customer base.

In September 2017, U.S. Water Services acquired Tonka Water for total consideration of $19.2 million. Tonka Water is a supplier of municipal and industrial water treatment systems that will expand U.S. Water Services' geographic and customer markets.

U.S. Water Services expects cash flow from operations of approximately $15 million in 2018 ($12 million in 2017). Cash flow in 2018 could be impacted by the timing of equipment sales.

Corporate and Other.

BNI Energy. BNI Energy anticipates selling 4.4 million tons of lignite coal in 2018 (4.7 million tons were sold in 2017) and has sold 2.3 million tons for the six months ended June 30, 2018 (2.3 million tons were sold for the six months ended June 30, 2017). BNI Energy operates under cost-plus fixed fee agreements extending through December 31, 2037.

OUTLOOK (Continued)
Corporate and Other (Continued)

ALLETE Properties. ALLETE Properties represents our legacy Florida real estate investment. ALLETE Properties' major projects in Florida are Town Center at Palm Coast and Palm Coast Park, with approximately 1,900 acres combined of land available for sale. In addition to these two projects, ALLETE Properties has approximately 800 acres of other land available for sale. Market conditions can impact land sales and could result in our inability to cover our cost basis and operating expenses including fixed carrying costs such as community development district assessments and property taxes.

Our revised strategy incorporates the possibility of a bulk sale of ALLETE Properties entire portfolio. Proceeds from a bulk sale would be strategically deployed to support growth in ALLETE Clean Energy and U.S. Water Services, collectively our Energy Infrastructure and Related Services businesses. ALLETE Properties continues to pursue sales of individual parcels over time and will continue to maintain key entitlements and infrastructure without making additional investments or acquisitions.

Income Taxes.

ALLETE's aggregate federal and multi-state statutory tax rate is approximately 28 percent for 2018. ALLETE also has tax credits and other tax adjustments that reduce the combined 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 income taxes, state and federal tax law changes that become effective during the year, business combinations, tax planning initiatives and resolution of prior years' tax matters. We expect our effective tax rate to be a benefit of approximately 10 percent for 2018 primarily due to a lower statutory tax rate resulting from the TCJA, and federal production tax credits as a result of wind energy generation. We also expect that our effective tax rate will be lower than the combined statutory rate over the next 12 years due to production tax credits attributable to our wind energy generation.

We expect the federal income tax rate change of the TCJA to result in lower income tax expense on an ongoing basis for our Regulated Operations, ALLETE Clean Energy and U.S. Water Services segments as well as our Corporate and Other businesses. The lower income tax expense for our Regulated Operations segment is mostly offset by lower revenue as the benefit of the TCJA is being returned to customers under regulatory proceedings with the MPUC and PSCW. (See Note 6. Regulatory Matters.) We do not expect a material impact on the Company's ability to utilize its federal and state NOL and tax credit carryforwards due to the TCJA.

LIQUIDITY AND CAPITAL RESOURCES

Liquidity Position. ALLETE is well-positioned to meet the Company's liquidity needs. As of June 30, 2018, we had cash and cash equivalents of $121.9 million, $394.7 million in available consolidated lines of credit and a debt-to-capital ratio of 42 percent.

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

	June 30, 2018	%	December 31, 2017	%
Millions				
Shareholders' Equity	$2,108.2	58	$2,068.2	58

Long-Term Debt (Including Long-Term Debt Due Within One Year)	1,528.8	42	1,513.3	42
	$3,637.0	100	$3,581.5	100

LIQUIDITY AND CAPITAL RESOURCES (Continued)

Cash Flows. Selected information from the Consolidated Statement of Cash Flows is as follows:

For the Six Months Ended June 30,	2018	2017
Millions		
Cash, Cash Equivalents and Restricted Cash at Beginning of Period	$110.1	$38.3
Cash Flows from (used for)		
Operating Activities	194.4	184.4
Investing Activities	(138.5)	(84.7)
Financing Activities	(33.2)	(41.5)
Change in Cash, Cash Equivalents and Restricted Cash	22.7	58.2
Cash, Cash Equivalents and Restricted Cash at End of Period	$132.8	$96.5

Operating Activities. Cash from operating activities was higher in 2018 compared to 2017 primarily due to higher amounts collected from customers under cost recovery riders which are anticipated to be refunded in future periods and higher accounts payable due to timing of payments. These increases were partially offset by higher contributions to the defined benefit pension plans.

Investing Activities. Cash used for investing activities was higher in 2018 compared to 2017 primarily due to higher capital expenditures.

Financing Activities. Cash used for financing activities was lower in 2018 due to lower repayments of long-term debt and lower contingent consideration payments. These decreases in cash used for financing activities were partially offset by higher dividends on common stock as well as lower proceeds from the issuance of common stock and long-term debt.

Working Capital. Additional working capital, if and when needed, generally is provided by consolidated bank lines of credit and the issuance of securities, including long-term debt, common stock and commercial paper. As of June 30, 2018, we had consolidated bank lines of credit aggregating $407.0 million ($407.0 million as of December 31, 2017), the majority of which expire in October 2020. We had $12.3 million outstanding in standby letters of credit and no outstanding draws under our lines of credit as of June 30, 2018 (