INTEGRYS HOLDING, INC.

FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2018

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GLOSSARY OF TERMS AND ABBREVIATIONS

The abbreviations and terms set forth below are used throughout this report and have the meanings assigned to them below:

Subsidiaries and Affiliates	
ATC	American Transmission Company LLC
Bluewater	Bluewater Natural Gas Holding, LLC
ITF	Integrys Transportation Fuels, LLC
MERC	Minnesota Energy Resources Corporation
MGU	Michigan Gas Utilities Corporation
NSG	North Shore Gas Company
PDL	WPS Power Development, LLC
PELLC	Peoples Energy, LLC
PGL	The Peoples Gas Light and Coke Company
UMERC	Upper Michigan Energy Resources Corporation
WBS	WEC Business Services LLC
WE	Wisconsin Electric Power Company
WEC Energy Group	WEC Energy Group, Inc.
WG	Wisconsin Gas LLC
WPS	Wisconsin Public Service Corporation
WPSI	WPS Investments, LLC
WRPC	Wisconsin River Power Company

Federal and State Regulatory Agencies	
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
ICC	Illinois Commerce Commission
MPSC	Michigan Public Service Commission
MPUC	Minnesota Public Utilities Commission
PSCW	Public Service Commission of Wisconsin
WDNR	Wisconsin Department of Natural Resources

Accounting Terms	
AFUDC	Allowance for Funds Used During Construction
ARO	Asset Retirement Obligation
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
CWIP	Construction Work In Progress
FASB	Financial Accounting Standards Board
GAAP	Generally Accepted Accounting Principles
LIFO	Last-In, First-Out
OPEB	Other Postretirement Employee Benefits

Environmental Terms	
CAA	Clean Air Act
CO_2	Carbon Dioxide
CPP	Clean Power Plan
GHG	Greenhouse Gas
NOV	Notice of Violation
WPDES	Wisconsin Pollutant Discharge Elimination System

Measurements

Dth	Dekatherm
MW	Megawatt
MWh	Megawatt-hour

Other Terms and Abbreviations

AIA	Affiliated Interest Agreement
CNG	Compressed Natural Gas
Compensation Committee	Compensation Committee of the Board of Directors of WEC Energy Group, Inc.
D.C. Circuit Court of Appeals	United States Court of Appeals for the District of Columbia Circuit
FTR	Financial Transmission Right
MISO	Midcontinent Independent System Operator, Inc.
MISO Energy Markets	MISO Energy and Operating Reserves Market
QIP	Qualifying Infrastructure Plant
ROE	Return on Equity
SMP	Natural Gas System Modernization Program
Supreme Court	United States Supreme Court
Tax Legislation	Tax Cuts and Jobs Act of 2017
VITA	Variable Income Tax Adjustment Rider

FINANCIAL STATEMENTS AND NOTES

A. INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Shareholder of Integrys Holding, Inc.:

Milwaukee, Wisconsin

We have audited the accompanying consolidated financial statements of Integrys Holding, Inc. and its subsidiaries (the "Company"), which comprise the consolidated balance sheets and the consolidated statements of capitalization as of December 31, 2018 and 2017, and the related consolidated income statements, consolidated statements of comprehensive income, consolidated statements of equity, and consolidated statements of cash flows for the three years ended December 31, 2018, and the related notes to the consolidated financial statements.

Management's Responsibility for the Consolidated Financial Statements

Management is responsible for the preparation and fair presentation of these consolidated financial statements in accordance with accounting principles generally accepted in the United States of America; this includes the design, implementation, and maintenance of internal control relevant to the preparation and fair presentation of consolidated financial statements that are free from material misstatement, whether due to fraud or error.

Auditors' Responsibility

Our responsibility is to express an opinion on these consolidated financial statements based on our audits. We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the consolidated financial statements are free from material misstatement.

An audit involves performing procedures to obtain audit evidence about the amounts and disclosures in the consolidated financial statements. The procedures selected depend on the auditor’s judgment, including the assessment of the risks of material misstatement of the consolidated financial statements, whether due to fraud or error. In making those risk assessments, the auditor considers internal control relevant to the Company's preparation and fair presentation of the consolidated financial statements in order to design audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control. Accordingly, we express no such opinion. An audit also includes evaluating the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements.

We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Opinion

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of Integrys Holding, Inc. and its subsidiaries as of December 31, 2018 and 2017, and the results of their operations and their cash flows for the three years ended December 31, 2018, in accordance with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP

Milwaukee, Wisconsin
March 26, 2019

INTEGRYS HOLDING, INC.

B. CONSOLIDATED INCOME STATEMENTS

Year Ended December 31 *(in millions)*	2018	2017	2016
Operating revenues	**$ 3,344.7**	$ 3,264.9	$ 3,088.9
Operating expenses			
Cost of sales	**1,315.4**	1,228.1	1,080.7
Other operation and maintenance	**1,028.4**	1,016.0	1,138.0
Depreciation and amortization	**338.7**	320.3	283.5
Property and revenue taxes	**72.3**	75.1	71.8
Total operating expenses	**2,754.8**	2,639.5	2,574.0
Operating income	**589.9**	625.4	514.9
Equity in earnings of transmission affiliate	**—**	93.8	82.2
Other income, net	**29.6**	36.7	33.2
Interest expense	**150.8**	144.0	134.2
Other expense	**(121.2)**	(13.5)	(18.8)
Income before income taxes	**468.7**	611.9	496.1
Income tax expense	**123.4**	221.5	196.7
Net income attributed to common shareholder	**$ 345.3**	$ 390.4	$ 299.4

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

INTEGRYS HOLDING, INC.

C. CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year Ended December 31 *(in millions)*	2018	2017	2016
Net income	**$ 345.3**	$ 390.4	$ 299.4
Other comprehensive income (loss), net of tax			
Derivatives accounted for as cash flow hedges			
Reclassification of net losses to net income, net of tax	**0.6**	0.5	0.6
Cumulative effect adjustment from adoption of ASU 2018-02	**(0.2)**	—	—
Cash flow hedges, net	**0.4**	0.5	0.6
Defined benefit plans			
Pension and OPEB adjustments arising during the period, net of tax	**(2.2)**	1.0	0.2
Amortization of pension and OPEB costs included in net periodic benefit cost, net of tax of $2.0, $3.0, and $2.9, respectively	**5.1**	4.3	4.3
Cumulative effect adjustment from adoption of ASU 2018-02	**(3.0)**	—	—
Defined benefit plans, net	**(0.1)**	5.3	4.5
Other comprehensive income, net of tax	**0.3**	5.8	5.1
Comprehensive income attributed to common shareholder	**$ 345.6**	$ 396.2	$ 304.5

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

INTEGRYS HOLDING, INC.

D. CONSOLIDATED BALANCE SHEETS

At December 31 *(in millions, except share and per share data)*	2018	2017
Assets		
Current assets		
Cash and cash equivalents	**$ 24.7**	$ 19.3
Accounts receivable and unbilled revenues, net of reserves of $89.6 and $84.8, respectively	**665.0**	668.1
Receivables from related parties	**59.3**	15.6
Materials, supplies, and inventories	**244.2**	238.0
Notes receivable from related party	**139.5**	278.2
Prepaid taxes	**41.5**	57.5
Other	**78.6**	57.6
Current assets	**1,252.8**	1,334.3
Long-term assets		
Property, plant, and equipment, net of accumulated depreciation of $3,541.8 and $3,442.5, respectively	**9,128.8**	8,460.4
Regulatory assets	**1,466.7**	1,385.7
Equity investment in transmission affiliate	**—**	621.1
Goodwill	**635.8**	635.8
Other	**361.5**	333.5
Long-term assets	**11,592.8**	11,436.5
Total assets	**$ 12,845.6**	$ 12,770.8
Liabilities and Equity		
Current liabilities		
Short-term debt	**$ 479.5**	$ 533.0
Current portion of long-term debt	**75.0**	255.0
Accounts payable	**479.7**	435.4
Payables to related parties	**109.8**	66.2
Accrued taxes	**63.0**	107.9
Customer credit balances	**87.6**	79.6
Other	**160.0**	163.6
Current liabilities	**1,454.6**	1,640.7
Long-term liabilities		
Long-term debt	**3,402.7**	2,994.6
Deferred income taxes	**1,129.9**	1,146.9
Deferred investment tax credits	**55.9**	57.8
Regulatory liabilities	**1,540.2**	1,479.2
Environmental remediation liabilities	**525.4**	557.7
Pension and OPEB obligations	**188.2**	209.8
AROs	**381.5**	501.7
Other	**177.6**	178.2
Long-term liabilities	**7,401.4**	7,125.9
Commitments and contingencies (Note 22)		
Common stock – $0.01 par value; 10,000 shares authorized, 1,020 shares issued and outstanding	**—**	—
Additional paid in capital	**2,301.5**	2,664.9
Retained earnings	**1,705.3**	1,356.8
Accumulated other comprehensive loss	**(17.2)**	(17.5)
Total common shareholder's equity	**3,989.6**	4,004.2
Total liabilities and equity	**$ 12,845.6**	$ 12,770.8

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

INTEGRYS HOLDING, INC.

E. CONSOLIDATED STATEMENTS OF CASH FLOWS

Year Ended December 31 *(in millions)*	2018	2017	2016
Operating activities			
Net income	**$ 345.3**	$ 390.4	$ 299.4
Reconciliation to cash provided by operating activities			
Depreciation and amortization	**338.7**	320.3	283.5
Deferred income taxes and investment tax credits, net	**144.2**	237.5	257.0
Contributions and payments related to pension and OPEB plans	**(61.1)**	(70.2)	(2.4)
Equity income in transmission affiliate, net of distributions	**—**	(9.3)	(26.0)
Cash paid for benefit-related transfers with WBS	**(0.3)**	(36.7)	(31.2)
Change in –			
Accounts receivable and unbilled revenues	**(70.2)**	(34.1)	(124.3)
Materials, supplies, and inventories	**(5.9)**	32.7	58.9
Prepaid taxes	**15.9**	(5.8)	70.5
Other current assets	**31.0**	5.3	1.6
Accounts payable	**160.5**	(10.3)	(8.6)
Accrued taxes	**(34.0)**	44.3	25.1
Other current liabilities	**3.6**	37.2	(21.6)
Other, net	**46.9**	(73.3)	22.7
Net cash provided by operating activities	**914.6**	828.0	804.6
Investing activities			
Capital expenditures	**(1,092.2)**	(960.0)	(665.6)
Acquisition of Forward Wind Energy Center	**(77.1)**	—	—
Proceeds from the sale of assets and businesses	**4.5**	4.3	99.7
Proceeds from assets transferred to WBS	**0.1**	25.5	7.6
Payments for assets transferred from WBS	**(70.6)**	(46.1)	(95.0)
Proceeds from the sale of investments held in rabbi trust	**118.6**	8.7	1.7
Purchase of investments held in rabbi trust	**(65.0)**	(3.7)	(59.2)
Short-term notes receivable from related parties, net	**138.7**	(278.2)	14.8
Capital contributions to transmission affiliate	**—**	(34.1)	(23.9)
Other, net	**(0.8)**	3.5	(2.6)
Net cash used in investing activities	**(1,043.8)**	(1,280.1)	(722.5)
Financing activities			
Issuance of common stock to parent	**—**	—	66.4
Retirement of long-term debt	**(369.9)**	(125.0)	(278.6)
Issuance of long-term debt	**600.0**	310.0	200.0
Repayment of loan	**—**	—	(28.6)
Change in short-term debt	**(53.5)**	305.0	(77.5)
Short-term debt to related parties, net	**—**	(42.0)	(53.1)
Other, net	**(4.4)**	(4.1)	(1.9)
Net cash provided by (used in) financing activities	**172.2**	443.9	(173.3)
Net change in cash, cash equivalents, and restricted cash	**43.0**	(8.2)	(91.2)
Cash, cash equivalents, and restricted cash at beginning of year	**39.0**	47.2	138.4
Cash, cash equivalents, and restricted cash at end of year	**$ 82.0**	$ 39.0	$ 47.2

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

INTEGRYS HOLDING, INC.

F. CONSOLIDATED STATEMENTS OF EQUITY

(in millions, except per share data)	Common Stock	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Shareholder's Equity
Balance at December 31, 2015	$ —	$ 2,691.7	$ 667.0	$ (28.4)	$ 3,330.3
Net income attributed to common shareholder	—	—	299.4	—	299.4
Other comprehensive income	—	—	—	5.1	5.1
Issuance of common stock to parent	—	66.4	—	—	66.4
Transfer of our ownership in WBS to WEC Energy Group	—	(73.0)	—	—	(73.0)
Other	—	0.2	—	—	0.2
Balance at December 31, 2016	$ —	$ 2,685.3	$ 966.4	$ (23.3)	$ 3,628.4
Net income attributed to common shareholder	—	—	390.4	—	390.4
Other comprehensive income	—	—	—	5.8	5.8
Transfer of net assets to UMERC	—	(20.6)	—	—	(20.6)
Other	—	0.2	—	—	0.2
Balance at December 31, 2017	**$ —**	**$ 2,664.9**	**$ 1,356.8**	**$ (17.5)**	**$ 4,004.2**
Net income attributed to common shareholder	**—**	**—**	**345.3**	**—**	**345.3**
Other comprehensive income	**—**	**—**	**—**	**3.5**	**3.5**
Transfer of WPSI's ownership interest in ATC and related taxes	**—**	**(363.4)**	**—**	**—**	**(363.4)**
Cumulative effect adjustment from ASU 2018-02 adoption	**—**	**—**	**3.2**	**(3.2)**	**—**
Balance at December 31, 2018	**$ —**	**$ 2,301.5**	**$ 1,705.3**	**$ (17.2)**	**$ 3,989.6**

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

INTEGRYS HOLDING, INC.

G. CONSOLIDATED STATEMENTS OF CAPITALIZATION

At December 31 *(in millions)*			2018	2017
Common shareholder's equity (see accompanying statement)			**$ 3,989.6**	$ 4,004.2
Long-term debt	**Interest Rate**	**Year Due**		
WPS Senior Notes (unsecured)	1.65%	2018	**—**	250.0
	3.35%	2021	**400.0**	—
	6.08%	2028	**50.0**	50.0
	5.55%	2036	**125.0**	125.0
	3.671%	2042	**300.0**	300.0
	4.752%	2044	**450.0**	450.0
PGL First and Refunding Mortgage Bonds (secured) [1]	8.00%	2018	**—**	5.0
	4.63%	2019	**75.0**	75.0
	3.87%	2028	**150.0**	—
	3.90%	2030	**50.0**	50.0
	1.875%	2033	**50.0**	50.0
	4.00%	2033	**50.0**	50.0
	3.98%	2042	**100.0**	100.0
	3.96%	2043	**220.0**	220.0
	4.21%	2044	**200.0**	200.0
	3.65%	2046	**50.0**	50.0
	3.65%	2046	**150.0**	150.0
	3.77%	2047	**100.0**	100.0
NSG First Mortgage Bonds (secured) [2]	3.43%	2027	**28.0**	28.0
	3.87%	2028	**50.0**	—
	3.96%	2043	**54.0**	54.0
MGU Senior Notes (unsecured)	3.11%	2027	**30.0**	30.0
	3.41%	2032	**30.0**	30.0
	4.01%	2047	**30.0**	30.0
MERC Senior Notes (unsecured)	3.11%	2027	**40.0**	40.0
	3.41%	2032	**40.0**	40.0
	4.01%	2047	**40.0**	40.0
Integrys Senior Notes (unsecured)	4.17%	2020	**250.0**	250.0
Integrys Junior Notes (unsecured)	3.60%	2066	**—**	114.9
	6.00%	2073	**400.0**	400.0
Total			**3,512.0**	3,281.9
Unamortized debt issuance costs			**(33.6)**	(31.7)
Unamortized discount, net and other			**(0.7)**	(0.6)
Total long-term debt, including current portion			**3,477.7**	3,249.6
Current portion of long-term debt			**(75.0)**	(255.0)
Total long-term debt			**3,402.7**	2,994.6
Total long-term capitalization			**$ 7,392.3**	$ 6,998.8

[1] PGL's First Mortgage Bonds are subject to the terms and conditions of PGL's First Mortgage Indenture dated January 2, 1926, as supplemented. Under the terms of the Indenture, substantially all property owned by PGL is pledged as collateral for these outstanding debt securities.

PGL has used certain First Mortgage Bonds to secure tax exempt interest rates. The Illinois Finance Authority has issued Tax Exempt Bonds, and the proceeds from the sale of these bonds were loaned to PGL. In return, PGL issued equal principal amounts of certain collateralized First Mortgage Bonds.

[2] NSG's First Mortgage Bonds are subject to the terms and conditions of NSG's First Mortgage Indenture dated April 1, 1955, as supplemented. Under the terms of the Indenture, substantially all property owned by NSG is pledged as collateral for these outstanding debt securities.

The accompanying Notes to Consolidated Financial Statements are an integral part of these financial statements.

H. NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2018

NOTE 1—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Nature of Operations—As used in these notes, the term "financial statements" refers to the consolidated financial statements. This includes the income statements, statements of comprehensive income, balance sheets, statements of cash flows, statements of equity, and statements of capitalization, unless otherwise noted. In this report, when we refer to "us," "we," "our," or "ours," we are referring to Integrys Holding, Inc. (Integrys).

We are a wholly owned subsidiary of WEC Energy Group. Our financial statements include the accounts of Integrys, a diversified energy holding company, and the accounts of our subsidiaries in the following reportable segments:

- Wisconsin segment – Consists of WPS, which is engaged primarily in the generation of electricity and the distribution of electricity and natural gas in Wisconsin. WPS's electric and natural gas operations in the state of Michigan were also included in this segment prior to their transfer to UMERC, effective January 1, 2017.

- Illinois segment – Consists of PGL and NSG, which are engaged primarily in the distribution of natural gas in Illinois.

- Other states segment – Consists of MERC and MGU, which are engaged primarily in the distribution of natural gas in Minnesota and Michigan, respectively.

- Electric transmission segment – Consisted of our approximate 34% ownership interest in ATC, a for-profit, electric transmission company regulated by the FERC and certain state regulatory commissions, through December 31, 2017. In January 2018, we transferred our ownership in WPSI, which held our ownership interest in ATC, to another subsidiary of WEC Energy Group.

- Corporate and other segment – Consists of the Integrys holding company, the PELLC holding company, PDL, and ITF. During 2016, we completed the sale of ITF, and PDL sold both its natural gas-fired cogeneration facility and its landfill gas facility. In 2018, PDL also sold three of its distributed commercial and industrial solar projects. These PDL facilities were not significant to our operations. Effective January 1, 2016, we transferred our ownership in WBS to WEC Energy Group. This transaction was a non-cash equity transfer between entities under common control and, therefore, did not result in the recognition of a gain or loss. See Note 3, Disposition, for more information on the sale of ITF.

In December 2016, both the MPSC and the PSCW approved the operation of UMERC as a stand-alone utility owned by WEC Energy Group in the Upper Peninsula of Michigan, and UMERC became operational effective January 1, 2017. This utility holds the electric and natural gas distribution assets previously held by WPS, and the electric assets previously held by WE, located in the Upper Peninsula of Michigan. UMERC currently meets its market obligations through power purchase agreements with WPS and WE. UMERC will begin to generate electricity when its new generation solution in the Upper Peninsula of Michigan begins commercial operation, which is expected to occur on March 31, 2019. See Note 4, Related Parties, for more information on UMERC.

Our financial statements also reflect our proportionate interests in certain jointly owned utility facilities. See Note 8, Jointly Owned Utility Facilities, for more information. Investments in companies not controlled by us, but over which we have significant influence regarding the operating and financial policies of the investee, are accounted for using the equity method.

(b) Basis of Presentation—We prepare our financial statements in conformity with GAAP. We make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual results may differ from these estimates.

(c) Cash and Cash Equivalents—Cash and cash equivalents include marketable debt securities with an original maturity of three months or less.

(d) Operating Revenues—The following discussion includes our significant accounting policies related to operating revenues, including our adoption of ASU 2014-09, Revenues from Contracts with Customers. For additional required disclosures on disaggregation of operating revenues as required by this ASU, see Note 5, Operating Revenues.

Adoption of ASU 2014-09, Revenues from Contracts with Customers

On January 1, 2018, we adopted ASU 2014-09, Revenues from Contracts with Customers, and the related amendments. In accordance with the guidance, we recognize revenues when control of the promised goods or services is transferred to our customers in an amount that reflects the consideration we expect to be entitled to receive in exchange for those goods or services. These revenues include unbilled revenues, which are estimated using the amount of energy delivered to our customers but not billed until after the end of the period.

We adopted this standard using the modified retrospective method. Results for reporting periods beginning after January 1, 2018, are presented under the new standard. The comparative information has not been restated and continues to be reported under the accounting standards in effect for those periods. Adoption of the standard did not result in an adjustment to our opening retained earnings balance as of January 1, 2018, and we do not expect the adoption of the standard to have a material impact on our net income in future periods.

We adopted the following practical expedients and optional exemptions for the implementation of this standard:

- We elected to exclude from the transaction price any amounts collected from customers for all sales taxes and other similar taxes.
- When applicable, we elected to apply the standard to a portfolio of contracts with similar characteristics, primarily our tariff-based contracts, as we reasonably expect that the effects on the financial statements of applying this guidance to the portfolio would not differ materially from applying this guidance to the individual contracts.
- We elected to recognize revenue in the amount we have the right to invoice for performance obligations satisfied over time when the consideration received from a customer corresponds directly with the value provided to the customer during the same period.
- We elected to not disclose the remaining performance obligations of a contract that has an original expected duration of one year or less.
- We elected to apply this standard only to contracts that are not completed as of the date of initial application.

Revenues from Contracts with Customers

Electric Utility Operating Revenues

Electricity sales to residential and commercial and industrial customers are generally accomplished through requirements contracts, which provide for the delivery of as much electricity as the customer needs. These contracts represent discrete deliveries of electricity and consist of one distinct performance obligation satisfied over time, as the electricity is delivered and consumed by the customer simultaneously. For our Wisconsin residential and commercial and industrial customers, our performance obligation is bundled to consist of both the sale and the delivery of the electric commodity.

The transaction price of the performance obligations for residential and commercial and industrial customers is valued using the rates, charges, terms, and conditions of service included in the tariffs of our regulated electric utilities, which have been approved by state regulators. These rates often have a fixed component customer charge and a usage-based variable component charge. We recognize revenue for the fixed component customer charge monthly using a time-based output method. We recognize revenue for the usage-based variable component charge using an output method based on the quantity of electricity delivered each month. Our retail electric rates in Wisconsin include base amounts for fuel and purchased power costs, which also impact our revenues. The electric fuel rules set by the PSCW allow us to defer, for subsequent rate recovery or refund, under- or over-collections of actual fuel and purchased power costs that exceed a 2% price variance from the costs included in the rates charged to customers. Our electric utility monitors the deferral of under-collected costs to ensure that it does not cause them to earn a greater ROE than authorized by the PSCW.

Wholesale customers who resell power can choose to either bundle capacity and electricity services together under one contract with a supplier or purchase capacity and electricity separately from multiple suppliers. Furthermore, wholesale customers can choose to have our utility provide generation to match the customer's load, similar to requirements contracts, or they can purchase specified quantities of electricity and capacity. Contracts with wholesale customers that include capacity bundled with the delivery of

electricity contain two performance obligations, as capacity and electricity are often transacted separately in the marketplace at the wholesale level. When recognizing revenue associated with these contracts, the transaction price is allocated to each performance obligation based on its relative standalone selling price. Revenue is recognized as control of each individual component is transferred to the customer. Electricity is the primary product sold by our electric utility and represents a single performance obligation satisfied over time through discrete deliveries to a customer. Revenue from electricity sales is generally recognized as units are produced and delivered to the customer within the production month. Capacity represents the reservation of an electric generating facility and conveys the ability to call on a plant to produce electricity when needed by the customer. The nature of our performance obligation as it relates to capacity is to stand ready to deliver power. This represents a single performance obligation transferred over time, which generally represents a monthly obligation. Accordingly, capacity revenue is recognized on a monthly basis.

The transaction price of the performance obligations for wholesale customers is valued using the rates, charges, terms, and conditions of service, which have been approved by the FERC. These wholesale rates include recovery of fuel and purchased power costs from customers on a one-for-one basis. For the majority of our wholesale customers, the price billed for energy and capacity is a formula-based rate. Formula-based rates initially set a customer's current year rates based on the previous year’s expenses. This is a predetermined formula derived from the utility's costs and a reasonable rate of return. Because these rates are eventually trued up to reflect actual, current-year costs, they represent a form of variable consideration in certain circumstances. The variable consideration is estimated and recognized over time as wholesale customers receive and consume the capacity and electricity services.

We are an active participant in the MISO Energy Markets, where we bid our generation into the Day Ahead and Real Time markets and procure electricity for our retail and wholesale customers at prices determined by the MISO Energy Markets. Purchase and sale transactions are recorded using settlement information provided by MISO. These purchase and sale transactions are accounted for on a net hourly position. Net purchases in a single hour are recorded as purchased power in cost of sales and net sales in a single hour are recorded as resale revenues on our income statements. For resale revenues, our performance obligation is created only when electricity is sold into the MISO Energy Markets.

For all of our customers, consistent with the timing of when we recognize revenue, customer billings generally occur on a monthly basis, with payments typically due in full within 30 days.

Natural Gas Utility Operating Revenues

We recognize natural gas utility operating revenues under requirements contracts with residential, commercial and industrial, and transportation customers served under the tariffs of our regulated utilities. Tariffs provide our customers with the standard terms and conditions, including rates, related to the services offered. Requirements contracts provide for the delivery of as much natural gas as the customer needs. These requirements contracts represent discrete deliveries of natural gas and constitute a single performance obligation satisfied over time. Our performance obligation is both created and satisfied with the transfer of control of natural gas upon delivery to the customer. For most of our customers, natural gas is delivered and consumed by the customer simultaneously. A performance obligation can be bundled to consist of both the sale and the delivery of the natural gas commodity. In certain of our service territories, customers can purchase the commodity from a third party. In this case, the performance obligation only includes the delivery of the natural gas to the customer.

The transaction price of the performance obligations for our natural gas customers is valued using the rates, charges, terms, and conditions of service included in the tariffs of our regulated utilities, which have been approved by state regulators. These rates often have a fixed component customer charge and a usage-based variable component charge. We recognize revenue for the fixed component customer charge monthly using a time-based output method. We recognize revenue for the usage-based variable component charge using an output method based on natural gas delivered each month.

The tariffs of our natural gas utilities include various rate mechanisms that allow them to recover or refund changes in prudently incurred costs from rate case-approved amounts. The rates for all of our natural gas utilities include one-for-one recovery mechanisms for natural gas commodity costs. We defer any difference between actual natural gas costs incurred and costs recovered through rates as a current asset or liability. The deferred balance is returned to or recovered from customers at intervals throughout the year. In addition, the rates of PGL and NSG include riders for cost recovery or refund of uncollectible expense based on the difference between actual uncollectible write-offs and the amounts recovered in rates. The rates of PGL and NSG include riders for cost recovery of both environmental cleanup costs, energy conservation and management program costs, and income tax expense changes resulting from the Tax Legislation. Finally, PGL's rates include a cost recovery mechanism for SMP costs.

Consistent with the timing of when we recognize revenue, customer billings generally occur on a monthly basis, with payments typically due in full within 30 days.

Other Non-Utility Operating Revenues

A portion of our non-utility operating revenues are derived from servicing appliances for customers at MERC. These contracts customarily have a duration of one year or less and consist of a single performance obligation satisfied over time. We use a time-based output method to recognize revenues monthly for the service fee.

Other non-utility revenues are derived from distributed renewable solar projects, which consist primarily of sales of renewable energy and solar renewable energy certificates (SRECs) generated by PDL. The sale of SRECs is a distinct performance obligation as they are often sold separately from the renewable energy generated. Although the performance obligation for the sale of renewable energy is recognized over time and the performance obligation for SRECs is recognized at a point-in-time, the timing of revenue recognition is the same, as the generation of renewable energy and sales of SREC's occur concurrently.

Other Operating Revenues

Alternative Revenues

Alternative revenues are created from programs authorized by regulators that allow our utilities to record additional revenues by adjusting rates in the future, usually as a surcharge applied to future billings, in response to past activities or completed events. Alternative revenue programs allow compensation for the effects of weather abnormalities, other external factors, or demand side management initiatives. Alternative revenue programs can also provide incentive awards if the utility achieves certain objectives and in other limited circumstances. We record alternative revenues when the regulator-specified conditions for recognition have been met. We reverse these alternative revenues as the customer is billed, at which time this revenue is presented as revenues from contracts with customers.

Below is a summary of the alternative revenue programs at our utilities:

- The rates of PGL, NSG, and MERC include decoupling mechanisms. These mechanisms differ by state and allow the utilities to recover or refund the differences between actual and authorized margins for certain customer classes.
- MERC's rates include a conservation improvement program rider, which includes a financial incentive for meeting energy savings goals.
- WPS provides wholesale electric service to customers under market-based rates and FERC formula rates. The customer is charged a base rate each year based upon a formula using prior year actual costs and customer demand. A true-up is calculated based on the difference between the amount billed to customers for the demand component of their rates and what the actual cost of service was for the year. The true-up can result in an amount that we will recover from or refund to the customer. We consider the true-up portion of the wholesale electric revenues to be alternative revenues.

(e) Materials, Supplies, and Inventories—Our inventory as of December 31 consisted of:

(in millions)	2018	2017
Natural gas in storage	**$ 138.9**	$ 128.4
Materials and supplies	**75.5**	65.8
Fossil fuel	**29.8**	43.8
Total	**$ 244.2**	$ 238.0

PGL and NSG price natural gas storage injections at the calendar year average of the costs of natural gas supply purchased. Withdrawals from storage are priced on the LIFO cost method. Inventories stated on a LIFO basis represented approximately 35% and 34% of total inventories at December 31, 2018 and 2017, respectively. The estimated replacement cost of natural gas in inventory at December 31, 2018 and 2017, exceeded the LIFO cost by $72.4 million and $152.1 million, respectively. In calculating these replacement amounts, PGL and NSG used a Chicago city-gate natural gas price per Dth of $3.08 at December 31, 2018, and $4.68 at December 31, 2017.

Substantially all other natural gas in storage, materials and supplies, and fossil fuel inventories are recorded using the weighted-average cost method of accounting.

(f) Regulatory Assets and Liabilities—The economic effects of regulation can result in regulated companies recording costs and revenues that have been or are expected to be allowed in the rate-making process in a period different from the period in which the costs or revenues would be recognized by a nonregulated company. When this occurs, regulatory assets and regulatory liabilities are recorded on the balance sheet. Regulatory assets represent probable future revenues associated with certain costs or liabilities that have been deferred and are expected to be recovered through rates charged to customers. Regulatory liabilities represent amounts that are expected to be refunded to customers in future rates or amounts that are collected in rates for future costs.

Recovery or refund of regulatory assets and liabilities is based on specific periods determined by our regulators or occurs over the normal operating period of the assets and liabilities to which they relate. If at any reporting date a previously recorded regulatory asset is no longer probable of recovery, the regulatory asset is reduced to the amount considered probable of recovery with the reduction charged to expense in the reporting period the determination is made. See Note 6, Regulatory Assets and Liabilities, for more information.

(g) Property, Plant, and Equipment—We record property, plant, and equipment at cost. Cost includes material, labor, overhead, and both debt and equity components of AFUDC. Additions to and significant replacements of property are charged to property, plant, and equipment at cost; minor items are charged to other operation and maintenance expense. The cost of depreciable utility property less salvage value is charged to accumulated depreciation when property is retired.

We record straight-line depreciation expense over the estimated useful life of utility property using depreciation rates approved by the applicable regulators. Annual utility composite depreciation rates are shown below:

Annual Utility Composite Depreciation Rates	2018	2017	2016
WPS	**2.50%**	2.55%	2.58%
PGL	**3.25%**	3.29%	3.31%
NSG	**2.45%**	2.43%	2.44%
MERC *	**1.95%**	2.51%	2.53%
MGU	**2.61%**	2.61%	2.63%

* The 2018 rate reflects the impact of a new depreciation study approved by the MPUC in May 2018. The rates approved were effective retroactive to January 2017. An approximate $1.4 million reduction in depreciation expense was recorded in 2018 related to this depreciation study.

We capitalize certain costs related to software developed or obtained for internal use and record these costs to amortization expense over the estimated useful life of the related software, which ranges from 3 to 15 years. If software is retired prior to being fully amortized, the difference is recorded as a loss on the income statement.

Third parties reimburse us for all or a portion of expenditures for certain capital projects. Such contributions in aid of construction costs are recorded as a reduction to property, plant, and equipment.

See Note 7, Property, Plant, and Equipment, for more information.

(h) Allowance for Funds Used During Construction—AFUDC is included in utility plant accounts and represents the cost of borrowed funds (AFUDC – Debt) used during plant construction, and a return on shareholders' capital (AFUDC – Equity) used for construction purposes. AFUDC – Debt is recorded as a reduction of interest expense, and AFUDC – Equity is recorded in other income, net.

The majority of AFUDC is recorded at WPS. Approximately 50% of WPS's retail jurisdictional CWIP expenditures are subject to the AFUDC calculation. For 2018, WPS's average AFUDC retail rate was 7.72%, and its average AFUDC wholesale rate was 1.96%. The other utilities did not record significant AFUDC for 2018, 2017, or 2016.

Total AFUDC was as follows for the years ended December 31:

(in millions)	2018	2017	2016
AFUDC – Debt	**$ 1.9**	$ 1.6	$ 8.1
AFUDC – Equity	**4.6**	4.1	19.5

(i) Asset Impairment—Goodwill and other intangible assets with indefinite lives are subject to an annual impairment test. Interim impairment tests are performed when impairment indicators are present. Our reporting units containing goodwill perform annual goodwill impairment tests during the third quarter of each year. The carrying amount of the reporting unit's goodwill is considered not recoverable if the carrying amount of the reporting unit exceeds the reporting unit's fair value. An impairment loss is recorded for the excess of the carrying amount of the goodwill over its implied fair value. See Note 10, Goodwill and Other Intangible Assets, for more information. Intangible assets with definite lives are reviewed for impairment on a quarterly basis.

We periodically assess the recoverability of certain long-lived assets when factors indicate the carrying value of such assets may be impaired or such assets are planned to be sold. These assessments require significant assumptions and judgments by management. The long-lived assets assessed for impairment generally include certain assets within regulated operations that may not be fully recovered from our customers as a result of regulatory decisions that will be made in the future, as well as assets within nonregulated operations that are proposed to be sold or are currently generating operating losses. An impairment loss is recognized when the carrying amount of an asset is not recoverable and exceeds the fair value of the asset. The carrying amount of an asset is not recoverable if it exceeds the sum of the undiscounted cash flows expected to result from the use and eventual disposition of the asset. An impairment loss is measured as the excess of the carrying amount of the asset in comparison to the fair value of the asset.

When it becomes probable that a generating unit will be retired before the end of its useful life, we assess whether the generating unit meets the criteria for abandonment accounting. Generating units that are considered probable of abandonment are expected to cease operations in the near term, significantly before the end of their original estimated useful lives. If a generating unit meets the applicable criteria to be considered probable of abandonment, and the unit has been abandoned, we assess the likelihood of recovery of the remaining carrying value of that generating unit at the end of each reporting period. If it becomes probable that regulators will disallow full recovery as well as a return on the remaining net book value of a generating unit that is either abandoned or probable of being abandoned, an impairment loss may be required. An impairment loss would be recorded if the remaining carrying value of the generating unit is greater than the present value of the amount expected to be recovered from ratepayers. See Note 7, Property, Plant, and Equipment, for more information.

(j) Asset Retirement Obligations—We recognize, at fair value, legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development, and normal operation of the assets. An ARO liability is recorded, when incurred, for these obligations as long as the fair value can be reasonably estimated, even if the timing or method of settling the obligation is unknown. The associated retirement costs are capitalized as part of the related long-lived asset and are depreciated over the useful life of the asset. The ARO liabilities are accreted each period using the credit-adjusted risk-free interest rates associated with the expected settlement dates of the AROs. These rates are determined when the obligations are incurred. Subsequent changes resulting from revisions to the timing or the amount of the original estimate of undiscounted cash flows are recognized as an increase or a decrease to the carrying amount of the liability and the associated capitalized retirement costs. For our regulated entities, we recognize regulatory assets or liabilities for the timing differences between when we recover an ARO in rates and when we recognize the associated retirement costs. See Note 9, Asset Retirement Obligations, for more information.

(k) Emission Allowances—WPS accounts for emission allowances as inventory at average cost by vintage year. Charges to income result when allowances are used in operating WPS's generation plants. These charges are included in the costs subject to the fuel window rules. Gains on sales of allowances at WPS are returned to ratepayers.

(l) Stock-Based Compensation—Our employees participate in the WEC Energy Group stock-based compensation plans. In accordance with the WEC Energy Group shareholder approved WEC Energy Group 1993 Omnibus Stock Incentive Plan, Amended and Restated Effective as of January 1, 2016, WEC Energy Group provides long-term incentives through its equity interests to its non-employee directors, officers, and other key employees. The plan provides for the granting of stock options, restricted stock, performance shares, and other stock-based awards. Awards may be paid in WEC Energy Group common stock, cash, or a combination thereof. The number of shares of WEC Energy Group common stock authorized for issuance under the plan is 34.3 million.

Stock-based compensation expense is allocated to us based on the outstanding awards held by our employees and our allocation of labor costs. Awards classified as equity awards are measured based on their grant-date fair value. Awards classified as liability awards are recorded at fair value each reporting period. We account for forfeitures as they occur, rather than estimating potential future forfeitures and recording them over the vesting period.

Stock Options

Our employees are granted WEC Energy Group non-qualified stock options that generally vest on a cliff-basis after a three-year period. The exercise price of a stock option under the plan cannot be less than 100% of the fair market value of WEC Energy Group common stock on the grant date. Historically, all stock options have been granted with an exercise price equal to the fair market value of WEC Energy Group common stock on the date of the grant. Options may not be exercised within 6 months of the grant date except in the event of a change in control. Options expire no later than 10 years from the date of grant.

WEC Energy Group stock options are classified as equity awards. The fair value of each stock option was calculated using a binomial option-pricing model. The following table shows the estimated weighted-average fair value per stock option granted to our employees along with the weighted-average assumptions used in the valuation models:

	2018	2017	2016
Stock options granted	**45,740**	46,450	52,305
Estimated weighted-average fair value per stock option	**$ 7.77**	$ 7.44	$ 5.59
Assumptions used to value the options:			
Risk-free interest rate	**1.6% – 2.5%**	0.7% – 2.5%	0.4% – 1.8%
Dividend yield	**3.5%**	3.5%	4.0%
Expected volatility	**18.0%**	19.0%	18.0%
Expected life (years)	**6.0**	6.8	7.4

The risk-free interest rate was based on the United States Treasury interest rate with a term consistent with the expected life of the stock options. The dividend yield was based on WEC Energy Group's dividend rate at the time of the grant and historical stock prices. Expected volatility and expected life assumptions were based on WEC Energy Group's historical experience.

Restricted Shares

WEC Energy Group restricted shares granted to our employees have a three-year vesting period with one-third of the award vesting on each anniversary of the grant date. The restricted shares are classified as equity awards.

Performance Units

Officers and other key employees are granted performance units under the WEC Energy Group Performance Unit Plan. Under the plan, the ultimate number of units that will be awarded is dependent on WEC Energy Group's total shareholder return (stock price appreciation plus dividends) as compared to the total shareholder return of a peer group of companies over a three-year period, and beginning in 2017, other performance metrics as determined by the Compensation Committee. Participants may earn between 0% and 175% of the base performance unit award, as adjusted pursuant to the terms of the plan. Performance units also accrue forfeitable dividend equivalents in the form of additional performance units.

All grants of performance units are settled in cash and are accounted for as liability awards accordingly. The fair value of the performance units reflects our estimate of the final expected value of the awards, which is based on WEC Energy Group's stock price and performance achievement under the terms of the award. Stock-based compensation costs are recorded over the three-year performance period.

See Note 11, Common Equity, for more information on WEC Energy Group's stock-based compensation plans.

(m) Income Taxes—We follow the liability method in accounting for income taxes. Accounting guidance for income taxes requires the recording of deferred assets and liabilities to recognize the expected future tax consequences of events that have been reflected in our financial statements or tax returns and the adjustment of deferred tax balances to reflect tax rate changes. We are required to assess the likelihood that our deferred tax assets would expire before being realized. If we conclude that certain deferred tax assets are likely to expire before being realized, a valuation allowance would be established against those assets. GAAP requires that, if we conclude in a future period that it is more likely than not that some or all of the deferred tax assets would be realized before expiration, we reverse the related valuation allowance in that period. Any change to the allowance, as a result of a change in judgment about the realization of deferred tax assets, is reported in income tax expense.

Investment tax credits associated with regulated operations are deferred and amortized over the life of the assets. We and our subsidiaries are included in WEC Energy Group's consolidated federal and state income tax returns. In accordance with our tax allocation agreement with WEC Energy Group, we are allocated income tax payments and refunds based on our separate tax computation. See Note 15, Income Taxes, for more information.

We recognize interest and penalties accrued related to unrecognized tax benefits in income tax expense in our income statements.

In February 2018, the FASB issued ASU 2018-02, Income Statement - Reporting Comprehensive Income. The amendments in this update allow entities to reclassify the income tax effects that are stranded in accumulated other comprehensive income as a result of the Tax Legislation to retained earnings. These amendments are effective for fiscal years, and interim periods within those years, beginning after December 15, 2018, with early adoption permitted. We early adopted the amendments in the fourth quarter of 2018 and reclassified the stranded tax effects associated with the Tax Legislation from accumulated other comprehensive income to retained earnings. As of December 31, 2018, our accumulated other comprehensive income increased $3.2 million as a result of adopting ASU 2018-02, primarily related to our pension and post-retirement plans. The adoption of this guidance had no impact on our results of operations or cash flows.

(n) Fair Value Measurements—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).

Fair value accounting rules provide a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (Level 1 measurement) and the lowest priority to unobservable inputs (Level 3 measurement). The three levels of the fair value hierarchy are defined as follows:

Level 1 – Quoted prices are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 – Pricing inputs are observable, either directly or indirectly, but are not quoted prices included within Level 1. Level 2 includes those financial instruments that are valued using external inputs within models or other valuation methods.

Level 3 – Pricing inputs include significant inputs that are generally less observable from objective sources. These inputs may be used with internally developed methods that result in management's best estimate of fair value. Level 3 instruments include those that may be more structured or otherwise tailored to customers' needs.

Assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. We use a mid-market pricing convention (the mid-point price between bid and ask prices) as a practical measure for valuing certain derivative assets and liabilities. We primarily use a market approach for recurring fair value measurements and attempt to use valuation techniques that maximize the use of observable inputs and minimize the use of unobservable inputs.

When possible, we base the valuations of our derivative assets and liabilities on quoted prices for identical assets and liabilities in active markets. These valuations are classified in Level 1. The valuations of certain contracts not classified as Level 1 may be based on quoted market prices received from counterparties and/or observable inputs for similar instruments. Transactions valued using these inputs are classified in Level 2. Certain derivatives are categorized in Level 3 due to the significance of unobservable or internally-developed inputs.

We recognize transfers between levels of the fair value hierarchy at their value as of the end of the reporting period.

See Note 16, Fair Value Measurements, for more information.

(o) Derivative Instruments—We use derivatives as part of our risk management program to manage the risks associated with the price volatility of purchased power, generation, and natural gas costs for the benefit of our customers. Our approach is non-speculative and designed to mitigate risk. Our regulated hedging programs are approved by our state regulators.

We record derivative instruments on our balance sheets as assets or liabilities measured at fair value, unless they qualify for the normal purchases and sales exception, and are so designated. We continually assess our contracts designated as normal and will discontinue the treatment of these contracts as normal if the required criteria are no longer met. Changes in the derivative's fair value are recognized currently in earnings unless specific hedge accounting criteria are met or we receive regulatory treatment for the derivative. For most energy-related physical and financial contracts in our regulated operations that qualify as derivatives, our regulators allow the effects of fair value accounting to be offset to regulatory assets and liabilities.

We classify derivative assets and liabilities as current or long-term on our balance sheets based on the maturities of the underlying contracts. Cash flows from derivative activities are presented in the same category as the item being hedged within operating activities on our statements of cash flows.

Derivative accounting rules provide the option to present certain asset and liability derivative positions net on the balance sheets and to net the related cash collateral against these net derivative positions. We elected not to net these items. On our balance sheets, cash collateral provided to others is reflected in other current assets, and cash collateral received is reflected in other current liabilities. See Note 17, Derivative Instruments, for more information.

(p) Guarantees—We follow the guidance of the Guarantees Topic of the FASB ASC, which requires, under certain circumstances, that the guarantor recognize a liability for the fair value of the obligation undertaken in issuing the guarantee at its inception. See Note 18, Guarantees, for more information.

(q) Employee Benefits—The costs of pension and OPEB plans are expensed over the periods during which employees render service. These costs are distributed among WEC Energy Group's subsidiaries based on current employment status and actuarial calculations, as applicable. Our regulators allow recovery in rates for the utilities' net periodic benefit cost calculated under GAAP. See Note 19, Employee Benefits, for more information.

(r) Customer Deposits and Credit Balances—When utility customers apply for new service, they may be required to provide a deposit for the service. Customer deposits are recorded within other current liabilities on our balance sheets.

Utility customers can elect to be on a budget plan. Under this type of plan, a monthly installment amount is calculated based on estimated annual usage. During the year, the monthly installment amount is reviewed by comparing it to actual usage. If necessary, an adjustment is made to the monthly amount. Annually, the budget plan is reconciled to actual annual usage. Payments in excess of actual customer usage are presented as customer credit balances on our balance sheets.

(s) Environmental Remediation Costs—We are subject to federal and state environmental laws and regulations that in the future may require us to pay for environmental remediation at sites where we have been, or may be, identified as a potentially responsible party. Loss contingencies may exist for the remediation of hazardous substances at various potential sites, including coal combustion product landfill sites and manufactured gas plant sites. See Note 9, Asset Retirement Obligations, for more information regarding coal combustion product landfill sites and Note 22, Commitments and Contingencies, for more information regarding manufactured gas plant sites.

We record environmental remediation liabilities when site assessments indicate remediation is probable, and we can reasonably estimate the loss or a range of losses. The estimate includes both our share of the liability and any additional amounts that will not be paid by other potentially responsible parties or the government. When possible, we estimate costs using site-specific information but also consider historical experience for costs incurred at similar sites. Remediation efforts for a particular site generally extend over a period of several years. During this period, the laws governing the remediation process may change, as well as site conditions, potentially affecting the cost of remediation.

Our utilities have received approval to defer certain environmental remediation costs, as well as estimated future costs, through a regulatory asset. The recovery of deferred costs is subject to the applicable state Commission's approval.

We review our estimated costs of remediation annually for our manufactured gas plant sites and coal combustion product landfill sites. We adjust the liabilities and related regulatory assets, as appropriate, to reflect the new cost estimates. Any material changes in cost estimates are adjusted throughout the year.

(t) Customer Concentrations of Credit Risk—The geographic concentration of our customers in our service territories did not contribute significantly to our overall exposure to credit risk. We periodically review customers' credit ratings, financial statements,

and historical payment performance and require them to provide collateral or other security as needed. Credit risk exposure at PGL and NSG is mitigated by their rider for uncollectible expense discussed in Note 1(d), Operating Revenues. As a result, we did not have any significant concentrations of credit risk at December 31, 2018. In addition, there were no customers that accounted for more than 10% of our revenues for the year ended December 31, 2018.

(u) Subsequent Events—Subsequent events were evaluated for potential recognition or disclosure through March 26, 2019, which is the date the financial statements were available to be issued.

NOTE 2—ACQUISITION

On January 1, 2018, we adopted ASU 2017-01, Business Combinations (Topic 805): Clarifying the Definition of a Business (ASU 2017-01). The amendments in this update clarify the definition of a business and provide guidance on evaluating whether transactions should be accounted for as acquisitions (or disposals) of assets or businesses. ASU 2017-01 also clarifies that transaction costs are capitalized in an asset acquisition but expensed in a business combination.

Acquisition of a Wind Generation Facility in Wisconsin

In April 2018, WPS, along with two unaffiliated utilities, completed the purchase of Forward Wind Energy Center, which consists of 86 wind turbines located in Wisconsin with a total capacity of 138 MW. The aggregate purchase price was $172.9 million of which WPS's proportionate share was 44.6%, or $77.1 million. In addition, we incurred transaction costs that are recorded to a regulatory asset. Since 2008 and up until the acquisition, WPS purchased 44.6% of the facility's energy output under a power purchase agreement.

The table below shows the allocation of the purchase price to the assets acquired at the date of the acquisition, which are included in rate base.

(in millions)		
Current assets	**$**	**0.2**
Net property, plant, and equipment		**76.9**
Total purchase price	**$**	**77.1**

Under a joint ownership agreement with the two other utilities, WPS is entitled to its share of generating capability and output of the facility equal to its ownership interest. WPS is also paying its ownership share of additional capital expenditures and operating expenses. Forward Wind Energy Center is included in the Wisconsin segment.

NOTE 3—DISPOSITION

Corporate and Other Segment – Sale of Integrys Transportation Fuels

In February 2016, we sold ITF, a provider of CNG fueling services and a single-source provider of CNG fueling facility design, construction, operation, and maintenance. There was no gain or loss recorded on the sale, as ITF's assets and liabilities were adjusted to fair value, less costs to sell in 2015. The results of operations of ITF remained in continuing operations through the sale date as the sale of ITF did not represent a shift in our corporate strategy and did not have a major effect on our operations and financial results. We recognized income before income taxes from ITF of $5.8 million for the year ended December 31, 2016.

NOTE 4—RELATED PARTIES

We and our subsidiaries routinely enter into transactions with related parties, including WEC Energy Group, its other subsidiaries, ATC, and other affiliated entities.

We provide and receive services, property, and other items of value to and from our parent, WEC Energy Group, and other subsidiaries of WEC Energy Group.

Following our acquisition by WEC Energy Group on June 29, 2015, Integrys Business Support, LLC (IBS) changed its name to WEC Business Services LLC, and a new AIA (Non-WBS AIA) went into effect. The new Non-WBS AIA included the former Wisconsin Energy Corporation subsidiaries. It governed the provision and receipt of services by WEC Energy Group's subsidiaries, except that WBS continued to provide services to us and our subsidiaries only under the existing WBS AIAs. WBS provided services to WEC Energy

Group and the former Wisconsin Energy Corporation subsidiaries under interim WBS AIAs. The Non-WBS AIA included no other significant changes from the prior Non-IBS AIA. The PSCW and all other relevant state commissions approved the Non-WBS AIA or granted appropriate waivers related to the Non-WBS AIA.

Services under the Non-WBS AIA were subject to various pricing methodologies. All services provided by any regulated subsidiary to another regulated subsidiary were priced at cost. All services provided by any regulated subsidiary to any nonregulated subsidiary were priced at the greater of cost or fair market value. All services provided by any nonregulated subsidiary to any regulated subsidiary were priced at the lesser of cost or fair market value. All services provided by any regulated or nonregulated subsidiary to WBS were priced at cost.

WBS provided several categories of services (including financial, human resource, and administrative services) to us pursuant to the WBS AIAs, which were approved, or from which we were granted appropriate waivers, by the appropriate regulators, including the PSCW. As required by FERC regulations for centralized service companies, WBS renders services at cost. The PSCW must be notified prior to making changes to the services offered under and the allocation methods specified in the WBS AIAs. Other modifications or amendments to the WBS AIAs would require PSCW approval. Recovery of allocated costs is addressed in our rate cases.

A new AIA took effect January 1, 2017. The new agreement replaced the previous agreements. The pricing methodology and services under this new agreement are substantially identical to those under the agreements that were replaced. All of the applicable state commissions approved modifications to the new AIA to incorporate WEC Energy Group's acquisition of Bluewater. See below for more information about the Bluewater acquisition.

Effective January 1, 2016, we transferred our ownership in WBS to WEC Energy Group. This transaction was a $73.0 million non-cash equity transfer between entities under common control, and therefore, did not result in the recognition of a gain or loss.

Effective January 1, 2018, we transferred WPSI's ownership interest in ATC, and related taxes, to another subsidiary of WEC Energy Group. This transaction was a $363.4 million non-cash equity transfer between entities under common control, and therefore, did not result in the recognition of a gain or loss.

We pay ATC for transmission and other related services it provides. In addition, we provide a variety of operational, maintenance, and project management work for ATC, which is reimbursed by ATC. Services are billed to and from ATC under agreements approved by the PSCW, at each of our fully allocated costs.

WPS provides services to WRPC under an operating agreement approved by the PSCW. WPS is also under a service agreement with WRPC where it is billed for services provided by WRPC. Services are billed to and from WRPC under these agreements at a fully allocated cost.

Our balance sheets included the following receivables and payables related to transactions entered into with ATC:

(in millions)	**December 31, 2018**	**December 31, 2017**
Accounts receivable		
Services provided to ATC	**$ 1.2**	$ 0.7
Accounts payable		
Network transmission services from ATC	**8.8**	9.0

The following table shows activity associated with our related party transactions for the years ended December 31:

(in millions)	2018	2017	2016
Transactions with WE			
Natural gas sales to WE from WPS	**$ 1.9**	$ 1.6	$ 1.9
Billings to WE from WPS [1]	**10.9**	4.5	4.2
Billings from WE to WPS [1]	**17.8**	28.2	9.0
Transactions with WBS [1]			
Billings to WBS [2]	**48.2**	103.5	24.8
Billings from WBS [3]	**322.4**	457.7	377.0
Transactions with UMERC [4]			
Electric sales to UMERC from WPS	**15.8**	16.2	—
Natural gas sales to UMERC from WPS	**2.7**	2.5	—
Transactions with Bluewater [5]			
Storage service fees	**4.7**	0.3	—
Transactions related to ATC			
Charges to ATC for services and construction	**7.9**	6.2	8.6
Charges from ATC for network transmission services	**106.1**	107.8	109.4
Refund from ATC related to a FERC audit	**6.6**	—	—
Refund from ATC per FERC ROE order	**—**	8.9	—
Transactions with equity-method investees			
Rental payments to WRPC [6]	**1.3**	1.3	—
Purchases of energy from WRPC	**—**	0.5	3.7
Charges from WRPC for services	**2.4**	2.2	—
Charges to WRPC for operations	**1.2**	0.9	0.7

(1) Includes amounts billed for services, pass through costs, and other items in accordance with the approved AIAs.

(2) Includes $0.1 million and $25.5 million for the transfer of a PGL training facility to WBS for the years ended December 31, 2018 and 2017, respectively. Includes $7.6 million primarily for the transfer of certain software assets to WBS for the year ended December 31, 2016.

(3) Includes $70.6 million, $46.1 million, and $95.0 million for the transfer of certain software assets to us for the years ended December 31, 2018, 2017, and 2016, respectively. The year ended December 31, 2017, includes $36.7 million of cash paid related to pension trust assets transferred to us in conjunction with the Integrys pension plan split for the year ended December 31, 2017. Effective January 1, 2017, the Integrys Energy Group Retirement Plan was split into six separate plans. While the split did not impact our pension benefit obligation, federal regulations required a different allocation of assets among the new plans. Assets were transferred out of our plan in January 2017. See Note 19, Employee Benefits, for more information. Includes $0.3 million and $31.2 million for the transfer of certain benefit-related liabilities to WBS for the years ended December 31, 2018 and 2016, respectively.

(4) UMERC became operational effective January 1, 2017. See below for more information.

(5) WEC Energy Group's acquisition of Bluewater was completed June 30, 2017. See below for more information.

(6) In March 2017, WPS terminated its purchased power agreement with WRPC and entered into a lease agreement with WRPC to lease 50% of its hydroelectric power generation facilities.

We manage our liquidity in part by maintaining adequate financing commitments with related parties. We have the ability to borrow to and from our parent, WEC Energy Group, in amounts up to $400 million. At December 31, 2018 and 2017, we had short-term notes receivable from WEC Energy Group of $139.5 million and $278.2 million, respectively. See Note 13, Short-Term Debt and Lines of Credit, for more information.

Parent Company's Acquisition of Natural Gas Storage Facilities in Michigan

In June 2017, WEC Energy Group completed its acquisition of Bluewater for $226.0 million. Bluewater owns natural gas storage facilities in Michigan that provide a portion of the current storage needs for WPS's natural gas utility operations. In September 2017, WPS entered into a long-term service agreement with a wholly owned subsidiary of Bluewater to take a portion of the storage, which was then approved by the PSCW in November 2017. See Note 24, Regulatory Environment, for more information.

Upper Michigan Energy Resources Corporation

In December 2016, both the MPSC and the PSCW approved the operation of UMERC as a stand-alone utility in the Upper Peninsula of Michigan. UMERC, a subsidiary of WEC Energy Group, became operational effective January 1, 2017, and WPS transferred customers and property, plant, and equipment as of that date. WPS transferred approximately 9,000 retail electric customers and 5,300 natural gas customers to UMERC, along with approximately 600 miles of electric distribution lines and approximately 100 miles of natural gas distribution mains. WPS also transferred related electric distribution substations in the Upper Peninsula of Michigan and all property rights for the distribution assets to UMERC. The book value of the net assets (including the related deferred income tax liabilities) transferred to UMERC from WPS in 2017, was $20.6 million. This transaction was a non-cash equity transfer recorded to additional paid in capital between entities under common control, and therefore, did not result in the recognition of a gain or loss.

UMERC obtains energy through the MISO Energy Markets and meets its market obligations through power purchase agreements with WE and WPS. UMERC will begin to generate electricity when its new generation solution in the Upper Peninsula of Michigan begins commercial operation, which is expected to occur on March 31, 2019.

NOTE 5—OPERATING REVENUES

Disaggregation of Operating Revenues

The following tables present our operating revenues disaggregated by revenue source. We disaggregate revenues into categories that depict how the nature, amount, timing, and uncertainty of revenues and cash flows are affected by economic factors. For our segments, revenues are further disaggregated by electric and natural gas operations and then by customer class. Each customer class within our electric and natural gas operations have different expectations of service, energy and demand requirements, and are impacted by regulatory activities within their jurisdictions.

Comparable amounts have not been presented for the years ended December 31, 2017 and 2016, due to our adoption of ASU 2014-09, Revenues from Contracts with Customers, under the modified retrospective method. See Note 1(d), Operating Revenues, for more information about our significant accounting policies related to operating revenues.

(in millions)	Wisconsin	Illinois	Other States	Total Utility Operations	Corporate and Other	Reconciling Eliminations	Integrys Holding Consolidated
Year ended December 31, 2018							
Electric	$ 1,192.2	$ —	$ —	$ 1,192.2	$ —	$ —	$ 1,192.2
Natural gas	305.5	1,406.8	428.4	2,140.7	—	—	2,140.7
Total utility revenues	1,497.7	1,406.8	428.4	3,332.9	—	—	3,332.9
Other non-utility revenues	—	0.2	16.1	16.3	7.8	—	24.1
Total revenues from contracts with customers	1,497.7	1,407.0	444.5	3,349.2	7.8	—	3,357.0
Other operating revenues	0.8	(7.0)	(6.3)	(12.5)	0.2	—	(12.3)
Total operating revenues	$ 1,498.5	$1,400.0	$438.2	$ 3,336.7	$ 8.0	$ —	$ 3,344.7

Revenues from Contracts with Customers

Electric Utility Operating Revenues

The following table disaggregates electric utility operating revenues into customer class:

(in millions)	Electric Utility Operating Revenues
Year Ended December 31, 2018	
Residential	$ 381.5
Small commercial and industrial	371.4
Large commercial and industrial	238.8
Other	8.5
Total retail revenues	1,000.2
Wholesale	142.3
Resale	38.5
Other utility revenues	11.2
Total electric utility operating revenues	$ 1,192.2

Natural Gas Utility Operating Revenues

The following table disaggregates natural gas utility operating revenues into customer class:

(in millions)	Wisconsin	Illinois	Other States	Total Natural Gas Utility Operating Revenues
Year Ended December 31, 2018				
Residential	$ 177.7	$ 877.5	$ 263.3	$ 1,318.5
Commercial and industrial	107.6	266.9	140.0	514.5
Total retail revenues	285.3	1,144.4	403.3	1,833.0
Transport	19.7	244.0	31.8	295.5
Other utility revenues *	0.5	18.4	(6.7)	12.2
Total natural gas utility operating revenues	$ 305.5	$ 1,406.8	$ 428.4	$ 2,140.7

* Includes amounts collected from (refunded to) customers for purchased gas adjustment costs.

Other Non-Utility Operating Revenues

Other non-utility operating revenues consist primarily of the following:

(in millions)	Year Ended December 31, 2018
Appliance service revenues	$ 15.9
Distributed renewable solar project revenues	7.8
Other	0.4
Total other non-utility operating revenues	$ 24.1

Other Operating Revenues

Other operating revenues consist primarily of the following:

(in millions)	Year Ended December 31, 2018
Alternative revenues *	$ (41.7)
Late payment charges	28.4
Leases	1.0
Total other operating revenues	$ (12.3)

* Negative amounts can result from alternative revenues being reversed to revenues from contracts with customers as the customer is billed for these alternative revenues. Negative amounts can also result from revenues to be refunded to customers subject to decoupling mechanisms and wholesale true-ups, as discussed in Note 1(d), Operating Revenues.

NOTE 6—REGULATORY ASSETS AND LIABILITIES

The following regulatory assets were reflected on our balance sheets as of December 31:

(in millions)	2018	2017	See Note
Regulatory assets [1] [2]			
Environmental remediation costs [3]	**$ 577.2**	$ 598.9	22
Pension and OPEB costs [4]	**496.5**	476.2	19
AROs	**156.7**	150.7	9
Plant retirements	**78.1**	8.3	7
Income tax related items [5]	**42.2**	12.0	15
Uncollectible expense [6]	**38.7**	35.1	1(d)
Energy costs recoverable through rate adjustments [7]	**28.1**	20.3	1(d)
Termination of a tolling agreement with Fox Energy Company LLC [8]	**21.7**	27.2	
Derivatives	**16.0**	14.1	1(o)
Unamortized loss on reacquired debt [9]	**13.6**	14.6	
De Pere Energy Center [10]	**10.1**	14.0	
Crane Creek wind project production tax credits [11]	**0.4**	22.8	
Other, net	**37.8**	28.7	
Total regulatory assets	**$ 1,517.1**	$ 1,422.9	
Balance sheet presentation			
Current assets	**$ 50.4**	$ 37.2	
Regulatory assets	**1,466.7**	1,385.7	
Total regulatory assets	**$ 1,517.1**	$ 1,422.9	

[1] Based on prior and current rate treatment, we believe it is probable that our utilities will continue to recover from customers the regulatory assets in this table. In accordance with GAAP, our regulatory assets do not include the allowance for ROE that is capitalized for regulatory purposes. This allowance was $15.1 million and $14.7 million at December 31, 2018 and 2017, respectively.

[2] As of December 31, 2018, we had $117.8 million of regulatory assets not earning a return and $5.3 million of regulatory assets earning a return based on short-term interest rates. The regulatory assets not earning a return primarily relate to uncollectible expense and certain environmental remediation costs, the recovery of which depends on the timing of the actual expenditures, as well as natural gas costs recoverable through rate adjustments, unamortized loss on reacquired debt, and our electric real-time market pricing program. The other regulatory assets in the table either earn a return or the cash has not yet been expended, in which case the regulatory assets are offset by liabilities.

[3] As of December 31, 2018, we had made cash expenditures of $51.8 million related to these environmental remediation costs. The remaining $525.4 million represents our estimated future cash expenditures.

[4] Primarily represents the unrecognized future pension and OPEB costs related to our defined benefit pension and OPEB plans. We are authorized recovery of these regulatory assets over the average remaining service life of each plan.

[5] For information on the regulatory treatment of the impacts of the Tax Legislation in our various jurisdictions, see Note 24, Regulatory Environment.

[6] Represents amounts recoverable from customers related to our uncollectible expense tracking mechanisms and riders. These mechanisms allow us to recover or refund the difference between actual uncollectible write-offs and the amounts recovered in rates.

[7] Represents energy costs that will be recovered from customers in the future.

[8] Represents an early termination fee of a tolling agreement WPS had with the Fox Energy Center. Prior to the purchase of the Fox Energy Center in 2013, WPS supplied natural gas for the facility and purchased capacity and the associated energy output under the tolling agreement. WPS is authorized recovery of this asset over a nine-year period that began on January 1, 2014.

[9] Amounts are recovered over the term of the replacement debt for PGL and NSG as authorized by the ICC.

(10) Prior to WPS purchasing the De Pere Energy Center in 2002, WPS had a long-term power purchase contract with them that was accounted for as a capital lease. As a result of the purchase, the capital lease obligation was reversed, and the difference between the capital lease asset and the purchase price was recorded as a regulatory asset. WPS is authorized recovery of this regulatory asset through 2023.

(11) In 2012, WPS elected to claim and subsequently received a Section 1603 Grant for the Crane Creek wind project in lieu of the production tax credit. As a result, WPS reversed previously recorded production tax credits and recorded regulatory assets. In May 2018, the PSCW issued an order requiring WPS to use a portion of its tax benefits from the Tax Legislation that was signed into law in December 2017 to reduce the regulatory assets related to its Crane Creek wind project production tax credits. See Note 24, Regulatory Environment, for more information.

The following regulatory liabilities were reflected on our balance sheets as of December 31:

(in millions)	2018	2017	See Note
Regulatory liabilities			
Income tax related items [1]	**$ 902.6**	$ 972.8	15
Removal costs [2]	**386.1**	376.1	
Pension and OPEB costs [3]	**149.8**	95.7	19
Decoupling	**30.5**	1.8	1(d)
Earnings sharing mechanism	**21.2**	—	24
Energy efficiency programs [4]	**18.2**	10.0	
Energy costs refundable through rate adjustments [5]	**17.7**	11.5	1(d)
Derivatives	**11.8**	6.4	1(o)
Other, net	**17.4**	16.7	
Total regulatory liabilities	**$ 1,555.3**	$ 1,491.0	
Balance sheet presentation			
Other current liabilities	**$ 15.1**	$ 11.8	
Regulatory liabilities	**1,540.2**	1,479.2	
Total regulatory liabilities	**$ 1,555.3**	$ 1,491.0	

(1) For information on the regulatory treatment of the impacts of the Tax Legislation in our various jurisdictions, see Note 24, Regulatory Environment.

(2) Represents amounts collected from customers to cover the future cost of property, plant, and equipment removals that are not legally required. Legal obligations related to the removal of property, plant, and equipment are recorded as AROs.

(3) Primarily represents the unrecognized future pension and OPEB benefits related to our defined benefit pension and OPEB plans. We will amortize these regulatory liabilities into net periodic benefit cost over the average remaining service life of each plan.

(4) Represents amounts refundable to customers related to programs at the utilities designed to meet energy efficiency standards.

(5) Represents an over-collection of energy costs that will be refunded to customers in the future. When the rates we charge to customers include energy costs that are higher than our actual energy costs, any over-collection outside of the allowable energy cost price variance is refunded to customers.

NOTE 7—PROPERTY, PLANT, AND EQUIPMENT

Property, plant, and equipment consisted of the following utility and non-utility assets at December 31:

(in millions)	2018	2017
Electric - generation	**$ 2,831.2**	$ 2,624.1
Electric - distribution	**1,510.0**	1,361.6
Natural gas - distribution, storage, and transmission	**7,232.8**	6,753.0
Plant to be retired, net	**—**	57.9
Other	**709.6**	582.9
Less: Accumulated depreciation	**3,532.0**	3,270.1
Net	**8,751.6**	8,109.4
CWIP	**324.1**	280.8
Net utility property, plant, and equipment	**9,075.7**	8,390.2
Non-utility and other property, plant, and equipment	**62.9**	88.7
Less: Accumulated depreciation	**9.8**	18.6
Net	**53.1**	70.1
CWIP	**—**	0.1
Net non-utility and other property, plant, and equipment	**53.1**	70.2
Total property, plant, and equipment	**$ 9,128.8**	$ 8,460.4

Wisconsin Segment Plant to be Retired

We have evaluated future plans for our older and less efficient fossil fuel generating units and have retired our plants identified below. In December 2017, a severance liability in the amount of $3.6 million was recorded in other current liabilities related to these plant retirements.

(in millions)	
Severance liability at December 31, 2017	$ 3.6
Severance payments	**(0.8)**
Total severance liability at December 31, 2018	**$ 2.8**

Pulliam Power Plant

In connection with a MISO ruling, WPS retired Pulliam Units 7 and 8 effective October 21, 2018. The carrying value of the Pulliam units was $33.8 million at December 31, 2018. This amount included the net book value of $57.2 million, which was classified as a regulatory asset on our balance sheet. In addition, a $23.4 million cost of removal reserve related to the Pulliam units was classified as a regulatory liability at December 31, 2018. WPS continues to amortize this regulatory asset on a straight-line basis using the composite depreciation rates approved by the PSCW before these generating units were retired. Amortization is included in depreciation and amortization in the income statement. WPS has FERC approval to continue to collect the carrying value of the Pulliam power plant using the approved composite depreciation rates, in addition to a return on the remaining carrying value. FERC has completed its prudency review of Pulliam, concluding that the retirement of this plant was prudent. WPS will address the accounting and regulatory treatment related to the retirement of the Pulliam power plant with the PSCW in conjunction with its anticipated 2019 rate case. See Note 22, Commitments and Contingencies, for more information.

Edgewater Unit 4

The Edgewater 4 generating unit was retired effective September 28, 2018. The carrying value of the generating unit was $8.1 million at December 31, 2018. This amount included the net book value of WPS's ownership share of this generating unit of $10.0 million, which was classified as a regulatory asset on our balance sheet. In addition, a $1.9 million cost of removal reserve related to the Edgewater 4 generating unit was classified as a regulatory liability at December 31, 2018. WPS continues to amortize this regulatory asset on a straight-line basis using the composite depreciation rates approved by the PSCW before this generating unit was retired. Amortization is included in depreciation and amortization in the income statement. WPS has FERC approval to continue to collect the carrying value of the Edgewater 4 generating unit using the approved composite depreciation rates, in addition to a return on the

remaining carrying value. FERC has completed its prudency review of Edgewater 4, concluding that the retirement of this plant was prudent. WPS will address the accounting and regulatory treatment related to the retirement of the Edgewater 4 generating unit with the PSCW in conjunction with its anticipated 2019 rate case. See Note 22, Commitments and Contingencies, for more information.

NOTE 8—JOINTLY OWNED UTILITY FACILITIES

WPS holds a joint ownership interest in certain electric generating facilities. WPS is entitled to its share of generating capability and output of each facility equal to its respective ownership interest. WPS also pays its ownership share of additional construction costs, fuel inventory purchases, and operating expenses, unless specific agreements have been executed to limit its maximum exposure to additional costs. WPS records its proportionate share of significant jointly owned electric generating facilities as property, plant, and equipment on the balance sheets.

Information related to jointly owned utility facilities at December 31, 2018 was as follows:

(in millions, except for percentages and MW)	Weston Unit 4	Columbia Energy Center Units 1 and 2 [2]	Forward Wind Energy Center
Ownership	**70.0%**	**28.1%**	**44.6%**
WPS's share of rated capacity (MW) [1]	**384.9**	**314.8**	**8.7**
In-service date	**2008**	**1975 and 1978**	**2008**
Property, plant, and equipment	**$ 615.4**	**$ 438.8**	**$ 123.7**
Accumulated depreciation	**$ (205.2)**	**$ (132.2)**	**$ (43.7)**
CWIP	**$ 1.9**	**$ 0.3**	**$ 0.1**

[1] Values are primarily based on the net dependable capacity ratings for summer 2019 using historical generation. The summer period is the most relevant for capacity planning purposes. This is a result of continually reaching demand peaks in the summer months, primarily due to air conditioning demand.

[2] Columbia Energy Center (Columbia) is jointly owned by Wisconsin Power and Light (WPL), Madison Gas and Electric (MGE), and WPS. In October 2016, WPL received an order from the PSCW approving amendments to the Columbia joint operating agreement between the parties allowing WPS and MGE to forgo certain capital expenditures at Columbia. As a result, WPL will incur these capital expenditures in exchange for a proportional increase in its ownership share of Columbia. Based upon the additional capital expenditures WPL expects to incur through June 1, 2020, WPS's ownership interest would decrease to 27.5%.

WPS's proportionate share of direct expenses for the joint operation of these plants is recorded in operating expenses in the income statements. WPS has supplied its own financing for all jointly owned projects.

NOTE 9—ASSET RETIREMENT OBLIGATIONS

Our utilities have recorded AROs primarily for the removal of natural gas distribution mains and service pipes (including asbestos and polychlorinated biphenyls [PCBs]); asbestos abatement at certain generation facilities, office buildings, and service centers; the dismantling of wind generation projects; the disposal of PCB-contaminated transformers; the closure of fly-ash landfills at certain generation facilities; and the removal of above ground storage tanks. Regulatory assets and liabilities are established by our utilities to record the differences between ongoing expense recognition under the ARO accounting rules and the rate-making practices for retirement costs authorized by the applicable regulators. AROs have also been recorded at PDL for the removal of solar equipment components.

The following table shows changes to our AROs during the years ended December 31:

(in millions)	2018	2017	2016
Balance as of January 1	**$ 501.7**	$ 492.7	$ 509.2
Accretion	**24.4**	24.1	25.1
Additions and revisions to estimated cash flows	**(110.7)** [1]	21.0 [2]	—
Liabilities settled	**(33.9)**	(36.1)	(41.6)
Balance as of December 31	**$ 381.5**	$ 501.7	$ 492.7

[1] AROs decreased $127.3 million in 2018 due to revisions made to estimated cash flows primarily for changes in the cost to retire natural gas distribution pipe at PGL. Also in 2018, AROs increased $10.7 million as a result of revisions made to estimated cash flows for the abatement of

asbestos at WPS's Pulliam power plant, and a $5.6 million ARO was recorded for the legal requirement to dismantle, at retirement, the wind generation project known as Forward Wind Energy Center. See Note 2, Acquisition, for more information on Forward Wind Energy Center.

(2) AROs increased $20.5 million in 2017 due to revisions made to estimated cash flows primarily for changes in the cost to retire natural gas distribution pipe at PGL and NSG.

NOTE 10—GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill represents the excess of the cost of an acquisition over the fair value of the identifiable net assets acquired. The following table shows our goodwill balances by segment as of December 31, 2018 and 2017. Our goodwill balances did not change during the years ended December 31, 2018 and 2017.

	Wisconsin		Illinois		Other States		Total	
(in millions)	2018	2017	2018	2017	2018	2017	2018	2017
Gross goodwill	**$ 36.4**	$ 36.4	**$ 630.1**	$ 630.1	**$ 267.0**	$ 267.0	**$ 933.5**	$ 933.5
Accumulated impairment losses	**—**	—	**(192.8)**	(192.8)	**(104.9)**	(104.9)	**(297.7)**	(297.7)
Net goodwill	**$ 36.4**	$ 36.4	**$ 437.3**	$ 437.3	**$ 162.1**	$ 162.1	**$ 635.8**	$ 635.8

In the third quarter of 2018, annual impairment tests were completed at all of our reporting units that carried a goodwill balance as of July 1, 2018. No impairments resulted from these tests.

The identifiable intangible assets other than goodwill listed below are classified as other long-term assets on our balance sheets.

	December 31, 2018			December 31, 2017		
(in millions)	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Amortized intangible assets (1)	**$ 8.7**	**$ (7.2)**	**$ 1.5**	$ 8.7	$ (6.0)	$ 2.7
Unamortized intangible assets (2)	**5.7**	**—**	**5.7**	5.7	—	5.7
Total intangible assets	**$ 14.4**	**$ (7.2)**	**$ 7.2**	$ 14.4	$ (6.0)	$ 8.4

(1) Primarily represents contractual service agreements that provide for major maintenance and protection against unforeseen maintenance costs related to the combustion turbine generators at WPS's Fox Energy Center. The remaining weighted-average amortization period for our amortized intangible assets at December 31, 2018, was approximately one year.

(2) Consists primarily of a trade name.

NOTE 11—COMMON EQUITY

Stock-Based Compensation

The following table summarizes our pre-tax stock-based compensation expense and the related tax benefit recognized in income for the years ended December 31:

(in millions)	2018	2017	2016
Stock options	**$ 2.8**	$ 2.0	$ 1.4
Restricted stock	**4.9**	2.0	3.4
Performance units	**8.9**	8.7	4.0
Stock-based compensation expense	**$ 16.6**	$ 12.7	$ 8.8
Related tax benefit	**$ 4.6**	$ 5.1	$ 3.5

Stock-based compensation costs capitalized during 2018, 2017, and 2016 were not significant.

Stock Options

The following is a summary of our employees' WEC Energy Group stock option activity during 2018:

Stock Options	Number of Options	Weighted-Average Exercise Price	Weighted-Average Remaining Contractual Life *(in years)*	Aggregate Intrinsic Value *(in millions)*
Outstanding as of January 1, 2018	93,465	$ 56.81		
Granted	**45,740**	**$ 66.02**		
Exercised	**(3,430)**	**$ 56.78**		
Outstanding as of December 31, 2018	**135,775**	**$ 59.91**	**8.1**	**$ 1.3**
Exercisable as of December 31, 2018	**15,365**	**$ 57.36**	**7.6**	**$ 0.2**

The aggregate intrinsic value of outstanding and exercisable options in the above table represents the total pre-tax intrinsic value that would have been received by the option holders had they exercised all of their options on December 31, 2018. This is calculated as the difference between WEC Energy Group's closing stock price on December 31, 2018, and the option exercise price, multiplied by the number of in-the-money stock options. The intrinsic value of options exercised during the year ended December 31, 2018, was $0.1 million. Cash received by WEC Energy Group from exercises of its options by our employees was $0.2 million during the year ended December 31, 2018. No WEC Energy Group stock options held by our employees were exercised during the years ended December 31, 2017 and 2016.

As of December 31, 2018, we expected to recognize approximately $1.8 million of unrecognized compensation cost related to unvested and outstanding WEC Energy Group stock options over the next 1.7 years on a weighted-average basis.

During the first quarter of 2019, the Compensation Committee awarded 45,243 non-qualified WEC Energy Group stock options with an exercise price of $68.18 and a weighted-average grant date fair value of $8.60 per option to certain of our officers and other key employees under its normal schedule of awarding long-term incentive compensation.

Restricted Shares

The following is a summary of our employees' WEC Energy Group restricted stock activity during 2018:

Restricted Shares	Number of Shares	Weighted-Average Grant Date Fair Value
Outstanding and unvested as of January 1, 2018	18,030	$ 56.11
Granted	**4,206**	**$ 64.99**
Released	**(8,211)**	**$ 55.94**
Transferred	**198**	**$ 64.99**
Forfeited	**(1,363)**	**$ 58.37**
Outstanding and unvested as of December 31, 2018	**12,860**	**$ 59.02**

The intrinsic value of WEC Energy Group restricted stock held by our employees that was released was $0.5 million and $0.4 million for the years ended December 31, 2018 and 2017, respectively. The actual tax benefit from released restricted shares for the same years was $0.1 million and $0.2 million, respectively. No shares of WEC Energy Group restricted stock held by our employees were released during 2016.

As of December 31, 2018, we expected to recognize approximately $1.8 million of unrecognized compensation cost related to unvested and outstanding WEC Energy Group restricted stock over the next 1.5 years on a weighted-average basis.

During the first quarter of 2019, the Compensation Committee awarded 3,946 WEC Energy Group restricted shares to our officers and other key employees under its normal schedule of awarding long-term incentive compensation. The grant date fair value of these awards was $68.18 per share.

Performance Units

During 2018, 2017, and 2016, the Compensation Committee awarded 18,260; 19,990; and 19,710 WEC Energy Group performance units, respectively, to our officers and other key employees under the WEC Energy Group Performance Unit Plan.

At December 31, 2018, our employees held 51,546 of outstanding WEC Energy Group performance units, including dividend equivalents. A liability of $3.1 million was recorded on our balance sheet at December 31, 2018 related to these outstanding units. As of December 31, 2018, we expected to recognize approximately $8.1 million of unrecognized compensation cost related to unvested and outstanding WEC Energy Group performance units over the next 1.3 years on a weighted-average basis.

During the first quarter of 2019, performance units held by our employees with an intrinsic value of $1.4 million were settled. The actual tax benefit from the distribution of these awards was $0.3 million. In January 2019, the Compensation Committee also awarded 17,099 WEC Energy Group performance units to our officers and other key employees under its normal schedule of awarding long-term incentive compensation.

Restrictions

Our ability to transfer funds to WEC Energy Group primarily depends on the availability of funds from our utility subsidiaries. Various financing arrangements and regulatory requirements impose certain restrictions on the ability of our subsidiaries to transfer funds to us in the form of cash dividends, loans, or advances. All of our utility subsidiaries, with the exception of MGU, are prohibited from loaning funds to us, either directly or indirectly.

In accordance with WPS's most recent rate order, WPS may not pay common dividends above the test year forecasted amounts reflected in its rate case, if it would cause its average common equity ratio, on a financial basis, to fall below its authorized level of 51%. A return of capital in excess of the test year amount can be paid by WPS at the end of the year provided that its average common equity ratio does not fall below the authorized level.

NSG's long-term debt obligations contain provisions and covenants restricting the payment of cash dividends and the purchase or redemption of its capital stock.

We have the option to defer interest payments on our junior subordinated notes, from time to time, for one or more periods of up to ten consecutive years per period. During any period in which we defer interest payments, we may not declare or pay any dividends or distributions on, or redeem, purchase, acquire, or make a liquidation payment on, any of our capital stock.

See Note 13, Short-Term Debt and Lines of Credit, for discussion of certain financial covenants related to the short-term debt obligations of our subsidiaries.

As of December 31, 2018, restricted net assets of our consolidated subsidiaries totaled approximately $2.5 billion.

We do not believe that these restrictions will materially affect our operations or limit any dividend payments in the foreseeable future.

NOTE 12—PREFERRED STOCK

The following table shows our subsidiaries' authorized shares of preferred stock at December 31, 2018 and 2017. There were no shares outstanding.

	Shares Authorized
WPS	
$100 par value, Preferred Stock	**1,000,000**
PGL	
$100 par value, Cumulative Preferred Stock	**430,000**
NSG	
$100 par value, Cumulative Preferred Stock	**160,000**

NOTE 13—SHORT-TERM DEBT AND LINES OF CREDIT

The following table shows our short-term borrowings and their corresponding weighted-average interest rates as of December 31:

(in millions, except percentages)	2018	2017
Commercial paper		
Amount outstanding at December 31	**$ 479.5**	$ 533.0
Average interest rate on amounts outstanding at December 31	**2.86%**	1.81%

Our average amount of commercial paper borrowings based on daily outstanding balances during 2018, was $431.3 million with a weighted-average interest rate during the period of 2.26%.

WPS and PGL have entered into bank back-up credit facilities to maintain short-term credit liquidity which, among other terms, requires them to maintain, subject to certain exclusions, a total funded debt to capitalization ratio of 65% or less. As of December 31, 2018, both companies were in compliance with their respective financial covenants.

The information in the table below relates to our revolving credit facilities used to support our commercial paper borrowing program, including remaining available capacity under these facilities as of December 31:

(in millions)	Maturity	2018
Revolving credit facility (WPS)	October 2022	**$ 400.0**
Revolving credit facility (PGL)	October 2022	**350.0**
Revolving short-term notes payable to WEC Energy Group		**400.0**
Total short-term credit capacity		**$ 1,150.0**
Less:		
Commercial paper outstanding		**$ 479.5**
Letters of credit issued inside credit facilities		**1.3**
Short-term debt to WEC Energy Group		**—**
Available capacity under existing credit agreements		**$ 669.2**

The WPS and PGL facilities have renewal provisions for two one-year extensions, subject to lender approval.

The bank back-up credit facilities contain customary covenants, including certain limitations on the respective companies' ability to sell assets. The credit facilities also contain customary events of default, including payment defaults, material inaccuracy of representations and warranties, covenant defaults, bankruptcy proceedings, certain judgments, Employee Retirement Income Security Act of 1974 defaults, and change of control.

NOTE 14—LONG-TERM DEBT

See our statements of capitalization for details on our long-term debt.

Integrys Holding, Inc.

In May 2018, we redeemed at par all $114.9 million outstanding of our 2006 Junior Subordinated Notes Due 2066.

Wisconsin Public Service Corporation

In November 2018, WPS issued $400.0 million of 3.35% Senior Notes due November 21, 2021. WPS used the net proceeds to pay all $250.0 million outstanding principal amount of its 1.65% Senior Notes at maturity in December 2018, to repay short-term debt, and for working capital and other corporate purposes.

The Peoples Gas Light and Coke Company

In November 2018, PGL issued $150.0 million of 3.87% Series FFF Bonds due November 1, 2028. The net proceeds were used for general corporate purposes, including funding capital expenditures and the refinancing of short-term debt.

In November 2018, PGL's $5.0 million of 8.00% Series TT Bonds matured, and the outstanding principal was repaid with proceeds from issuing commercial paper.

North Shore Gas Company

In November 2018, NSG issued $50.0 million of 3.87% Series R Bonds due November 1, 2028. The net proceeds were used for general corporate purposes, including funding capital expenditures and the refinancing of short-term debt.

Bonds and Notes

The following table shows the future maturities of our long-term debt outstanding as of December 31, 2018:

(in millions)	Payments
2019	$ 75.0
2020	250.0
2021	400.0
2022	—
2023	—
Thereafter	2,787.0
Total	$ 3,512.0

We amortize debt premiums, discounts, and debt issuance costs over the life of the debt and we include the costs in interest expense.

Effective August 2023, our $400.0 million of 2013 6.00% Junior Subordinated Notes due 2073 will bear interest at the three-month LIBOR plus 322 basis points and will reset quarterly.

Our long-term debt obligations, and those of certain of our subsidiaries, contain covenants related to payment of principal and interest when due and various financial reporting obligations. Failure to comply with these covenants could result in an event of default, which could result in the acceleration of outstanding debt obligations.

NOTE 15—INCOME TAXES

Income Tax Expense

The following table is a summary of income tax expense for each of the years ended December 31:

(in millions)	2018	2017	2016
Current tax benefit	**$ (20.8)**	$ (16.0)	$ (60.3)
Deferred income taxes, net	**146.2**	239.2	260.8
Investment tax credit, net	**(2.0)**	(1.7)	(3.8)
Total income tax expense	**$ 123.4**	$ 221.5	$ 196.7

Statutory Rate Reconciliation

The provision for income taxes for each of the years ended December 31 differs from the amount of income tax determined by applying the applicable United States statutory federal income tax rate to income before income taxes as a result of the following:

	2018		2017*		2016	
(in millions)	Amount	Effective Tax Rate	Amount	Effective Tax Rate	Amount	Effective Tax Rate
Expected tax at statutory federal tax rates	**$ 98.4**	**21.0 %**	$ 214.2	35.0 %	$ 173.6	35.0 %
State income taxes net of federal tax benefit	**29.7**	**6.3 %**	28.1	4.6 %	23.2	4.7 %
Tax Legislation	**—**	**— %**	(19.3)	(3.2)%	—	— %
AFUDC – Equity	**(1.0)**	**(0.2)%**	(1.4)	(0.2)%	(6.8)	(1.4)%
Other, net	**(3.7)**	**(0.8)%**	(0.1)	— %	6.7	1.3 %
Total income tax expense	**$ 123.4**	**26.3 %**	$ 221.5	36.2 %	$ 196.7	39.6 %

* The net impact of Tax Legislation in the amount of $21.2 million is represented in both the Tax Legislation and state income taxes net of federal tax benefit lines above.

Deferred Income Tax Assets and Liabilities

On December 22, 2017, the Tax Legislation was signed into law. For businesses, the Tax Legislation reduced the corporate federal tax rate from a maximum of 35% to a 21% rate effective January 1, 2018. In December 2017, we recorded a net tax benefit related to the remeasurement of our deferred taxes in the amount of $1,090 million. Accordingly, the tax benefit related to our regulated operations was recorded as both an increase to regulatory liabilities as well as a decrease to certain existing regulatory assets at December 31, 2017. The effects of the Tax Legislation related to our non-utility and non-regulated operations resulted in the recording of an income tax benefit of $21.2 million for the year ended December 31, 2017. This tax benefit was primarily due to a re-measurement of deferred tax assets and liabilities.

On December 22, 2017, the Securities and Exchange Commission staff issued guidance in Staff Accounting Bulletin 118 (SAB 118), Income Tax Accounting Implications of the Tax Cuts and Jobs Act, which provided for a measurement period of up to one year from the enactment date to complete accounting under GAAP for the tax effects of the legislation. Due to the complex and comprehensive nature of the enacted tax law changes, and their application under GAAP, certain amounts related to bonus depreciation and future tax benefit utilization recorded in the financial statements as a result of the Tax Legislation were considered "provisional" and subject to revision at December 31, 2017, and through 2018, as discussed in SAB 118.

In 2018, we considered all available guidance from industry and income tax authorities related to these tax items, and revised our Alternative Minimum Tax Credit valuation allowance, and revised our estimates for re-measurement of deferred income taxes related to guidance on bonus depreciation. At December 31, 2018, we no longer considered any amounts related to bonus depreciation and future tax benefit utilization "provisional." However, any further amendments or technical corrections to the Tax Legislation could subject these tax items to revision.

The components of deferred income taxes at December 31 were as follows:

(in millions)	2018	2017
Deferred tax assets		
Tax gross up – regulatory items	**$ 250.1**	$ 265.0
Future tax benefits	**45.3**	142.9
Other	**70.6**	47.7
Total deferred tax assets	**366.0**	455.6
Valuation allowance	**(11.0)**	(14.2)
Net deferred tax assets	**$ 355.0**	$ 441.4
Deferred tax liabilities		
Property-related	**$ 1,371.6**	$ 1,468.5
Employee benefits and compensation	**72.6**	53.0
Regulatory deferrals	**17.8**	49.4
Other	**22.9**	17.4
Total deferred tax liabilities	**1,484.9**	1,588.3
Deferred tax liability, net	**$ 1,129.9**	$ 1,146.9

Consistent with rate-making treatment, deferred taxes in the table above are offset for temporary differences that have related regulatory assets and liabilities.

The components of net deferred tax assets associated with federal and state tax benefit carryforwards as of December 31, 2018 and 2017 are summarized in the tables below:

2018 *(in millions)*	Gross Value	Deferred Tax Effect	Valuation Allowance	Earliest Year of Expiration
Future tax benefits as of December 31, 2018				
Federal foreign tax credit	**$ —**	**$ 9.7**	**$ (9.7)**	**2018**
Other federal tax credit	**—**	**20.1**	**(1.3)**	**2038**
State net operating loss	**181.7**	**10.9**	**—**	**2023**
State tax credit	**—**	**4.6**	**—**	**2018**
Balance as of December 31, 2018	**$ 181.7**	**$ 45.3**	**$ (11.0)**	

2017 *(in millions)*	Gross Value	Deferred Tax Effect	Valuation Allowance
Future tax benefits as of December 31, 2017			
Federal foreign tax credit	$ —	$ 13.5	$ (13.5)
Other federal tax credit	—	109.8	(0.1)
Charitable contribution	12.9	3.7	(0.6)
State net operating loss	183.0	11.0	—
State tax credit	—	4.9	—
Balance as of December 31, 2017	$ 195.9	$ 142.9	$ (14.2)

Valuation allowances of $11.0 million have been established for certain tax benefit carryforwards based on our projected ability to realize such benefits by off-setting future tax liabilities. Realization is dependent on generating sufficient tax liabilities prior to expiration of the tax benefit carryforwards.

Unrecognized Tax Benefits

A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows:

(in millions)	2018	2017
Balance at January 1	**$ 17.3**	$ 8.8
Increase related to tax positions of prior years	**—**	8.1
Decrease related to tax positions of prior years	**(0.2)**	**—**
Increase related to tax positions of the current year	**—**	0.4
Balance at December 31	**$ 17.1**	$ 17.3

The amount of unrecognized tax benefits at December 31, 2018 and 2017, excludes deferred tax assets related to uncertainty in income taxes of $1.1 million and $1.8 million, respectively. At December 31, 2018 and 2017, the net amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate for continuing operations was $16.0 million and $15.5 million, respectively.

For the years ended December 31, 2018 and 2017, we recognized $0.1 million of interest expense and $0.1 million of interest income related to unrecognized tax benefits in our income statements, respectively. For the year ended December 31, 2016, we recognized no interest related to unrecognized tax benefits in our income statement. For the years ended December 31, 2018, 2017, and 2016, we recognized no penalties related to unrecognized tax benefits in our income statements. At December 31, 2018, we had $0.4 million of interest accrued and no penalties accrued related to unrecognized tax benefits on our balance sheets. At December 31, 2017, we had $0.2 million of interest accrued and no penalties accrued related to unrecognized tax benefits on our balance sheets.

Although analysis of our unrecognized tax benefits is ongoing, the potential estimated decrease in the total amounts of unrecognized tax benefits within the next 12 months is approximately $3.0 million associated with statutes of limitations on certain tax years. We do not anticipate any significant increases in the total amounts of unrecognized tax benefits within the next 12 months.

We file income tax returns in the United States federal jurisdiction and state tax returns based on income in our major state operating jurisdictions of Wisconsin, Illinois, Michigan, and Minnesota. We also file tax returns in other state and local jurisdictions with varying statutes of limitations. As of December 31, 2018, we were subject to examination by federal as well as by state or local tax authorities for the 2013 through 2018 tax years in our major operating jurisdictions as follows:

Jurisdiction	Year
Federal	2015-2018
Illinois	2013-2018
Michigan	2016-2018
Minnesota	2014-2018
Wisconsin	2014-2018

NOTE 16—FAIR VALUE MEASUREMENTS

The following tables summarize our financial assets and liabilities that were accounted for at fair value on a recurring basis, categorized by level within the fair value hierarchy:

	December 31, 2018			
(in millions)	Level 1	Level 2	Level 3	Total
Derivative assets				
Natural gas contracts	**$ 5.2**	**$ 1.7**	**$ —**	**$ 6.9**
FTRs	**—**	**—**	**3.0**	**3.0**
Coal contracts	**—**	**0.4**	**—**	**0.4**
Total derivative assets	**$ 5.2**	**$ 2.1**	**$ 3.0**	**$ 10.3**
Investments held in rabbi trust	**$ 65.0**	**$ —**	**$ —**	**$ 65.0**
Derivative liabilities				
Natural gas contracts	**$ 3.1**	**$ 0.6**	**$ —**	**$ 3.7**

	December 31, 2017			
(in millions)	Level 1	Level 2	Level 3	Total
Derivative assets				
Natural gas contracts	$ 1.0	$ 3.4	$ —	$ 4.4
Petroleum products contracts	0.3	—	—	0.3
FTRs	—	—	2.0	2.0
Coal contracts	—	0.4	—	0.4
Total derivative assets	$ 1.3	$ 3.8	$ 2.0	$ 7.1
Investments held in rabbi trust	$ 120.7	$ —	$ —	$ 120.7
Derivative liabilities				
Natural gas contracts	$ 4.1	$ 3.6	$ —	$ 7.7
Coal contracts	—	0.5	—	0.5
Total derivative liabilities	$ 4.1	$ 4.1	$ —	$ 8.2

The derivative assets and liabilities listed in the tables above include options, swaps, futures, physical commodity contracts, and other instruments used to manage market risks related to changes in commodity prices. They also include FTRs, which are used to manage electric transmission congestion costs in the MISO Energy Markets. See Note 17, Derivative Instruments, for more information.

We hold investments in our rabbi trust. These investments are restricted as they can only be withdrawn from the trust to fund participants' benefits under our deferred compensation plan and certain non-qualified pension plans. These investments are included in other long-term assets on our balance sheets. The net unrealized gains included in earnings related to the investments held at the end of the period were $18.8 million and $4.0 million for the years ended December 31, 2017 and 2016, respectively. The net unrealized gains included in earnings for the year ended December 31, 2018 were not significant.

The following table summarizes the changes to derivatives classified as Level 3 in the fair value hierarchy at December 31:

(in millions)	2018	2017	2016
Balance at the beginning of the period	**$ 2.0**	$ 2.0	$ 2.0
Realized and unrealized losses	**—**	—	(0.2)
Purchases	**9.0**	6.9	7.1
Sales	**—**	—	(0.2)
Settlements	**(8.0)**	(6.9)	(6.7)
Balance at the end of the period	**$ 3.0**	$ 2.0	$ 2.0

Unrealized gains and losses on Level 3 derivatives are deferred as regulatory assets or liabilities. Therefore, these fair value measurements have no impact on earnings. Realized gains and losses on these instruments are included in cost of sales on the income statements.

Fair Value of Financial Instruments

The following table shows the financial instruments included on our balance sheets that are not recorded at fair value at December 31:

	2018		2017	
(in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	**$ 3,477.7**	**$ 3,486.9**	$ 3,249.6	$ 3,499.1

The fair value of long-term debt is categorized within Level 2 of the fair value hierarchy.

NOTE 17—DERIVATIVE INSTRUMENTS

The following table shows our derivative assets and derivative liabilities, none of which are designated as hedging instruments.

	December 31, 2018		December 31, 2017	
(in millions)	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Other current				
Natural gas contracts	**$ 6.5**	**$ 3.5**	$ 4.3	$ 6.6
Petroleum products contracts	**—**	**—**	0.3	—
FTRs	**3.0**	**—**	2.0	—
Coal contracts	**0.2**	**—**	—	0.5
Total other current	**$ 9.7**	**$ 3.5**	$ 6.6	$ 7.1
Other long-term				
Natural gas contracts	**$ 0.4**	**$ 0.2**	$ 0.1	$ 1.1
Coal contracts	**0.2**	**—**	0.4	—
Total other long-term	**$ 0.6**	**$ 0.2**	$ 0.5	$ 1.1
Total	**$ 10.3**	**$ 3.7**	$ 7.1	$ 8.2

Realized gains and losses on derivative instruments are primarily recorded in cost of sales on our income statements. Our estimated notional sales volumes and realized gains (losses) were as follows for the years ended:

	December 31, 2018		December 31, 2017		December 31, 2016	
(in millions)	Volume	Gains	Volume	Gains (Losses)	Volume	Gains (Losses)
Natural gas contracts	96.0 Dth	**$ 11.9**	77.2 Dth	$ (5.9)	92.9 Dth	$ (37.7)
Petroleum products contracts	1.8 gallons	**0.4**	1.3 gallons	0.1	4.4 gallons	(0.6)
FTRs	9.3 MWh	**12.5**	9.1 MWh	6.4	8.4 MWh	6.0
Total		**$ 24.8**		$ 0.6		$ (32.3)

The following table shows derivative assets and derivative liabilities if derivative instruments by counterparty were presented net on our balance sheets:

	December 31, 2018		December 31, 2017	
(in millions)	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Gross amount recognized on the balance sheet	**$ 10.3**	**$ 3.7**	$ 7.1	$ 8.2
Gross amount not offset on the balance sheet	**(3.0)** [1]	**(3.2)** [2]	(3.3)	(6.1) [3]
Net amount	**$ 7.3**	**$ 0.5**	$ 3.8	$ 2.1

(1) Includes cash collateral received of $0.2 million.

(2) Includes cash collateral posted of $0.4 million.

(3) Includes cash collateral posted of $2.8 million.

At December 31, 2018 and 2017, we had posted cash collateral of $1.0 million and $9.4 million, respectively, in our margin accounts. At December 31, 2018, we had also received cash collateral of $0.2 million in our margin accounts. Certain of our derivative and non-derivative commodity instruments contain provisions that could require "adequate assurance" in the event of a material change in our creditworthiness, or the posting of additional collateral for instruments in net liability positions, if triggered by a decrease in credit ratings. We did not have any derivative instruments with specific credit risk-related contingent features that were in a net liability position at December 31, 2018. The aggregate fair value of all derivative instruments with these features that were in a net liability position at December 31, 2017 was $3.7 million. At December 31, 2017, we had not posted any cash collateral related to the credit risk-related contingent features of these commodity instruments. If all of the credit risk-related contingent features contained in derivative instruments in a net liability position had been triggered at December 31, 2017, we would have been required to post collateral of $2.7 million.

NOTE 18—GUARANTEES

The following table shows our outstanding guarantees:

		Expiration		
(in millions)	**Total Amounts Committed at December 31, 2018**	**Less Than 1 Year**	**1 to 3 Years**	**Over 3 Years**
Guarantees supporting commodity transactions of subsidiaries [1]	**$ 88.6**	$ 69.6	$ 1.0	$ 18.0
Standby letters of credit [2]	**21.4**	—	0.2	21.2
Other guarantees [3]	**17.7**	—	10.0	7.7
Total guarantees	**$ 127.7**	$ 69.6	$ 11.2	$ 46.9

(1) Consists of (a) $5.0 million and $6.0 million to support the business operations of WBS and PDL, respectively; and (b) $62.1 million and $15.5 million related to natural gas supply at MERC and MGU, respectively. These amounts are not reflected on our balance sheets.

(2) At our request or the request of our subsidiaries, financial institutions have issued standby letters of credit for the benefit of third parties that have extended credit to our subsidiaries. These amounts are not reflected on our balance sheets.

(3) Consists of (a) $7.7 million to support PDL's future payment obligations related to its distributed solar generation projects, of which $6.6 million is covered by a reciprocal guarantee from a third party that is not reflected on our balance sheets and (b) $10.0 million related to the sale of a nonregulated retail marketing business previously owned by us, of which an insignificant liability was recorded.

NOTE 19—EMPLOYEE BENEFITS

Pension and Other Postretirement Employee Benefits

Through December 31, 2016, we maintained a noncontributory, qualified pension plan sponsored by WBS that covered the majority of our employees. Effective January 1, 2017, that plan was split into six separate plans. While the split did not impact our pension benefit obligation, federal regulations required a different allocation of assets among the new plans. We maintain several unfunded non-qualified retirement plans and our subsidiaries maintain noncontributory, qualified pension plans.

In addition, we and our subsidiaries offer multiple OPEB plans to employees. The benefits for a portion of these plans are funded through irrevocable trusts, as allowed for income tax purposes. WEC Energy Group also offers medical, dental, and life insurance benefits to active employees and their dependents. We expense the costs of these benefits as incurred.

The defined benefit pension plans are closed to all new hires. In addition, the service accruals for the defined benefit pension plans were frozen for non-union employees as of January 1, 2013. These employees receive an annual company contribution to their 401(k) savings plan, which is calculated based on age, wages, and full years of vesting service as of December 31 each year. In October 2017, we remeasured the obligations of our OPEB plan as a result of a plan design change to move all participants to the same Medicare Advantage plan design starting January 1, 2018.

We use a year-end measurement date to measure the funded status of all of our pension and OPEB plans. Due to the regulated nature of our business, we have concluded that substantially all of the unrecognized costs resulting from the recognition of the funded status of our pension and OPEB plans qualify as a regulatory asset.

The following tables provide a reconciliation of the changes in our plans' benefit obligations and fair value of assets:

	Pension Costs		OPEB Costs	
(in millions)	**2018**	**2017**	**2018**	**2017**
Change in benefit obligation				
Obligation at January 1	**$ 1,359.3**	$ 1,297.6	**$ 394.4**	$ 408.4
Service cost	**27.0**	26.0	**13.0**	13.9
Interest cost	**50.0**	52.1	**14.3**	16.3
Plan amendments	**—**	—	**(3.3)**	(27.1)
Actuarial (gain) loss	**(81.4)**	79.4	**(111.6)**	1.6
Participant contributions	**—**	—	**6.0**	5.9
Benefit payments	**(93.1)**	(95.8)	**(23.3)**	(24.6)
Transfer	**—**	**—**	**(5.4)**	—
Obligation at December 31	**$ 1,261.8**	$ 1,359.3	**$ 284.1**	$ 394.4
Change in fair value of plan assets				
Fair value at January 1	**$ 1,198.6**	$ 1,017.2	**$ 452.9**	$ 419.6
Actual return on plan assets	**(67.4)**	171.9	**(19.4)**	50.4
Employer contributions	**60.7**	68.8	**0.4**	1.4
Net transfer from affiliates	**—**	36.5 *	**—**	0.2 *
Participant contributions	**—**	—	**6.0**	5.9
Benefit payments	**(93.1)**	(95.8)	**(23.3)**	(24.6)
Transfer	**—**	—	**(0.1)**	—
Fair value at December 31	**$ 1,098.8**	$ 1,198.6	**$ 416.5**	$ 452.9
Funded status at December 31	**$ (163.0)**	$ (160.7)	**$ 132.4**	$ 58.5

* Related to our receipt of pension assets from affiliates as a result of our pension plan split for the year ended December 31, 2017. Assets were transferred into our plan in January 2017. See Note 4, Related Parties, for more information.

The amounts recognized on our balance sheets at December 31 related to the funded status of the benefit plans were as follows:

	Pension Costs		OPEB Costs	
(in millions)	**2018**	**2017**	**2018**	**2017**
Other long-term assets	**$ 9.0**	$ 29.5	**$ 148.6**	$ 78.1
Pension and OPEB obligations	**172.0**	190.2	**16.2**	19.6
Total net (liabilities) assets	**$ (163.0)**	$ (160.7)	**$ 132.4**	$ 58.5

The accumulated benefit obligation for the defined benefit pension plans was $1,141.9 million and $1,255.7 million at December 31, 2018 and 2017, respectively.

The following table shows information for pension plans with an accumulated benefit obligation in excess of plan assets. Amounts presented are as of December 31:

(in millions)	**2018**	**2017**
Projected benefit obligation	**$ 484.4**	$ 529.8
Accumulated benefit obligation	**438.1**	481.1
Fair value of plan assets	**329.9**	339.6

The following table shows the amounts that have not yet been recognized in our net periodic benefit cost as of December 31:

	Pension Costs		OPEB Costs	
(in millions)	2018	2017	2018	2017
Pre-tax accumulated other comprehensive income (loss) [1]				
Net actuarial loss (gain)	**$ 24.3**	$ 28.2	**$ (1.8)**	$ (1.6)
Prior service credits	**—**	—	**(0.1)**	(0.2)
Total	**$ 24.3**	$ 28.2	**$ (1.9)**	$ (1.8)
Net regulatory assets (liabilities) [2]				
Net actuarial loss (gain)	**$ 513.5**	$ 493.9	**$ (81.4)**	$ (20.1)
Prior service costs (credits)	**7.1**	8.8	**(92.5)**	(102.1)
Total	**$ 520.6**	$ 502.7	**$ (173.9)**	$ (122.2)

[1] Amounts related to the nonregulated entities are included in accumulated other comprehensive loss.

[2] Amounts related to the utilities are recorded as net regulatory assets or liabilities.

The following table shows the estimated amounts that will be amortized into net periodic benefit cost during 2019:

(in millions)	Pension Costs	OPEB Costs
Net actuarial loss (gain)	$ 45.9	$ (3.8)
Prior service costs (credits)	1.7	(13.2)
Total 2019 – estimated amortization	$ 47.6	$ (17.0)

The components of net periodic benefit cost for the years ended December 31 are as follows:

	Pension Costs			OPEB Costs		
(in millions)	2018	2017	2016	2018	2017	2016
Service cost	**$ 27.0**	$ 26.0	$ 27.9	**$ 13.0**	$ 13.9	$ 15.8
Interest cost	**50.0**	52.1	54.4	**14.3**	16.3	18.8
Expected return on plan assets	**(79.3)**	(78.5)	(75.2)	**(32.1)**	(30.2)	(28.8)
(Gain) loss on plan settlement	**(0.1)**	3.0	9.9	**—**	—	—
Amortization of prior service cost (credit)	**1.7**	1.7	1.7	**(12.8)**	(10.7)	(8.1)
Amortization of net actuarial loss	**49.7**	45.6	46.7	**1.3**	2.9	5.6
Net periodic benefit cost (credit)	**$ 49.0**	$ 49.9	$ 65.4	**$ (16.3)**	$ (7.8)	$ 3.3

Effective January 1, 2018, we adopted ASU 2017-07, Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost, which modifies certain aspects of the accounting for employee benefit costs. Under the new guidance, only the service cost component can be included in total operating expenses. The remaining components of net periodic benefit cost are required to be presented in the income statement separately from the service cost component, outside of operating income. As required, this change was applied retrospectively to all prior periods presented. Accordingly, for the years ended December 31, 2018, 2017, and 2016, we have presented the service cost component of our retirement benefit plans in other operation and maintenance on the income statements, while presenting the non-service cost components in other income, net.

As required by ASU 2017-07, our income statements for the years ended December 31, 2017 and 2016, were retroactively restated from what was previously presented in our 2017 Annual Report. The impacts to our income statements from adoption of this standard are reflected in the table below.

	Year Ended December 31, 2017			Year Ended December 31, 2016		
(in millions)	2017 Annual Report Income Statement	Impact of ASU 2017-07	Income Statement After Adoption	2017 Annual Report Income Statement	Impact of ASU 2017-07	Income Statement After Adoption
Operating expenses						
Other operation and maintenance	$ 1,017.6	$ (1.6)	$ 1,016.0	$ 1,156.9	$ (18.9)	$ 1,138.0
Other expense						
Other income, net	38.3	(1.6)	36.7	52.1	(18.9)	33.2

In addition, under ASU 2017-07, only the service cost component of net periodic benefit cost is eligible for capitalization to property, plant, and equipment. In prior periods, a portion of all net benefit cost components was capitalized to property, plant, and equipment. As required, this amendment was applied prospectively, beginning January 1, 2018. As a result of the application of accounting principles for rate regulated entities, the non-service cost components of the net benefit cost that are no longer eligible for capitalization under this standard, but are capitalized under the regulatory framework, will be presented as regulatory assets or liabilities rather than property, plant, and equipment.

The weighted-average assumptions used to determine the benefit obligations for the plans were as follows for the years ended December 31:

	Pension		OPEB	
	2018	2017	2018	2017
Discount rate	**4.30%**	3.69%	**4.25%**	3.62%
Rate of compensation increase	**4.00%**	4.00%	**N/A**	N/A
Assumed medical cost trend rate (Pre 65)	**N/A**	N/A	**6.25%**	6.50%
Ultimate trend rate (Pre 65)	**N/A**	N/A	**5.00%**	5.00%
Year ultimate trend rate is reached (Pre 65)	**N/A**	N/A	**2024**	2024
Assumed medical cost trend rate (Post 65)	**N/A**	N/A	**5.90%**	6.00%
Ultimate trend rate (Post 65)	**N/A**	N/A	**5.00%**	5.00%
Year ultimate trend rate is reached (Post 65)	**N/A**	N/A	**2028**	2028

The weighted-average assumptions used to determine the net periodic benefit cost for the plans were as follows for the years ended December 31:

	Pension Costs		
	2018	2017	2016
Discount rate	**3.75%**	4.13%	4.26%
Expected return on assets	**7.25%**	7.25%	7.25%
Rate of compensation increase	**4.00%**	4.00%	4.00%

	OPEB Costs		
	2018	2017	2016
Discount rate	**3.62%**	4.00%	4.34%
Expected return on assets	**7.25%**	7.25%	7.25%
Assumed medical cost trend rate (Pre 65)	**6.50%**	7.00%	7.50%
Ultimate trend rate (Pre 65)	**5.00%**	5.00%	5.00%
Year ultimate trend rate is reached (Pre 65)	**2024**	2021	2021
Assumed medical cost trend rate (Post 65)	**6.00%**	7.00%	7.50%
Ultimate trend rate (Post 65)	**5.00%**	5.00%	5.00%
Year ultimate trend rate is reached (Post 65)	**2028**	2021	2021

WEC Energy Group consults with its investment advisors on an annual basis to help forecast expected long-term returns on plan assets by reviewing historical returns as well as calculating expected total trust returns using the weighted-average of long-term

market returns for each of the major target asset categories utilized in the fund. For 2019, the expected return on assets assumption for the pension and OPEB plans is 7.25%.

Assumed health care cost trend rates have a significant effect on the amounts reported by us for health care plans. For the year ended December 31, 2018, a one-percentage-point change in assumed health care cost trend rates would have had the following effects:

(in millions)	1% Increase	1% Decrease
Effect on total of service and interest cost components of net periodic postretirement health care benefit cost	$ 4.0	$ (3.1)
Effect on health care component of the accumulated postretirement benefit obligations	23.4	(19.3)

Plan Assets

Current pension trust assets and amounts which are expected to be contributed to the trusts in the future are expected to be adequate to meet pension payment obligations to current and future retirees.

The Investment Trust Policy Committee oversees investment matters related to all of our funded benefit plans. The Committee works with external actuaries and investment consultants on an on-going basis to establish and monitor investment strategies and target asset allocations. Forecasted cash flows for plan liabilities are regularly updated based on annual valuation results. Target allocations are determined utilizing projected benefit payments and risk analyses of appropriate investments. They are intended to reduce risk, provide long-term financial stability for the plans and maintain funded levels which meet long-term plan obligations while preserving sufficient liquidity for near-term benefit payments.

Our pension plan's assets are invested in a corporate pension trust with a target asset allocation of 45% equity investments, 45% fixed income investments, and 10% private equity and real estate investments. Our two largest OPEB trusts have target asset allocations of 45% equity investments and 55% fixed income investments, and 50% equity investments and 50% fixed income investments, respectively. Equity securities include investments in large-cap, mid-cap, and small-cap companies primarily located in the United States. Fixed income securities include corporate bonds of companies from diversified industries, mortgage and other asset backed securities, commercial paper, and United States Treasuries.

Pension and OPEB plan investments are recorded at fair value. See Note 1(n), Fair Value Measurements, for more information regarding the fair value hierarchy and the classification of fair value measurements based on the types of inputs used.

The following tables provide the fair values of our investments by asset class:

	December 31, 2018							
	Pension Plan Assets				OPEB Assets			
(in millions)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Asset Class								
Equity securities:								
United States Equity	$ 135.7	$ —	$ —	$ 135.7	$ 45.3	$ —	$ —	$ 45.3
International Equity	137.7	0.5	—	138.2	50.3	0.1	—	50.4
Fixed income securities: *								
United States Bonds	28.0	204.7	—	232.7	79.4	64.6	—	144.0
International Bonds	4.0	36.1	—	40.1	4.3	3.1	—	7.4
	$ 305.4	$ 241.3	$ —	$ 546.7	$ 179.3	$ 67.8	$ —	$ 247.1
Investments measured at net asset value				$ 552.1				$ 169.4
Total	$ 305.4	$ 241.3	$ —	$ 1,098.8	$ 179.3	$ 67.8	$ —	$ 416.5

* This category represents investment grade bonds of United States and foreign issuers denominated in United States dollars from diverse industries.

	December 31, 2017							
	Pension Plan Assets				OPEB Plan Assets			
(in millions)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Asset Class								
Cash and cash equivalents	$ —	$ 37.4	$ —	$ 37.4	$ 16.2	$ 0.8	$ —	$ 17.0
Equity securities:								
United States Equity	164.7	—	—	164.7	50.4	—	—	50.4
International Equity	165.2	—	0.7	165.9	59.5	—	0.2	59.7
Fixed income securities: *								
United States Bonds	30.0	217.4	—	247.4	80.5	63.1	—	143.6
International Bonds	3.9	35.6	—	39.5	4.2	3.4	—	7.6
Private Equity and Real Estate	—	105.7	21.1	126.8	—	2.2	0.4	2.6
	$ 363.8	$ 396.1	$ 21.8	$ 781.7	$ 210.8	$ 69.5	$ 0.6	$ 280.9
Investments measured at net asset value				$ 416.9				$ 172.0
Total	$ 363.8	$ 396.1	$ 21.8	$ 1,198.6	$ 210.8	$ 69.5	$ 0.6	$ 452.9

* This category represents investment grade bonds of United States and foreign issuers denominated in United States dollars from diverse industries.

The following tables set forth a reconciliation of changes in the fair value of pension and OPEB plan assets categorized as Level 3 in the fair value hierarchy:

	Private Equity and Real Estate		International Equity	
(in millions)	Pension	OPEB	Pension	OPEB
Beginning balance at January 1, 2018	**$ 21.1**	**$ 0.4**	**$ 0.7**	**$ 0.2**
Realized and unrealized losses	**1.7**	**—**	**(0.1)**	**—**
Purchases	**4.1**	**0.1**	**—**	**—**
Liquidations	**(0.1)**	**—**	**—**	**—**
Transfers out of level 3	**(26.8)**	**(0.5)**	**(0.6)**	**(0.2)**
Ending balance at December 31, 2018	**$ —**	**$ —**	**$ —**	**$ —**

	Private Equity and Real Estate		International Equity		U.S. Bonds
(in millions)	Pension	OPEB	Pension	OPEB	Pension
Beginning balance at January 1, 2017	$ —	$ —	$ —	$ —	$ 0.6
Realized and unrealized losses	—	—	(0.2)	—	(0.6)
Purchases	21.1	0.4	0.9	0.2	—
Ending balance at December 31, 2017	$ 21.1	$ 0.4	$ 0.7	$ 0.2	**$ —**

Cash Flows

We expect to contribute $0.7 million to the pension plans and $0.3 million to the OPEB plans in 2019, dependent upon various factors affecting us, including our liquidity position and the effects of the new Tax Legislation.

The following table shows the payments, reflecting expected future service, that we expect to make for pension and OPEB:

(in millions)	Pension	OPEB
2019	$ 101.4	$ 16.7
2020	97.3	18.8
2021	99.9	19.8
2022	97.3	19.8
2023	94.0	20.5
2024 through 2028	430.2	108.7

Savings Plans

WEC Energy Group sponsors a 401(k) savings plan that allows substantially all of our full-time employees to contribute a portion of their pre-tax and/or after-tax income in accordance with plan-specified guidelines. A percentage of employee contributions are matched by us through a contribution into the employee's savings plan account, up to certain limits. The 401(k) savings plans include an Employee Stock Ownership Plan. Certain employees receive an employer retirement contribution, which amounts are contributed to an employee's savings plan account based on the employee's wages, age, and years of service. Our share of the total costs incurred under all of these plans was $22.1 million in 2018, $21.7 million in 2017, and $19.0 million in 2016.

NOTE 20—INVESTMENT IN AMERICAN TRANSMISSION COMPANY

At December 31, 2017, our electric transmission investment segment consisted of WPSI's ownership interest in ATC, which was approximately 34%. In January 2018, we transferred our ownership interest in ATC to another subsidiary of WEC Energy Group. ATC is a for-profit, transmission-only company regulated by the FERC for cost of service and certain state regulatory commissions for routing and siting of transmission-related projects. The following table provides a reconciliation of the changes in our investment in ATC:

(in millions)	2018	2017	2016
Balance at January 1	**$ 621.1**	$ 600.2	$ 550.4
Less: Transfer of ownership interest	**621.1**	—	—
Add: Earnings from equity method investment	**—**	93.8	82.2
Add: Capital contributions	**—**	34.1	23.9
Less: Distributions	**—**	107.0 *	56.2
Less: Other	**—**	—	0.1
Balance at December 31	**$ —**	$ 621.1	$ 600.2

* Of this amount, $22.5 million was recorded as a receivable from ATC in other current assets at December 31, 2017.

See Note 4, Related Parties, for more information on transactions with ATC.

NOTE 21—SEGMENT INFORMATION

We use operating income to measure segment profitability and to allocate resources to our businesses. At December 31, 2018, we reported five segments, which are described below.

- The Wisconsin segment includes the electric and natural gas utility and non-utility operations of WPS. Through December 31, 2016, the Wisconsin segment included WPS's electric and natural gas operations in the Upper Peninsula of Michigan. Effective January 1, 2017, WPS transferred its customers and electric and natural gas distribution assets located in the Upper Peninsula of Michigan to UMERC. See Note 4, Related Parties, for more information on UMERC.

- The Illinois segment includes the natural gas utility and non-utility operations of PGL and NSG.

- The other states segment includes the natural gas utility and non-utility operations of MERC and MGU.

- Through December 31, 2017, the electric transmission investment segment included our approximate 34% ownership interest in ATC, a for-profit, transmission-only company regulated by the FERC for cost of service and certain state regulatory commissions for routing and siting of transmission projects. In January 2018, we transferred our ownership interest in ATC to another subsidiary of WEC Energy Group. See Note 4, Related Parties, for more information.

- The corporate and other segment includes the operations of the Integrys holding company, the PELLC holding company, PDL, and ITF. The sale of ITF was completed in the first quarter of 2016. See Note 3, Disposition, for more information on the sale of ITF.

All of our operations and assets are located within the United States. The following tables show summarized financial information related to our reportable segments for the years ended December 31, 2018, 2017, and 2016.

	Regulated Operations							
2018 *(in millions)*	**Wisconsin**	**Illinois**	**Other States**	**Electric Transmission Investment**	**Total Regulated Operations**	**Corporate and Other**	**Reconciling Eliminations**	**Integrys Holding Consolidated**
External revenues	**$ 1,498.5**	**$1,400.0**	**$ 438.2**	**$ —**	**$ 3,336.7**	**$ 8.0**	**$ —**	**$ 3,344.7**
Other operation and maintenance	**448.0**	**472.3**	**101.0**	**—**	**1,021.3**	**7.1**	**—**	**1,028.4**
Depreciation and amortization	**141.9**	**170.3**	**24.1**	**—**	**336.3**	**2.4**	**—**	**338.7**
Operating income (loss)	**266.4**	**255.8**	**68.8**	**—**	**591.0**	**(1.1)**	**—**	**589.9**
Interest expense	**53.9**	**51.2**	**8.7**	**—**	**113.8**	**37.8**	**(0.8)**	**150.8**
Capital expenditures and asset acquisitions	**521.4**	**545.0**	**102.9**	**—**	**1,169.3**	**—**	**—**	**1,169.3**
Total assets	**5,217.7**	**6,162.3**	**1,127.0**	**—**	**12,507.0**	**410.0**	**(71.4)**	**12,845.6**

	Regulated Operations							
2017 *(in millions)*	**Wisconsin**	**Illinois**	**Other States**	**Electric Transmission Investment**	**Total Regulated Operations**	**Corporate and Other**	**Reconciling Eliminations**	**Integrys Holding Consolidated**
External revenues	$ 1,485.4	$1,355.5	$ 411.2	$ —	$ 3,252.1	$ 12.8	$ —	$ 3,264.9
Other operation and maintenance *	447.5	464.4	101.0	—	1,012.9	3.1	—	1,016.0
Depreciation and amortization	139.3	152.6	24.8	—	316.7	3.6	—	320.3
Operating income *	285.1	279.9	54.4	—	619.4	6.0	—	625.4
Equity in earnings of transmission affiliate	—	—	—	93.8	93.8	—	—	93.8
Interest expense	54.3	45.0	8.7	—	108.0	40.1	(4.1)	144.0
Capital expenditures	335.8	545.2	74.5	—	955.5	4.5	—	960.0
Total assets	4,741.3	5,823.3	1,045.9	643.7	12,254.2	599.6	(83.0)	12,770.8

* Includes the retroactive restatement impacts of the implementation of ASU 2017-07. See Note 19, Employee Benefits, for more information on this new standard.

	Regulated Operations							
2016 *(in millions)*	**Wisconsin**	**Illinois**	**Other States**	**Electric Transmission Investment**	**Total Regulated Operations**	**Corporate and Other**	**Reconciling Eliminations**	**Integrys Holding Consolidated**
External revenues	$ 1,448.2	$1,242.2	$ 376.6	$ —	$ 3,067.0	$ 21.9	$ —	$ 3,088.9
Other operation and maintenance *	503.7	509.1	112.6	—	1,125.4	12.6	—	1,138.0
Depreciation and amortization	124.1	134.0	21.1	—	279.2	4.3	—	283.5
Operating income (loss) *	253.0	215.6	47.5	—	516.1	(1.2)	—	514.9
Equity in earnings of transmission affiliate	—	—	—	82.2	82.2	—	—	82.2
Interest expense	48.1	38.9	8.5	—	95.5	46.7	(8.0)	134.2
Capital expenditures	311.2	293.2	59.5	—	663.9	1.7	—	665.6
Total assets	4,639.4	5,392.7	966.2	600.2	11,598.5	464.1	(233.8)	11,828.8

* Includes the retroactive restatement impacts of the implementation of ASU 2017-07. See Note 19, Employee Benefits, for more information on this new standard.

NOTE 22—COMMITMENTS AND CONTINGENCIES

We and our subsidiaries have significant commitments and contingencies arising from our operations, including those related to unconditional purchase obligations, operating leases, environmental matters, and enforcement and litigation matters.

Unconditional Purchase Obligations

Our natural gas utilities have obligations to distribute and sell natural gas to their customers, and our electric utility has obligations to distribute and sell electricity to its customers. The utilities expect to recover costs related to these obligations in future customer rates. In order to meet these obligations, we routinely enter into long-term purchase and sale commitments for various quantities and lengths of time.

The following table shows our minimum future commitments related to these purchase obligations as of December 31, 2018, including those of our subsidiaries.

			Payments Due By Period					
(in millions)	Date Contracts Extend Through	Total Amounts Committed	2019	2020	2021	2022	2023	Later Years
Electric utility:								
Purchased power	2041	$ 410.8	$ 75.1	$ 48.2	$ 46.8	$ 41.8	$ 39.7	$ 159.2
Coal supply and transportation	2024	325.4	115.0	63.1	48.2	47.6	50.8	0.7
Natural gas utility supply and transportation	2048	1,157.1	202.0	168.8	107.5	83.9	51.9	543.0
Total		$ 1,893.3	$ 392.1	$ 280.1	$ 202.5	$ 173.3	$ 142.4	$ 702.9

Operating Leases

We lease property, plant, and equipment under various terms. The operating leases generally require us to pay property taxes, insurance premiums, and maintenance costs associated with the leased property. Many of our leases contain one of the following options upon the end of the lease term: (a) purchase the property at the current fair market value, or (b) exercise a renewal option, as set forth in the lease agreement.

Rental expense attributable to operating leases was $2.6 million, $3.8 million, and $2.4 million in 2018, 2017, and 2016, respectively.

Future minimum payments under noncancelable operating leases are payable as follows:

Year Ending December 31	Payments *(in millions)*
2019	$ 0.5
2020	0.3
2021	0.3
2022	0.3
2023	0.3
Later years	2.9
Total	$ 4.6

Environmental Matters

Consistent with other companies in the energy industry, we face significant ongoing environmental compliance and remediation obligations related to current and past operations. Specific environmental issues affecting us include, but are not limited to, current and future regulation of air emissions such as sulfur dioxide, nitrogen oxide, fine particulates, mercury, and GHGs; water intake and discharges; disposal of coal combustion products such as fly ash; and remediation of impacted properties, including former manufactured gas plant sites.

We have continued to pursue a proactive strategy to manage our environmental compliance obligations, including:

- the development of additional sources of renewable electric energy supply;
- the addition of improvements for water quality matters such as treatment technologies to meet regulatory discharge limits and improvements to our cooling water intake systems;
- the addition of emission control equipment to existing facilities to comply with ambient air quality standards and federal clean air rules;

- the protection of wetlands and waterways, threatened and endangered species, and cultural resources associated with utility construction projects;
- the retirement of old coal-fired power plants and conversion to modern, efficient, natural gas generation, super-critical pulverized coal generation, and/or replacement with renewable generation;
- the beneficial use of ash and other products from coal-fired units; and
- the remediation of former manufactured gas plant sites.

Air Quality

National Ambient Air Quality Standards

After completing its review of the 2008 ozone standard, the EPA released a final rule in October 2015, which lowered the limit for ground-level ozone, creating a more stringent standard than the 2008 National Ambient Air Quality Standards. The EPA issued final nonattainment area designations on May 1, 2018. The following counties within our service territories were designated as partial nonattainment: Door, Manitowoc, and Sheboygan shorelines. The state of Wisconsin will need to develop a state implementation plan to bring these areas back into attainment. We will be required to comply with this state implementation plan no earlier than 2020. We believe we are well positioned to meet the requirements associated with the ozone standard and do not expect to incur significant costs to comply.

Mercury and Air Toxics Standards

In December 2018, the EPA proposed to revise the Supplemental Cost Finding for the mercury and air toxics standards (MATS) rule as well as the CAA required risk and technology review (RTR). The EPA was required by the Supreme Court to review both costs and benefits of complying with the MATS rule. After its review of costs, the EPA determined that it is not appropriate and necessary to regulate hazardous air pollutant emissions from power plants under Section 112 of the CAA. As a result, under the proposed rule, the emission standards and other requirements of the MATS rule first enacted in 2012 would remain in place. The EPA is not proposing to remove coal and oil fired power plants from the list of sources that are regulated under Section 112. The EPA also proposes that no revisions to MATS are warranted based on the results of the RTR. As a result, we do not expect the proposed rule to have a material impact on our financial condition or operations.

Climate Change

In 2015, the EPA issued a final rule regulating GHG emissions from existing generating units, referred to as the Clean Power Plan, and final performance standards for modified and reconstructed generating units and new fossil-fueled power plants. In February 2016, the Supreme Court stayed the effectiveness of the CPP until disposition of certain litigation in the D.C. Circuit Court of Appeals challenging the rule and, to the extent that further appellate review is sought, at the Supreme Court. In April 2017, pursuant to motions made by the EPA, the D.C. Circuit Court of Appeals ordered the challenges to the CPP, as well as related performance standards for new, reconstructed, and modified fossil-fueled power plants, to be held in abeyance, which remains the case.

In December 2017, the EPA issued an advanced notice of proposed rulemaking to solicit input on whether it is appropriate to replace the CPP. Then, in August 2018, the EPA issued a proposed replacement rule for the CPP, the Affordable Clean Energy (ACE) rule. The proposed ACE rule would require the EPA to develop emission guidelines for states to use to develop their individual state plans. The state plans would focus on reducing GHG emissions by improving the efficiency of fossil-fueled power plants.

In December 2018, the EPA proposed to revise the New Source Performance Standards for GHG emissions from new, modified, and reconstructed fossil fueled power plants. The EPA determined that the best system of emission reduction (BSER) for new, modified, and reconstructed coal units is highly efficient generation that would be equivalent to supercritical steam conditions for larger units and subcritical steam conditions for smaller units. This proposed BSER would replace the determination from the 2015 rule, which identified BSER as partial carbon capture and storage.

In addition, we are evaluating our goals, and possible subsequent actions, with respect to national and international efforts to reduce future GHG emissions in order to limit future global temperature increases to less than two degrees Celsius. We are working with industry members to evaluate potential GHG reduction pathways.

We continue to evaluate opportunities and actions that preserve fuel diversity, lower costs for our customers, and contribute towards long-term GHG reductions. WEC Energy Group's plan, which includes us, is to work with our industry partners,

environmental groups, and the State of Wisconsin, with goals of reducing CO_2 emissions by approximately 40% and 80% below 2005 levels by 2030 and 2050, respectively. We have implemented and continue to evaluate numerous options in order to meet WEC Energy Group's CO_2 reduction goals. As a result of WEC Energy Group's generation reshaping plan, we retired approximately 300 MW of coal generation in 2018, consisting of the Pulliam power plant and the jointly-owned Edgewater Unit 4 generation units. See Note 7, Property, Plant, and Equipment, for more information.

We are required to report our CO_2 equivalent emissions from our electric generating facilities under the EPA Greenhouse Gases Reporting Program. For 2017, we reported aggregated CO_2 equivalent emissions of approximately 5.7 million metric tonnes to the EPA. Based upon our preliminary analysis of the data, we estimate that we will report CO_2 equivalent emissions of approximately 6.4 million metric tonnes to the EPA for 2018. The level of CO_2 and other GHG emissions varies from year to year and is dependent on the level of electric generation and mix of fuel sources, which is determined primarily by demand, the availability of the generating units, the unit cost of fuel consumed, and how our units are dispatched by MISO.

We are also required to report CO_2 equivalent emissions related to the natural gas that our natural gas utilities distribute and sell. For 2017, we reported aggregated CO_2 equivalent emissions of approximately 16.9 million metric tonnes to the EPA. Based upon our preliminary analysis of the data, we estimate that we will report CO_2 equivalent emissions of approximately 18.9 million metric tonnes to the EPA for 2018.

Water Quality

Clean Water Act Cooling Water Intake Structure Rule

In August 2014, the EPA issued a final regulation under Section 316(b) of the Clean Water Act, that requires the location, design, construction, and capacity of cooling water intake structures at existing power plants to reflect the Best Technology Available (BTA) for minimizing adverse environmental impacts. The rule became effective in October 2014 and applies to all of our existing generating facilities with cooling water intake structures.

The rule requires state permitting agencies to make BTA determinations, subject to EPA oversight, over the next several years as facility permits are reissued. Based on our assessment, we believe that existing technologies at our generating facilities, except for Weston Unit 2, satisfy the BTA requirements. WPS retired Pulliam Units 7 and 8 effective October 21, 2018. See Note 7, Property, Plant, and Equipment, for more information on the retirement of the Pulliam generating units. Therefore, WPS will not be required to make alterations to the existing water intake at these units. Based on the March 2018 reissued WPDES permit for Weston, the WDNR will not require physical modifications to the Weston Unit 2 intake structure to meet the BTA requirements based on low capacity use of the unit.

We have received an interim BTA determination made by the WDNR as part of the March 2018 reissued WPDES permit for Weston Units 3 and 4. We expect that the WDNR will conclude, in the next permit reissuance, that the existing cooling tower systems for Weston Units 3 and 4 are BTA. Due to the retirement of Pulliam Units 7 and 8, we do not believe that BTA determinations will be necessary for these units. We also have provided information to the WDNR about planned unit retirements.

As a result of past capital investments completed to address 316(b) compliance at WPS, we believe our fleet overall is well positioned to meet the new regulation and do not expect to incur significant costs to comply with this regulation.

Steam Electric Effluent Limitation Guidelines

The EPA's final steam electric effluent limitation guidelines (ELG) rule took effect in January 2016. This rule created new requirements for several types of power plant wastewaters. The two new requirements that affect WPS relate to discharge limits for bottom ash transport water (BATW) and wet flue gas desulfurization (FGD) wastewater. Various petitions challenging the rule were consolidated and are pending in the United States Court of Appeals for the Fifth Circuit. In April 2017, the EPA issued an administrative stay of certain compliance deadlines while further reviewing the rule. In September 2017, the EPA issued a final rule (Postponement Rule) to postpone the earliest compliance date to November 1, 2020 for the BATW and wet FGD wastewater requirements. The latest ELG rule compliance date remains December 31, 2023 for any new wastewater treatment requirements contained in power plant discharge permits. This rule applies to wastewater discharges from our power plant processes in Wisconsin. Litigation over various aspects of the final ELG rule and the Postponement Rule is pending in several federal courts.

As a result of past capital investments completed to address ELG compliance at WPS, we believe our fleet overall is well positioned to meet this new regulation. Our power plant facilities already have advanced wastewater treatment technologies installed that meet many of the discharge limits established by this rule. However, as currently constructed, the ELG rule will require additional wastewater treatment retrofits as well as installation of other equipment to minimize process water use. Due to completed and pending generating unit retirements, we believe the only facility that will require bottom ash system modifications is Weston Unit 3. Based on preliminary engineering, the estimated rule compliance cost is approximately $20 million.

Land Quality

Manufactured Gas Plant Remediation

We have identified sites at which our utilities or a predecessor company owned or operated a manufactured gas plant or stored manufactured gas. We have also identified other sites that may have been impacted by historical manufactured gas plant activities. Our natural gas utilities are responsible for environmental remediation of these sites, some of which are in the EPA Superfund Alternative Approach Program. We are also working with various state jurisdictions in our investigation and remediation planning. These sites are at various stages of investigation, monitoring, remediation, and closure.

In addition, we are coordinating the investigation and cleanup of some of these sites subject to the jurisdiction of the EPA under what is called a "multisite" program. This program involves prioritizing the work to be done at the sites, preparation and approval of documents common to all of the sites, and use of a consistent approach in selecting remedies. At this time, we cannot estimate future remediation costs associated with these sites beyond those described below.

The future costs for detailed site investigation, future remediation, and monitoring are dependent upon several variables including, among other things, the extent of remediation, changes in technology, and changes in regulation. Historically, our regulators have allowed us to recover incurred costs, net of insurance recoveries and recoveries from potentially responsible parties, associated with the remediation of manufactured gas plant sites. Accordingly, we have established regulatory assets for costs associated with these sites.

We have established the following regulatory assets and reserves related to manufactured gas plant sites as of December 31:

(in millions)	2018	2017
Regulatory assets	**$ 577.2**	$ 598.9
Reserves for future remediation	**525.4**	557.5

Renewables, Efficiency, and Conservation

Wisconsin Legislation

In 2005, Wisconsin enacted Act 141, which established a goal that 10% of all electricity consumed in Wisconsin be generated by renewable resources by December 31, 2015. WPS achieved a renewable energy percentage of 9.74% and met its compliance requirements by constructing various wind parks and by also relying on renewable energy purchases. WPS continues to review its renewable energy portfolios and acquire cost-effective renewables as needed to meet its requirements on an ongoing basis. The PSCW administers the renewable program related to Act 141, and WPS funds the program, along with other utilities, based on 1.2% of its annual operating revenues.

Enforcement and Litigation Matters

We and our subsidiaries are involved in legal and administrative proceedings before various courts and agencies with respect to matters arising in the ordinary course of business. Although we are unable to predict the outcome of these matters, management believes that appropriate reserves have been established and that final settlement of these actions will not have a material effect on our financial condition or results of operations.

Manlove Field Matter

In September 2017, the Illinois Department of Natural Resources, Office of Oil and Gas Resource Management, issued an NOV to PGL related to a leak of natural gas that PGL identified at its Manlove Gas Storage Field in December 2016. PGL quickly contained the leak

after it was discovered. The leak resulted in the migration of natural gas from a well located at the facility to the Mahomet Aquifer located in central Illinois, which impacted residential freshwater wells. PGL has been working with residents potentially impacted by the natural gas leak, and the Illinois state agencies to investigate and remediate the impacts of the natural gas leak to the Mahomet Aquifer. In October 2017, the Illinois Attorney General (AG) filed a complaint against PGL alleging certain violations of the Illinois Environmental Protection Act and the Oil and Gas Act. PGL entered into an interim order with the State of Illinois in October 2017 whereby PGL agreed, among other things, to continue actions it was already undertaking proactively. In addition, in December 2017, the Illinois Environmental Protection Agency served an NOV to PGL alleging the same violations as the AG, and in January 2018, served an NOV alleging certain violations of Illinois air emission rules arising from the construction and operation of flaring equipment at the leak site. Both matters have been referred to the AG for enforcement.

In the complaint, as is customary in these types of actions, the AG cited to the statutory penalties allowed by law. Ultimately, the assessment of any penalties is at the AG's discretion. In the event the AG wishes to consider such penalties, we believe that PGL's high level of cooperation and quick action to remedy the situation and to work with the potentially impacted homeowners would be taken into account. At this time, we believe that civil penalties, if any, will not have a material impact on our financial statements.

Consent Decrees

Wisconsin Public Service Corporation Consent Decree – Weston and Pulliam Power Plants

In November 2009, the EPA issued an NOV to WPS, which alleged violations of the CAA's New Source Review requirements relating to certain projects completed at the Weston and Pulliam power plants from 1994 to 2009. WPS entered into a Consent Decree with the EPA resolving this NOV. This Consent Decree was entered by the United States District Court for the Eastern District of Wisconsin in March 2013.

The final Consent Decree includes:

- the installation of emission control technology, including ReACT™ on Weston 3,
- changed operating conditions,
- limitations on plant emissions,
- beneficial environmental projects totaling $6.0 million, and
- a civil penalty of $1.2 million.

The Consent Decree also contains requirements to refuel, repower, and/or retire certain Weston and Pulliam units. Effective June 1, 2015, WPS retired Weston Unit 1 and Pulliam Units 5 and 6. In May 2016, the EPA approved WPS's proposed revision to update requirements reflecting the conversion of Weston Unit 2 from coal to natural gas fuel, and also proposed revisions to the list of beneficial environmental projects required by the Consent Decree. WPS retired Pulliam Units 7 and 8 on October 21, 2018. See Note 7, Property, Plant, and Equipment, for more information about the retirement. WPS completed the mitigation projects required and received a completeness letter from the EPA in October 2018. We plan to request termination of the WPS Consent Decree during 2019.

WPS received approval from the PSCW in its 2015 rate order to defer and amortize the undepreciated book value of the retired plant related to Weston Unit 1 and Pulliam Units 5 and 6 starting June 1, 2015, and concluding by 2023. Therefore, in June 2015, WPS recorded a regulatory asset of $11.5 million for the undepreciated book value. In addition, WPS received approval from the PSCW in its rate orders to recover prudently incurred costs as a result of complying with the terms of the Consent Decree, with the exception of the civil penalty.

Joint Ownership Power Plants Consent Decree – Columbia and Edgewater

In December 2009, the EPA issued an NOV to Wisconsin Power and Light, the operator of the Columbia and Edgewater plants, and the other joint owners of these plants, including Madison Gas and Electric, WE (former co-owner of an Edgewater unit), and WPS. The NOV alleged violations of the CAA's New Source Review requirements related to certain projects completed at those plants. WPS, along with Wisconsin Power and Light, Madison Gas and Electric, and WE, entered into a Consent Decree with the EPA resolving this NOV. This Consent Decree was entered by the United States District Court for the Western District of Wisconsin in June 2013.

The final Consent Decree includes:

- the installation of emission control technology, including scrubbers at the Columbia plant,
- changed operating conditions,
- limitations on plant emissions,
- beneficial environmental projects, with WPS's portion totaling $1.3 million, and
- WPS's portion of a civil penalty and legal fees totaling $0.4 million.

As a result of continued implementation of the Consent Decree related to the jointly owned Columbia and Edgewater plants, the Edgewater 4 generating unit was retired on September 28, 2018. See Note 7, Property, Plant, and Equipment, for more information about the retirement.

NOTE 23—SUPPLEMENTAL CASH FLOW INFORMATION

(in millions)	2018	2017	2016
Cash (paid) for interest, net of amount capitalized	**$ (146.1)**	$ (137.7)	$ (137.5)
Cash (paid) received for income taxes, net	**(1.1)**	58.9	149.6
Significant non-cash transactions:			
Accounts payable related to construction costs	**60.4**	141.9	161.0
Receivable related to corporate-owned life insurance proceeds	**7.7**	—	—
Non-cash equity transfer of WPSI's ownership interest in ATC and related taxes to another subsidiary of WEC Energy Group *	**363.4**	—	—
Non-cash equity transfer of net assets to UMERC *	**0.4**	20.6	—
Non-cash equity transfer of our ownership in WBS to WEC Energy Group *	**—**	—	73.0

* See Note 4, Related Parties, for more information on these transactions.

Effective January 1, 2018, we adopted ASU 2016-18, Restricted Cash. Under this ASU, amounts generally described as restricted cash and restricted cash equivalents are included with cash and cash equivalents when reconciling the beginning-of-the period and end-of-the period total amounts shown on the statements of cash flows. As a result, we no longer present transfers between cash and cash equivalents and restricted cash and restricted cash equivalents in the statements of cash flows. Instead, changes in restricted cash are classified as either operating activities, investing activities, or financing activities.

The majority of our restricted cash consists of amounts held in our rabbi trust, which are used to fund participants' benefits under our deferred compensation plan and certain non-qualified pension plans. All assets held within the rabbi trust are restricted as they can only be withdrawn from the trust to make qualifying benefit payments.

Our statements of cash flows for the years ended December 31, 2017 and 2016 were retroactively restated from what was previously presented in our 2017 Annual Report to reflect the adoption of ASU 2016-18. The impacts to our statements of cash flows from adoption of this standard are reflected in the table below.

	Year Ended December 31, 2017			Year Ended December 31, 2016		
(in millions)	2017 Annual Report Cash Flows	Impact of ASU 2016-18	Cash Flows After Adoption	2017 Annual Report Cash Flows	Impact of ASU 2016-18	Cash Flows After Adoption
Operating Activities						
Change in –						
Other current assets	$ 6.4	$ (1.1)	$ 5.3	$ 1.5	$ 0.1	$ 1.6
Other, net	(73.4)	0.1	(73.3)	22.5	0.2	22.7
Net cash provided by operating activities	829.0	(1.0)	828.0	804.3	0.3	804.6
Investing Activities						
Withdrawal of restricted cash from rabbi trust for qualifying payments	19.5	(19.5)	—	26.6	(26.6)	—
Proceeds from the sale of investments held in rabbi trust	—	8.7	8.7	—	1.7	1.7
Purchase of investments held in rabbi trust	—	(3.7)	(3.7)	—	(59.2)	(59.2)
Net cash used in investing activities	(1,265.6)	(14.5)	(1,280.1)	(638.4)	(84.1)	(722.5)
Net change in cash, cash equivalents, and restricted cash	7.3	(15.5)	(8.2)	(7.4)	(83.8)	(91.2)
Cash, cash equivalents, and restricted cash at beginning of year	12.0	35.2	47.2	19.4	119.0	138.4
Cash, cash equivalents, and restricted cash at end of year	$ 19.3	$ 19.7	$ 39.0	$ 12.0	$ 35.2	$ 47.2

The following table provides a reconciliation of cash and cash equivalents and restricted cash reported within the balance sheets to the sum of the total of the same amounts shown in the statements of cash flows at December 31:

(in millions)	2018	2017	2016
Cash and cash equivalents	**$ 24.7**	$ 19.3	$ 12.0
Restricted cash included in other current assets	**—**	—	0.8
Restricted cash included in other long-term assets	**57.3**	19.7	34.4
Cash, cash equivalents, and restricted cash	**$ 82.0**	$ 39.0	$ 47.2

Effective January 1, 2018, we retrospectively adopted ASU 2016-15, Classification of Certain Cash Receipts and Cash Payments. There are eight main provisions of this ASU for which current GAAP either was unclear or did not include specific guidance. The adoption of this guidance had no impact on our financial statements for the years ended December 31, 2018, 2017, and 2016.

ASU 2016-15 provides an accounting policy election for classifying distributions received from equity method investments. We adopted the cumulative earnings approach for classifying distributions received in the statements of cash flows. Under the cumulative earnings approach, we compare the distributions received to cumulative equity method earnings since inception. Any distributions received up to the amount of cumulative equity earnings are considered a return on investment and classified in operating activities. Any excess distributions are considered a return of investment and classified in investing activities. We did not receive any excess distributions during the years ended December 31, 2018, 2017, and 2016.

NOTE 24—REGULATORY ENVIRONMENT

Tax Cuts and Jobs Act of 2017

In December 2017, our regulated utilities deferred for return to ratepayers, through future refunds, bill credits, riders, or reductions in other regulatory assets, the estimated tax benefit of $1,069 million related to the Tax Legislation that was signed into law in December 2017. This tax benefit resulted from the revaluation of deferred taxes. The Tax Legislation also reduced the corporate federal tax rate from a maximum of 35% to a 21% rate, effective January 1, 2018. We have received written orders from the PSCW and the MPSC addressing the refunding of certain of these tax benefits to ratepayers in Wisconsin and Michigan, respectively. The ICC has approved the VITA in Illinois, and the MPUC addressed the impacts to MERC in its 2018 rate order. See the Variable Income Tax Adjustment Rider discussion and the 2018 Minnesota Rate Case discussion below for more information. A summary of the Wisconsin and Michigan orders is outlined below.

Wisconsin

In May 2018, the PSCW issued an order regarding the benefits associated with the Tax Legislation. The PSCW order requires WPS's electric utility operations to use 40% of the current 2018 and 2019 tax benefits to reduce certain regulatory assets. The remaining 60% is to be returned to electric customers in the form of bill credits. For WPS's natural gas utility operations, the PSCW indicated that 100% of the current 2018 and 2019 tax benefits should be returned to natural gas customers in the form of bill credits. Regarding the net tax benefit associated with the revaluation of deferred taxes, amortization required in accordance with normalization accounting is to be used to reduce certain regulatory assets for WPS's electric utility operations and is being deferred for its natural gas utility operations. The timing and method of returning the remaining net tax benefit associated with the revaluation of deferred taxes for WPS's electric and natural gas utility operations was not addressed and will be determined in a future rate proceeding.

Michigan

In February 2018, the MPSC issued an order requiring Michigan utilities to make three filings related to the Tax Legislation. The first of those filings, which was filed in March 2018, prospectively addressed the impact on base rates for the change in tax expense resulting from the federal tax rate reduction from 35% to 21%. MGU proposed providing a volumetric bill credit, subject to reconciliation and true up. In May 2018, the MPSC issued an order approving a settlement that resulted in volumetric bill credits for all of MGU's customers effective July 1, 2018.

The second filing, which was filed in July 2018, addressed the impact on base rates for the change in tax expense resulting from the federal tax rate reduction from 35% to 21% from January 1, 2018 until July 1, 2018. MGU proposed to return the tax savings from these months to customers via volumetric bill credits over multiple months. The MPSC issued an order approving a settlement in September 2018. In accordance with the settlement order, the savings were returned to MGU's customers via volumetric bill credits that were in effect from October 1, 2018 through December 31, 2018.

The third filing was filed in October 2018 and addressed the remaining impacts of the Tax Legislation on base rates – most notably the re-measurement of deferred tax balances. MGU proposed providing a volumetric bill credit, subject to reconciliation and true up, to return these remaining impacts of the Tax Legislation to customers. The MPSC has not yet issued an order with respect to this filing.

Wisconsin Public Service Corporation

2018 and 2019 Rates

During April 2017, WPS, along with WE and WG, filed an application with the PSCW for approval of a settlement agreement they made with several of their commercial and industrial customers regarding 2018 and 2019 base rates. In September 2017, the PSCW issued an order that approved the settlement agreement, which freezes base rates through 2019 for WPS's electric and natural gas customers. Based on the PSCW order, WPS's authorized ROE remains at 10.0%, and its current capital cost structure will remain unchanged through 2019.

In addition to freezing base rates, the settlement agreement extends and expands the electric real-time market pricing program options for large commercial and industrial customers. Additionally, the agreement allows WPS to extend, through 2019, the deferral for the revenue requirement of ReACT™ costs above the authorized $275.0 million level, and other deferrals related to its electric real-time market pricing program and network transmission expenses. The total cost of the ReACT™ project, excluding $51 million of AFUDC, was $342 million.

Pursuant to the settlement agreement, WPS also agreed to adopt, beginning in 2018, the earnings sharing mechanism that has been in place for WE and WG since January 2016, and agreed to keep the mechanism in place through 2019. Under this earnings sharing mechanism, if WPS earns above its authorized ROE, 50% of the first 50 basis points of additional utility earnings must be shared with customers. All utility earnings above the first 50 basis points must also be shared with customers.

As required in the settlement agreement, WPS anticipates initiating a rate proceeding with the PSCW by April 1, 2019.

Acquisition of a Wind Energy Generation Facility in Wisconsin

In October 2017, WPS, along with two other unaffiliated utilities, entered into an agreement to purchase Forward Wind Energy Center, which consists of 86 wind turbines located in Wisconsin with a total capacity of 138 MW. The FERC approved the transaction in January 2018, and the PSCW approved the transaction in March 2018. The transaction closed on April 2, 2018. See Note 2, Acquisition, for more information.

Proposed Solar Generation Projects

On May 31, 2018, WPS, along with an unaffiliated utility, filed an application with the PSCW for approval to acquire ownership interests in two proposed solar projects in Wisconsin. Badger Hollow Solar Farm will be located in Iowa County, Wisconsin, and Two Creeks Solar Project will be located in Manitowoc County, Wisconsin. Subject to receipt of the PSCW's approval, WPS will own 100 MW of the output of each project for a total of 200 MW. WPS's share of the cost of both projects is estimated to be $260 million.

Natural Gas Storage Facilities in Michigan

In January 2017, WEC Energy Group signed an agreement for the acquisition of Bluewater. Bluewater owns natural gas storage facilities in Michigan that provide a portion of the current storage needs for WPS's natural gas utility operations. As a result of this agreement, WPS, along with WE and WG, filed a request with the PSCW in February 2017 for a declaratory ruling on various items associated with the storage facilities. In the filing, WPS requested that the PSCW review and confirm the reasonableness and prudency of its potential long-term storage service agreement and interstate natural gas transportation contract related to the storage facilities. WPS, along with WE and WG, also requested approval to amend WEC Energy Group's AIA to ensure WBS and WEC Energy Group's other subsidiaries could provide services to the storage facilities. During June 2017, the PSCW granted, subject to various conditions, these declarations and approvals, and WEC Energy Group acquired Bluewater on June 30, 2017. In September 2017, WPS entered into the long-term service agreement for the natural gas storage, which was then approved by the PSCW in November 2017.

2016 Wisconsin Rate Order

In April 2015, WPS initiated a rate proceeding with the PSCW. In December 2015, the PSCW issued a final written order for WPS, effective January 1, 2016. The order, which reflected a 10.0% ROE and a common equity component average of 51.0%, authorized a net retail electric rate decrease of $7.9 million (-0.8%) and a net retail natural gas rate decrease of $6.2 million (-2.1%). The decrease in retail electric rates was due to lower monitored fuel costs in 2016 compared with 2015. Absent the adjustment for electric fuel costs, WPS would have realized an electric rate increase. Based on the order, the PSCW allowed WPS to escrow ATC and MISO network transmission expenses through 2016. In addition, system support resource payments are escrowed until a future rate proceeding. The order directed WPS to defer as a regulatory asset or liability the differences between actual transmission expenses and those included in rates. In addition, the PSCW approved a deferral for ReACT™, which required WPS to defer the revenue requirement of ReACT™ costs above the authorized $275.0 million level through 2016. Fuel costs will continue to be monitored using a 2% tolerance window.

In March 2016, WPS requested extensions from the PSCW through 2017 for the deferral of the revenue requirement of ReACT™ costs above the authorized $275.0 million level as well as escrow accounting of ATC and MISO network transmission expenses. In April 2016, WPS also requested to extend through 2017 the previously approved deferral of the revenue requirement difference between the Real Time Market Pricing and the standard tariffed rates for any of WPS's large commercial and industrial customers who entered into a service agreement with WPS under Real Time Market Pricing prior to April 15, 2016. These requests were approved by the PSCW in June 2016.

The Peoples Gas Light and Coke Company and North Shore Gas Company

Natural Gas System Modernization Program Proceedings

In December 2015, the ICC ordered a series of stakeholder workshops to evaluate PGL's SMP. This ICC action did not impact PGL's ongoing work to modernize and maintain the safety of its natural gas distribution system, but it instead provided the ICC with an opportunity to analyze long-term elements of the program through the stakeholder workshops. The workshops were completed in March 2016. In July 2016, the ICC initiated a proceeding to review, among other things, the planning, reporting, and monitoring of the program, including the target end date for the program, and issued a final order in January 2018. The order did not have a

significant impact on PGL's existing SMP design and execution. An appeal related to the final order was filed by the Illinois Attorney General in April 2018.

Qualifying Infrastructure Plant Rider

In July 2013, Illinois Public Act 98-0057, The Natural Gas Consumer, Safety & Reliability Act, became law. This law provides PGL with a cost recovery mechanism that allows collection, through a surcharge on customer bills, of prudently incurred costs to upgrade Illinois natural gas infrastructure. In September 2013, PGL filed with the ICC requesting the proposed rider, which was approved in January 2014.

PGL's QIP rider is subject to an annual reconciliation whereby costs are reviewed for accuracy and prudency. In March 2019, PGL filed its 2018 reconciliation with the ICC, which, along with the 2017, 2016, and 2015 reconciliations, are still pending. In February 2018, PGL agreed to a settlement of the 2014 reconciliation, which included a rate base reduction of $5.4 million and a $4.7 million refund to ratepayers.

As of December 31, 2018, there can be no assurance that all costs incurred under PGL's QIP rider during the open reconciliation years will be deemed recoverable by the ICC.

Variable Income Tax Adjustment Rider

In April 2018, the ICC approved the VITA proposed by PGL and NSG. The VITA recovers or refunds changes in income tax expense resulting from differences in income tax rates and amortization of deferred tax excesses and deficiencies (in accordance with the Tax Legislation) from the amounts used in the last PGL and NSG rate case, effective January 25, 2018.

Minnesota Energy Resources Corporation

2018 Minnesota Rate Case

In October 2017, MERC initiated a rate proceeding with the MPUC. In November 2017, the MPUC approved an interim rate order, effective January 1, 2018, authorizing a retail natural gas rate increase of $9.5 million (3.78%). In March 2018, to reflect changes in MERC's effective tax rate as a result of the enactment of the Tax Legislation, the MPUC approved a $2.5 million reduction in interim retail natural gas rates to $7.0 million (2.81%), effective April 1, 2018. The interim rates reflect a 9.11% ROE and a common equity component average of 50.9%.

In December 2018, the MPUC issued a final written order for MERC. The order authorized a retail natural gas rate increase of $3.1 million (1.26%). The rates reflect a 9.7% ROE and a common equity component average of 50.9%. In January 2019, the Minnesota Attorney General filed a petition for reconsideration requesting the MPUC reconsider its decision to set the ROE at 9.7%. In February 2019, this petition was denied by the MPUC. Interim rates remain in effect until final rates are implemented, which is expected to be in the second quarter of 2019. MERC’s customers will be entitled to a refund to the extent the interim rate increase exceeds the final approved rate increase. Therefore, as of December 31, 2018, MERC recorded a $5.1 million regulatory liability for amounts to be refunded to customers.

The final order addressed the various impacts of the Tax Legislation, including the remeasurement of deferred tax balances. All of the impacts from the Tax Legislation will be included in base rates. The order also approved MERC's continued use of its decoupling mechanism for residential customers. Effective January 1, 2019, MERC's small commercial and industrial customers will no longer be included in the decoupling mechanism.

2016 Minnesota Rate Order

In September 2015, MERC initiated a rate proceeding with the MPUC. In October 2016, the MPUC issued a final written order for MERC, effective March 1, 2017. The order authorized a retail natural gas rate increase of $6.8 million (3.0%). The rates reflected a 9.11% ROE and a common equity component average of 50.32%. The order approved MERC's request to continue the use of its decoupling mechanism for another three years. The final approved rate increase was lower than the interim rates collected from customers during 2016. Therefore, we refunded $4.1 million to MERC's customers in 2017.

Michigan Gas Utilities Corporation

2016 Michigan Rate Order

In June 2015, MGU initiated a rate proceeding with the MPSC. In December 2015, the MPSC issued a final written order, effective January 1, 2016, approving a settlement agreement for MGU. The order authorized a retail natural gas rate increase of $3.4 million (2.4%), a 9.9% ROE, and a common equity component average of 52.0%. Based on the settlement agreement, MGU discontinued the use of its decoupling mechanism after December 31, 2015. In addition, since bonus depreciation was in effect in 2016, MGU established a regulatory liability for the resulting cost savings and must refund the liability in its next general rate case.

NOTE 25—ACCUMULATED OTHER COMPREHENSIVE LOSS

The following table shows the changes, net of tax, to our accumulated other comprehensive loss:

(in millions)	Cash Flow Hedges	Defined Benefit Plans	Accumulated Other Comprehensive Loss
Balance at December 31, 2015	$ (2.5)	$ (25.9)	$ (28.4)
Other comprehensive income before reclassifications	—	0.2	0.2
Amounts reclassified out of accumulated other comprehensive loss	0.6	4.3	4.9
Net 2016 other comprehensive income	0.6	4.5	5.1
Balance at December 31, 2016	(1.9)	(21.4)	(23.3)
Other comprehensive income before reclassifications	—	1.0	1.0
Amounts reclassified out of accumulated other comprehensive loss	0.5	4.3	4.8
Net 2017 other comprehensive income	0.5	5.3	5.8
Balance at December 31, 2017	(1.4)	(16.1)	(17.5)
Other comprehensive loss before reclassifications	**—**	**(2.2)**	**(2.2)**
Amounts reclassified out of accumulated other comprehensive loss	**0.6**	**5.1**	**5.7**
Cumulative effect adjustment from adoption of ASU 2018-02 *	**(0.2)**	**(3.0)**	**(3.2)**
Net 2018 other comprehensive income (loss)	**0.4**	**(0.1)**	**0.3**
Balance at December 31, 2018	**$ (1.0)**	**$ (16.2)**	**$ (17.2)**

* During the fourth quarter of 2018, we early adopted ASU 2018-02. As a result, we reclassified the stranded tax effects associated with the Tax Legislation from accumulated other comprehensive loss to retained earnings. See Note 1(m), Income Taxes, for more information.

NOTE 26—OTHER INCOME, NET

Total other income, net was as follows for the years ended December 31:

(in millions)	2018	2017	2016
(Losses) gains on investments held in rabbi trust	**$ (1.8)**	$ 21.5	$ 5.1
Non-service credit (cost) components of net periodic benefit costs	**4.4**	(1.6)	(18.9)
AFUDC – Equity	**4.6**	4.2	19.5
Interest income from parent	**4.6**	2.5	—
Gain on repurchase of notes	**—**	—	25.7
Other, net	**17.8**	10.1	1.8
Total other income, net	**$ 29.6**	$ 36.7	$ 33.2

NOTE 27—NEW ACCOUNTING PRONOUNCEMENTS

In February 2016, the FASB issued ASU 2016-02, Leases (Topic 842), which revised the previous guidance (Topic 840) regarding accounting for leases. Revisions include requiring a lessee to recognize a lease asset and a lease liability on its balance sheet for each lease, including operating leases with an initial term greater than 12 months. In addition, required quantitative and qualitative disclosures related to lease agreements were expanded. For lessors however, accounting for leases was largely unchanged from previous provisions of GAAP.

We have finalized our inventory of leases, documented our technical accounting issues, and implemented required changes to internal controls and processes as a result of the new lease guidance. In addition, we continue to finalize the related financial disclosures that will be incorporated into our annual report for the year ended December 31, 2019.

As required, we adopted Topic 842 for interim and annual periods beginning January 1, 2019. We utilized the following practical expedients, which were available under ASU 2016-02, in our adoption of the new lease guidance.

- We did not reassess whether any expired or existing contracts were leases or contained leases.
- We did not reassess the lease classification for any expired or existing leases (that is, all leases that were classified as operating leases in accordance with Topic 840 continue to be classified as operating leases, and all leases that were classified as capital leases in accordance with Topic 840 continue to be classified as capital leases).
- We did not reassess the accounting for initial direct costs for any existing leases.

We did not elect the practical expedient allowing entities to account for the nonlease components in lease contracts as part of the single lease component to which they were related. Instead, in accordance with ASC 842-10-15-31, our policy is to account for each lease component separately from the nonlease components of the contract.

We did not elect the practical expedient to use hindsight in determining the lease term and in assessing impairment of our right-of-use assets. No impairment losses were included in the measurement of our right-of-use assets upon our adoption of Topic 842.

In January 2018, the FASB issued ASU 2018-01, Leases (Topic 842): Land Easement Practical Expedient for Transition to Topic 842, which is an amendment to ASU 2016-02. Land easements (also commonly referred to as rights of way) represent the right to use, access or cross another entity's land for a specified purpose. This new guidance permits an entity to elect a transitional practical expedient, to be applied consistently, to not evaluate under Topic 842 land easements that were already in existence or had expired at the time of the entity's adoption of Topic 842. Once Topic 842 is adopted, an entity is required to apply Topic 842 prospectively to all new (or modified) land easements to determine whether the arrangement should be accounted for as a lease. We elected this practical expedient upon our adoption of Topic 842, resulting in none of our land easements being treated as leases.

In July 2018, the FASB issued ASU 2018-11, Leases (Topic 842): Targeted Improvements, which amends ASU 2016-02 and allows entities the option to initially apply Topic 842 at the adoption date and recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption, if required. We used the optional transition method to apply the new guidance as of January 1, 2019, rather than as of the earliest period presented.

While we are still refining our estimates, we expect that the right of use asset and related lease liability that we will record related to our operating leases will be less than $5 million, and we had no capital leases upon adoption. We did not require a cumulative-effect adjustment upon adoption of Topic 842, and the new guidance is not expected to have any impact on future net income or cash flows.

Financial Instruments Credit Losses

In June 2016, the FASB issued ASU 2016-13, Measurement of Credit Losses on Financial Instruments. This guidance is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019. This ASU introduces a new impairment model known as the current expected credit loss model. The ASU requires a financial asset measured at amortized cost to be presented at the net amount expected to be collected. Previously, recognition of the full amount of credit losses was generally delayed until the loss was probable of occurring. We are currently assessing the effects this guidance may have on our consolidated financial statements.

Cloud Computing

In August 2018, the FASB issued ASU 2018-15, Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract. The standard allows entities who are customers in hosting arrangements that are service contracts to apply the existing internal-use software guidance to determine which implementation costs to capitalize as an asset related to the service contract and which costs to expense. The guidance specifies classification for capitalizing implementation costs and related amortization expense within the financial statements and requires additional disclosures. The guidance will be effective for annual reporting periods, including interim reporting within those periods, beginning after December 15, 2019. Early adoption is permitted and can be applied either retrospectively or prospectively. We are currently evaluating the transition methods and the impact the adoption of this standard may have on our consolidated financial statements.