INTEGRYS HOLDING, INC.

FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2016

INTEGRYS HOLDING, INC.
FINANCIAL STATEMENTS
For the Year Ended December 31, 2016
TABLE OF CONTENTS

		Page
FINANCIAL STATEMENTS AND NOTES		1
A.	Independent Auditors' Report	1
B.	Consolidated Income Statements	2
C.	Consolidated Statements of Comprehensive Income	3
D.	Consolidated Balance Sheets	4
E.	Consolidated Statements of Cash Flows	5
F.	Consolidated Statements of Equity	6
G.	Consolidated Statements of Capitalization	7
H.	Notes to Consolidated Financial Statements	8

		Page
Note 1	Summary of Significant Accounting Policies	8
Note 2	Merger	15
Note 3	Dispositions	16
Note 4	Related Parties	18
Note 5	Investment in American Transmission Company	20
Note 6	Supplemental Cash Flow Information	21
Note 7	Regulatory Assets and Liabilities	22
Note 8	Property, Plant, and Equipment	24
Note 9	Jointly Owned Utility Facilities	24
Note 10	Asset Retirement Obligations	25
Note 11	Goodwill and Other Intangible Assets	25
Note 12	Common Equity	26
Note 13	Preferred Stock	28
Note 14	Short-Term Debt and Lines of Credit	28
Note 15	Long-Term Debt	29
Note 16	Income Taxes	30
Note 17	Guarantees	32
Note 18	Employee Benefits	33
Note 19	Commitments and Contingencies	37
Note 20	Fair Value Measurements	44
Note 21	Derivative Instruments	45
Note 22	Regulatory Environment	46
Note 23	Accumulated Other Comprehensive Loss	50
Note 24	Other Income, Net	50
Note 25	Segment Information	50
Note 26	New Accounting Pronouncements	52

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
IES	Integrys Energy Services, Inc.
Integrys	Integrys Holding, Inc. (previously known as Integrys Energy Group, Inc.)
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
UPPCO	Upper Peninsula Power Company
WBS	WEC Business Services LLC
WEC Energy Group	WEC Energy Group, Inc. (previously known as Wisconsin Energy Corporation)
WE	Wisconsin Electric Power Company
WPS	Wisconsin Public Service Corporation
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
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
CSAPR	Cross-State Air Pollution Rule
GHG	Greenhouse Gas
MATS	Mercury and Air Toxics Standards
NAAQS	National Ambient Air Quality Standards
NOV	Notice of Violation
NOx	Nitrogen Oxide
SO_2	Sulfur Dioxide

Measurements

Dth	Dekatherm (One Dth equals one million Btu)
MW	Megawatt (One MW equals one million Watts)
MWh	Megawatt-hour

Other Terms and Abbreviations

AG	Attorney General
AIA	Affiliated Interest Agreement
ALJ	Administrative Law Judge
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
FTRs	Financial Transmission Rights
Merger Agreement	Agreement and Plan of Merger, dated as of June 22, 2014, between Integrys Energy Group, Inc. and Wisconsin Energy Corporation
MISO	Midcontinent Independent System Operator, Inc.
MISO Energy Markets	MISO Energy and Operating Reserves Market
QIP	Qualifying Infrastructure Plant
ROE	Return on Equity
SMP	Gas System Modernization Program
Supreme Court	United States Supreme Court

FINANCIAL STATEMENTS AND NOTES

A. INDEPENDENT AUDITORS' REPORT

INDEPENDENT AUDITORS' REPORT

To the Board of Directors 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 consolidated statements of capitalization as of December 31, 2016 and 2015, and the related consolidated income statements, consolidated statements of comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2016, 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, 2016 and 2015, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2016, in accordance with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP

Milwaukee, Wisconsin
March 17, 2017

INTEGRYS HOLDING, INC.

B. CONSOLIDATED INCOME STATEMENTS

Year Ended December 31 *(in millions)*	2016	2015	2014
Operating revenues	**$ 3,088.9**	$ 3,219.1	$ 4,145.6
Operating expenses			
Cost of sales	**1,080.7**	1,300.3	2,130.5
Other operation and maintenance	**1,156.9**	1,064.6	1,225.6
Depreciation and amortization	**283.5**	292.5	290.6
Property and revenue taxes	**71.8**	72.9	67.7
Merger costs	**—**	86.9	10.4
Impairment losses	**—**	47.3	—
Gain on sale of UPPCO, net of transaction costs	**—**	—	(85.4)
Total operating expenses	**2,592.9**	2,864.5	3,639.4
Operating income	**496.0**	354.6	506.2
Equity in earnings of transmission affiliate	**82.2**	70.6	85.7
Other income, net	**52.1**	29.1	34.5
Interest expense	**134.2**	151.1	154.8
Other income (expense)	**0.1**	(51.4)	(34.6)
Income before income taxes	**496.1**	303.2	471.6
Income tax expense	**196.7**	132.0	193.4
Net income from continuing operations	**299.4**	171.2	278.2
Discontinued operations, net of tax	**—**	(0.8)	1.8
Net income	**299.4**	170.4	280.0
Preferred stock dividends of subsidiary	**—**	(2.7)	(3.1)
Net income attributed to common shareholder	**$ 299.4**	$ 167.7	$ 276.9

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)*	2016	2015	2014
Net income	**$ 299.4**	$ 170.4	$ 280.0
Other comprehensive income (loss), net of tax			
Derivatives accounted for as cash flow hedges			
Reclassification of net losses (gains) to net income, net of tax of $0.4, $0.4, and $1.2, respectively	**0.6**	0.7	(0.1)
Defined benefit plans			
Pension and OPEB adjustments arising during the period, net of tax of $0.1, $(2.6), and $(3.0), respectively	**0.2**	(3.1)	(6.0)
Amortization of pension and OPEB costs included in net periodic benefit cost, net of tax of $2.9, $1.4, and $0.8, respectively	**4.3**	1.6	1.7
Defined benefit plans, net	**4.5**	(1.5)	(4.3)
Other comprehensive income (loss), net of tax	**5.1**	(0.8)	(4.4)
Comprehensive income	**304.5**	169.6	275.6
Preferred stock dividends of subsidiary	**—**	(2.7)	(3.1)
Comprehensive income attributed to common shareholder	**$ 304.5**	$ 166.9	$ 272.5

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)*	2016	2015
Assets		
Current assets		
Cash and cash equivalents	**$ 12.0**	$ 19.4
Accounts receivable and unbilled revenues, net of reserves of $47.6 and $49.9, respectively	**618.1**	471.2
Receivables from related parties	**14.0**	2.8
Materials, supplies, and inventories	**270.1**	328.2
Assets held for sale	**—**	115.1
Prepaid taxes	**51.7**	122.2
Other	**61.3**	54.7
Current assets	**1,027.2**	1,113.6
Long-term assets		
Property, plant, and equipment, net of accumulated depreciation of $3,315.5 and $3,267.9, respectively	**7,779.9**	7,418.6
Regulatory assets	**1,535.1**	1,641.6
Equity investment in transmission affiliate	**600.2**	550.4
Goodwill	**635.8**	635.8
Other	**250.6**	218.2
Long-term assets	**10,801.6**	10,464.6
Total assets	**$ 11,828.8**	$ 11,578.2
Liabilities and Equity		
Current liabilities		
Short-term debt	**$ 228.0**	$ 305.5
Current portion of long-term debt	**125.0**	100.0
Accounts payable	**482.1**	469.4
Payables to related parties	**48.3**	18.8
Note payable to related party	**42.0**	95.1
Accrued taxes	**64.7**	50.0
Liabilities held for sale	**—**	30.0
Other	**200.7**	286.4
Current liabilities	**1,190.8**	1,355.2
Long-term liabilities		
Long-term debt	**2,940.7**	3,069.9
Deferred income taxes	**1,948.0**	1,664.9
Deferred investment tax credits	**59.6**	62.2
Regulatory liabilities	**507.7**	459.5
Environmental remediation liabilities	**578.4**	598.2
Pension and OPEB obligations	**300.9**	335.9
AROs	**492.7**	509.2
Other	**181.6**	192.9
Long-term liabilities	**7,009.6**	6,892.7
Commitments and contingencies (Note 19)		
Common stock – $0.01 par value; 10,000 shares authorized, 1,020 and 1,000 shares issued and outstanding at December 31, 2016 and 2015, respectively	**—**	—
Additional paid in capital	**2,685.3**	2,691.7
Retained earnings	**966.4**	667.0
Accumulated other comprehensive loss	**(23.3)**	(28.4)
Total common shareholder's equity	**3,628.4**	3,330.3
Total liabilities and equity	**$ 11,828.8**	$ 11,578.2

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)*	2016	2015	2014
Operating activities			
Net income	**$ 299.4**	$ 170.4	$ 280.0
Reconciliation to cash provided by operating activities			
Depreciation and amortization	**283.5**	299.6	298.7
Deferred income taxes and investment tax credits, net	**257.0**	159.9	165.9
Contributions and payments related to pension and OPEB plans	**(2.4)**	(16.4)	(108.8)
Equity income in transmission affiliate, net of distributions	**(26.0)**	(6.9)	(11.3)
Impairment losses	**—**	47.3	—
Gain on sale of UPPCO	**—**	—	(86.5)
Change in –			
Accounts receivable and unbilled revenues	**(124.3)**	227.9	136.7
Materials, supplies, and inventories	**58.9**	(13.8)	(120.2)
Prepaid taxes	**70.5**	13.9	10.7
Other current assets	**1.5**	(17.2)	(26.5)
Accounts payable	**(8.6)**	(32.4)	13.2
Other current liabilities	**3.5**	29.4	18.4
Other, net	**(8.7)**	(57.8)	31.1
Net cash provided by operating activities	**804.3**	803.9	601.4
Investing activities			
Capital expenditures	**(665.6)**	(887.9)	(856.7)
Payments for assets received from WBS	**(95.0)**	—	—
Capital contributions to transmission affiliate	**(23.9)**	(6.8)	(17.0)
Proceeds from the sale of IES's retail energy business, net of cash divested	**—**	14.0	311.6
Proceeds from the sale of UPPCO, net of cash divested	**—**	—	336.5
Proceeds from the sale of assets and other businesses	**99.7**	72.9	23.0
Withdrawal of restricted cash from Rabbi trust for qualifying payments	**26.6**	15.5	—
Rabbi trust funding related to change in control	**—**	(14.3)	(115.5)
Short-term notes receivable from related parties, net	**14.8**	—	—
Cash proceeds from corporate owned life insurance policies	**—**	17.3	—
Other, net	**5.0**	(6.1)	(18.4)
Net cash used in investing activities	**(638.4)**	(795.4)	(336.5)
Financing activities			
Issuance of common stock to parent	**66.4**	—	—
Purchase of common stock	**—**	(23.9)	(143.5)
Dividends paid on common stock	**—**	(125.4)	(216.3)
Exercise of stock options	**—**	4.1	85.8
Redemption of WPS preferred stock	**—**	(52.7)	—
Retirement of long-term debt	**(278.6)**	(130.1)	(175.0)
Issuance of long-term debt	**200.0**	250.0	200.0
Repayment of loan	**(28.6)**	—	—
Change in short-term debt	**(77.5)**	(12.1)	(8.4)
Short-term notes payable to related parties, net	**(53.1)**	95.1	—
Other, net	**(1.9)**	(12.1)	(11.8)
Net cash used in financing activities	**(173.3)**	(7.1)	(269.2)
Net change in cash and cash equivalents	**(7.4)**	1.4	(4.3)
Cash and cash equivalents at beginning of year	**19.4**	18.0	22.3
Cash and cash equivalents at end of year	**$ 12.0**	$ 19.4	$ 18.0

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)	Shares in Deferred Compensation Trust	Common Stock	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Shareholder's Equity	Preferred Stock of Subsidiary	Total Equity
Balance at December 31, 2013	$ (23.0)	$ 79.9	$ 2,660.5	$ 567.1	$ (23.2)	$ 3,261.3	$ 51.1	$ 3,312.4
Net income attributed to common shareholders	—	—	—	276.9	—	276.9	—	276.9
Other comprehensive loss	—	—	—	—	(4.4)	(4.4)	—	(4.4)
Issuance of common stock	—	0.1	2.3	—	—	2.4	—	2.4
Stock-based compensation	—	—	(20.9)	(0.8)	—	(21.7)	—	(21.7)
Dividends on common stock (dividends per common share of $2.72)	—	—	—	(216.3)	—	(216.3)	—	(216.3)
Shares purchased for the deferred compensation trust	(0.6)	—	—	—	—	(0.6)	—	(0.6)
Other	2.7	—	0.3	(0.9)	—	2.1	—	2.1
Balance at December 31, 2014	$ (20.9)	$ 80.0	$ 2,642.2	$ 626.0	$ (27.6)	$ 3,299.7	$ 51.1	$ 3,350.8
Net income attributed to common shareholder	—	—	—	167.7	—	167.7	—	167.7
Other comprehensive loss	—	—	—	—	(0.8)	(0.8)	—	(0.8)
Stock-based compensation	—	—	(6.3)	(0.2)	—	(6.5)	—	(6.5)
Dividends on common stock (dividends per common share of $1.58)	—	—	—	(125.4)	—	(125.4)	—	(125.4)
Redemption of WPS preferred stock	—	—	(1.6)	—	—	(1.6)	(51.1)	(52.7)
Other	20.9	(80.0)	57.4	(1.1)	—	(2.8)	—	(2.8)
Balance at December 31, 2015	$ —	$ —	$ 2,691.7	$ 667.0	$ (28.4)	$ 3,330.3	$ —	$ 3,330.3
Net income attributed to common shareholder	$ —	$ —	$ —	$ 299.4	$ —	299.4	$ —	299.4
Other comprehensive income	—	—	—	—	5.1	5.1	—	5.1
Issuance of common stock to parent	—	—	66.4	—	—	66.4	—	66.4
Non-cash equity transfer of our ownership in WBS to WEC Energy Group	—	—	(73.0)	—	—	(73.0)	—	(73.0)
Other	—	—	0.2	—	—	0.2	—	0.2
Balance at December 31, 2016	**$ —**	**$ —**	**$ 2,685.3**	**$ 966.4**	**$ (23.3)**	**$ 3,628.4**	**$ —**	**$ 3,628.4**

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

G. CONSOLIDATED STATEMENTS OF CAPITALIZATION

At December 31 *(in millions)*			2016	2015
Common equity (see accompanying statement)			**$ 3,628.4**	$ 3,330.3
Long-term debt	**Interest Rate**	**Year Due**		
WPS Notes (unsecured)	5.65%	2017	**125.0**	125.0
	1.65%	2018	**250.0**	250.0
	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]	2.21%	2016	**—**	50.0
	8.00%	2018	**5.0**	5.0
	4.63%	2019	**75.0**	75.0
	3.90%	2030	**50.0**	50.0
	1.875%	2033	**50.0**	50.0
	4.00%	2033	**50.0**	50.0
	4.30%	2035	**—**	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**	—
	3.65%	2046	**150.0**	—
NSG First Mortgage Bonds (secured) [2]	3.43%	2027	**28.0**	28.0
	3.96%	2043	**54.0**	54.0
Integrys Senior Notes (unsecured)	8.00%	2016	**—**	50.0
	4.17%	2020	**250.0**	250.0
Integrys Junior Notes (unsecured)	3.05% [3]	2066	**114.9**	269.8
Integrys Junior Notes (unsecured)	6.00%	2073	**400.0**	400.0
Total			**3,096.9**	3,201.8
Unamortized debt issuance costs			**(30.5)**	(31.1)
Unamortized discount, net and other			**(0.7)**	(0.8)
Total long-term debt, including current portion			**3,065.7**	3,169.9
Current portion of long-term debt			**(125.0)**	(100.0)
Total long-term debt			**2,940.7**	3,069.9
Total long-term capitalization			**$ 6,569.1**	$ 6,400.2

[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.

[3] Variable interest rate reset quarterly. The rate was 3.05% as of December 31, 2016. Prior to December 1, 2016, the rate was fixed at 6.11% .

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

H. NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2016

NOTE 1—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) General Information—On June 29, 2015, Wisconsin Energy Corporation acquired our predecessor, Integrys Energy Group, Inc., which became a wholly owned subsidiary of Wisconsin Energy Corporation. Wisconsin Energy Corporation then changed its name to WEC Energy Group, Inc. In this report, when we refer to the "WEC Merger," we are referring to this acquisition. See Note 2, Merger, for more information.

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

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 it became operational effective January 1, 2017. This utility holds the electric and natural gas distribution assets previously held by WPS and WE located in the Upper Peninsula of Michigan. UMERC obtains its energy through the MISO Energy Markets and meets its obligations through power purchase agreements with WPS and WE.

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 that were transferred to UMERC effective January 1, 2017 are also included in this segment .

- 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. UPPCO's electric operations in the state of Michigan prior to its sale in August 2014 are also included in this segment. See Note 3, Dispositions, for more information on the sale of UPPCO.

- Electric transmission segment – Consists of our approximate 34% ownership interest in ATC, a federally regulated electric transmission company.

- Corporate and other segment – Consists of the Integrys holding company, the PELLC holding company, WBS, PDL, and ITF. During 2016, we completed the sale of ITF and PDL sold its natural gas-fired cogeneration facility and its landfill gas facility. 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 a gain or loss recognized. In addition, the discontinued operations of IES's retail energy business prior to its sale in November 2014 are also included in this segment. See Note 3, Dispositions, for more information on these sales.

Our financial statements also reflect our proportionate interests in certain jointly owned utility facilities. See Note 9, Jointly Owned Utility Facilities, for more information. The cost method of accounting is used for investments when we do not have significant influence over the operating and financial policies of the investee. 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. See Note 5, Investment in American Transmission Company, for more information.

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.

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

(c) Revenues and Customer Receivables—We recognize revenues related to the sale of energy on the accrual basis and include estimated amounts for services provided but not yet billed to customers.

We present revenues net of pass-through taxes on the income statements.

Below is a summary of the significant mechanisms our utility subsidiaries had in place that allowed them to recover or refund changes in prudently incurred costs from rate case-approved amounts:

- Fuel and purchased power costs were recovered from customers on a one-for-one basis by our Wisconsin wholesale electric operations and our Michigan retail electric operations.

- Our retail electric rates in Wisconsin are established by the PSCW and include base amounts for fuel and purchased power costs. 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. WPS 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.

- The rates for all of our natural gas utilities included 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.

- The rates of PGL and NSG included riders for cost recovery of both environmental cleanup costs and energy conservation and management program costs.

- MERC's rates included a conservation improvement program rider for cost recovery of energy conservation and management program costs as well as a financial incentive for meeting energy savings goals.

- The rates of PGL and NSG included 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, NSG, MERC, and MGU included decoupling mechanisms. These mechanisms differ by state and allow utilities to recover or refund differences between actual and authorized margins. MGU's decoupling mechanism was discontinued after December 31, 2015. See Note 22, Regulatory Environment, for more information.

- PGL's rates included a cost recovery mechanism for SMP costs.

Revenues are also impacted by other accounting policies related to PGL's natural gas hub and WPS's participation in the MISO Energy Markets. Amounts collected from PGL's wholesale customers that use the natural gas hub are credited to natural gas costs, resulting in a reduction to retail customers' charges for natural gas and services. WPS sells and purchases power in the MISO Energy Markets, which operate under both day-ahead and real-time markets. WPS records energy transactions in the MISO Energy Markets on a net basis for each hour. If WPS was a net seller in a particular hour, the net amount was reported as operating revenue. If WPS was a net purchaser in a particular hour, the net amount was recorded as cost of sales on our income statements.

We provide regulated electric and natural gas service to customers in northeastern Wisconsin and provided this service to customers in the Upper Peninsula of Michigan through December 31, 2016. See Note 4, Related Parties, for information regarding the transfer of our customers located in the Upper Peninsula of Michigan to UMERC effective January 1, 2017. We also provide regulated natural gas service to customers in Illinois, Minnesota, and Michigan. The geographic concentration of our customers 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 recovery mechanisms for uncollectible expense discussed above. As a result, we did not have any significant concentrations of credit risk at December 31, 2016. In addition, there were no customers that accounted for more than 10% of our revenues for the year ended December 31, 2016.

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

(in millions)	2016	2015
Natural gas in storage	**$ 149.1**	$ 190.9
Fossil fuel	**66.7**	76.3
Materials and supplies	**54.3**	61.0
Total	**$ 270.1**	$ 328.2

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 38% of total inventories at December 31, 2016, and 39% of total inventories at December 31, 2015. The estimated replacement cost of natural gas in inventory at December 31, 2016 and 2015, exceeded the LIFO cost by $92.9 million and $15.2 million, respectively. In calculating these replacement amounts, PGL and NSG used a Chicago city-gate natural gas price per Dth of $3.63 at December 31, 2016, and $2.48 at December 31, 2015.

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

(e) Investments Held in Rabbi Trust—We have investments that are held in a rabbi trust that is 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. The trust holds investments that are classified as trading securities for accounting purposes. As we do not intend to sell the investments in the near term, they are included in other long-term assets on our balance sheets. The net unrealized gains (losses) included in earnings related to the investments held at the end of the period were $4.0 million, $(0.4) million, and $1.8 million for the years ended December 31, 2016, 2015, and 2014, respectively.

(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 the 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 7, 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 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	2016	2015	2014
WPS	**2.58%**	2.60%	2.63%
PGL	**3.31%**	3.35%	3.20%
NSG	**2.44%**	2.45%	2.44%
MERC	**2.53%**	2.50%	2.49%
MGU	**2.63%**	2.65%	2.65%

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.

We receive grants related to certain renewable generation projects under federal and state grant programs. Our policy is to reduce the depreciable basis of the qualifying project by the grant received. We then reflect the benefit of the grant in income over the life of the related renewable generation project through a reduction in depreciation expense.

See Note 8, 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 2016, WPS's average AFUDC retail rate was 7.72%, and its average AFUDC wholesale rate was 3.00%. The other utilities did not record significant AFUDC for 2016, 2015, or 2014.

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

(in millions)	**2016**	**2015**	**2014**
AFUDC – Debt	**$ 8.1**	$ 7.1	$ 5.2
AFUDC – Equity	**19.5**	17.7	12.5

(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. Intangible assets with definite lives are reviewed for impairment on a quarterly basis. Other long-lived assets are tested for recoverability whenever events or changes in circumstances indicate that their carrying value may not be recoverable.

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.

Due to the WEC Merger, we changed the date of our annual goodwill impairment test during 2016 from April 1 to July 1. 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 11, Goodwill and Other Intangible Assets, for more information.

The carrying amount of assets held for sale is not recoverable if the carrying amount exceeds the fair value less estimated costs to sell the asset. An impairment loss is recorded for the excess of the asset’s carrying amount over the fair value less estimated costs to sell.

The carrying amounts of cost and equity method investments are assessed for impairment by comparing the fair values of these investments to their carrying amounts, if a fair value assessment was completed, or by reviewing for the presence of impairment indicators. If an impairment exists and it is determined to be other-than-temporary, a loss is recognized equal to the amount by which the carrying amount exceeds the investment's fair value.

(j) 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.

(k) 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 our 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 to their present values 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 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 10, Asset Retirement Obligations, for more information.

(l) 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 10, Asset Retirement Obligations, for more information regarding coal combustion product landfill sites and Note 19, 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.

(m) Income Taxes—We and our subsidiaries are included within the consolidated United States income tax return filed by WEC Energy Group. We and our consolidated subsidiaries are a party to a tax allocation arrangement with WEC Energy Group and its consolidated subsidiaries.

Deferred income taxes have been recorded to recognize the expected future tax consequences of events that have been included in the financial statements by using currently enacted tax rates for the differences between the income tax basis of assets and liabilities and the basis reported in the financial statements. 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. We defer certain adjustments made to income taxes that will impact future rates and record regulatory assets or liabilities related to these adjustments.

We use the deferral method of accounting for investment tax credits (ITCs). Under this method, we record the ITCs as deferred credits and amortize such credits as a reduction to the provision for income taxes over the life of the asset that generated the ITCs. ITCs that do not reduce income taxes payable for the current year are eligible for carryover and recognized as a deferred income tax asset.

We report interest and penalties accrued related to income taxes as a component of income tax expense in our income statements.

See Note 16, Income Taxes, for more information regarding accounting for income taxes.

(n) Guarantees—We follow the guidance of the Guarantees Topic of the FASB Accounting Standards Codification, which requires that the guarantor recognize, at the inception of the guarantee, a liability for the fair value of the obligation undertaken in issuing the guarantee. See Note 17, Guarantees, for more information.

(o) Employee Benefits—The costs of pension and OPEB plans are expensed over the periods during which employees render service. These costs are allocated 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 18, Employee Benefits, for more information.

(p) Stock-Based Compensation—Prior to the WEC Merger, our employees were granted awards under our stock-based compensation plans. Pursuant to the Merger Agreement, immediately prior to completion of the merger, all of our outstanding stock-based

compensation awards became fully vested and were either paid to award recipients in cash, or the value of the awards was deferred into a deferred compensation plan. The additional expense recorded in 2015 associated with the accelerated vesting of these awards totaled $22.7 million and is included in merger costs on the income statement. The total intrinsic value of awards that were settled in 2015 due to the WEC Merger was $61.7 million. The actual tax benefit realized for the tax deductions from the settled awards was $22.7 million. See Note 2, Merger, for more information regarding the merger.

In 2016, our employees were granted awards under WEC Energy Group's stock-based compensation plans. In accordance with the shareholder approved WEC Energy Group 1993 Omnibus Stock Incentive Plan, Amended and Restated Effective as of January 1, 2016, WEC Energy Group provides a long-term incentive through its equity interests to its non-employee directors, selected 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 based on an estimate of the final expected value of the awards.

Stock Options

Our employees are granted WEC Energy Group non-qualified stock options that 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 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 fair value per stock option granted to our employees along with the weighted-average assumptions used in the valuation models:

	2016
Non-qualified stock options granted	**52,305**
Estimated fair value per non-qualified stock option	**$ 5.59**
Risk-free interest rate	**0.4% – 1.8%**
Dividend yield	**4.0%**
Expected volatility	**18.0%**
Expected life (years)	**7.4**

The risk-free interest rate is 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 current dividend rate 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 have a three-year vesting period, and generally, one-third of the award vests 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. All grants are settled in cash and are accounted for as liability awards accordingly. Stock-based compensation costs are recorded over the three-year performance period.

See Note 12, Common Equity, for more information on WEC Energy Group's stock-based compensation plans.

(q) 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.

Derivatives were transferred between levels of the fair value hierarchy primarily due to observable pricing becoming available. We recognize transfers at their value as of the end of the reporting period.

Due to the short-term nature of cash and cash equivalents, net accounts receivable and unbilled revenues, accounts payable, and short-term borrowings, the carrying amount of each such item approximates fair value. The fair value of our long-term debt is estimated based upon the quoted market value for the same issue, similar issues, or upon the quoted market prices of United States Treasury issues having a similar term to maturity, adjusted for the issuing company's bond rating and the present value of future cash flows. The fair value of long-term debt is categorized within Level 2 of the fair value hierarchy.

See Note 20, Fair Value Measurements, for more information.

(r) 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. Realized gains and losses on derivative instruments are primarily recorded in cost of sales on our income statements. 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. See Note 21, Derivative Instruments, for more information.

(s) Customer Deposits and Credit Balances—When utility customers apply for new service, they may be required to provide a deposit for the service.

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 recorded within current liabilities on our balance sheets.

(t) Subsequent Events—Subsequent events were evaluated for potential recognition or disclosure through March 17, 2017, which is the date the financial statements were available to be issued.

NOTE 2—MERGER

On June 29, 2015, the WEC Merger was completed and we became a wholly owned subsidiary of Wisconsin Energy Corporation. Wisconsin Energy Corporation then changed its name to WEC Energy Group, Inc. Our shareholders received 1.128 shares of Wisconsin Energy Corporation common stock and $18.58 in cash for each share of our common stock. In addition, all of our unvested stock-based compensation awards became fully vested upon the close of the transaction. All outstanding awards were either paid out in cash to award recipients or the value of the awards was deferred into a deferred compensation plan. The total purchase price was approximately $5.6 billion.

The merger was subject to the approvals of various government agencies, including the FERC, Federal Communications Commission, PSCW, ICC, MPSC, and MPUC. Approvals were obtained from all agencies subject to several conditions.

The PSCW order requires that any future electric generation projects affecting Wisconsin ratepayers submitted by WEC Energy Group or its subsidiaries will first consider the extent to which existing intercompany resources can meet energy and capacity needs. In September 2015, WPS and WE filed a joint integrated resource plan with the PSCW for their combined loads, which indicated that there is no need to proceed with the proposed construction of a new generating unit at the Fox Energy Center site at this time. WPS has been authorized to recover the costs it has recorded related to the proposed construction.

The ICC order includes a base rate freeze for PGL and NSG effective for two years after the close of the merger. This base rate freeze does not impact PGL's or NSG's ability to adjust rates through various riders or gas cost recovery mechanisms.

We do not believe that the conditions set forth in the various regulatory orders approving the merger will have a material impact on our operations or financial results.

In connection with the merger, we recorded pre-tax merger costs of $86.9 million and $10.4 million during 2015 and 2014, respectively. Merger costs recorded during 2016 were not significant. Merger costs consisted of employee-related expenses, professional fees, and other miscellaneous costs. Included in the 2015 merger costs was $43.2 million of expense related to the accelerated vesting of our outstanding stock-based compensation awards and change-in-control payments.

The 2015 merger costs also included $18.4 million of severance expense that resulted from employee reductions related to the post-merger integration. Severance expense incurred during 2016 was not significant. The 2015 severance expense was recorded in the following segments:

(in millions)	Year ended December 31, 2015
Wisconsin	$ 4.6
Illinois	0.9
Other states	0.1
Corporate and other	12.8
Total severance expense	$ 18.4

Severance payments of $2.6 million and $15.7 million were made during 2016 and 2015, respectively. The severance accruals on our balance sheets were not significant at December 31, 2016 and 2015.

NOTE 3—DISPOSITIONS

Dispositions

Corporate and Other Segment – Sale of Integrys Transportation Fuels

In November 2015, we sold our 30% joint interest in AMP Trillium LLC. This transaction was not significant, and there was no gain or loss recorded on the sale. In addition, in the fourth quarter of 2015, we lowered the fair value of the remaining ITF assets to fair market value, less costs to sell. This pre-tax fair value adjustment of $26.5 million ($16.0 million after-tax) was recorded in impairment losses on the income statements.

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 sale of ITF met the criteria to qualify as held for sale at December 31, 2015, but did not meet the requirements to qualify as a discontinued operation. 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 and losses before income taxes from ITF of $20.9 million and $0.5 million for the years ended December 31, 2015, and 2014, respectively.

The following table shows the carrying values of the major classes of assets and liabilities included as held for sale on our balance sheet at December 31:

(in millions)	2015
Accounts receivable and unbilled revenues	$ 29.2
Materials, supplies, and inventories	18.4
Other current assets	1.6
Property, plant, and equipment	51.4
Goodwill	3.8
Other long-term assets	10.7
Total assets	$ 115.1
Accounts payable	$ 12.6
Accrued payroll and benefits	2.4
Other current liabilities	5.5
Deferred income taxes	6.5
Deferred investment tax credits	1.2
Pension and OPEB obligations	1.2
Other long-term liabilities	0.6
Total liabilities	$ 30.0

Corporate and Other Segment – Sale of Certain PDL Solar Power Generation Plants

In June 2015, we sold 48 solar power generation plants owned by PDL, including our ownership interest in INDU Solar Holdings, LLC, to TerraForm Power, Inc. (TerraForm) for $47.8 million. These solar plants were located throughout Arizona, California, Connecticut, Massachusetts, New Jersey, and Pennsylvania. In 2015, we recorded a pre-tax gain on the sale of $5.2 million, which included transaction costs of $0.9 million. The results of operations of these solar assets remained in continuing operations through the sale date as the sale did not represent a shift in our corporate strategy and did not have a major effect on our operations and financial results. In connection with the sale, we entered into an asset management agreement with TerraForm related to the majority of the remaining solar assets owned by PDL. Under this agreement, TerraForm is contracted to perform the day-to-day management of these remaining solar assets. We recognized income before income taxes from these solar assets of approximately $1 million and $3 million for the period ended May 31, 2015, and the year ended December 31, 2014, respectively.

Corporate and Other Segment – Sale of WPS Westwood Generation, LLC (Westwood)

In November 2012, Sunbury Holdings, LLC, a subsidiary of IES, sold all of the membership interests of Westwood, a waste coal generation plant located in Pennsylvania. In addition to cash proceeds received, IES received a $4.0 million note receivable from the buyer with a seven and one-half year term. In 2015, we evaluated the collectability of the note receivable and recorded an impairment loss of $3.8 million, which was reported in impairment losses on the income statements.

Corporate and Other Segment – Sale of Compressed Natural Gas Fueling Stations

In November 2014, ITF sold eight CNG fueling stations to AMP Trillium LLC, a joint venture between ITF and AMP Americas LLC. At the time of sale, ITF owned 30% and AMP Americas LLC owned 70% of AMP Trillium LLC. The fair value of the CNG fueling stations was $13.0 million. ITF received cash proceeds of $7.2 million, a $2.7 million note receivable from the buyer with a seven-year term, and a $3.1 million equity interest in the joint venture to maintain its ownership interest. In 2014, we recorded a pre-tax gain of $1.8 million ($1.1 million after-tax) related to the sale of the CNG fueling stations and deferred a gain of $0.8 million that was to be recognized over the lives of the stations sold. The subsequent sale of ITF's interest in the joint venture triggered the recognition of this deferred gain. The pre-tax gain was reported as a component of other operation and maintenance on the income statements. The results of operations of the CNG fueling stations remained in continuing operations through the sale date as the sale did not represent a shift in our corporate strategy and did not have a major effect on our operations and financial results.

Other States Segment – Sale of UPPCO

In August 2014, we sold all of the stock of UPPCO to Balfour Beatty Infrastructure Partners LP for $336.5 million, which was net of cash divested of $0.2 million. In 2014, we recorded a pre-tax gain of $85.4 million ($51.2 million after-tax) related to the sale of UPPCO, which was net of transaction costs of $1.1 million. Following the sale, we provided certain administrative and operational services to UPPCO during a transition period of up to 30 months with a one month extension for a limited number of reporting functions and a one year extension for audit support. The sale of UPPCO met the criteria to qualify as held for sale but did not meet the requirements to qualify as a discontinued operation. The results of operations of UPPCO remained in continuing operations through the sale date due to WPS having significant continuing cash flows with UPPCO that continued after the sale related to certain power purchase transactions.

Corporate and Other Segment – Winnebago Energy Center

In May 2014, a fire significantly damaged the Winnebago Energy Center, a landfill-gas-to-electric facility that was owned by PDL. In the third quarter of 2014, we decided to abandon the facility and received proceeds of $6.1 million for both insurance recovery for the damage caused by the fire and from the sale of miscellaneous parts. As a result, we recorded a pre-tax gain of $5.0 million ($3.0 million after-tax) in 2014. The results of operations of the Winnebago Energy Center remained in continuing operations through the sale date as the sale did not represent a shift in our corporate strategy and did not have a major effect on our operations and financial results.

Discontinued Operations

See Note 6, Supplemental Cash Flow Information, for cash flow information related to discontinued operations.

Corporate and Other Segment – Sale of IES Retail Energy Business

In November 2014, we sold IES's retail energy business to Exelon Generation Company, LLC (Exelon) for $325.6 million, which was net of cash divested of $7.6 million. We recorded a pre-tax loss on the sale of $28.8 million ($17.3 million after tax), which included transaction costs of $4.5 million in 2014. Included in these costs was an immaterial amount related to severances. Included in the sale were commodity contracts that did not meet the GAAP definition of derivative instruments and, therefore, were not reflected on the balance sheets.

The retail energy business consisted of mostly financial assets and liabilities; therefore, it did not qualify as held for sale under the applicable accounting guidance. The sale of the retail energy business was the result of a previously announced shift in our corporate strategy to focus on the regulated businesses and had a major effect on our operations and financial results. Therefore, its results of operations were classified as discontinued operations beginning in the fourth quarter of 2014.

The following table shows the components of discontinued operations related to the sale of the IES retail energy business recorded on the income statements:

(in millions)	2015	2014
Operating revenues	$ —	$ 2,587.1
Cost of sales	—	(2,444.7)
Other operation and maintenance	(1.2)	(91.5)
Depreciation and amortization	—	(2.7)
Property and revenue taxes	(0.2)	(4.9)
Goodwill impairment loss	—	(6.7)
Loss on sale of IES retail energy business	—	(28.8)
Other income, net	0.1	0.6
Interest expense	—	(0.7)
Income before taxes	(1.3)	7.7
Income tax expense (benefit)	0.5	(7.3) *
Discontinued operations, net of tax	$ (0.8)	$ 0.4

* See Note 16, Income Taxes, for more information.

The June 2014 announcement of the potential sale triggered an interim goodwill impairment test. Based on the results of the interim goodwill impairment analysis, IES recorded a non-cash goodwill impairment loss in the second quarter of 2014. This goodwill impairment loss was a result of the offers received for IES's retail energy business.

Corporate and Other Segment – Sale of WPS Beaver Falls Generation, LLC (Beaver Falls) and WPS Syracuse Generation, LLC (Syracuse)

In March 2013, WPS Empire State, Inc. sold all of the membership interests of Beaver Falls and Syracuse, both of which owned natural gas-fired generation plants located in the state of New York. The sale agreement included a potential annual payment to us for a four-year period following the sale based on a certain level of earnings achieved by the buyer (an earn-out). In September 2014, we entered into an agreement to receive $2.0 million in settlement of this earn-out agreement, which is presented in other operation and maintenance in the table below.

The following table shows the components of discontinued operations related to Beaver Falls and Syracuse recorded on the income statements:

(in millions)	2014
Other operation and maintenance	$ 2.0
Income before taxes	2.0
Income tax expense	(0.8)
Discontinued operations, net of tax	$ 1.2

Corporate and Other Segment – Uncertain Tax Positions

In 2014, we recorded a $0.7 million after-tax gain at the corporate and other segment when we remeasured an uncertain tax position included in liability for unrecognized tax benefits due to a lapse in the statute of limitations.

NOTE 4—RELATED PARTIES

We and our subsidiaries routinely enter into transactions with related parties, including WEC Energy Group, its 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 the WEC Merger on June 29, 2015, Integrys Business Support, LLC (IBS) changed its name to WBS, and a new AIA (Non-WBS AIA) went into effect. The new Non-WBS AIA included the former Wisconsin Energy Corporation and its 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.

On April 1, 2016, we, along with WEC Energy Group and other affiliates, filed a new agreement for approval with the PSCW and all other relevant state commissions. The PSCW approved the new agreement in August 2016. We later received approval from the two other states reviewing the agreement, and the new agreement took effect January 1, 2017. The new agreement replaces the previous agreements. The pricing methodology and services under this new agreement are substantially identical to those under the agreements being replaced. In February 2017, a request was filed with the PSCW for modifications to the new AIA to incorporate WEC Energy Group's acquisition of a natural gas storage facility in Michigan. For more information on the natural gas storage facility acquisition, see below.

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 a gain or loss recognized.

We provide services to and receive services from ATC for its transmission facilities under several agreements approved by the PSCW. Services are billed to ATC under these agreements at our fully allocated cost. See Note 5, Investment in American Transmission Company, for more information.

We provide services to WRPC under an operating agreement approved by the PSCW. We are also party to a service agreement with WRPC under which either party may be a service provider. Services are billed to and from WRPC under these agreements at a fully allocated cost.

(in millions)	**2016**	**2015**	**2014**
Transactions with WE [1]			
Billings from WE to WPS	**$ 9.0**	$ 13.4	$ —
Billings to WE from WPS	**4.2**	4.9	—
Transactions with WBS [1]			
Billings from WBS [2]	**377.0**	—	—
Billings to WBS [3]	**24.8**	—	—
Transactions with equity-method investees			
Purchases of energy from WRPC	**3.7**	3.8	3.7
Charges to WRPC for operations	**0.7**	1.1	1.4

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

(2) Includes $31.2 million for the transfer of certain benefit-related liabilities to WBS and $95.0 million for the transfer of certain software assets to us for the year ended December 31, 2016.

(3) Includes $7.6 million for the transfer of certain software assets to WBS for the year ended December 31, 2016.

We manage our liquidity in part by maintaining adequate financing commitments with related parties. We have the ability to borrow up to $400.0 million from our parent, WEC Energy Group. At December 31, 2016 and 2015, our short-term note payable balance with WEC Energy Group was $42.0 million and $95.1 million, respectively.

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 estimated net book value of the property, plant, and equipment transferred to UMERC from WPS as of January 1, 2017, was $19 million. This transaction was a non-cash equity transfer between entities under common control, and therefore, did not result in a gain or loss recognized.

UMERC obtains its energy through the MISO Energy Markets and meets its market obligations through power purchase agreements with WPS and WE. The new utility has also proposed a long-term generation solution for electric reliability in the region.

Parent Company's Acquisition of a Natural Gas Storage Facility in Michigan

In January 2017, WEC Energy Group signed an agreement for the acquisition of a natural gas storage facility in Michigan that would provide for some of WPS's storage needs for its natural gas utility operations. WPS plans to enter into a long-term service agreement to take the allocated storage, subject to PSCW approval and closing of the acquisition. PSCW approval and closing of this transaction are expected to occur by the third quarter of 2017.

NOTE 5—INVESTMENT IN AMERICAN TRANSMISSION COMPANY

Our electric transmission segment consists of WPS Investments, LLC's ownership interest in ATC, which was approximately 34% at December 31, 2016. ATC is a for-profit, transmission-only company regulated by the FERC and certain state regulatory commissions. We have one representative on ATC's ten-member board of directors. Each member of the board has only one vote. Due to voting requirements, no individual board member has more than 10% of the voting control. The following table shows changes to our investment in ATC during the years ended December 31:

(in millions)	2016	2015	2014
Balance at beginning of period	**$ 550.4**	$ 536.7	$ 508.4
Add: Earnings from equity method investment	**82.2**	70.6	85.7
Add: Capital contributions	**23.9**	6.8	17.0
Less: Distributions received	**56.2**	63.7	74.4
Less: Other	**0.1**	—	—
Balance at end of period	**$ 600.2**	$ 550.4	$ 536.7

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 are reimbursed by ATC. We are required to pay the cost of needed transmission infrastructure upgrades for new generation projects while the projects are under construction. ATC reimburses us for these costs when the new generation is placed in service.

The following table summarizes our significant related party transactions with ATC during the years ended December 31:

(in millions)	2016	2015	2014
Charges to ATC for services and construction	**$ 8.6**	$ 10.3	$ 9.9
Charges from ATC for network transmission services	**109.4**	101.3	103.8

As of December 31, 2016 and 2015, our balance sheets included the following receivables and payables related to ATC:

(in millions)	2016	2015
Accounts receivable		
Services provided to ATC	**$ 1.1**	$ 0.5
Accounts payable		
Services received from ATC	**8.8**	8.5

Summarized financial data for ATC is included in the tables below:

(in millions)	2016	2015	2014
Income statement data			
Revenues	**$ 650.8**	$ 615.8	$ 635.0
Operating expenses	**322.5**	319.3	307.4
Other expense	**95.5**	96.1	88.9
Net income	**$ 232.8**	$ 200.4	$ 238.7

(in millions)	December 31, 2016	December 31, 2015
Balance sheet data		
Current assets	**$ 75.8**	$ 80.5
Noncurrent assets	**4,312.9**	3,948.3
Total assets	**$ 4,388.7**	$ 4,028.8
Current liabilities	**$ 495.1**	$ 330.3
Long-term debt	**1,865.3**	1,790.7
Other noncurrent liabilities	**271.5**	245.0
Shareholders' equity	**1,756.8**	1,662.8
Total liabilities and shareholders' equity	**$ 4,388.7**	$ 4,028.8

NOTE 6—SUPPLEMENTAL CASH FLOW INFORMATION

(in millions)	2016	2015	2014
Cash (paid) for interest, net of amount capitalized	**$ (137.5)**	$ (150.0)	$ (146.8)
Cash received (paid) for income taxes, net	**149.6**	42.5	(6.3)
Significant non-cash transactions:			
Accounts payable related to construction costs	**161.0**	165.4	180.5
Non-cash equity transfer of our ownership in WBS to WEC Energy Group	**73.0**	—	—
Restricted cash used to purchase investments held in the rabbi trust	**59.2**	70.0	—
Note receivable received related to the sale of AMP Trillium*	**—**	12.0	—
Capital assets received related to the sale of AMP Trillium*	**—**	6.3	—
ITF fueling station sale financed with note receivable	**—**	2.8	—
Purchase of a natural gas distribution business in Minnesota financed with note payable	**—**	2.6	—
Accounts receivable converted to notes receivable related to sales of ITF fueling stations constructed on behalf of others	**—**	—	10.9
Portion of ITF fueling station sale financed with note receivable *	**—**	—	2.7
Equity interest in joint venture received for a portion of the ITF fueling station sale *	**—**	—	3.1
Equity issued for employee stock ownership plan	**—**	—	1.7

* ITF owned a 30% interest in AMP. See Note 3, Dispositions, for more information on the sale of ITF.

At December 31, 2016 and 2015, restricted cash of $33.6 million and $118.4 million, respectively, was recorded within other long-term assets on our balance sheets. The majority of this amount was held in the rabbi trust and represents a portion of the required funding for the rabbi trust that was triggered by the announcement of the WEC Merger. Withdrawals of restricted cash from the rabbi trust for qualifying payments are shown as an investing activity on the statements of cash flows. Decreases in restricted cash due to the purchase of restricted investments held in the rabbi trust are reflected as non-cash transactions on the statements of cash flows and are included in the table above. See Note 2, Merger, for more information about the WEC Merger.

Discontinued Operations

Significant non-cash transactions and other information related to discontinued operations for the sale of IES's retail energy business are disclosed below.

(in millions)	2014
Operating activities	
Depreciation and amortization expense	$ 2.7
Net unrealized gains on energy contracts	(22.7)
Deferred income taxes and investment tax credits	36.1
Remeasurement of uncertain tax positions included in our liability for unrecognized tax benefits	(0.7)
Loss on sale of IES's retail energy business *	24.3
Other	33.4
Investing activities	
Capital expenditures	(0.8)

* See Note 3, Dispositions, for more information.

NOTE 7—REGULATORY ASSETS AND LIABILITIES

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

(in millions)	2016	2015	See Note
Regulatory assets [1] [2]			
Environmental remediation costs [3]	**$ 633.2**	$ 654.0	19
Unrecognized pension and OPEB costs [4]	**532.4**	588.2	18
AROs	**139.5**	136.7	10
Income tax related items [5]	**75.0**	63.8	
Termination of a tolling agreement with Fox Energy Company LLC [6]	**33.7**	39.1	
Crane Creek production tax credits [7]	**29.6**	30.9	
Uncollectible expense [8]	**25.6**	23.1	1(c)
Energy costs recoverable through rate adjustments [9]	**22.9**	20.9	
Derivatives	**16.9**	40.4	1(r)
De Pere Energy Center [10]	**16.7**	19.0	
Unamortized loss on reacquired debt [11]	**15.5**	15.7	
Other	**44.4**	46.9	
Total regulatory assets	**$ 1,585.4**	$ 1,678.7	
Balance Sheet Presentation			
Current assets [12]	**$ 50.3**	$ 37.1	
Regulatory assets	**1,535.1**	1,641.6	
Total regulatory assets	**$ 1,585.4**	$ 1,678.7	

[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 the table.

[2] As of December 31, 2016, we had $18.8 million of regulatory assets not earning a return. The regulatory assets not earning a return relate to certain environmental remediation costs, the recovery of which depends on the timing of the actual expenditures. The other regulatory assets in the table either earn a return or the cash has not yet been expended, in which case the assets are offset by liabilities.

[3] As of December 31, 2016, we had not yet made cash expenditures for $578.4 million of these environmental remediation costs.

[4] Represents the unrecognized future pension and OPEB costs resulting from actuarial gains and losses on defined benefit and OPEB plans. We are authorized recovery of this regulatory asset over the average remaining service life of each plan.

[5] Represents adjustments related to deferred income taxes, which are recovered in rates as the temporary differences that generated the income tax benefit reverse.

(6) 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.

(7) 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. WPS also reduced the depreciable basis of the qualifying facility by the amount of the grant proceeds, which will result in a reduction of depreciation and amortization expense over a 12-year period. WPS recorded a regulatory asset for the deferral of previously recorded production tax credits and is authorized recovery of this net regulatory asset through 2039.

(8) Represents amounts recoverable from customers related to uncollectible expense riders at NSG and PGL. These riders allow NSG and PGL to recover or refund the difference between actual uncollectible write-offs and the amounts recovered in rates.

(9) Represents energy costs that will be recovered from customers in the future.

(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) Amounts are recovered over the term of the replacement debt for NSG and PGL as authorized by the ICC.

(12) Short-term regulatory assets are included in accounts receivable and unbilled revenues on our balance sheets.

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

(in millions)	2016	2015	See Note
Regulatory liabilities			
Removal costs (1)	**$ 372.1**	$ 350.1	
Unrecognized pension and OPEB costs (2)	**58.6**	26.3	18
Derivatives	**25.9**	8.7	1(r)
Energy costs refundable through rate adjustments (3)	**20.1**	59.6	
Uncollectible expense (4)	**13.8**	11.5	1(c)
Energy efficiency programs (5)	**12.8**	11.2	
Crane Creek depreciation deferral (6)	**8.0**	8.3	
Other	**7.4**	17.6	
Total regulatory liabilities	**$ 518.7**	$ 493.3	
Balance sheet presentation			
Other current liabilities	**$ 11.0**	$ 33.8	
Regulatory liabilities	**507.7**	459.5	
Total regulatory liabilities	**$ 518.7**	$ 493.3	

(1) Represents amounts collected from customers to cover the cost of future removal of property, plant, and equipment.

(2) Represents the unrecognized future pension and OPEB costs resulting from actuarial gains and losses on defined benefit and OPEB plans. We will amortize this regulatory liability into net periodic benefit cost over the average remaining service life of each plan.

(3) Represents energy costs that will be refunded to customers in the future.

(4) Represents amounts refundable to customers related to uncollectible expense riders at NSG and PGL. These riders allow NSG and PGL to recover or refund the difference between actual uncollectible write-offs and the amounts recovered in rates.

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

(6) Represents the book depreciation taken on the Crane Creek wind project prior to WPS's election to claim a Section 1603 Grant for the project in lieu of the production tax credit. See more information in the regulatory assets section above.

NOTE 8—PROPERTY, PLANT, AND EQUIPMENT

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

(in millions)	2016	2015
Electric utility property, plant, and equipment	**$ 4,277.7**	$ 3,722.8
Natural gas utility property, plant, and equipment	**6,549.6**	6,184.0
Total utility property, plant, and equipment	**10,827.3**	9,906.8
Less: Accumulated depreciation	**3,300.5**	3,216.7
Net	**7,526.8**	6,690.1
CWIP	**180.9**	485.9
Net utility property, plant, and equipment	**7,707.7**	7,176.0
Non-utility and other property, plant, and equipment	**87.1**	186.2
Less: Accumulated depreciation	**15.0**	51.2
Net *	**72.1**	135.0
CWIP	**0.1**	107.6
Net non-utility and other property, plant, and equipment	**72.2**	242.6
Total property, plant, and equipment	**$ 7,779.9**	$ 7,418.6

* In 2015, impairments of $12.1 million were recorded to net non-utility plant and other property, plant, and equipment. These impairment losses are included in impairment losses on our income statements.

We evaluate property, plant, and equipment for impairment whenever indicators of impairment exist.

On January 1, 2017, WPS transferred approximately 600 miles of electric distribution lines and approximately 100 miles of natural gas distribution mains to UMERC. WPS also transferred related electric distribution substations in the Upper Peninsula of Michigan. The estimated net book value of the property, plant, and equipment we transferred to UMERC was $19 million. See Note 4, Related Parties, for more information.

NOTE 9—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 facilities at December 31, 2016 was as follows:

(in millions, except for percentages and MWs)	Weston Unit 4	Columbia Energy Center Units 1 and 2 [2]	Edgewater Unit 4
Ownership	**70.0%**	**31.8%**	**31.8%**
WPS's share of rated capacity (MWs) [1]	**373.5**	**334.4**	**98.0**
In-service date	**2008**	**1975 and 1978**	**1969**
Property, plant, and equipment	**$ 596.3**	**$ 417.9**	**$ 45.8**
Accumulated depreciation	**$ (170.3)**	**$ (128.3)**	**$ (31.7)**
CWIP	**$ 0.2**	**$ 41.2**	**$ 0.1**

[1] Based on expected capacity ratings for summer 2017. 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. See Note 19, Commitments and Contingencies, for more information related to the requirement to refuel, repower, or retire Edgewater Unit 4.

NOTE 10—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 by PDL for the removal of solar equipment components.

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

(in millions)	2016	2015	2014
Balance as of January 1	**$ 509.2**	$ 479.1	$ 489.9
Accretion	**25.1**	23.9	24.6
Additions and revisions to estimated cash flows	**—**	19.6 [1]	(17.6) [2]
Liabilities settled	**(41.6)**	(13.4)	(17.8)
Balance as of December 31	**$ 492.7**	$ 509.2	$ 479.1

[1] During 2015, an ARO of $9.0 million was recorded for the Hazardous and Solid Waste Management System; Disposal of Coal Combustion Residuals from Electric Utilities rule passed by the EPA in April 2015. In addition, our AROs increased $8.2 million in 2015 due to revisions made to estimated cash flows for changes in the weighted average cost to retire natural gas distribution pipe at PGL and NSG. We also revised the AROs recorded for WPS's fly-ash landfills during 2015 due to changes in estimated removal costs and settlement dates.

[2] During 2014, we revised the AROs recorded for our natural gas distribution pipes at PGL primarily due to changes in the weighted average cost to retire pipe.

NOTE 11—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 changes to our goodwill balances by segment during the years ended December 31, 2016 and 2015:

	Wisconsin		Illinois		Other States		Corporate and Other		Total	
(in millions)	2016	2015	2016	2015	2016	2015	2016	2015	2016	2015
Balance as of January 1										
Gross goodwill	**$ 36.4**	$ 36.4	**$ 630.1**	$ 630.1	**$ 267.0**	$ 267.0	**$ —**	$ 19.6	**$ 933.5**	$ 953.1
Accumulated impairment losses	**—**	—	**(192.8)**	(192.8)	**(104.9)**	(104.9)	**—**	—	**(297.7)**	(297.7)
Net goodwill as of January 1	**36.4**	36.4	**437.3**	437.3	**162.1**	162.1	**—**	19.6	**635.8**	655.4
ITF goodwill reclassified to held for sale *	**—**	—	**—**	—	**—**	—	**—**	(19.6)	**—**	(19.6)
Balance as of December 31										
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 as of December 31	**$ 36.4**	$ 36.4	**$ 437.3**	$ 437.3	**$ 162.1**	$ 162.1	**$ —**	$ —	**$ 635.8**	$ 635.8

* We reclassified ITF's goodwill to assets held for sale during the third quarter of 2015. Due to the offers received for ITF, we recorded a non-cash goodwill impairment loss related to ITF of $15.8 million during the fourth quarter of 2015. See Note 3, Dispositions, for more information.

Due to the WEC Merger, we changed the date of our annual goodwill impairment test during 2016 from April 1 to July 1. Since no more than 12 months is allowed to elapse between impairment tests, we performed a step zero qualitative impairment test as of April 1, 2016, and a quantitative impairment test as of July 1, 2016. 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, 2016			December 31, 2015		
(in millions)	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount	Gross Carrying Amount	Accumulated Amortization	Net Carrying Amount
Amortized intangible assets [1] [2]	**$ 16.0**	**$ (11.1)**	**$ 4.9**	$ 16.0	$ (7.8)	$ 8.2
Unamortized intangible assets [3]	**5.7**	**—**	**5.7**	5.7	—	5.7
Total intangible assets	**$ 21.7**	**$ (11.1)**	**$ 10.6**	$ 21.7	$ (7.8)	$ 13.9

(1) Primarily relates to 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, 2016, was approximately three years.

(2) During the second quarter of 2015, an impairment loss of $4.9 million was recorded related to the net carrying amount of PDL's amortized intangible assets. This loss is included in impairment losses on our income statements.

(3) Consists primarily of a trade name.

NOTE 12—COMMON EQUITY

Stock-Based Compensation

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

(in millions)	2016	2015	2014
WEC Energy Group stock options	**$ 1.4**	$ —	$ —
WEC Energy Group restricted shares	**3.4**	—	—
WEC Energy Group performance units	**4.0**	—	—
Integrys stock options	**—**	—	2.7
Integrys performance stock rights	**—**	3.3	16.8
Integrys restricted share units	**—**	8.2	9.9
Integrys non-employee director deferred stock units	**—**	0.9	0.8
Stock-based compensation expense	**$ 8.8**	$ 12.4	$ 30.2
Related tax benefit	**$ 3.5**	$ 5.0	$ 12.1

Stock-based compensation costs capitalized during 2016, 2015, and 2014 were not significant.

Stock Options

The following is a summary of our employees' WEC Energy Group stock option activity during 2016:

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, 2016	—	$ —		
Granted	**52,305**	**$ 55.36**		
Forfeited	**(5,675)**	**$ 55.36**		
Outstanding as of December 31, 2016	**46,630**	**$ 55.36**	**9.1**	**$ 0.1**
Exercisable as of December 31, 2016	**3,825**	**$ 55.36**	**9.1**	**$ —**

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, 2016. This is calculated as the difference between WEC Energy Group's closing stock price on December 31, 2016, and the option exercise price, multiplied by the number of in-the-money stock options.

As of December 31, 2016, our estimated unrecognized compensation cost related to unvested WEC Energy Group stock options was not significant.

During the first quarter of 2017, the Compensation Committee awarded 46,450 non-qualified WEC Energy Group stock options with an exercise price of $58.31 and a weighted-average grant date fair value of $7.44 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 2016:

Restricted Shares	Number of Shares	Weighted-Average Grant Date Fair Value
Outstanding as of January 1, 2016	—	$ —
Granted	**28,845**	$ 55.48
Forfeited	**(7,422)**	$ 55.48
Outstanding as of December 31, 2016	**21,423**	$ 55.48

As of December 31, 2016, we expect to recognize approximately $2.5 million of unrecognized compensation cost related to WEC Energy Group restricted stock over the next 2.0 years on a weighted-average basis.

During the first quarter of 2017, the Compensation Committee awarded 4,605 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 $58.10 per share.

Performance Units

In 2016, the Compensation Committee awarded 19,710 WEC Energy Group performance units to our officers and other key employees under the WEC Energy Group Performance Unit Plan.

As of December 31, 2016, we expect to recognize approximately $4.4 million of unrecognized compensation cost related to WEC Energy Group performance units over the next 1.4 years on a weighted-average basis.

In January 2017, the Compensation Committee awarded 19,990 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 in the form of cash dividends, loans, or advances, primarily depends on the availability of funds from our utility subsidiaries. Various laws, regulations, and financial covenants impose restrictions on the ability of certain of our utility subsidiaries to transfer funds to us in the form of dividends. 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.

See Note 14, 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, 2016, total restricted net assets of consolidated subsidiaries were $2,140.3 million. Our equity in undistributed earnings of 50% or less owned investees accounted for by the equity method was $187.6 million at December 31, 2016.

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.

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

NOTE 13—PREFERRED STOCK

The following table shows our subsidiaries' authorized shares of preferred stock at December 31, 2016 and 2015. 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 14—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)	2016	2015
Commercial paper		
Amount outstanding at December 31	**$ 228.0**	$ 305.5
Average interest rate on amounts outstanding at December 31	**1.03%**	0.66%
Short-term notes payable to WEC Energy Group		
Amount outstanding at December 31	**42.0**	95.1
Average interest rate on amount outstanding at December 31	**1.05%**	0.81%

Our average amount of commercial paper borrowings based on daily outstanding balances during 2016, was $229.3 million with a weighted-average interest rate during the period of 0.62%. Our average amount of short-term notes payable to WEC Energy Group based on daily outstanding balances during 2016, was $37.5 million with a weighted-average interest rate during the period of 0.83%.

As of December 31, 2016, we had approximately $730.0 million of available capacity under our bank back-up credit facility and our intercompany short-term debt facility with WEC Energy Group. As of December 31, 2016, we had $228.0 million of commercial paper outstanding that was supported by the credit facilities and $42.0 million of borrowings under our intercompany loan facility with WEC Energy Group.

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 minimum total funded debt to capitalization ratio of less than 65%. As of December 31, 2016, all 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	2016
Revolving credit facility (WPS)	December 2020	$ 250.0
Revolving credit facility (PGL)	December 2020	350.0
Revolving short-term notes payable to WEC Energy Group		400.0
Total short-term credit capacity		$ 1,000.0
Less:		
Commercial paper outstanding		$ 228.0
Short-term notes payable to WEC Energy Group		42.0
Available capacity under existing credit agreements		$ 730.0

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 15—LONG-TERM DEBT

In June 2016, our $50.0 million of 8.00% unsecured senior notes matured and were repaid with short-term borrowings from WEC Energy Group, which were funded by commercial paper issued by WEC Energy Group.

In February 2016, we repurchased and retired $154.9 million aggregate principal amount of our 6.11% Junior Notes for a purchase price of $128.6 million, plus accrued and unpaid interest, through a modified “dutch auction” tender offer. The gain associated with this repurchase was included in other income, net on our income statement. In connection with this transaction, we issued approximately $66.4 million of additional common stock to WEC Energy Group in satisfaction of its obligations under a replacement capital covenant relating to the 6.11% Junior Notes. Effective December 1, 2016, the remaining $114.9 million aggregate principal amount of the 6.11% Junior Notes bears interest at the three-month London Interbank Offered Rate (LIBOR) plus 2.12% and will reset quarterly.

The Peoples Gas Light and Coke Company

In December 2016, PGL issued $150.0 million of 3.65% Series DDD Bonds due December 15, 2046. The net proceeds were used for general corporate purposes, including capital expenditures and the refinancing of short-term debt.

In November 2016, PGL issued $50.0 million of 3.65% Series CCC Bonds due December 15, 2046. The net proceeds were used to repay at maturity PGL's $50.0 million aggregate principal amount outstanding of 2.21% First and Refunding Mortgage Bonds, Series XX.

In June 2016, PGL issued commercial paper to redeem at par, its $50.0 million of 4.30% Series RR First and Refunding Mortgage Bonds that were due in 2035.

Bonds and Notes

The following table shows the future maturities of our long-term debt outstanding as of December 31, 2016:

(in millions)	Payments
2017	$ 125.0
2018	255.0
2019	75.0
2020	250.0
2021	—
Thereafter	2,391.9
Total	$ 3,096.9

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 16—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)	2016	2015	2014
Current tax (benefit) expense	**$ (60.3)**	$ (27.9)	$ 44.1
Deferred income taxes, net	**260.8**	161.4	141.3
Investment tax credit, net	**(3.8)**	(1.5)	8.0
Total income tax expense related to continuing operations	**196.7**	132.0	193.4
Total income tax (benefit) expense related to discontinued operations	**—**	(0.5)	7.2
Total	**$ 196.7**	$ 131.5	$ 200.6

Statutory Rate Reconciliation

The income tax expense 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:

	2016		2015		2014	
(in millions)	Amount	Effective Tax Rate	Amount	Effective Tax Rate	Amount	Effective Tax Rate
Expected tax at statutory federal tax rates	**$ 173.6**	**35.0 %**	$ 106.1	35.0 %	$ 165.0	35.0 %
State income taxes net of federal tax benefit	**23.2**	**4.7 %**	18.1	6.0 %	35.5 *	7.5 %*
Valuation allowance change	**(2.1)**	**(0.4)%**	16.9	5.5 %	(4.9)	(1.0)%
AFUDC – Equity	**(6.8)**	**(1.4)%**	(6.1)	(2.0)%	(3.6)	(0.8)%
Other, net	**8.8**	**1.7 %**	(3.0)	(1.0)%	1.4	0.3 %
Total income tax expense	**$ 196.7**	**39.6 %**	$ 132.0	43.5 %	$ 193.4	41.0 %

* Includes the impact of a $13.0 million expense caused by the remeasurement of deferred taxes related to the sale of IES's retail energy business.

Deferred Income Tax Assets and Liabilities

The components of deferred income taxes as of December 31 are as follows:

(in millions)	2016	2015
Deferred income tax assets		
Future tax benefits	**$ 171.8**	$ 175.7
Other	**56.8**	36.0
Total deferred income tax assets	**228.6**	211.7
Valuation allowance	**(15.0)**	(17.1)
Net deferred income tax assets	**$ 213.6**	$ 194.6
Deferred income tax liabilities		
Plant-related	**$ 1,978.0**	$ 1,702.1
Regulatory deferrals	**95.3**	97.6
Employee benefits and compensation	**60.6**	28.4
Other	**27.7**	37.9
Total deferred income tax liabilities	**2,161.6**	1,866.0
Deferred income tax liabilities, net	**$ 1,948.0**	$ 1,671.4
Balance sheet presentation		
Deferred income tax liabilities – included in liabilities held for sale	**$ —**	$ 6.5
Deferred income tax liabilities, net	**1,948.0**	1,664.9
Total deferred income tax liabilities, net	**$ 1,948.0**	$ 1,671.4

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, 2016 and 2015 are summarized in the tables below:

2016 *(in millions)*	**Gross Value**	**Deferred Tax Effect**	**Valuation Allowance**	**Earliest Year of Expiration**
Future tax benefits as of December 31, 2016				
Federal net operating loss	**$ 74.2**	**$ 26.0**	**$ —**	**2035**
Federal foreign tax credit	**—**	**13.5**	**(13.5)**	**2017**
Other federal tax credit	**—**	**112.4**	**—**	**2025**
Charitable contribution	**3.8**	**1.5**	**(1.5)**	**2016**
State net operating loss	**270.3**	**13.6**	**—**	**2025**
State tax credit	**—**	**4.8**	**—**	**2016**
Balance as of December 31, 2016	**$ 348.3**	**$ 171.8**	**$ (15.0)**	

2015 *(in millions)*	**Gross Value**	**Deferred Tax Effect**	**Valuation Allowance**	**Earliest Year of Expiration**
Future tax benefits as of December 31, 2015				
Federal net operating loss	$ 92.0	$ 32.2	$ —	2031
Federal foreign tax credit	—	15.2	(15.2)	2017
Other federal tax credit	—	113.5	—	2025
Charitable contribution	4.7	1.9	(1.9)	2016
State net operating loss	172.3	8.6	—	2024
State tax credit	—	4.3	—	2016
Balance as of December 31, 2015	$ 269.0	$ 175.7	$ (17.1)	

Valuation allowances of $15.0 million have been established for certain tax benefit carryforwards based on our projected ability to realize such benefits by offsetting future tax liabilities. This is primarily the result of the extension of bonus depreciation. 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)	2016	2015
Balance at January 1	**$ 3.4**	$ 3.3
Increase related to tax positions taken in prior years	**6.5**	0.3
Decrease related to tax positions taken in prior years	**(0.1)**	—
Increase related to tax positions taken in current year	**0.8**	0.5
Decrease related to settlements	**—**	(0.7)
Decrease related to lapse of statutes	**(1.8)**	—
Balance at December 31	**$ 8.8**	$ 3.4

We had accrued interest of $0.1 million and no accrued penalties related to unrecognized tax benefits at December 31, 2016. We had accrued interest of $0.1 million and accrued penalties of $0.1 million related to unrecognized tax benefits at December 31, 2015.

Our effective tax rate could be affected by recognition of $7.8 million of unrecognized tax benefits related to continuing operations in periods after December 31, 2016.

Our subsidiaries file income tax returns in the United States federal jurisdiction and in various state and local jurisdictions as part of WEC Energy Group's filings.

With a few exceptions, we are no longer subject to federal income tax examinations by the United States Internal Revenue Service for years prior to 2013.

We file 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. With a few exceptions, we are no longer subject to state and local tax examinations for years prior to 2011. As of December 31, 2016, we were subject to examination by state or local tax authorities for the 2011 through 2016 tax years in our major state operating jurisdictions as follows:

Jurisdiction	Year
Federal	2013-2016
Illinois	2013-2016
Michigan	2012-2016
Minnesota	2014-2016
Wisconsin	2011-2016

Within the next 12 months, we do not expect to significantly change the amount of unrecognized tax benefits.

NOTE 17—GUARANTEES

The following table shows our outstanding guarantees:

	Total Amounts Committed	Expiration		
(in millions)	at December 31, 2016	Less Than 1 Year	1 to 3 Years	Over 3 Years
Guarantees supporting commodity transactions of subsidiaries [1]	**$ 150.6**	$ 71.6	$ 5.0	$ 74.0
Standby letters of credit [2]	**10.3**	9.9	0.4	—
Other guarantees [3]	**29.0**	—	6.8	22.2
Total guarantees	**$ 189.9**	$ 81.5	$ 12.2	$ 96.2

(1) Consists of (a) $5.0 million and $10.0 million to support the business operations of WBS and PDL, respectively; and (b) $101.2 million and $34.4 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) $19.0 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 18—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 March 2014, we remeasured the obligations of certain OPEB plans as a result of a plan design change to move participants age 65 and older to a Medicare Advantage plan starting January 1, 2015.

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)	**2016**	**2015**	**2016**	**2015**
Change in benefit obligation				
Obligation at January 1	**$ 1,602.7**	$ 1,705.7	**$ 458.6**	$ 520.0
Service cost	**27.9**	29.4	**15.8**	22.4
Interest cost	**54.5**	67.4	**18.8**	20.8
Transfer to affiliates *	**(301.2)**	—	**(28.4)**	—
Plan amendments	**—**	—	**(18.9)**	—
Actuarial loss (gain)	**27.9**	(51.1)	**(21.4)**	(85.6)
Participant contributions	**—**	—	**6.0**	6.6
Benefit payments	**(114.2)**	(148.9)	**(22.1)**	(25.3)
Plan curtailment	—	0.2	—	(0.3)
Obligation at December 31	**$ 1,297.6**	$ 1,602.7	**$ 408.4**	$ 458.6
Change in fair value of plan assets				
Fair value at January 1	**$ 1,304.6**	$ 1,495.6	**$ 428.3**	$ 447.7
Actual return on plan assets	**82.8**	(49.8)	**27.5**	(9.4)
Employer contributions	**2.3**	7.7	**0.1**	8.7
Transfer to affiliates *	**(258.3)**	—	**(20.2)**	—
Participant contributions	**—**	—	**6.0**	6.6
Benefit payments	**(114.2)**	(148.9)	**(22.1)**	(25.3)
Fair value at December 31	**$ 1,017.2**	$ 1,304.6	**$ 419.6**	$ 428.3
Funded status at December 31	**$ (280.4)**	$ (298.1)	**$ 11.2**	$ (30.3)

* Benefit obligations and plan assets were moved along with our employees who were transferred to/from affiliated entities. Effective January 1, 2016, we transferred our ownership in WBS to WEC Energy Group. The benefit obligations and plan assets related to WBS employees were also transferred at that time. 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)	**2016**	**2015**	**2016**	**2015**
Other long-term assets	**$ —**	$ —	**$ 31.7**	$ 8.7
Liabilities held for sale	**—**	0.8	**—**	0.4
Pension and OPEB obligations	**280.4**	297.3	**20.5**	38.6
Total net assets (liabilities)	**$ (280.4)**	$ (298.1)	**$ 11.2**	$ (30.3)

The accumulated benefit obligation for the defined benefit pension plans was $1,181.2 million and $1,456.8 million at December 31, 2016 and 2015, 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)	**2016**	**2015**
Projected benefit obligation	**$ 1,297.6**	$ 1,602.7
Accumulated benefit obligation	**1,181.2**	1,456.8
Fair value of plan assets	**1,017.2**	1,304.6

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)	**2016**	**2015**	**2016**	**2015**
Accumulated other comprehensive loss (pre-tax) [1]				
Net actuarial loss (gain)	**$ 37.1**	$ 44.3	**$ (1.6)**	$ (1.3)
Prior service credits	**—**	—	**(0.1)**	(0.1)
Total	**$ 37.1**	$ 44.3	**$ (1.7)**	$ (1.4)
Net regulatory assets (liabilities) [2]				
Net actuarial loss	**$ 547.5**	$ 596.6	**$ 1.4**	$ 28.0
Prior service costs (credits)	**10.5**	12.2	**(85.6)**	(74.9)
Total	**$ 558.0**	$ 608.8	**$ (84.2)**	$ (46.9)

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

[2] Amounts related to the utilities and WBS 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 2017:

(in millions)	**Pension Costs**	**OPEB Costs**
Net actuarial loss	$ 45.3	$ 3.4
Prior service costs (credits)	1.7	(9.9)
Total 2017 – estimated amortization	$ 47.0	$ (6.5)

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

	Pension Costs			OPEB Costs		
(in millions)	2016	2015	2014	2016	2015	2014
Service cost	**$ 27.9**	$ 29.4	$ 24.8	**$ 15.8**	$ 22.4	$ 21.0
Interest cost	**54.4**	67.4	76.2	**18.8**	20.8	23.5
Expected return on plan assets	**(75.2)**	(105.4)	(112.4)	**(28.8)**	(31.7)	(33.0)
Loss on plan settlement	**9.9**	1.2	0.9	**—**	—	—
Plan curtailment	**—**	(0.3)	—	**—**	—	—
Amortization of prior service cost (credit)	**1.7**	2.0	0.6	**(8.1)**	(10.3)	(9.4)
Amortization of net actuarial loss	**46.7**	50.2	33.3	**5.6**	8.9	3.2
Net periodic benefit cost	**$ 65.4**	$ 44.5	$ 23.4	**$ 3.3**	$ 10.1	$ 5.3

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

	Pension		OPEB	
	2016	2015	2016	2015
Discount rate	**4.19%**	4.47%	**4.09%**	4.33%
Rate of compensation increase	**4.00%**	4.00%	**N/A**	N/A
Assumed medical cost trend rate	**N/A**	N/A	**7.00%**	7.50%
Ultimate trend rate	**N/A**	N/A	**5.00%**	5.00%
Year ultimate trend rate is reached	**N/A**	N/A	**2021**	2021

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		
	2016	2015	2014
Discount rate	**4.26%**	4.08%	4.92%
Expected return on assets	**7.25%**	7.75%	8.00%
Rate of compensation increase	**4.00%**	4.23%	4.23%

	OPEB Costs		
	2016	2015	2014
Discount rate	**4.34%**	4.00%	4.65%
Expected return on assets	**7.25%**	7.75%	8.00%
Assumed medical cost trend rate (Pre 65/Post 65)	**7.50%**	6.00%	6.50%
Ultimate trend rate	**5.00%**	5.00%	5.00%
Year ultimate trend rate is reached	**2021**	2023	2019

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 2017, the expected return on assets assumption for the pension and OPEB plans is 7.25%.

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 trust target asset allocation is 60% equity securities and 40% fixed income securities. Our two largest OPEB trusts have target asset allocations of 50% equity investments and 50% fixed income, and 45% equity investments and 55% fixed income, respectively. Equity securities primarily 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(q), 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. Following our adoption of ASU 2015-07 on January 1, 2016, the assets that are not subject to leveling are investments that are valued using the net asset value per share (or its equivalent) practical expedient. We have applied this approach retrospectively to the 2015 table for comparability.

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

	December 31, 2016							
	Pension Plan Assets				OPEB Assets			
(in millions)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Asset Class								
Cash and cash equivalents	**$ 1.8**	**$ 26.5**	**$ —**	**$ 28.3**	**$ 18.7**	**$ 0.7**	**$ —**	**$ 19.4**
Equity securities:								
United States Equity	**131.1**	**0.1**	**—**	**131.2**	**14.4**	**—**	**—**	**14.4**
International Equity	**25.0**	**0.5**	**—**	**25.5**	**0.8**	**0.2**	**—**	**1.0**
Fixed income securities: *								
United States Bonds	**—**	**209.4**	**0.6**	**210.0**	**—**	**59.3**	**—**	**59.3**
International Bonds	**—**	**27.8**	**—**	**27.8**	**—**	**3.4**	**—**	**3.4**
	157.9	**264.3**	**0.6**	**422.8**	**33.9**	**63.6**	**—**	**97.5**
Investments measured at net asset value				**594.4**				**322.1**
Total	**$ 157.9**	**$ 264.3**	**$ 0.6**	**$ 1,017.2**	**$ 33.9**	**$ 63.6**	**$ —**	**$ 419.6**

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

	December 31, 2015							
	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	$ —	$ 29.6	$ —	$ 29.6	$ 6.9	$ 1.0	$ —	$ 7.9
Equity securities:								
United States Equity	34.0	3.5	—	37.5	7.0	0.1	—	7.1
International Equity	72.1	—	—	72.1	18.8	—	—	18.8
Fixed income securities: *								
United States Bonds	11.4	169.7	—	181.1	0.4	5.8	—	6.2
International Bonds	—	40.1	—	40.1	—	1.4	—	1.4
	117.5	242.9	—	360.4	33.1	8.3	—	41.4
Investments measured at net asset value				944.2				386.9
Total	$ 117.5	$ 242.9	$ —	$ 1,304.6	$ 33.1	$ 8.3	$ —	$ 428.3

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

The following table sets forth a reconciliation of changes in the fair value of pension plan assets categorized as Level 3 in the fair value hierarchy during 2016. There was no level 3 activity in 2015.

(in millions)	United States Bonds
Beginning balance at January 1, 2016	$ —
Purchases	0.6
Ending balance at December 31, 2016	$ 0.6

Cash Flows

In January 2017, we contributed $68.0 million to the pension plans and expect to contribute an additional $0.7 million in 2017, dependent on various factors affecting us, including our liquidity position and possible tax law changes. We do not expect to contribute to the OPEB plans in 2017.

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

(in millions)	Pension	OPEB
2017	$ 81.0	$ 20.2
2018	83.0	22.3
2019	96.9	23.9
2020	104.7	24.6
2021	105.1	26.1
2022 through 2026	466.0	144.8

Savings Plans

WEC Energy Group sponsors a 401(k) savings plan which 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. Certain employees participate in a defined contribution pension plan, in 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 $19.0 million in 2016, $33.8 million in 2015, and $35.0 million in 2014.

NOTE 19—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

We routinely enter into long-term purchase and sale commitments for various quantities and lengths of time. 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.

The following table shows our minimum future commitments related to these purchase obligations as of December 31, 2016, including those of our subsidiaries.

			Payments Due By Period					
(in millions)	Date Contracts Extend Through	Total Amounts Committed	2017	2018	2019	2020	2021	Later Years
Electric utility:								
Purchased power	2027	$ 622.7	$ 85.8	$ 54.7	$ 57.7	$ 60.1	$ 58.7	$ 305.7
Coal supply and transportation	2019	141.9	85.8	42.8	13.3	—	—	—
Natural gas utility supply and transportation	2028	613.7	187.8	149.5	117.6	73.5	27.6	57.7
Total		$ 1,378.3	$ 359.4	$ 247.0	$ 188.6	$ 133.6	$ 86.3	$ 363.4

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 $2.4 million, $10.8 million, and $14.7 million in 2016, 2015, and 2014, respectively.

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

Year Ending December 31	Payments *(in millions)*
2017	$ 5.5
2018	5.5
2019	4.5
2020	4.0
2021	4.1
Later years	38.4
Total	$ 62.0

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 SO_2, NOx, fine particulates, mercury, and GHGs; water 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 and super-critical pulverized coal generation;
- the beneficial use of ash and other products from coal-fired units; and
- the remediation of former manufactured gas plant sites.

Air Quality

Cross-State Air Pollution Rule

In July 2011, the EPA issued the CSAPR, which replaced a previous rule, the Clean Air Interstate Rule. The purpose of the CSAPR was to limit the interstate transport of NOx and SO_2 that contribute to fine particulate matter and ozone nonattainment in downwind states through a proposed allowance allocation and trading plan. After several lawsuits and related appeals, in October 2014, the D.C. Circuit Court of Appeals issued a decision that allowed the EPA to begin implementing CSAPR on January 1, 2015. The emissions budgets of Phase I of the rule applied in 2015 and 2016, while the Phase II emissions budgets discussed below apply to 2017 and beyond.

In December 2015, the EPA published its proposed update to the CSAPR for the 2008 ozone NAAQS and issued the final rule in September 2016. Starting in 2017, this rule requires reductions in the ozone season (May 1 through September 30) NOx emissions

from power plants in 23 states in the eastern United States, including Wisconsin. The EPA updated Phase II CSAPR NOx ozone season budgets for electric generating units in the affected states. In the final rule, the EPA significantly increased the NOx ozone season budget from the proposed rule for Wisconsin starting in 2017. We believe we are well positioned to meet the rule requirements and do not expect to incur significant costs to comply with this rule.

Sulfur Dioxide National Ambient Air Quality Standards

The EPA issued a revised 1-Hour SO_2 NAAQS that became effective in August 2010. The EPA issued a final rule in August 2015 describing the implementation requirements and established a compliance timeline for the revised standard. The final rule affords state agencies some latitude in rule implementation. A nonattainment designation could have negative impacts for a localized geographic area, including additional permitting requirements for new or existing sources in the area.

In June 2016, we provided modeling to the WDNR that shows the area around the Weston Power Plant to be in compliance. Based upon the submittal, the WDNR provided final modeling to the EPA demonstrating the area around the Weston Power Plant to be in compliance. We expect that the EPA will consider the WDNR's recommendation and finalize its recommended designation in August 2017, for finalization by the end of 2017.

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.

8-Hour Ozone National Ambient Air Quality Standards

The EPA completed its review of the 2008 8-hour ozone standard in November 2014, and announced a proposal to tighten (lower) the NAAQS. In October 2015, the EPA released the final rule, which lowered the limit for ground-level ozone. This is expected to cause nonattainment designations for some counties in Wisconsin with potential future impacts for our fossil-fueled power plant fleet. For nonattainment areas, the state of Wisconsin will have to develop a state implementation plan to bring the areas back into attainment. We will be required to comply with this state implementation plan no earlier than 2020 and are in the process of reviewing and determining potential impacts resulting from this rule. We believe we are well positioned to meet the rule requirements and do not expect to incur significant costs to comply with this rule.

Mercury and Other Hazardous Air Pollutants

In December 2011, the EPA issued the final MATS rule, which imposes stringent limitations on emissions of mercury and other hazardous air pollutants from coal and oil-fired electric generating units beginning in April 2015. In addition, Wisconsin has state mercury rules that require a 90% reduction of mercury; however, these rules are not in effect as long as MATS is in place. In June 2015, the Supreme Court ruled on a challenge to the MATS rule and remanded the case back to the D.C. Circuit Court of Appeals, ruling that the EPA failed to appropriately consider the cost of the regulation. The MATS rule remains in effect until the D.C. Circuit Court of Appeals takes action on the EPA's April 2016 updated cost evaluation.

We believe that our fleet is well positioned to comply with the final MATS rule and do not expect to incur any significant additional costs to comply with this regulation. Construction and testing of the ReACT™ multi-pollutant control system at Weston Unit 3 is complete, and the unit is currently in compliance with both MATS and our Consent Decree emission requirements.

Climate Change

In 2015, the EPA issued the Clean Power Plan, a final rule regulating GHG emissions from existing generating units, a proposed federal plan and model trading rules as alternatives or guides to state compliance plans, and final performance standards for modified and reconstructed generating units and new fossil-fueled power plants. In October 2015, following publication of the final rule for existing fossil-fueled generating units, numerous states (including Wisconsin), trade associations, and private parties filed lawsuits challenging the final rule, including a request to stay the implementation of the final rule pending the outcome of these legal challenges. The D.C. Circuit Court of Appeals denied the stay request, but in February 2016, the Supreme Court stayed the effectiveness of the Clean Power Plan until disposition of the litigation in the D.C. Circuit Court of Appeals and to the extent that further appellate review is sought, at the Supreme Court. In addition, in February 2016, the Governor of Wisconsin issued Executive Order 186, which prohibits state agencies, departments, boards, commissions, or other state entities from developing or promoting the development of a state plan. The D.C. Circuit Court of Appeals heard the case in September 2016.

The final rule for existing fossil-fueled generating units seeks to achieve state-specific GHG emission reduction goals by 2030, and would have required states to submit plans by September 2016. The goal of the final rule is to reduce nationwide GHG emissions by 32% from 2005 levels. The rule is seeking GHG emission reductions in Wisconsin of 41% below 2012 levels by 2030. Interim goals starting in 2022 would require states to achieve about two-thirds of the 2030 required reduction. The building blocks used by the EPA to determine each state's emission reduction requirements include a combination of improving power plant efficiency, increasing reliance on combined cycle natural gas units, and adding new renewable energy resources. We continue to evaluate possible reduction opportunities and actions that preserve fuel diversity, lower costs for our customers, and contribute towards long-term GHG reductions, given the uncertain future of the Clean Power Plan and current fuel and technology markets. Our evaluation to date indicates that the Clean Power Plan, as well as current fuel markets and advances in technology, are not expected to result in significant additional compliance costs, including capital expenditures, but could impact how we operate our existing fossil-fueled power plants.

However, the timelines for the 2022 through 2029 interim goals and the 2030 final goal for states, as well as all other aspects of the rule, likely will be changed due to the stay and subsequent legal proceedings. With the new Federal Executive Administration as of January 2017, the Clean Power Plan, or its successor, could be significantly changed from the final rule of October 2015. Notwithstanding the potential changes to the Clean Power Plan, addressing climate change is an integral component of our strategic planning process. We continue to reshape our portfolio of electric generation facilities with investments that will improve our environmental performance, including reduced GHG intensity of our operating fleet. As the regulation of GHG emissions takes shape, our plan is to work with our industry partners, environmental groups, and the State of Wisconsin, with a goal of reducing CO_2 emissions by approximately 40% below 2005 levels by 2030. We continue to evaluate numerous options in order to meet our CO_2 reduction goal, such as increased utilization of existing natural gas combined cycle units, co-firing or switching to natural gas in existing coal-fired units, reduced operation or retirement of existing coal-fired units, addition of new renewable energy resources (wind, solar), and consideration of supply and demand-side energy efficiency and distributed generation.

Draft Federal Plan and Model Trading Rules (Model Rules) were also published in October 2015 for use in developing state plans or for use in states where a plan is not submitted or approved. In December 2015, the state of Wisconsin submitted petitions for reconsideration of the EPA's final standards for existing, as well as for new, modified, and reconstructed generating units. A petition for reconsideration of the EPA's final standards for existing generating units was also submitted jointly by the Wisconsin utilities. Among other things, the petitions narrowly asked the EPA to consider revising the state goal for existing units to reflect the 2013 retirement of the Kewaunee Power Station, which could lower the state's CO_2 equivalent reduction goal by about 10%. In May 2016, the EPA denied the state of Wisconsin's petition for reconsideration related to new, modified, and reconstructed generating units. The EPA has not issued decisions yet regarding the above referenced petitions for reconsideration of the final EPA standards for existing generating units. In December 2016, the EPA withdrew the draft Model Rules and accompanying draft documents from the review process and made working drafts available to the public. They are not final documents, are not signed by the Administrator, and will not be published in the Federal Register. The EPA’s docket will remain open, with the potential for completing the agency’s work on these materials and finalizing them at a later date.

We are required to report our CO_2 equivalent emissions from our electric generating facilities under the EPA Greenhouse Gases Reporting Program. For 2015, 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 5.7 million metric tonnes to the EPA for 2016. The level of CO_2 and other GHG emissions vary from year to year and are 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 amounts related to the natural gas that our natural gas utilities distribute and sell. For 2015, we reported aggregated CO_2 equivalent emissions of approximately 17.8 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 17.5 million metric tonnes to the EPA for 2016.

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, which requires that the location, design, construction, and capacity of cooling water intake structures at existing power plants reflect the Best Technology Available (BTA) for minimizing adverse environmental impacts from both impingement (entrapping organisms on water intake screens) and

entrainment (drawing organisms into water intake). The rule became effective in October 2014, and applies to all of our existing generating facilities with cooling water intake structures.

Facility owners must select from seven compliance options available to meet the impingement mortality (IM) reduction standard. The rule requires state permitting agencies to make BTA determinations, subject to EPA oversight, for IM reduction 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 Pulliam Units 7 and 8 and Weston Unit 2, satisfy the IM BTA requirements. We plan to evaluate the available IM options for Pulliam Units 7 and 8. We also expect that limited studies will be required to support the future WDNR BTA determinations for Weston Unit 2. Based on preliminary discussions with the WDNR, we anticipate that the WDNR will not require physical modifications to the Weston Unit 2 intake structure to meet the IM BTA requirements based on low capacity use of the unit.

BTA determinations must also be made by the WDNR to address entrainment mortality (EM) reduction on a site-specific basis taking into consideration several factors. BTA determinations for EM will be made in future permit reissuances for Pulliam Units 7 and 8 and Weston Units 2 through 4.

During 2017 and 2018, we will continue to complete studies and evaluate options to address the EM BTA requirements at our plants. With the exception of Weston Units 3 and 4 (which have existing cooling towers that meet EM BTA requirements), we cannot yet determine what, if any, intake structure or operational modifications will be required to meet the new EM BTA requirements at our facilities. We also expect that limited studies to support WDNR BTA determinations will be conducted at the Weston facility. Based on preliminary discussions with the WDNR, we anticipate that the WDNR will not require physical modifications to the Weston Unit 2 intake structure to meet the EM BTA requirements based on low capacity use of the unit. Entrainment studies are currently being conducted at Pulliam Units 7 and 8.

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 Guidelines

The EPA's final steam electric effluent guidelines rule took effect in January 2016 and applies to discharges of wastewater from our power plant processes in Wisconsin. This rule is being litigated in the United States Court of Appeals for the Fifth Circuit and may result in changes to the discharge requirements. The WDNR will continue to modify the state rules as necessary and incorporate the new requirements into our facility permits, which are renewed every five years. We expect the new requirements to be phased in between 2018 and 2023 as our permits are renewed. Our power plant facilities already have advanced wastewater treatment technologies installed that meet many of the discharge limits established by this rule. However, these standards will require additional wastewater treatment retrofits as well as installation of other equipment to minimize process water use. The final rule phases in new or more stringent requirements related to limits of arsenic, mercury, selenium, and nitrogen in wastewater discharged from wet scrubber systems. The rule also requires dry fly ash handling, which is already in place at all of our power plants. Dry bottom ash transport systems are required by the new rule, and modifications will be required at Pulliam Units 7 and 8 and Weston Unit 3. We are beginning preliminary engineering for compliance with the rule and estimate a total cost range of $25 million to $35 million for these bottom ash transport systems.

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 the 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)	2016	2015
Regulatory assets	**$ 633.2**	$ 654.0
Reserves for future remediation	**578.2**	598.0

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. We continue to review our renewable energy portfolios and acquire cost-effective renewables as needed to meet our requirements on an ongoing basis. The PSCW administers the renewable program related to Act 141, and we fund the program, along with other utilities, based on 1.2% of our annual operating revenues.

Michigan Legislation

In 2008, Michigan enacted Act 295, which required 10% of the state's energy to come from renewables by 2015 and energy optimization (efficiency) targets up to 1% annually by 2015. In December 2016, Michigan revised this legislation with Act 342, which requires additional renewable energy requirements beyond 2015. We were in compliance with these requirements as of December 31, 2016.

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.

Weston Title V Air Permit

In May 2014, the WDNR issued a NOV alleging that we failed to maintain a minimum sorbent feed rate prior to the Continuous Emissions Monitoring System certification and included an issue related to reporting NOx emissions from the Weston Unit 4 auxiliary boiler. In June 2015, the WDNR issued a NOV alleging that we failed to comply with mercury reporting requirements related to challenged matters in the 2013 Weston Title V permit. In June 2016, the WDNR issued a letter closing both the May 2014 and June 2015 NOVs with no further action.

Consent Decrees

Wisconsin Public Service Corporation Consent Decree – Weston and Pulliam

In November 2009, the EPA issued a NOV to WPS, which alleged violations of the CAA's New Source Review requirements relating to certain projects completed at the Weston and Pulliam 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 (including refueling, repowering, and/or retirement of units),
- 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 March 2016, WPS submitted a proposed revision to the EPA 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. These proposed revisions were approved by the EPA in May 2016. The revisions to the environmental projects are not expected to materially impact the overall costs noted above.

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.

Also, in May 2010, WPS received from the Sierra Club a Notice of Intent to file a civil lawsuit based on allegations that WPS violated the CAA at the Weston and Pulliam plants. WPS entered into a Standstill Agreement with the Sierra Club by which the parties agreed to negotiate as part of the EPA NOV process, rather than litigate. The Standstill Agreement ended in October 2012, but no further action has been taken by the Sierra Club as of December 31, 2016. It is unknown whether the Sierra Club will take further action in the future.

Joint Ownership Power Plants Consent Decree – Columbia and Edgewater

In December 2009, the EPA issued a 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 (including refueling, repowering, and/or retirement of units),
- 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.

The Consent Decree contains a requirement to, among other things, refuel, repower, or retire Edgewater Unit 4, of which WPS is a joint owner, by no later than December 31, 2018. In the first quarter of 2015, management of the joint owners recommended that Edgewater Unit 4 be retired in December 2018. However, a final decision on how to address the requirement for this unit has not yet been made by the joint owners, as early retirement is contingent on various operational and market factors, and other alternatives to retirement are still available.

NOTE 20—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, 2016			
(in millions)	Level 1	Level 2	Level 3	Total
Assets				
Derivative assets				
Natural gas contracts	**$ 2.3**	**$ 22.4**	**$ —**	**$ 24.7**
FTRs	**—**	**—**	**2.0**	**2.0**
Coal contracts	**—**	**0.1**	**—**	**0.1**
Total derivative assets	**$ 2.3**	**$ 22.5**	**$ 2.0**	**$ 26.8**
Investments held in rabbi trust	**$ 103.9**	**$ —**	**$ —**	**$ 103.9**
Liabilities				
Derivative liabilities				
Natural gas contracts	**$ —**	**$ 0.2**	**$ —**	**$ 0.2**
Coal contracts	**—**	**1.4**	**—**	**1.4**
Total derivative liabilities	**$ —**	**$ 1.6**	**$ —**	**$ 1.6**

	December 31, 2015			
(in millions)	Level 1	Level 2	Level 3	Total
Assets				
Derivative assets				
Natural gas contracts	$ 0.5	$ 1.2	$ —	$ 1.7
FTRs	—	—	2.0	2.0
Total derivative assets	$ 0.5	$ 1.2	$ 2.0	$ 3.7
Investments held in rabbi trust	$ 39.8	$ —	$ —	$ 39.8
Liabilities				
Derivative liabilities				
Natural gas contracts	$ 2.8	$ 24.7	$ —	$ 27.5
Petroleum products contracts	0.5	—	—	0.5
Coal contracts	—	4.7	—	4.7
Total derivative liabilities	$ 3.3	$ 29.4	$ —	$ 32.7

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 21, Derivative Instruments, for more information.

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

(in millions)	2016	2015	2014
Balance at the beginning of the period	**$ 2.0**	$ (6.9)	$ (1.3)
Realized and unrealized losses	**(0.2)**	(10.7)	(7.6)
Purchases	**7.1**	9.8	4.3
Sales	**(0.2)**	(0.1)	—
Settlements	**(6.7)**	5.2	(3.5)
Transfers out of Level 3	**—**	4.7	1.2
Balance at the end of the period	**$ 2.0**	$ 2.0	$ (6.9)

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 flow through 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:

	2016		2015	
(in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion	**$ 3,065.7**	**$ 3,164.7**	$ 3,169.9	$ 3,233.1

NOTE 21—DERIVATIVE INSTRUMENTS

The following table shows our derivative assets and derivative liabilities:

	December 31, 2016		December 31, 2015	
(in millions)	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Other current				
Natural gas contracts	**$ 22.3**	**$ 0.2**	$ 1.2	$ 25.6
Petroleum products contracts	**—**	**—**	—	0.5
FTRs	**2.0**	**—**	2.0	—
Coal contracts	**—**	**0.9**	—	3.3
Total other current	**$ 24.3**	**$ 1.1**	$ 3.2	$ 29.4
Other long-term				
Natural gas contracts	**$ 2.4**	**$ —**	$ 0.5	$ 1.9
Coal contracts	**0.1**	**0.5**	—	1.4
Total other long-term	**$ 2.5**	**$ 0.5**	$ 0.5	$ 3.3
Total	**$ 26.8**	**$ 1.6**	$ 3.7	$ 32.7

Our estimated notional sales volumes and realized gains (losses) were as follows for the years ended:

	December 31, 2016		December 31, 2015		December 31, 2014	
(in millions)	Volume	Gains (Losses)	Volume	Gains (Losses)	Volume	Gains (Losses)
Natural gas contracts	92.9 Dth	**$ (37.7)**	85.2 Dth	$ (55.0)	76.9 Dth	$ 8.0
Petroleum products contracts	4.4 gallons	**(0.6)**	7.9 gallons	(3.4)	7.3 gallons	(0.5)
FTRs	8.4 MWh	**6.0**	9.0 MWh	3.3	8.7 MWh	3.2
Total		**$ (32.3)**		$ (55.1)		$ 10.7

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

	December 31, 2016		December 31, 2015	
(in millions)	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Gross amount recognized on the balance sheet	**$ 26.8**	**$ 1.6**	$ 3.7	$ 32.7
Gross amount not offset on the balance sheet *	**(0.2)**	**(0.2)**	(1.7)	(4.5)
Net amount	**$ 26.6**	**$ 1.4**	$ 2.0	$ 28.2

* Includes cash collateral posted of $2.8 million as of December 31, 2015. There was no cash collateral included at December 31, 2016.

As of December 31, 2016 and 2015, we had posted cash collateral of $16.4 million and $21.8 million, respectively, 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. The aggregate fair value of all derivative instruments with specific credit

risk-related contingent features that were in a net liability position at December 31, 2016 and 2015, was $0.2 million and $23.8 million, respectively. At December 31, 2016 and 2015, 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, 2016, we would not have been required to post any collateral. At December 31, 2015, we would have been required to post collateral of $18.0 million.

NOTE 22—REGULATORY ENVIRONMENT

Wisconsin Public Service Corporation

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 reflects 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 to 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, future system support resource payments will continue to be 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 current 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 amounts deferred related to these items as of December 31, 2016, were not material.

2015 Wisconsin Rate Order

In April 2014, WPS initiated a rate proceeding with the PSCW. In December 2014, the PSCW issued a final written order for WPS, effective January 1, 2015. It authorized a net retail electric rate increase of $24.6 million and a net retail natural gas rate decrease of $15.4 million, reflecting a 10.20% ROE. The order authorized a common equity component average of 50.28%. The PSCW approved a change in rate design for WPS, which includes higher fixed charges to better match the related fixed costs of providing service. In addition, the order continued to exclude a decoupling mechanism that was terminated beginning January 1, 2014.

The primary driver of the increase in retail electric rates was higher costs of fuel for electric generation of approximately $42 million. In addition, 2015 rates included approximately $9 million of lower refunds to customers related to decoupling over-collections. In 2015 rates, WPS refunded approximately $4 million to customers related to 2013 decoupling over-collections compared with refunding approximately $13 million to customers in 2014 rates related to 2012 decoupling over-collections. Absent these adjustments for electric fuel costs and decoupling refunds, WPS would have realized an electric rate decrease. In addition, WPS received approval from the PSCW to defer and amortize the undepreciated book value associated with Pulliam Units 5 and 6 and Weston Unit 1 starting with the actual retirement date, June 1, 2015, and concluding by 2023. See Note 19, Commitments and Contingencies, for more information. The PSCW allowed WPS to escrow ATC and MISO network transmission expenses for 2015 and 2016. As a result, WPS deferred as a regulatory asset the difference between actual transmission expenses and those included in rates until a future rate proceeding. Finally, the PSCW ordered that 2015 fuel costs should continue to be monitored using a 2% tolerance window.

The retail natural gas rate decrease was driven by the approximate $16 million year-over-year negative impact of decoupling refunds to and collections from customers. In 2015 rates, WPS refunded approximately $8 million to customers related to 2013 decoupling over-collections compared with recovering approximately $8 million from customers in 2014 rates related to 2012 decoupling under-collections. Absent the adjustment for decoupling refunds to and collections from customers, WPS would have realized a retail natural gas rate increase.

2014 Wisconsin Rate Order

In March 2013, WPS initiated a rate proceeding with the PSCW. In December 2013, the PSCW issued a final written order for WPS, effective January 1, 2014. It authorized a net retail electric rate decrease of $12.8 million and a net retail natural gas rate increase of $4.0 million, reflecting a 10.20% ROE. The order also included a common equity component average of 50.14%. The retail electric rate impact consisted of a rate increase, including recovery of the difference between a 2012 fuel refund and a 2013 rate increase, entirely offset by a portion of estimated fuel cost over-collections from customers in 2013. Retail electric rates were further decreased by 2012 decoupling over-collections to be returned to customers in 2014. The retail natural gas rate impact consisted of a rate decrease, which was more than offset by the positive impact of 2012 decoupling under-collections of approximately $8 million to be recovered from customers in 2014. Both the retail electric and retail natural gas rate changes included the recovery of pension and other employee benefit increases that were deferred in WPS's 2013 rate case. The PSCW also authorized the recovery of prudently incurred 2014 environmental mitigation project costs related to compliance with a Consent Decree signed in January 2013 for the Pulliam and Weston sites. See Note 19, Commitments and Contingencies, for more information. Additionally, the order required WPS to terminate its decoupling mechanism, beginning January 1, 2014.

2015 Michigan Rate Order

In October 2014, WPS initiated a rate proceeding with the MPSC. In April 2015, the MPSC issued a final written order for WPS, effective April 24, 2015, approving a settlement agreement. The order authorized a retail electric rate increase of $4.0 million to be implemented over three years to recover costs for the 2013 acquisition of the Fox Energy Center as well as other capital investments associated with the Crane Creek wind farm and environmental upgrades at generation plants. The rates reflected a 10.2% ROE and a common equity component average of 50.48%. The increase reflected the continued deferral of costs associated with the Fox Energy Center until the second anniversary of the order. The increase also reflected the deferral of Weston Unit 3 ReACT™ environmental project costs. On the second anniversary of the order, WPS will discontinue the deferral of Fox Energy Center costs and will begin amortizing this deferral along with the deferral associated with the termination of a tolling agreement related to the Fox Energy Center. WPS also received approval from the MPSC to defer and amortize the undepreciated book value of the retired plant associated with Pulliam Units 5 and 6 and Weston Unit 1 starting with the actual retirement date, June 1, 2015, and concluding by 2023. As a result of the formation of UMERC, WPS transferred the deferrals mentioned above, as well as its customers and property, plant, and equipment located in the Upper Peninsula of Michigan to the new utility, effective January 1, 2017. Therefore, the terms and conditions of this rate order are now applicable to UMERC. UMERC will not seek an increase to legacy WPS retail electric base rates that would become effective prior to January 1, 2018.

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

Base Rate Freeze

In June 2015, the ICC approved the WEC Merger subject to the condition that PGL and NSG will not seek increases of their base rates that would become effective earlier than two years after the close of the merger.

Illinois Investigations

In March 2015, the ICC opened a docket, naming PGL as respondent, to investigate the veracity of certain allegations included in anonymous letters that the ICC staff received regarding PGL's SMP. This matter is still pending.

In November 2015, the ICC initiated an investigation into whether we, PGL, or WEC Energy Group knowingly misled or withheld material information from the ICC at its open meeting on May 20, 2015. The investigation relates to the ICC Staff's presentation of independent audit findings reached for PGL's SMP. The Illinois AG conducted an inquiry into this matter, as well as the veracity of certain allegations included in anonymous letters that the ICC staff received regarding PGL's SMP. In May 2016, PGL entered into settlement agreements that fully resolved and settled all contested issues with the ICC, the Illinois AG, and the Citizens Utility Board regarding the ICC's investigation of the May 20, 2015, open meeting and all pending Illinois AG inquiries. As part of the settlements, PGL agreed to make payments totaling $18.5 million, the majority of which consisted of credits to customers, voluntary contributions to certain public utility funds, and low-income customer funds.

In December 2015, the ICC ordered a series of stakeholder workshops to evaluate the SMP. This ICC action did not impact our ongoing work to modernize and maintain the safety of our 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 commenced in

January 2016 and were completed in March 2016. The ICC staff submitted a report on the workshop process in May 2016. In July 2016, the ICC initiated a proceeding before an ALJ to take evidence for purposes of determining, among other things, the planning, reporting, and monitoring of the program, including what the target end date for the program should be. On March 1, 2017, the ICC issued an order directing additional hearings be held before the ALJ on certain issues to further develop the evidentiary record in this case. This proceeding is still expected to result in a final order by the ICC in 2017. We are currently unable to determine what, if any, long-term impact there will be on PGL's SMP.

2015 Illinois Rate Order

In February 2014, PGL and NSG initiated a rate proceeding with the ICC. In January 2015, the ICC issued a final written order for PGL and NSG, effective January 28, 2015. The order authorized a retail natural gas rate increase of $74.8 million for PGL and $3.7 million for NSG. In February 2015, the ICC issued an amendatory order that revised the increases to $71.1 million for PGL and $3.5 million for NSG, effective February 26, 2015, to reflect the extension of bonus depreciation in 2014. The rates for PGL reflected a 9.05% ROE and a common equity component average of 50.33%. The rates for NSG reflected a 9.05% ROE and a common equity component average of 50.48%. The rate order allowed PGL and NSG to continue the use of their decoupling mechanisms and uncollectible expense true-up mechanisms. In addition, PGL recovers a return on certain investments and depreciation expense through the QIP rider, and accordingly, such costs are not subject to PGL's rate order.

Qualifying Infrastructure Plant Rider

In July 2013, Illinois Public Act 98-0057, The Natural Gas Consumer, Safety & Reliability Act, became law. The Act gives PGL a cost recovery mechanism for prudently incurred costs to upgrade Illinois natural gas infrastructure that are collected through a surcharge on customer bills. This Act eliminated a requirement for PGL and NSG to file biennial rate proceedings under existing Illinois coal-to-gas legislation. In September 2013, PGL filed with the ICC requesting the proposed rider, which was approved in January 2014 and became effective as of January 1, 2014.

PGL's QIP rider is subject to an annual reconciliation whereby costs are reviewed for accuracy and prudence. No schedule has been set for the 2015 reconciliation. The ALJ has placed the 2014 reconciliation on stay, pending resolution of several open matters related to PGL's SMP. Although schedules have not been set for the reconciliations, discovery has continued for both the 2014 and 2015 reconciliations. As of December 31, 2016, there can be no assurance that all costs incurred under the QIP rider will be recoverable.

2013 Illinois Rate Order

In July 2012, PGL and NSG initiated a rate proceeding with the ICC. In June 2013, the ICC issued a final written order, effective June 27, 2013. The order authorized a retail natural gas rate increase of $57.2 million for PGL and $6.6 million for NSG. The rates for PGL reflected a 9.28% ROE and a common equity component average of 50.43%. The rates for NSG reflected a 9.28% ROE and a common equity component average of 50.32%. The rate order also allowed PGL and NSG to continue the use of their decoupling mechanisms.

In August 2013, the ICC granted certain rehearing requests on tax-related issues filed by PGL, NSG, and other intervenors. PGL and NSG asked for a correction of the revenue requirement for deferred tax assets related to tax net operating losses (NOLs) incurred in 2012 and 2013. In the ICC’s order, these deferred tax assets were included in rate base, but computational errors were made. Other intervenors requested the exclusion from rate base of the deferred tax asset related to the 2012 tax NOL. The tax NOLs in question resulted from PGL and NSG claiming accelerated depreciation deductions in 2012 and 2013. In December 2013, the ICC evaluated and approved a correction of the computational errors and rejected the intervenors' proposed exclusion of the 2012 tax NOL. Customer rates were increased by $2.6 million for PGL and $0.1 million for NSG for the impact of this correction, effective January 1, 2014.

Minnesota Energy Resources Corporation

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 reflect 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 currently

authorized decoupling mechanism for another three years. The final approved rate increase was lower than the interim rates collected from customers during 2016. Therefore, as of December 31, 2016, we estimated that $3.0 million will be refunded to MERC's customers in May 2017.

2015 Minnesota Rate Order

In September 2013, MERC initiated a rate proceeding with the MPUC. In October 2014, the MPUC issued a final written order for MERC, effective April 1, 2015. The order authorized a retail natural gas rate increase of $7.6 million (2.9%). The rates reflected a 9.35% ROE and a common equity component average of 50.31%. The order approved a deferral of customer billing system costs, for which recovery will be requested in MERC's 2016 rate case. A decoupling mechanism with a 10% cap remained in effect for MERC's residential and small commercial and industrial customers. The final approved rate increase was lower than the interim rates collected from customers during 2014. Therefore, MERC refunded $4.7 million to customers in 2015.

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%). The rates reflect 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.

2014 Michigan Rate Order

In June 2013, MGU initiated a rate proceeding with the MPSC. In November 2013, the MPSC issued a final written order for MGU, effective January 1, 2014. The order authorized a retail natural gas rate increase of $4.5 million (3.5%). The rates reflected a 10.25% ROE and a common equity component average of 48.62%. In addition, the order required MGU to terminate its decoupling mechanism after December 31, 2013, and replace it with a new decoupling mechanism based on total margins, beginning January 1, 2015. The decoupling mechanism did not cover variations in volumes due to actual weather being different from rate case-assumed weather. The rate order also terminated MGU's uncollectible expense true-up mechanism after December 31, 2013.

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 and it became operational effective January 1, 2017. This utility holds the electric and natural gas distribution assets previously held by WE and WPS located in the Upper Peninsula of Michigan. See Note 4, Related Parties, for more information.

NOTE 23—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, 2013	$ (3.1)	$ (20.1)	$ (23.2)
Other comprehensive loss before reclassifications	—	(6.0)	(6.0)
Amounts reclassified out of accumulated other comprehensive loss	(0.1)	1.7	1.6
Net 2014 other comprehensive loss	(0.1)	(4.3)	(4.4)
Balance at December 31, 2014	(3.2)	(24.4)	(27.6)
Other comprehensive loss before reclassifications	—	(3.1)	(3.1)
Amounts reclassified out of accumulated other comprehensive loss	0.7	1.6	2.3
Net 2015 other comprehensive income (loss)	0.7	(1.5)	(0.8)
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)**

NOTE 24—OTHER INCOME, NET

Total other income, net was as follows at December 31:

(in millions)	2016	2015	2014
Gain on repurchase of notes	**$ 25.7**	$ —	$ —
Equity portion of AFUDC	**19.5**	17.7	12.5
Gains (losses) on exchange-traded funds	**5.1**	(3.3)	2.9
Key executive life insurance income for retired employees	**1.2**	2.8	2.9
Federal excise tax credit	**1.1**	7.3	4.4
Earnings from equity method investments, excluding ATC	**0.9**	0.3	2.6
Gain on sale of land at the holding company	**—**	—	3.5
Other, net	**(1.4)**	4.3	5.7
Total other income, net	**$ 52.1**	$ 29.1	$ 34.5

NOTE 25—SEGMENT INFORMATION

At December 31, 2016, 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, as well as the operations of UPPCO prior to its sale to Balfour Beatty Infrastructure Partners LP in August 2014. See Note 3, Dispositions, for more information on the sale of UPPCO.

- The electric transmission investment segment includes our approximate 34% ownership interest in ATC, a for-profit, electric transmission company regulated by the FERC and certain state regulatory commissions.

- The corporate and other segment includes the operations of the Integrys holding company, the PELLC holding company, WBS, PDL, and ITF, as well as the discontinued operations of IES prior to its sale in November 2014. Effective January 1, 2016, we transferred our ownership in WBS to WEC Energy Group. See Note 4, Related Parties, for more information. The sale of ITF was was also completed in the first quarter of 2016. See Note 3, Dispositions, for more information on the sales of IES and 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, 2016, 2015, and 2014.

	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	**493.2**	**530.6**	**113.9**	**—**	**1,137.7**	**19.2**	**—**	**1,156.9**
Depreciation and amortization	**124.1**	**134.0**	**21.1**	**—**	**279.2**	**4.3**	**—**	**283.5**
Operating income (loss)	**263.5**	**194.1**	**46.2**	**—**	**503.8**	**(7.8)**	**—**	**496.0**
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**

	Regulated Operations							
2015 *(in millions)*	**Wisconsin**	**Illinois**	**Other States**	**Electric Transmission Investment**	**Total Regulated Operations**	**Corporate and Other**	**Reconciling Eliminations**	**Integrys Holding Consolidated**
External revenues	$ 1,483.3	$1,253.6	$ 399.6	$ —	$ 3,136.5	$ 82.6	$ —	$ 3,219.1
Other operation and maintenance	488.7	465.1	105.9	—	1,059.7	4.9	—	1,064.6
Depreciation and amortization	121.0	125.8	19.5	—	266.3	26.2	—	292.5
Merger costs	5.2	6.3	0.1	—	11.6	75.3	—	86.9
Impairment losses	—	—	—	—	—	47.3	—	47.3
Operating income (loss)	227.5	209.6	40.4	—	477.5	(122.9)	—	354.6
Equity in earnings of transmission affiliate	—	—	—	70.6	70.6	—	—	70.6
Interest expense	58.3	38.8	10.1	—	107.2	53.4	(9.5)	151.1
Capital expenditures	371.0	368.3	53.0	—	792.3	95.6	—	887.9
Total assets	4,439.9	5,169.6	897.4	550.4	11,057.3	932.7	(411.8)	11,578.2

	Regulated Operations							
2014 *(in millions)*	**Wisconsin**	**Illinois**	**Other States**	**Electric Transmission Investment**	**Total Regulated Operations**	**Corporate and Other**	**Reconciling Eliminations**	**Integrys Holding Consolidated**
External revenues	$ 1,668.4	$1,764.8	$ 617.4	$ —	$ 4,050.6	$ 95.0	$ —	$ 4,145.6
Other operation and maintenance	499.8	565.5	150.7	—	1,216.0	9.5	0.1	1,225.6
Depreciation and amortization	116.8	114.8	23.7	—	255.3	35.3	—	290.6
Merger costs	—	—	—	—	—	10.4	—	10.4
Gain on sale of UPPCO, net of transaction costs	—	—	(85.4)	—	(85.4)	—	—	(85.4)
Operating income (loss)	257.6	123.6	146.8	—	528.0	(21.8)	—	506.2
Equity in earnings of transmission affiliate	—	—	—	85.7	85.7	—	—	85.7
Interest expense	57.4	34.5	12.0	—	103.9	63.2	(12.3)	154.8
Capital expenditures	322.0	355.3	57.8	—	735.1	121.6	—	856.7
Total assets	4,205.2	5,055.3	880.8	536.7	10,678.0	993.0	(473.0)	11,198.0

NOTE 26—NEW ACCOUNTING PRONOUNCEMENTS

Revenue Recognition

In May 2014, the FASB and the International Accounting Standards Board issued their joint revenue recognition standard, ASU 2014-09, Revenue from Contracts with Customers. Several amendments were issued subsequent to the standard to clarify the guidance. The core principle of the guidance is to recognize revenue in an amount that an entity is entitled to receive in exchange for goods and services. The guidance also requires additional disclosures about the nature, amount, timing, and uncertainty of revenues and the related cash flows arising from contracts with customers.

We intend to adopt this standard for interim and annual periods beginning January 1, 2018, as required, and plan to use the modified retrospective method of adoption. This method will result in a cumulative-effect adjustment that will be recorded on the balance sheet as of the beginning of 2018, as if the standard had always been in effect. Disclosures in 2018 will include a reconciliation of results under the new revenue guidance compared with what would have been reported in 2018 under the old revenue recognition guidance in order to help facilitate comparability with the prior periods.

We are currently reviewing our contracts with customers and related financial disclosures to evaluate the impact of the amended guidance on our existing revenue recognition policies and procedures. We consider tariff sales at our regulated utilities, excluding the revenue component related to alternative revenue programs, to be in the scope of the new standard. We have evaluated the nature of these revenues and do not expect that there will be a significant shift in the timing or pattern of revenue recognition for such sales. However, in our evaluation, we are also monitoring unresolved implementation issues for our industry, including the impacts of the new guidance on our ability to recognize revenue for certain contracts where collectability is uncertain and the accounting for contributions in aid of construction (CIAC). We currently account for CIAC funds received from customers and/or developers outside of revenue, as a reduction to property, plant, and equipment. The final resolution of these issues could impact our current accounting policies and revenue recognition.

Classification and Measurement of Financial Instruments

In January 2016, the FASB issued ASU 2016-01, Classification and Measurement of Financial Assets and Liabilities. This guidance is effective for fiscal years and interim periods beginning after December 15, 2017, and will be recorded with a cumulative-effect adjustment to beginning retained earnings as of the beginning of the fiscal year in which the guidance is effective. This guidance requires equity investments, including other ownership interests such as partnerships, unincorporated joint ventures, and limited liability companies, to be measured at fair value with changes in fair value recognized in net income. It also simplifies the impairment assessment of equity investments without readily determinable fair values and amends certain disclosure requirements associated with the fair value of financial instruments. This ASU does not apply to investments accounted for under the equity method of accounting. We are currently assessing the effects this guidance may have on our financial statements.

Leases

In February 2016, the FASB issued ASU 2016-02, Leases. This guidance is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2018, and will be applied using a modified retrospective approach. The main provision of this ASU is that lessees will be required to recognize lease assets and lease liabilities for most leases, including those classified as operating leases under GAAP. We are currently assessing the effects this guidance may have on our financial statements.

Stock-Based Compensation

In March 2016, the FASB issued ASU 2016-09, Improvements to Employee Share-Based Payment Accounting. This guidance is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2016. Under this ASU, all excess tax benefits and tax deficiencies are recognized as income tax expense or benefit in the income statement, the tax effects of exercised or vested awards are treated as discrete items in the reporting period in which they occur, and excess tax benefits are recognized in the current period regardless of whether the benefit reduces taxes payable. On the cash flow statement, excess tax benefits are classified along with other income tax cash flows as an operating activity, and cash paid by an employer when directly withholding shares for tax purposes is classified as a financing activity. We adopted this guidance effective January 1, 2017, and do not expect it to impact our financial statements.

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, 2020. 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 financial statements.

Classification of Certain Cash Receipts and Cash Payments

In August 2016, the FASB issued ASU 2016-15, Classification of Certain Cash Receipts and Cash Payments. This guidance is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2017, and will be applied using a retrospective transition method. There are eight main provisions of this ASU for which current GAAP either is unclear or does not include specific guidance. We are currently assessing the effects this guidance may have on our financial statements.

Restricted Cash

In November 2016, the FASB issued ASU 2016-18, Restricted Cash. This guidance is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2017. Under this ASU, amounts generally described as restricted cash and restricted cash equivalents should be 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. We do not believe the adoption of this guidance will have a significant impact on our financial statements.

Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost

In March 2017, the FASB issued ASU 2017-07, Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost. This guidance is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2017. Under this ASU, an employer is required to disaggregate the service cost component from the other components of the net benefit cost. The amendments provide explicit guidance on how to present the service cost component and the other components of the net benefit cost in the income statement and allow only the service cost component of the net benefit cost to be eligible for capitalization. The amendments should be applied retrospectively for the presentation of the service cost component and the other components of the net benefit cost in the income statement, and prospectively for the capitalization of the service cost component in assets. We are currently assessing the effects this guidance may have on our financial statements.