INTEGRYS HOLDING, INC.

FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2020

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For the Year Ended December 31, 2020
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GLOSSARY OF TERMS AND ABBREVIATIONS

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

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

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

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

Environmental Terms	
ACE	Affordable Clean Energy
Act 141	2005 Wisconsin Act 141
BATW	Bottom Ash Transport Water
BSER	Best System of Emission Reduction
CAA	Clean Air Act
CO_2	Carbon Dioxide
CPP	Clean Power Plan
CSAPR	Cross-State Air Pollution Rule
EGU	Electric Utility Generating Unit
ELG	Steam Electric Effluent Limitation Guidelines

GHG	Greenhouse Gas
GMZ	Groundwater Management Zone
NOV	Notice of Violation
NSPS	New Source Performance Standards
PCB	Polychlorinated Biphenyls
VN	Violation Notice

Measurements

Dth	Dekatherm
MW	Megawatt
MWh	Megawatt-hour

Other Terms and Abbreviations

AG	Attorney General
AIA	Affiliated Interest Agreement
Badger Hollow I	Badger Hollow Solar Park I
Compensation Committee	Compensation Committee of the Board of Directors of WEC Energy Group, Inc.
D.C. Circuit Court of Appeals	United States Court of Appeals for the District of Columbia Circuit
COVID-19	Coronavirus Disease – 2019
FTR	Financial Transmission Right
ITC	Investment Tax Credit
LIBOR	London Interbank Offered Rate
MISO	Midcontinent Independent System Operator, Inc.
MISO Energy Markets	MISO Energy and Operating Reserves Market
Omnibus Stock Incentive Plan	WEC Energy Group 1993 Omnibus Stock Incentive Plan, Amended and Restated Effective as of January 1, 2016
QIP	Qualifying Infrastructure Plant
REC	Renewable Energy Certificate
ROE	Return on Equity
SMP	Natural Gas System Modernization Program
SPC	COVID-19 Special Purpose Charge
Tax Legislation	Tax Cuts and Jobs Act of 2017
Two Creeks	Two Creeks Solar Park
VITA	Variable Income Tax Adjustment Rider

FINANCIAL STATEMENTS AND NOTES

A. INDEPENDENT AUDITORS' REPORT

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

Milwaukee, Wisconsin

We have audited the accompanying consolidated financial statements of Integrys Holding, Inc. and its subsidiaries (the "Company") (a wholly owned subsidiary of WEC Energy Group, Inc.), which comprise the consolidated balance sheets as of December 31, 2020 and 2019, and the related consolidated statements of income, comprehensive income, equity, and cash flows for each of the three years in the period ended December 31, 2020, 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, 2020 and 2019, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2020, in accordance with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP

Milwaukee, Wisconsin
March 31, 2021

INTEGRYS HOLDING, INC.

B. CONSOLIDATED INCOME STATEMENTS

Year Ended December 31 *(in millions)*	2020	2019	2018
Operating revenues	**$ 3,114.6**	$ 3,199.0	$ 3,344.7
Operating expenses			
Cost of sales	**974.0**	1,159.4	1,315.4
Other operation and maintenance	**955.1**	963.0	1,028.4
Depreciation and amortization	**405.3**	376.5	338.7
Property and revenue taxes	**85.5**	80.2	72.3
Total operating expenses	**2,419.9**	2,579.1	2,754.8
Operating income	**694.7**	619.9	589.9
Other income, net	**42.2**	55.6	29.6
Interest expense	**171.0**	165.8	150.8
Other expense	**(128.8)**	(110.2)	(121.2)
Income before income taxes	**565.9**	509.7	468.7
Income tax expense	**119.0**	104.2	123.4
Net income	**$ 446.9**	$ 405.5	$ 345.3

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)*	2020	2019	2018
Net income	**$ 446.9**	$ 405.5	$ 345.3
Other comprehensive income (loss), net of tax			
Derivatives accounted for as cash flow hedges			
Reclassification of net loss to net income, net of tax	**0.4**	0.6	0.6
Cumulative effect adjustment from adoption of ASU 2018-02	**—**	—	(0.2)
Cash flow hedges, net	**0.4**	0.6	0.4
Defined benefit plans			
Pension and OPEB adjustments arising during the period, net of tax	**(0.2)**	2.3	(2.2)
Amortization of pension and OPEB costs included in net periodic benefit cost, net of tax expense of $2.0	**5.5**	5.0	5.1
Cumulative effect adjustment from adoption of ASU 2018-02	**—**	—	(3.0)
Defined benefit plans, net	**5.3**	7.3	(0.1)
Other comprehensive income, net of tax	**5.7**	7.9	0.3
Comprehensive income	**$ 452.6**	$ 413.4	$ 345.6

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)*	2020	2019
Assets		
Current assets		
Cash and cash equivalents	**$ 6.6**	$ 11.8
Accounts receivable and unbilled revenues, net of reserves of $136.3 and $84.3, respectively	**546.5**	601.3
Accounts receivable from related parties	**65.4**	69.9
Materials, supplies, and inventories	**254.7**	260.4
Notes receivable from related party	**—**	166.9
Prepayments	**56.9**	55.7
Other	**46.5**	54.0
Current assets	**976.6**	1,220.0
Long-term assets		
Property, plant, and equipment, net of accumulated depreciation and amortization of $3,895.6 and $3,728.1, respectively	**11,008.5**	10,079.3
Regulatory assets	**1,420.5**	1,381.3
Goodwill	**635.8**	635.8
Other	**493.1**	473.5
Long-term assets	**13,557.9**	12,569.9
Total assets	**$ 14,534.5**	$ 13,789.9
Liabilities and Equity		
Current liabilities		
Short-term debt	**$ 421.5**	$ 185.5
Notes payable to related party	**68.1**	—
Current portion of long-term debt	**400.0**	250.0
Accounts payable	**444.5**	491.3
Accounts payable to related parties	**99.3**	133.2
Customer credit balances	**87.4**	93.7
Other	**254.3**	275.9
Current liabilities	**1,775.1**	1,429.6
Long-term liabilities		
Long-term debt	**3,740.7**	3,879.0
Deferred income taxes	**1,466.3**	1,320.1
Regulatory liabilities	**1,499.9**	1,540.9
Environmental remediation liabilities	**469.6**	500.2
Pension and OPEB obligations	**100.7**	146.3
AROs	**433.7**	397.3
Other	**191.9**	173.2
Long-term liabilities	**7,902.8**	7,957.0
Commitments and contingencies (Note 23)		
Shareholder's equity		
Common stock – $0.01 par value; 10,000 shares authorized, 1,020 shares issued and outstanding	**—**	—
Additional paid in capital	**2,302.5**	2,301.8
Retained earnings	**2,557.7**	2,110.8
Accumulated other comprehensive loss	**(3.6)**	(9.3)
Shareholder's equity	**4,856.6**	4,403.3
Total liabilities and equity	**$ 14,534.5**	$ 13,789.9

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)*	2020	2019	2018
Operating activities			
Net income	**$ 446.9**	$ 405.5	$ 345.3
Reconciliation to cash provided by operating activities			
Depreciation and amortization	**405.3**	376.5	338.7
Deferred income taxes and ITCs, net	**136.1**	159.6	144.2
Contributions and payments related to pension and OPEB plans	**(101.3)**	(50.9)	(61.1)
Change in –			
Accounts receivable and unbilled revenues, net	**61.3**	47.2	(70.2)
Materials, supplies, and inventories	**5.7**	(16.2)	(5.9)
Other current assets	**11.6**	4.9	46.9
Accounts payable	**(62.8)**	2.2	160.5
Other current liabilities	**(20.8)**	47.8	(30.4)
Other, net	**(96.5)**	(49.4)	46.6
Net cash provided by operating activities	**785.5**	927.2	914.6
Investing activities			
Capital expenditures	**(1,300.3)**	(1,278.5)	(1,092.2)
Acquisition of Forward Wind Energy Center	**—**	—	(77.1)
Payments for assets transferred from WBS	**—**	—	(70.6)
Proceeds from the sale of assets and businesses, net of cash divested	**10.3**	23.9	4.5
Proceeds from the sale of investments held in rabbi trust	**56.2**	0.2	118.6
Purchase of investments held in rabbi trust	**(37.8)**	—	(65.0)
Short-term notes receivable from related parties, net	**166.9**	(27.4)	138.7
Proceeds from cash surrender value of life insurance	**8.3**	7.9	—
Other, net	**(2.1)**	(4.3)	(0.7)
Net cash used in investing activities	**(1,098.5)**	(1,278.2)	(1,043.8)
Financing activities			
Retirement of long-term debt	**(300.0)**	(75.0)	(369.9)
Issuance of long-term debt	**310.0**	700.0	600.0
Change in short-term debt	**236.0**	(294.0)	(53.5)
Short-term debt to related parties, net	**68.1**	—	—
Other, net	**(2.7)**	(6.7)	(4.4)
Net cash provided by financing activities	**311.4**	324.3	172.2
Net change in cash, cash equivalents, and restricted cash	**(1.6)**	(26.7)	43.0
Cash, cash equivalents, and restricted cash at beginning of year	**55.3**	82.0	39.0
Cash, cash equivalents, and restricted cash at end of year	**$ 53.7**	$ 55.3	$ 82.0

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)	Common Stock	Additional Paid-In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Shareholder's Equity
Balance at December 31, 2017	$ —	$ 2,664.9	$ 1,356.8	$ (17.5)	$ 4,004.2
Net income	—	—	345.3	—	345.3
Other comprehensive income	—	—	—	3.5	3.5
Transfer of WPSI's ownership interest in ATC and related taxes	—	(363.4)	—	—	(363.4)
Cumulative effect adjustment from ASU 2018-02 adoption	—	—	3.2	(3.2)	—
Balance at December 31, 2018	$ —	$ 2,301.5	$ 1,705.3	$ (17.2)	$ 3,989.6
Net income	—	—	405.5	—	405.5
Other comprehensive income	—	—	—	7.9	7.9
Other	—	0.3	—	—	0.3
Balance at December 31, 2019	$ —	$ 2,301.8	$ 2,110.8	$ (9.3)	$ 4,403.3
Net income	**—**	**—**	**446.9**	**—**	**446.9**
Other comprehensive income	**—**	**—**	**—**	**5.7**	**5.7**
Other	**—**	**0.7**	**—**	**—**	**0.7**
Balance at December 31, 2020	**$ —**	**$ 2,302.5**	**$ 2,557.7**	**$ (3.6)**	**$ 4,856.6**

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

G. NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2020

NOTE 1—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

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

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

- Wisconsin segment – Consists of WPS, which is engaged in the generation of electricity and the distribution of electricity and natural gas in Wisconsin.
- 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.
- Corporate and other segment – Consists of the Integrys holding company, the PELLC holding company, and PDL. See Note 3, Disposition, for more information on the sale of our remaining PDL solar facilities.

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. We use the cumulative earnings approach for classifying distributions received in the statements of cash flows. Under the cumulative earnings approach, we compare the distributions received to cumulative equity method earnings since inception. Any distributions received up to the amount of cumulative equity earnings are considered a return on investment and classified in operating activities. Any excess distributions are considered a return of investment and classified in investing activities.

Our financial statements also reflect our proportionate interests in certain jointly owned utility facilities. See Note 9, Jointly Owned Utility Facilities, for more information.

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

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

(d) Operating Revenues—The following discussion includes our significant accounting policies related to operating revenues. For additional required disclosures on disaggregation of operating revenues, see Note 5, Operating Revenues.

Revenues from Contracts with Customers

Electric Utility Operating Revenues

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

The transaction price of the performance obligations for residential and commercial and industrial customers is valued using the rates, charges, terms, and conditions of service included in the tariffs of our regulated electric utility, which have been approved by the PSCW. These rates often have a fixed component customer charge and a usage-based variable component charge. We recognize revenue for the fixed component customer charge monthly using a time-based output method. We recognize revenue for the usage-based variable component charge using an output method based on the quantity of electricity delivered each month. The retail electric rates of WPS include base amounts for fuel and purchased power costs, which also impact our revenues. The electric fuel rules set by the PSCW allow us to defer, for subsequent rate recovery or refund, under- or over-collections of actual fuel and purchased power costs beyond 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 it to earn a greater ROE than authorized by the PSCW. In addition, WPS's residential tariffs include a mechanism for cost recovery or refund of uncollectible expense based on the difference between actual uncollectible write-offs and the amounts recovered in rates. See Note 25, Regulatory Environment, for more information on how COVID-19 has affected our cost recovery mechanisms.

Wholesale customers who resell power can choose to either bundle capacity and electricity services together under one contract with a supplier or purchase capacity and electricity separately from multiple suppliers. Furthermore, wholesale customers can choose to have WPS provide generation to match the customer's load, similar to requirements contracts, or they can purchase specified quantities of electricity and capacity. Contracts with wholesale customers that include capacity bundled with the delivery of electricity contain two performance obligations, as capacity and electricity are often transacted separately in the marketplace at the wholesale level. When recognizing revenue associated with these contracts, the transaction price is allocated to each performance obligation based on its relative standalone selling price. Revenue is recognized as control of each individual component is transferred to the customer. Electricity is the primary product sold by our electric utility and represents a single performance obligation satisfied over time through discrete deliveries to a customer. Revenue from electricity sales is generally recognized as units are produced and delivered to the customer within the production month. Capacity represents the reservation of an electric generating facility and conveys the ability to call on a plant to produce electricity when needed by the customer. The nature of our performance obligation as it relates to capacity is to stand ready to deliver power. This represents a single performance obligation transferred over time, which generally represents a monthly obligation. Accordingly, capacity revenue is recognized on a monthly basis.

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

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

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

Natural Gas Utility Operating Revenues

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

In certain of our service territories, customers can purchase the commodity from a third party. In this case, the performance obligation only includes the delivery of the natural gas to the customer.

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

The tariffs of our natural gas utilities include various rate mechanisms that allow them to recover or refund changes in prudently incurred costs from rate case-approved amounts. The rates for all of our natural gas utilities include one-for-one recovery mechanisms for natural gas commodity costs. We defer any difference between actual natural gas costs incurred and costs recovered through rates as a current asset or liability. The deferred balance is returned to or recovered from customers at intervals throughout the year. In addition, the rates of PGL and NSG, and the residential tariffs of WPS, include riders or other mechanisms for cost recovery or refund of uncollectible expense based on the difference between actual uncollectible write-offs and the amounts recovered in rates. The rates of PGL and NSG include riders for cost recovery of environmental cleanup costs, energy conservation and management program costs, and income tax expense changes resulting from the Tax Legislation. Finally, PGL's rates include a cost recovery mechanism for SMP costs, and similarly, MERC's rates include riders to recover costs incurred to replace or modify certain natural gas facilities. See Note 25, Regulatory Environment, for more information on how COVID-19 has affected our cost recovery mechanisms.

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

Other Non-Utility Operating Revenues

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

Other non-utility revenues were derived from distributed renewable solar projects, which consisted primarily of sales of renewable energy and solar RECs generated by PDL. The sale of solar RECs was a distinct performance obligation as they were often sold separately from the renewable energy generated. Although the performance obligation for the sale of renewable energy was recognized over time and the performance obligation for solar RECs was recognized at a point-in-time, the timing of revenue recognition was the same, as the generation of renewable energy and sales of solar REC's occurred concurrently. See Note 3, Disposition, for more information on the sale of our remaining PDL solar facilities.

Other Operating Revenues

Alternative Revenues

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

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

- The rates of PGL, NSG, and MERC include decoupling mechanisms. These mechanisms differ by state and allow the utilities to recover or refund the differences between actual and authorized margins for certain customer classes. See Note 25, Regulatory Environment, for more information.
- PGL and NSG were authorized to implement a SPC rider for the recovery of incremental direct costs resulting from the COVID-19 pandemic, foregone late fees and reconnection charges, and the costs associated with the ICC's bill payment assistance programs. See Note 25, Regulatory Environment, for more information.

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

(e) Credit Losses—The following discussion includes our significant accounting policies related to credit losses. For additional required disclosures on credit losses, see Note 6, Credit Losses.

Effective January 1, 2020, we adopted FASB ASU 2016-13, Financial Instruments – Credit Losses (Topic 326): Measurement of Credit Losses on Financial Instruments, using the modified retrospective transition method. This ASU amends the impairment model to utilize an expected loss methodology in place of the incurred loss methodology for financial instruments, including trade receivables. The amendment requires entities to consider a broader range of information to estimate expected credit losses, which may result in earlier recognition of loss. The cumulative effect of adopting this standard was not significant to our financial statements.

Our exposure to credit losses is related to our accounts receivable and unbilled revenue balances, which are primarily generated from the sale of electricity and natural gas by our regulated utility operations. Credit losses associated with our utility operations are analyzed at the reportable segment level as we believe contract terms, political and economic risks, and the regulatory environment are similar at this level as our reportable segments are generally based on the geographic location of the underlying utility operations. At the corporate and other segment, we had an accounts receivable and unbilled revenue balance at the beginning of 2020 related to the PDL residential solar facilities, which were sold in November 2020. See Note 3, Disposition, for more information.

We evaluate the collectability of our accounts receivable and unbilled revenue balances considering a combination of factors. For some of our larger customers and also in circumstances where we become aware of a specific customer's inability to meet its financial obligations to us, we record a specific allowance for credit losses against amounts due in order to reduce the net recognized receivable to the amount we reasonably believe will be collected. For all other customers, we use the accounts receivable aging method to calculate an allowance for credit losses. Using this method, we classify accounts receivable into different aging buckets and calculate a reserve percentage for each aging bucket based upon historical loss rates. The calculated reserve percentages are updated on at least an annual basis, in order to ensure recent macroeconomic, political, and regulatory trends are captured in the calculation, to the extent possible. Risks identified that we do not believe are reflected in the calculated reserve percentages, are assessed on a quarterly basis to determine whether further adjustments are required.

We monitor our ongoing credit exposure through active review of counterparty accounts receivable balances against contract terms and due dates. Our activities include timely account reconciliation, dispute resolution and payment confirmation. To the extent possible, we work with customers with past due balances to negotiate payment plans, but will disconnect customers for non-payment as allowed by our regulators if necessary, and employ collection agencies and legal counsel to pursue recovery of defaulted receivables. For our larger customers, detailed credit review procedures may be performed in advance of any sales being made. We sometimes require letters of credit, parental guarantees, prepayments or other forms of credit assurance from our larger customers to mitigate credit risk. See Note 25, Regulatory Environment, for information on certain regulatory actions that were and/or are being taken for the purpose of ensuring that essential utility services are available to our customers during the COVID-19 pandemic.

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

(in millions)	2020	2019
Natural gas in storage	**$ 153.5**	$ 146.3
Materials and supplies	**72.9**	77.4
Fossil fuel	**28.3**	36.7
Total	**$ 254.7**	$ 260.4

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 45% and 40% of total inventories at December 31, 2020 and 2019, respectively. The estimated replacement cost of natural gas in inventory at December 31, 2020 and 2019, exceeded the LIFO cost by $31.5 million and $9.8 million, respectively. In calculating these replacement amounts, PGL and NSG used a Chicago city-gate natural gas price per Dth of $2.31 at December 31, 2020, and $1.95 at December 31, 2019.

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

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

The recovery or refund of regulatory assets and liabilities is based on specific periods determined by our regulators or occurs over the normal operating period of the related assets and liabilities. If a previously recorded regulatory asset is no longer probable of recovery, the regulatory asset is reduced to the amount considered probable of recovery, and the reduction is charged to expense in the current period. See Note 7, Regulatory Assets and Liabilities, for more information.

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

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

Annual Utility Composite Depreciation Rates	2020	2019	2018
WPS	**2.63 %**	2.44 %	2.50 %
PGL	**3.16 %**	3.20 %	3.25 %
NSG	**2.48 %**	2.48 %	2.45 %
MERC [(1)]	**2.47 %**	2.33 %	1.95 %
MGU	**2.67 %**	2.54 %	2.61 %

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

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

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

See Note 8, Property, Plant, and Equipment, for more information.

(i) 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 2020, WPS's average AFUDC retail rate was 7.55%, and its average AFUDC wholesale rate was 5.59%. The other utilities did not record significant AFUDC for 2020, 2019, or 2018.

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

(in millions)	2020	2019	2018
AFUDC – Debt	**$ 4.7**	$ 2.5	$ 1.9
AFUDC – Equity	**12.0**	6.0	4.6

(j) 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. During the third quarter of each year, we perform an annual impairment test at all of our reporting units that carry a goodwill balance. The carrying amount of the reporting unit's goodwill is considered not recoverable if the carrying amount of the reporting unit's net assets 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.

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

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

We periodically assess the recoverability of equity method investments when factors indicate the carrying amount of such assets may be impaired. 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, an impairment loss is recognized equal to the amount by which the carrying amount exceeds the investment's fair value.

(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 the assets. An ARO liability is recorded, when incurred, for these obligations as long as the fair value can be reasonably estimated, even if the timing or method of settling the obligation is unknown. The associated retirement costs are capitalized as part of the related long-lived asset and are depreciated over the useful life of the asset. The ARO liabilities are accreted each period using the credit-adjusted risk-free interest rates associated with the expected settlement dates of the AROs. These rates are determined when the obligations are incurred. Subsequent changes resulting from revisions to the timing or the amount of the original estimate of undiscounted cash flows are recognized as an increase or a decrease to the carrying amount of the liability and the associated capitalized retirement costs. For our regulated entities, we recognize regulatory assets or liabilities for the timing differences between when we recover an ARO in rates and when we recognize the associated retirement costs. See Note 10, Asset Retirement Obligations, for more information.

(l) 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 electric fuel rules. Gains on sales of allowances at WPS are returned to ratepayers. See Note 1(d), Operating Revenues, for more information on the electric fuel rules.

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

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

Stock Options

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

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

	2020	2019	2018
Stock options granted	**66,500**	45,243	45,740
Estimated weighted-average fair value per stock option	**$ 10.82**	$ 8.60	$ 7.77
Assumptions used to value the options:			
Risk-free interest rate	**1.6% – 1.9%**	2.5% – 2.7%	1.6% – 2.5%
Dividend yield	**3.0 %**	3.6 %	3.5 %
Expected volatility	**16.0 %**	17.0 %	18.0 %
Expected life (years)	**8.6**	8.5	6.0

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

Restricted Shares

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

Performance Units

Officers and other key employees are granted performance units under the WEC Energy Group Performance Unit Plan. Under the plan, the ultimate number of units that will be awarded is dependent on WEC Energy Group's total shareholder return (stock price appreciation plus dividends) as compared to the total shareholder return of a peer group of companies over three years, as well as other performance metrics as may be determined by the Compensation Committee. Participants may earn between 0% and 175% of the performance unit award based on WEC Energy Group's total shareholder return. Pursuant to the terms of the plan, these percentages can be adjusted upwards or downwards based on WEC Energy Group's performance against additional performance measures, if any, adopted by the Compensation Committee. Performance units also accrue forfeitable dividend equivalents in the form of additional performance units.

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

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

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

As required, we adopted Topic 842 effective January 1, 2019. We utilized the following practical expedients, which were available under ASU 2016-02, in our adoption of the lease guidance.

- We did not reassess whether any expired or existing contracts were leases or contained leases.
- We did not reassess the lease classification for any expired or existing leases.
- We did not reassess the accounting for initial direct costs for any existing leases.

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

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

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

In July 2018, the FASB issued ASU 2018-11, Leases (Topic 842): Targeted Improvements, which amends ASU 2016-02 and allows entities the option to initially apply Topic 842 at the adoption date and recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption, if required. We used the optional transition method to apply this guidance as of January 1, 2019, rather than as of the earliest period presented. We identified no significant operating or finance leases as a result of our implementation of the lease guidance. As a result, the adoption of Topic 842 did not result in us recording any right of use assets or related lease liabilities related to operating leases, and we had no finance leases upon adoption.

Significant Judgments and Other Information

We are currently party to several easement agreements that allow us access to land we do not own for the purpose of constructing and maintaining certain electric power and natural gas equipment, and for certain natural gas storage rights. The majority of payments we make related to easements relate to our wind parks. We have not classified our easements as leases because we view the entire parcel of land specified in our easement agreements to be the identified asset, not just that portion of the parcel that contains our easement. As such, we have concluded that we do not control the use of an identified asset related to our easement agreements, nor do we obtain substantially all of the economic benefits associated with these shared-use assets.

As of March 31, 2021, we have not entered into any material leases that have not yet commenced.

(o) Income Taxes—We follow the liability method in accounting for income taxes. Accounting guidance for income taxes requires the recording of deferred assets and liabilities to recognize the expected future tax consequences of events that have been reflected in our financial statements or tax returns and the adjustment of deferred tax balances to reflect tax rate changes. We are required to assess the likelihood that our deferred tax assets would expire before being realized. If we conclude that certain deferred tax assets

are likely to expire before being realized, a valuation allowance would be established against those assets. GAAP requires that, if we conclude in a future period that it is more likely than not that some or all of the deferred tax assets would be realized before expiration, we reverse the related valuation allowance in that period. Any change to the allowance, as a result of a change in judgment about the realization of deferred tax assets, is reported in income tax expense.

ITCs associated with regulated operations are deferred and amortized over the life of the assets. We and our subsidiaries are included in WEC Energy Group's consolidated federal and state income tax returns. In accordance with our tax allocation agreement with WEC Energy Group, we are allocated income tax payments and refunds based on our separate tax computation. See Note 17, Income Taxes, for more information.

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

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

(p) 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.

See Note 18, Fair Value Measurements, for more information.

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

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

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

Derivative accounting rules provide the option to present certain asset and liability derivative positions net on the balance sheets and to net the related cash collateral against these net derivative positions. We elected not to net these items. On our balance sheets, cash collateral provided to others is reflected in other current assets. See Note 19, Derivative Instruments, for more information.

(r) Guarantees—We follow the guidance of the Guarantees Topic of the FASB ASC, which requires, under certain circumstances, that the guarantor recognize a liability for the fair value of the obligation undertaken in issuing the guarantee at its inception. See Note 20, Guarantees, for more information.

(s) Employee Benefits—The costs of pension and OPEB plans are expensed over the periods during which employees render service. These costs are distributed among WEC Energy Group's subsidiaries based on current employment status and actuarial calculations, as applicable. Our regulators allow recovery in rates for the utilities' net periodic benefit cost calculated under GAAP. See Note 21, Employee Benefits, for more information.

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

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

(u) 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 residual landfills and manufactured gas plant sites. See Note 10, Asset Retirement Obligations, for more information regarding coal combustion residual landfills and Note 23, 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 regulatory commission's approval.

We review our estimated costs of remediation annually for our manufactured gas plant sites and coal combustion residual landfills. 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.

(v) Customer Concentrations of Credit Risk—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 WPS, PGL, and NSG is mitigated by their recovery mechanisms for uncollectible expense discussed in Note 1(d), Operating Revenues. As a result, we did not have any significant concentrations of credit risk at December 31, 2020. In addition, there were no customers that accounted for more than 10% of our revenues for the year ended December 31, 2020.

(w) Subsequent Events—Due to the cold temperatures, wind, snow, and ice throughout the central part of the country during February 2021, the cost of gas purchased for our natural gas utility customers was temporarily driven higher than our normal winter weather expectations. We have regulatory mechanisms in place for recovering all prudently incurred gas costs. In addition, we have adequate liquidity and access to capital markets to manage any short-term increase in working capital resulting from the lag in recovery. For information on our gas cost recovery mechanism, see Note 1(d), Operating Revenues.

Subsequent events were evaluated for potential recognition or disclosure through March 31, 2021, which is the date the financial statements were available to be issued.

NOTE 2—ACQUISITION

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

Acquisition of a Wind Generation Facility in Wisconsin

In April 2018, WPS, along with two unaffiliated utilities, completed the purchase of Forward Wind Energy Center, which consists of 86 wind turbines located in Wisconsin with a total capacity of 138 MW. The aggregate purchase price was $172.9 million of which WPS's proportionate share was 44.6%, or $77.1 million. In addition, WPS incurred $1.9 million of transaction costs that were recorded as a regulatory asset. Since 2008 and up until the acquisition, WPS purchased 44.6% of the facility's energy output under a power purchase agreement. This acquisition was accounted for as an asset acquisition.

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

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

Under a joint ownership agreement with the two other utilities, WPS is entitled to its share of generating capability and output of the facility equal to its ownership interest. WPS is also paying its ownership share of additional capital expenditures and operating expenses. Forward Wind Energy Center is included in the Wisconsin segment. See Note 9, Jointly Owned Utility Facilities, for more information.

NOTE 3—DISPOSITION

Corporate and Other Segment – Sale of Certain WPS Power Development, LLC Solar Power Generation Facilities

In November 2020, we sold a portfolio of residential solar facilities owned by PDL for $10.5 million. These solar facilities were located in California and Hawaii. During the fourth quarter of 2020, we recorded an after-tax gain on the sale of $3.0 million primarily related to the recognition of deferred ITCs, which were included as a reduction of income tax expense on our income statements. The assets included in the sale were not material and, therefore, were not presented as held for sale. The results of operations of these facilities 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 2019, we sold four solar power generation facilities owned by PDL for $26.3 million. These solar facilities were located in Massachusetts. In 2019, we recorded an after-tax gain on the sales of $6.5 million primarily related to the recognition of deferred ITCs, which were included as a reduction of income tax expense on our income statements. The assets included in the sales were not

material and, therefore, were not presented as held for sale. The results of operations of these facilities remained in continuing operations through the sale dates as the sales did not represent a shift in our corporate strategy and did not have a major effect on our operations and financial results.

NOTE 4—RELATED PARTIES

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

We provide and receive services, property, and other items of value to and from our parent, WEC Energy Group, and other subsidiaries of WEC Energy Group pursuant to an AIA that became effective in 2017. The AIA was approved by the appropriate regulators. In accordance with the AIA, WBS provides several categories of services to us (including financial, human resource, and administrative services).

Prior to January 1, 2018, WPSI held an approximate 34% ownership interest in ATC, a for-profit, transmission-only company regulated by the FERC for cost of service and certain state regulatory commissions for routing and siting of transmission-related projects. Effective January 1, 2018, we transferred WPSI's ownership interest in ATC, and related taxes, to another subsidiary of WEC Energy Group. This transaction was a $363.4 million non-cash equity transfer between entities under common control, and therefore, did not result in the recognition of a gain or loss.

WPS pays ATC for transmission and other related services it provides. In addition, WPS provides a variety of operational, maintenance, and project management work for ATC, which is reimbursed by ATC. Services are billed to and from ATC under agreements approved by the PSCW, at each company's fully allocated costs. WPS is also required to initially fund the construction of transmission infrastructure upgrades needed for new generation projects. ATC owns these transmission assets and reimburses WPS for these costs when the new generation is placed in service.

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

Our balance sheets included the following receivables and payables for services provided to or received from ATC:

(in millions)	December 31, 2020	December 31, 2019
Accounts receivable		
Services provided to ATC	**$ 2.4**	$ 1.9
Amounts due from ATC for transmission infrastructure upgrades [(1)]	**3.0**	2.8
Accounts payable		
Services received from ATC	**9.0**	9.1

(1) The transmission infrastructure upgrades were related to the construction of WPS's two new solar projects, Badger Hollow I and Two Creeks. Amounts due related to Two Creeks were largely reimbursed by ATC in December 2020 as the new generation was placed in service.

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

(in millions)	2020	2019	2018
Transactions with WE			
Natural gas related sales to WE from WPS [1]	**$ 1.5**	$ 2.0	$ 1.9
Charges to WE from WPS for services and other items [2]	**8.3**	9.3	10.9
Charges from WE to WPS for services and other items [2]	**12.5**	13.2	17.8
Transactions with UMERC			
Electric sales to UMERC from WPS [3]	**—**	4.5	15.8
Natural gas related sales to UMERC from WPS [1]	**2.0**	2.8	2.7
Charges to UMERC from WPS for services and other items [2]	**4.4**	4.2	2.9
Transactions with Bluewater			
Storage service fees charged to WPS	**10.6**	11.2	4.7
Natural gas related sales to Bluewater from WPS [1]	**1.9**	1.1	—
Transactions with WBS			
Charges to WBS for services and other items [2]	**51.9**	83.9	48.2
Charges from WBS for services and other items [2]	**228.1**	272.3	322.4 [5]
Interest income on short-term borrowings to parent	**0.7**	2.8	4.6
Transactions related to ATC			
Charges to ATC for services and construction	**11.9**	11.0	7.9
Charges from ATC for network transmission services	**107.4**	107.8	106.1
Net refund from ATC related to FERC ROE orders	**3.3**	—	—
Refund from ATC related to a FERC audit	**—**	—	6.6
Transactions with WRPC			
Rental payments to WRPC [4]	**1.9**	1.9	1.3
Charges from WRPC for services	**2.6**	2.5	2.4
Charges to WRPC for operations	**1.2**	0.8	1.2

[1] Includes amounts related to the sale of natural gas and/or pipeline capacity.

[2] Includes amounts billed for services, pass through costs, asset and liability transfers, and other items in accordance with the approved AIA. As required by FERC regulations for centralized service companies, WBS renders services at cost. In addition, all services provided by any regulated subsidiary to another regulated subsidiary or WBS are priced at cost.

[3] On March 31, 2019, UMERC's new natural gas-fired generation in the Upper Peninsula of Michigan began commercial operation. Prior to its generating units achieving commercial operation, UMERC purchased a portion of its power from WPS.

[4] We have an agreement with WRPC whereby we receive 50% of the energy generated from its hydroelectric power generation facilities.

[5] Includes $70.6 million for the transfer of certain software assets to us.

We manage our liquidity in part by maintaining adequate financing commitments with related parties. We have the ability to borrow to and from our parent, WEC Energy Group, in amounts up to $400 million. At December 31, 2019, we had a short-term note receivable from WEC Energy Group of $166.9 million. We did not have any short-term notes receivable from WEC Energy Group at December 31, 2020. See Note 14, Short-Term Debt and Lines of Credit, for information on our short-term borrowings.

NOTE 5—OPERATING REVENUES

For more information about our significant accounting policies related to operating revenues, see Note 1(d), Operating Revenues.

Disaggregation of Operating Revenues

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

(in millions)	Wisconsin	Illinois	Other States	Total Utility Operations	Corporate and Other	Integrys Holding Consolidated
Year ended December 31, 2020						
Electric	**$ 1,136.9**	**$ —**	**$ —**	**$ 1,136.9**	**$ —**	**$ 1,136.9**
Natural gas	**269.5**	**1,267.9**	**361.0**	**1,898.4**	**—**	**1,898.4**
Total regulated revenues	**1,406.4**	**1,267.9**	**361.0**	**3,035.3**	**—**	**3,035.3**
Other non-utility revenues	**—**	**—**	**17.1**	**17.1**	**1.4**	**18.5**
Total revenues from contracts with customers	**1,406.4**	**1,267.9**	**378.1**	**3,052.4**	**1.4**	**3,053.8**
Other operating revenues	**0.7**	**54.0**	**6.0**	**60.7**	**0.1**	**60.8**
Total operating revenues	**$ 1,407.1**	**$ 1,321.9**	**$ 384.1**	**$ 3,113.1**	**$ 1.5**	**$ 3,114.6**

(in millions)	Wisconsin	Illinois	Other States	Total Utility Operations	Corporate and Other	Integrys Holding Consolidated
Year ended December 31, 2019						
Electric	$ 1,114.1	$ —	$ —	$ 1,114.1	$ —	$ 1,114.1
Natural gas	295.5	1,332.4	411.6	2,039.5	—	2,039.5
Total regulated revenues	1,409.6	1,332.4	411.6	3,153.6	—	3,153.6
Other non-utility revenues	—	0.1	16.6	16.7	4.0	20.7
Total revenues from contracts with customers	1,409.6	1,332.5	428.2	3,170.3	4.0	3,174.3
Other operating revenues	2.3	24.6	(2.2)	24.7	—	24.7
Total operating revenues	$ 1,411.9	$ 1,357.1	$ 426.0	$ 3,195.0	$ 4.0	$ 3,199.0

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

Revenues from Contracts with Customers

Electric Utility Operating Revenues

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

	Electric Utility Operating Revenues		
	Year Ended December 31		
(in millions)	2020	2019	2018
Residential	**$ 420.0**	$ 369.4	$ 381.5
Small commercial and industrial	**353.6**	355.9	371.4
Large commercial and industrial	**220.0**	223.3	238.8
Other	**8.4**	8.4	8.5
Total retail revenues	**1,002.0**	957.0	1,000.2
Wholesale	**95.1**	105.8	142.3
Resale	**19.6**	28.7	38.5
Other utility revenues	**20.2**	22.6	11.2
Total electric utility operating revenues	**$ 1,136.9**	$ 1,114.1	$ 1,192.2

Natural Gas Utility Operating Revenues

The following tables disaggregate natural gas utility operating revenues into customer class:

(in millions)	Wisconsin	Illinois	Other States	Total Natural Gas Utility Operating Revenues
Year Ended December 31, 2020				
Residential	**$ 156.4**	**$ 802.2**	**$ 220.8**	**$ 1,179.4**
Commercial and industrial	**83.9**	**221.0**	**115.8**	**420.7**
Total retail revenues	**240.3**	**1,023.2**	**336.6**	**1,600.1**
Transport	**19.6**	**215.6**	**31.5**	**266.7**
Other utility revenues [(1)]	**9.6**	**29.1**	**(7.1)**	**31.6**
Total natural gas utility operating revenues	**$ 269.5**	**$ 1,267.9**	**$ 361.0**	**$ 1,898.4**

(in millions)	Wisconsin	Illinois	Other States	Total Natural Gas Utility Operating Revenues
Year Ended December 31, 2019				
Residential	$ 178.4	$ 857.8	$ 258.2	$ 1,294.4
Commercial and industrial	105.9	261.7	148.7	516.3
Total retail revenues	284.3	1,119.5	406.9	1,810.7
Transport	17.1	245.3	31.6	294.0
Other utility revenues [(1)]	(5.9)	(32.4)	(26.9)	(65.2)
Total natural gas utility operating revenues	$ 295.5	$ 1,332.4	$ 411.6	$ 2,039.5

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

[(1)] Includes amounts collected from (refunded to) customers for purchased gas adjustment costs.

Other Non-Utility Operating Revenues

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

	Year Ended December 31		
(in millions)	2020	2019	2018
Appliance service revenues	**$ 17.1**	$ 16.6	$ 15.9
Distributed renewable solar project revenues	**1.4**	4.0	7.8
Other	**—**	0.1	0.4
Total other non-utility operating revenues	**$ 18.5**	$ 20.7	$ 24.1

Other Operating Revenues

Other operating revenues consist primarily of the following:

	Year Ended December 31		
(in millions)	**2020**	**2019**	**2018**
Alternative revenues [1]	**$ 39.1**	$ (7.9)	$ (41.7)
Late payment charges [2]	**20.9**	31.9	28.4
Rental revenues	**0.8**	0.7	1.0
Total other operating revenues	**$ 60.8**	$ 24.7	$ (12.3)

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

[2] The reduction in late payment charges is a result of various regulatory orders from our utility commissions in response to the COVID-19 pandemic, which include the suspension of late payment charges during a designated time period. PGL and NSG were authorized to implement a SPC rider for the recovery of these late payment charges related to COVID-19, thereby allowing them to record these late payment charges as alternative revenues. The total amount of late payment charges recorded as alternative revenues during the year ended December 31, 2020 was $8.5 million. See Note 25, Regulatory Environment, for more information.

NOTE 6—CREDIT LOSSES

The table below shows our gross third-party receivable balances and the related allowance for credit losses at December 31, 2020, by reportable segment.

(in millions)	**Wisconsin**	**Illinois**	**Other States**	**Total Utility Operations**	**Corporate and Other**	**Integrys Holding Consolidated**
Accounts receivable and unbilled revenues	**$ 209.1**	**$ 393.9**	**$ 79.8**	**$ 682.8**	**$ —**	**$ 682.8**
Allowance for credit losses	**18.3**	**111.6**	**6.4**	**136.3**	**—**	**136.3**
Accounts receivable and unbilled revenues, net [1]	**$ 190.8**	**$ 282.3**	**$ 73.4**	**$ 546.5**	**$ —**	**$ 546.5**
Total accounts receivable, net – past due greater than 90 days [1]	**$ 12.6**	**$ 34.5**	**$ 3.5**	**$ 50.6**	**$ —**	**$ 50.6**
Past due greater than 90 days – collection risk mitigated by regulatory mechanisms [1]	**94.4 %**	**100.0 %**	**— %**	**91.7 %**	**— %**	**91.7 %**

[1] Our exposure to credit losses for certain regulated utility customers is mitigated by regulatory mechanisms we have in place. Specifically, rates related to all of the customers in our Illinois segment, as well as the residential rates of WPS (which comprises our Wisconsin segment), include riders or other mechanisms for cost recovery or refund of uncollectible expense based on the difference between the actual provision for credit losses and the amounts recovered in rates. As a result, at December 31, 2020, $366.3 million, or 67.0%, of our net accounts receivable and unbilled revenues balance had regulatory protections in place to mitigate the exposure to credit losses. In addition, we have received specific orders related to the deferral of certain costs (including credit losses) incurred as a result of the COVID-19 pandemic. The additional protections related to our December 31, 2020 accounts receivable and unbilled revenue balances provided by these orders are subject to prudency reviews and are still being assessed. They are not reflected in the percentages in the above table or this note. See Note 25, Regulatory Environment, for more information on these orders.

A rollforward of the allowance for credit losses by reportable segment for the year ended December 31, 2020, is included below:

(in millions)	Wisconsin	Illinois	Other States	Total Utility Operations	Corporate and Other	Integrys Holding Consolidated
Balance at December 31, 2019	**$ 4.2**	**$ 75.9**	**$ 4.1**	**$ 84.2**	**$ 0.1**	**$ 84.3**
Provision for credit losses	**8.2**	**51.1**	**4.3**	**63.6**	**—**	**63.6**
Provision for credit losses deferred for future recovery or refund	**9.7**	**30.6**	**—**	**40.3**	**—**	**40.3**
Write-offs charged against the allowance	**(8.1)**	**(63.0)**	**(3.4)**	**(74.5)**	**—**	**(74.5)**
Recoveries of amounts previously written off	**4.3**	**17.0**	**1.4**	**22.7**	**—**	**22.7**
Sale of PDL residential solar facilities	**—**	**—**	**—**	**—**	**(0.1)**	**(0.1)**
Balance at December 31, 2020	**$ 18.3**	**$ 111.6**	**$ 6.4**	**$ 136.3**	**$ —**	**$ 136.3**

The increase in the allowance for credit losses at December 31, 2020, compared to December 31, 2019, was driven by higher past due accounts receivable balances at our utility segments, primarily related to residential customers. This increase in accounts receivable balances in arrears was driven by economic disruptions caused by the COVID-19 pandemic, including higher unemployment rates. Also, as a result of the COVID-19 pandemic and related regulatory orders we have received, we were unable to disconnect any of our Wisconsin and Illinois customers during the year ended December 31, 2020. See Note 25, Regulatory Environment, 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)	2020	2019	See Note
Regulatory assets [1] [2]			
Environmental remediation costs [3]	**$ 524.2**	$ 557.2	23
Pension and OPEB costs [4]	**457.9**	436.6	21
AROs	**152.7**	148.6	10
Uncollectible expense	**82.0**	52.2	6
Plant retirements	**58.5**	55.3	
Income tax related items	**52.0**	44.7	17
ReACT™	**18.2**	20.8	25
Invested capital tax rider [5]	**17.9**	11.2	
Derivatives	**16.1**	21.2	1(q)
Unamortized loss on reacquired debt [6]	**12.4**	12.7	
Forward Wind Energy Center [7]	**10.3**	17.9	
Other, net	**38.2**	23.7	
Total regulatory assets	**$ 1,440.4**	$ 1,402.1	
Balance sheet presentation			
Other current assets	**$ 19.9**	$ 20.8	
Regulatory assets	**1,420.5**	1,381.3	
Total regulatory assets	**$ 1,440.4**	$ 1,402.1	

(1) Based on prior and current rate treatment, we believe it is probable that our utilities will continue to recover from customers the regulatory assets in this table. In accordance with GAAP, our regulatory assets do not include the allowance for ROE that is capitalized for regulatory purposes. This allowance was $16.9 million and $21.3 million at December 31, 2020 and 2019, respectively.

(2) As of December 31, 2020, we had $188.1 million of regulatory assets not earning a return and $0.4 million of regulatory assets earning a return based on short-term interest rates. The regulatory assets not earning a return primarily relate to uncollectible expense, certain environmental remediation costs, COVID-19 deferred costs, PGL's and NSG's invested capital tax rider, unamortized loss on reacquired debt, and WPS's electric real-time market pricing program. The other regulatory assets in the table either earn a return at the applicable utility's weighted average cost of capital or the cash has not yet been expended, in which case the regulatory assets are offset by liabilities.

(3) As of December 31, 2020, we had made cash expenditures of $54.6 million related to these environmental remediation costs. The remaining $469.6 million represents our estimated future cash expenditures.

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

(5) Represents amounts recoverable from customers related to PGL's and NSG's invested capital tax rider. This rider allows PGL and NSG to recover or refund the difference between their actual invested capital tax and the amounts recovered in rates.

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

(7) In April 2018, WPS, along with two unaffiliated utilities, purchased the Forward Wind Energy Center. Based on an order from the PSCW, WPS was allowed to defer as a regulatory asset the incremental non-fuel costs associated with the purchase, ownership, and operation of the Forward Wind Energy Center. In the rate order WPS received from the PSCW in December 2019, WPS was authorized recovery of this regulatory asset over a period of two years that began on January 1, 2020. See Note 2, Acquisition, for more information on the acquisition of the Forward Wind Energy Center.

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

(in millions)	2020	2019	See Note
Regulatory liabilities			
Income tax related items	**$ 858.5**	$ 886.5	17
Removal costs [1]	**335.2**	325.1	
Pension and OPEB benefits [2]	**221.1**	213.5	21
Energy costs refundable through rate adjustments	**47.2**	62.8	1(d)
Earnings sharing mechanism	**36.8**	42.0	25
Electric transmission costs [3]	**16.8**	3.7	
Decoupling	**5.2**	36.9	1(d)
Energy efficiency programs [4]	**2.6**	14.9	
Other, net	**18.7**	16.3	
Total regulatory liabilities	**$ 1,542.1**	$ 1,601.7	
Balance sheet presentation			
Other current liabilities	**$ 42.2**	$ 60.8	
Regulatory liabilities	**1,499.9**	1,540.9	
Total regulatory liabilities	**$ 1,542.1**	$ 1,601.7	

(1) Represents amounts collected from customers to cover the future cost of property, plant, and equipment removals that are not legally required. Legal obligations related to the removal of property, plant, and equipment are recorded as AROs. See Note 10, Asset Retirement Obligations, for more information on our legal obligations.

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

(3) In accordance with the PSCW's approval of escrow accounting for WPS's ATC and MISO network transmission expenses, WPS defers as a regulatory asset or liability the difference between actual transmission costs and those included in rates until recovery or refund is authorized in a future rate proceeding.

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

Pulliam Power Plant

In connection with a MISO ruling, WPS retired Pulliam Units 7 and 8 on October 21, 2018. The net book value of the Pulliam units was $42.6 million at December 31, 2020, representing book value less cost of removal and accumulated depreciation. This amount was classified as a regulatory asset on our balance sheets as a result of the retirement of the plant. Effective with its rate order issued by the PSCW in December 2019, WPS received approval to collect a return of and on the entire net book value of the Pulliam units, and as a result, will continue to amortize this regulatory asset on a straight-line basis through 2031, using the composite depreciation rates approved by the PSCW before these generating units were retired. Amortization is included in depreciation and amortization in the income statement. WPS has FERC approval to continue to collect the net book value of the Pulliam power plant using the approved composite depreciation rates, in addition to a return on the remaining net book value. FERC has completed its prudency review of Pulliam, concluding that the retirement of this plant was prudent.

Edgewater Unit 4

The Edgewater 4 generating unit was retired on September 28, 2018. The net book value of the generating unit was $4.7 million at December 31, 2020, representing book value less cost of removal and accumulated depreciation. This amount was classified as a regulatory asset on our balance sheets as a result of the retirement of the plant. Effective with its rate order issued by the PSCW in December 2019, WPS received approval to collect a return of and on the entire net book value of the Edgewater 4 generating unit, and as a result, will continue to amortize this regulatory asset on a straight-line basis through 2026, using the composite depreciation rates approved by the PSCW before this generating unit was retired. Amortization is included in depreciation and amortization in the income statement. WPS has FERC approval to continue to collect the net book value of the Edgewater 4 generating unit using the approved composite depreciation rates, in addition to a return on the remaining net book value. FERC has completed its prudency review of Edgewater 4, concluding that the retirement of this plant was prudent.

Severance Liability for Plant Retirements

In December 2017, a severance liability of $3.6 million was recorded in other current liabilities on our balance sheets related to these plant retirements. The severance liability was reduced to zero in 2019. Activity related to this severance liability for the years ended December 31 was as follows:

(in millions)	2019	2018
Severance liability at January 1	$ 2.8	$ 3.6
Severance payments	(1.5)	(0.8)
Other	(1.3)	—
Total severance liability at December 31	$ —	$ 2.8

NOTE 8—PROPERTY, PLANT, AND EQUIPMENT

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

(in millions)	2020	2019
Electric – generation	**$ 2,981.5**	$ 2,840.0
Electric – distribution	**1,921.2**	1,738.3
Natural gas – distribution, storage, and transmission	**8,749.2**	7,833.2
Other	**877.1**	757.1
Less: Accumulated depreciation	**3,895.6**	3,722.5
Net	**10,633.4**	9,446.1
CWIP	**375.1**	610.9
Net utility property, plant, and equipment	**11,008.5**	10,057.0
Non-utility and other property, plant, and equipment	**—**	27.9
Less: Accumulated depreciation	**—**	5.6
Net non-utility and other property, plant, and equipment	**—**	22.3
Total property, plant, and equipment	**$ 11,008.5**	$ 10,079.3

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 utility facilities at December 31, 2020 was as follows:

(in millions, except for percentages and MW)	Weston Unit 4	Columbia Energy Center Units 1 and 2	Forward Wind Energy Center	Two Creeks [2]
Ownership	**70.0 %**	**27.5 %**	**44.6 %**	**66.7 %**
WPS's share of capacity (MW) [1]	**385.0**	**311.1**	**61.5**	**100.0**
In-service date	**2008**	**1975 and 1978**	**2008**	**2020**
Property, plant, and equipment	**$ 613.5**	**$ 422.3**	**$ 118.9**	**$ 136.0**
Accumulated depreciation	**$ (218.6)**	**$ (145.5)**	**$ (49.6)**	**$ (0.7)**
CWIP	**$ 3.8**	**$ 2.3**	**$ —**	**$ —**

[1] Capacity for Weston Unit 4 and Columbia Energy Center Units 1 and 2 is based on rated capacity, which is the net power output under average operating conditions with equipment in an average state of repair as of a given month in a given year. Values are primarily based on the net dependable expected capacity ratings for summer 2021 established by tests and may change slightly from year to year. 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. Capacity for Forward Wind Energy Center is based on nameplate capacity, which is the amount of energy a turbine should produce at optimal wind speeds. Capacity for Two Creeks is based on nameplate capacity, which is the maximum output that a generator should produce at continuous full power.

[2] Commercial operation was achieved in November 2020 for Two Creeks.

WPS has partnered with an unaffiliated utility to construct a solar project, Badger Hollow I, that will be located in Iowa County, Wisconsin. Once constructed, WPS will own 66.7%, or 100 MW, of Badger Hollow I. Commercial operation is targeted for the second quarter of 2021. The CWIP balance for Badger Hollow I as of December 31, 2020 was $115.3 million.

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

NOTE 10—ASSET RETIREMENT OBLIGATIONS

Our utilities have recorded AROs primarily for the removal of natural gas distribution mains and service pipes (including asbestos and PCBs); asbestos abatement at certain generation facilities, office buildings, and service centers; the dismantling of wind generation projects; the dismantling of solar generation projects; the disposal of PCB-contaminated transformers; the closure of coal combustion residual 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.

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

(in millions)	2020	2019	2018
Balance as of January 1	**$ 397.3**	$ 381.5	$ 501.7
Accretion	**17.6**	17.6	24.4
Additions and revisions to estimated cash flows	**47.5** [1]	36.4 [2]	(110.7) [3]
Liabilities settled	**(28.7)**	(38.2)	(33.9)
Balance as of December 31	**$ 433.7**	$ 397.3	$ 381.5

[1] AROs increased $39.3 million in 2020, primarily due to new natural gas distribution lines being placed into service at PGL. Also in 2020, AROs increased by $8.5 million as a result of AROs being recorded for the legal requirement to dismantle, at retirement, the Two Creeks solar generation project.

(2) AROs increased $40.1 million in 2019, primarily due to new natural gas distribution lines being placed into service at PGL.

(3) AROs decreased $127.3 million in 2018 due to revisions made to estimated cash flows primarily for changes in the cost to retire natural gas distribution pipe at PGL. Also in 2018, AROs increased $10.7 million as a result of revisions made to estimated cash flows for the abatement of asbestos at WPS's Pulliam power plant, and a $5.6 million ARO was recorded for the legal requirement to dismantle, at retirement, Forward Wind Energy Center. See Note 2, Acquisition, for more information on Forward Wind Energy Center.

NOTE 11—GOODWILL AND OTHER INTANGIBLE ASSETS

Goodwill

Goodwill represents the excess of the cost of an acquisition over the fair value of the identifiable net assets acquired. The table below shows our goodwill balances by segment as of December 31, 2020 and 2019. We had no changes to the carrying amount of goodwill during the years ended December 31, 2020 and 2019.

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

In the third quarter of 2020, annual impairment tests were completed at all of our reporting units that carried a goodwill balance as of July 1, 2020. No impairments resulted from these tests.

Intangible Assets

At December 31, 2020, we had $5.7 million of indefinite-lived intangible assets primarily related to a MGU trade name obtained through an acquisition, which is included in other long-term assets on our balance sheets. We had no changes to the carrying amount of these intangible assets during the years ended December 31, 2020 and 2019.

NOTE 12—COMMON EQUITY

Stock-Based Compensation

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

(in millions)	2020	2019	2018
Stock options	$ 3.4	$ 2.4	$ 2.8
Restricted stock	4.0	3.7	4.9
Performance units	10.7	17.8	8.9
Stock-based compensation expense	$ 18.1	$ 23.9	$ 16.6
Related tax benefit	$ 5.0	$ 6.5	$ 4.6

Stock-based compensation costs capitalized during 2020, 2019, and 2018 were not significant.

Stock Options

The following is a summary of our employees' WEC Energy Group stock option activity during 2020:

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, 2020	138,081	$ 63.17		
Granted	**66,500**	**$ 91.49**		
Exercised	**(56,641)**	**$ 57.66**		
Transferred	**82,005**	**$ 56.51**		
Forfeited	**(3,602)**	**$ 74.57**		
Outstanding as of December 31, 2020	**226,343**	**$ 70.28**	**7.3**	**$ 4.9**
Exercisable as of December 31, 2020	**60,352**	**$ 55.01**	**5.1**	**$ 2.2**

The aggregate intrinsic value of outstanding and exercisable options in the above table represents the total pre-tax intrinsic value that would have been received by the option holders had they exercised all of their options on December 31, 2020. This is calculated as the difference between WEC Energy Group's closing stock price on December 31, 2020, and the option exercise price, multiplied by the number of in-the-money stock options. The intrinsic value of options exercised during the years ended December 31, 2020 and 2019 was $2.2 million and $0.8 million, respectively. Cash received by WEC Energy Group from exercises of its options by our employees was $3.3 million and $2.0 million during the years ended December 31, 2020 and 2019, respectively. The actual tax benefit from option exercises for the same periods was approximately $0.6 million and $0.2 million, respectively. WEC Energy Group stock options held by our employees that were exercised during the year ended December 31, 2018 were not significant.

As of December 31, 2020, we expected to recognize approximately $1.2 million of unrecognized compensation cost related to unvested and outstanding WEC Energy Group stock options over the next 1.8 years on a weighted-average basis.

During the first quarter of 2021, the Compensation Committee awarded 60,431 non-qualified WEC Energy Group stock options with an exercise price of $91.06 and a weighted-average grant date fair value of $13.20 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 2020:

Restricted Shares	Number of Shares	Weighted-Average Grant Date Fair Value
Outstanding and unvested as of January 1, 2020	7,206	$ 65.45
Granted	**4,890**	**$ 91.49**
Released	**(5,366)**	**$ 63.62**
Transferred	**3,284**	**$ 66.08**
Forfeited	**(885)**	**$ 77.96**
Outstanding and unvested as of December 31, 2020	**9,129**	**$ 78.76**

The intrinsic value of WEC Energy Group restricted stock held by our employees that was released was $0.5 million, $0.6 million, and $0.5 million for the years ended December 31, 2020, 2019, and 2018, respectively. The actual tax benefit from released restricted shares for the same years was $0.1 million, $0.2 million, and $0.1 million, respectively.

As of December 31, 2020, we expected to recognize approximately $1.7 million of unrecognized compensation cost related to unvested and outstanding WEC Energy Group restricted stock over the next 1.8 years on a weighted-average basis.

During the first quarter of 2021, the Compensation Committee awarded 4,206 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 $91.06 per share.

Performance Units

During 2020, 2019, and 2018, the Compensation Committee awarded 21,172; 17,099; and 18,260 WEC Energy Group performance units, respectively, to our officers and other key employees under the WEC Energy Group Performance Unit Plan.

Performance units with an intrinsic value of $4.7 million and $1.4 million were settled during 2020 and 2019, respectively. The actual tax benefit from the distribution of performance units was approximately $1.0 million and $0.3 million for the years ended December 31, 2020 and 2019, respectively.

During 2020, 16,101 performance units were transferred to us from WBS in connection with the transfer of certain employees. At December 31, 2020, our employees held 63,929 WEC Energy Group performance units, including dividend equivalents. A liability of $6.1 million was recorded on our balance sheet at December 31, 2020 related to these outstanding units. As of December 31, 2020, we expected to recognize approximately $8.1 million of unrecognized compensation cost related to unvested and outstanding WEC Energy Group performance units over the next 1.6 years on a weighted-average basis.

During the first quarter of 2021, performance units held by our employees with an intrinsic value of $3.5 million were settled. The actual tax benefit from the distribution of these awards was $0.7 million. In January 2021, the Compensation Committee also awarded 18,231 WEC Energy Group performance units to our officers and other key employees under its normal schedule of awarding long-term incentive compensation.

Restrictions

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

In accordance with WPS's most recent rate order, WPS may not pay common dividends above the test year forecasted amounts reflected in its rate case, if it would cause its average common equity ratio, on a financial basis, to fall below its authorized level of 52.5%. 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 common stock.

We have the option to defer interest payments on our junior subordinated notes, from time to time, for one or more periods of up to ten consecutive years per period. During any period in which we defer interest payments, we may not declare or pay any dividends or distributions on, or redeem, purchase, acquire, or make a liquidation payment on, any of our common 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, 2020, restricted net assets of our consolidated subsidiaries totaled approximately $3.1 billion.

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, of which none were issued and outstanding, at December 31, 2020 and 2019.

	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)	2020	2019
Commercial paper		
Amount outstanding at December 31	**$ 421.5**	$ 185.5
Average interest rate on amounts outstanding at December 31	**0.18 %**	1.95 %

Our average amount of commercial paper borrowings based on daily outstanding balances during 2020, was $142.2 million with a weighted-average interest rate during the period of 0.55%.

WPS and PGL have entered into bank back-up credit facilities to maintain short-term credit liquidity which, among other terms, requires them to maintain, subject to certain exclusions, a total funded debt to capitalization ratio of 65% or less. As of December 31, 2020, both companies were in compliance with their respective financial covenants.

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

(in millions)	Maturity	2020
Revolving credit facility (WPS)	October 2022	**$ 400.0**
Revolving credit facility (PGL)	October 2022	**350.0**
Revolving short-term notes payable to WEC Energy Group		**400.0**
Total short-term credit capacity		**$ 1,150.0**
Less:		
Commercial paper outstanding		**$ 421.5**
Letters of credit issued inside credit facilities		**1.3**
Short-term debt to WEC Energy Group		**68.1**
Available capacity under existing credit agreements		**$ 659.1**

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

The following table is a summary of our long-term debt outstanding (excluding finance leases) as of December 31:

(in millions)			2020	2019
Long-term debt	**Interest Rate**	**Year Due**		
WPS Senior Notes (unsecured)	3.35%	2021	**$ 400.0**	$ 400.0
	6.08%	2028	**50.0**	50.0
	5.55%	2036	**125.0**	125.0
	3.671%	2042	**300.0**	300.0
	4.752%	2044	**450.0**	450.0
	3.30%	2049	**300.0**	300.0
Integrys Senior Notes (unsecured)	4.17%	2020	**—**	250.0
Integrys Junior Notes (unsecured) [1]	6.00%	2073	**400.0**	400.0
PGL First and Refunding Mortgage Bonds (secured) [2]	2.64%	2024	**75.0**	75.0
	3.87%	2028	**150.0**	150.0
	2.96%	2029	**275.0**	275.0
	3.90%	2030	**50.0**	50.0
	1.98%	2030	**200.0**	—
	3.06%	2031	**50.0**	50.0
	1.875%	2033	**—**	50.0
	4.00%	2033	**50.0**	50.0
	3.98%	2042	**100.0**	100.0
	3.96%	2043	**220.0**	220.0
	4.21%	2044	**200.0**	200.0
	3.65%	2046	**50.0**	50.0
	3.65%	2046	**150.0**	150.0
	3.77%	2047	**100.0**	100.0
NSG First Mortgage Bonds (secured) [3]	3.43%	2027	**28.0**	28.0
	3.87%	2028	**50.0**	50.0
	3.96%	2043	**54.0**	54.0
MERC Senior Notes (unsecured)	2.69%	2025	**50.0**	—
	3.11%	2027	**40.0**	40.0
	3.41%	2032	**40.0**	40.0
	4.01%	2047	**40.0**	40.0
MGU Senior Notes (unsecured)	2.69%	2025	**60.0**	—
	3.11%	2027	**30.0**	30.0
	3.41%	2032	**30.0**	30.0
	4.01%	2047	**30.0**	30.0
Total			**4,147.0**	4,137.0
Unamortized debt issuance costs			**(36.8)**	(37.8)
Unamortized discount, net and other			**(0.8)**	(0.9)
Total long-term debt, including current portion			**4,109.4**	4,098.3
Current portion of long-term debt			**(400.0)**	(250.0)
Total long-term debt [4]			**$ 3,709.4**	$ 3,848.3

(1) 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.

(2) 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.

(3) 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.

(4) The amount of long-term debt on our balance sheet includes finance lease obligations of $31.3 million and $30.7 million at December 31, 2020 and 2019, respectively.

We amortize debt premiums, discounts, and debt issuance costs over the life of the debt using the straight-line method and we include the costs in interest expense.

Integrys Holding, Inc.

In November 2020, our $250.0 million of 4.17% Senior Notes matured, and outstanding principal was paid with proceeds received from WEC Energy Group issuing commercial paper.

The Peoples Gas Light and Coke Company

In August 2020, PGL redeemed at par all $50.0 million outstanding of its 1.875% Series WW Bonds due February 1, 2033.

In December 2020, PGL issued $200.0 million of 1.98% Series JJJ Bonds due December 1, 2030, and used the net proceeds for general corporate purposes, including capital expenditures and the refinancing of short-term debt.

Minnesota Energy Resources Corporation

In April 2020, MERC issued $50.0 million of 2.69% Senior Notes due May 1, 2025, and used the net proceeds to repay intercompany short-term debt to its parent, Integrys, and for general corporate purposes, including capital expenditures.

Michigan Gas Utilities Corporation

In April 2020, MGU issued $60.0 million of 2.69% Senior Notes due May 1, 2025, and used the net proceeds to repay intercompany short-term debt to its parent, Integrys, and for general corporate purposes, including capital expenditures.

Maturities of Long-Term Debt Outstanding

The following table shows the future maturities of our long-term debt outstanding (excluding obligations under finance leases) as of December 31, 2020:

(in millions)	Payments
2021	$ 400.0
2022	—
2023	—
2024	75.0
2025	110.0
Thereafter	3,562.0
Total	$ 4,147.0

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. As of December 31, 2020, we were in compliance with our covenants related to our long-term debt obligations.

NOTE 16—LEASES

Two Creeks Solar Park

Related to WPS's investment in Two Creeks, WPS, along with an unaffiliated utility, entered into several land leases in Manitowoc County, Wisconsin that commenced in the third quarter of 2019. The leases are for a total of approximately 900 acres of land and were determined to be finance leases under Topic 842. Each lease has an initial term of 30 years with two optional 10-year

extensions. WPS expects the two optional extensions to be exercised, and, as a result, the land leases will be amortized over the 50-year extended term of the leases. The lease payments are being recovered through rates.

WPS treats these land lease contracts as operating leases for rate-making purposes. WPS's total obligation under the finance leases for Two Creeks was $11.0 million as of December 31, 2020, and will decrease to zero over the remaining lives of the leases.

Badger Hollow Solar Park I

Related to WPS's investment in Badger Hollow I, WPS, along with an unaffiliated utility, entered into several land leases in Iowa County, Wisconsin that commenced in the third quarter of 2019. The leases are for a total of approximately 1,400 acres of land and were determined to be finance leases under Topic 842. Each lease has an initial construction term that ends upon achieving commercial operation, then automatically extends for 25 years with an option for an additional 25-year extension. WPS expects the optional extension to be exercised, and, as a result, the land leases will be amortized over the extended term of the leases. The lease payments are being recovered through rates.

WPS treats these land lease contracts as operating leases for rate-making purposes. WPS's total obligation under the finance leases for Badger Hollow I was $20.3 million as of December 31, 2020, and will decrease to zero over the remaining lives of the leases.

Amounts Recognized in the Financial Statements and Other Information

Lease expense related to the Two Creeks and Badger Hollow I finance leases was not significant in 2020 or 2019. Other information related to these leases for the years ended December 31 are as follows:

Other information *(dollar amounts in millions)*	**2020**	**2019**
Non-cash activity – right of use assets obtained in exchange for finance lease liabilities	**$ —**	$ 30.3
Weighted average remaining lease term	**50.0 years**	51.0 years
Weighted average discount rate [1]	**4.2 %**	4.2 %

[1] Because these leases do not provide an implicit rate of return, WPS used the fully collateralized incremental borrowing rates based upon information available for similarly rated companies in determining the present value of lease payments.

The following table summarizes WPS's finance lease right of use assets, which were included in property, plant and equipment on our balance sheets at December 31:

(in millions)	**2020**	**2019**
Two Creeks land leases		
Under finance leases	**$ 10.8**	$ 10.8
Accumulated amortization	**(0.3)**	(0.1)
Total Two Creeks land leases	**$ 10.5**	$ 10.7
Badger Hollow I land leases		
Under finance leases	**$ 19.5**	$ 19.5
Accumulated amortization	**(0.6)**	(0.2)
Total Badger Hollow I land leases	**$ 18.9**	$ 19.3
Total finance lease right of use assets	**$ 29.4**	$ 30.0

Future minimum lease payments under WPS's finance leases and the present value of their net minimum lease payments as of December 31, 2020, were as follows:

(in millions)	Two Creeks	Badger Hollow I	Total Finance Leases
2021	$ 0.3	$ 0.7	$ 1.0
2022	0.3	0.7	1.0
2023	0.3	0.7	1.0
2024	0.3	0.7	1.0
2025	0.3	0.7	1.0
Thereafter	31.6	52.7	84.3
Total minimum lease payments	33.1	56.2	89.3
Less: Interest	(22.1)	(35.9)	(58.0)
Present value of minimum lease payments	11.0	20.3	31.3
Less: Short-term lease liabilities	—	—	—
Long-term lease liabilities	$ 11.0	$ 20.3	$ 31.3

Long-term lease liabilities related to WPS's finance leases were included in long-term debt on our balance sheet.

NOTE 17—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)	2020	2019	2018
Current tax expense (benefit)	**$ 9.6**	$ (55.4)	$ (20.8)
Deferred income taxes, net	**111.3**	162.1	146.2
ITC, net	**(1.9)**	(2.5)	(2.0)
Total income tax expense	**$ 119.0**	$ 104.2	$ 123.4

Statutory Rate Reconciliation

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

	2020		2019		2018	
(in millions)	Amount	Effective Tax Rate	Amount	Effective Tax Rate	Amount	Effective Tax Rate
Statutory federal income tax	**$ 118.8**	**21.0 %**	$ 107.0	21.0 %	$ 98.4	21.0 %
State income taxes net of federal tax benefit	**37.9**	**6.7 %**	34.8	6.8 %	29.7	6.3 %
Federal excess deferred tax amortization – Wisconsin unprotected [1]	**(12.7)**	**(2.2)%**	—	— %	—	— %
Federal excess deferred tax amortization [2]	**(12.4)**	**(2.2)%**	(13.2)	(2.6)%	(11.4)	(2.4)%
Uncertain tax positions	**(6.6)**	**(1.2)%**	(2.9)	(0.6)%	(3.3)	(0.7)%
Deferred ITCs recognized from PDL solar sale	**(6.5)**	**(1.1)%**	(6.6)	(1.3)%	—	— %
AFUDC – Equity	**(2.5)**	**(0.4)%**	(1.3)	(0.3)%	(1.0)	(0.2)%
ITC restored	**(1.9)**	**(0.3)%**	(2.5)	(0.5)%	(2.0)	(0.4)%
Foreign tax credit	**—**	**— %**	(6.7)	(1.3)%	(3.8)	(0.8)%
Other, net	**4.9**	**0.7 %**	(4.4)	(0.8)%	16.8	3.5 %
Total income tax expense	**$ 119.0**	**21.0 %**	$ 104.2	20.4 %	$ 123.4	26.3 %

(1) In accordance with the rate order received from the PSCW in December 2019, we are amortizing these unprotected deferred tax benefits over periods ranging from two years to four years, to reduce near-term rate impacts to our customers. The decrease in income tax expense related to the amortization of the deferred tax benefits is offset by a decrease in revenue as the benefits are returned to customers, resulting in no impact on net income.

(2) The Tax Legislation required us to remeasure our deferred income taxes and we began to amortize the resulting excess protected deferred income taxes beginning in 2018 in accordance with normalization requirements. The decrease in income tax expense related to the amortization of the deferred tax benefits is offset by a decrease in revenue as the benefits are returned to customers, resulting in no impact on net income.

See Note 25, Regulatory Environment, for more information about the impact of the Tax Legislation and the Wisconsin rate orders.

Deferred Income Tax Assets and Liabilities

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

(in millions)	2020	2019
Deferred tax assets		
Tax gross up – regulatory items	**$ 240.0**	$ 242.1
Future tax benefits	**47.0**	26.2
Other	**60.8**	47.1
Total deferred tax assets	**347.8**	315.4
Deferred tax liabilities		
Property-related	**$ 1,635.0**	$ 1,500.1
Employee benefits and compensation	**97.8**	79.2
Regulatory deferrals	**40.8**	26.7
Other	**40.5**	29.5
Total deferred tax liabilities	**1,814.1**	1,635.5
Deferred tax liability, net	**$ 1,466.3**	$ 1,320.1

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, 2020 and 2019 are summarized in the tables below:

2020 *(in millions)*	Gross Value	Deferred Tax Effect	Valuation Allowance	Earliest Year of Expiration
Future tax benefits as of December 31, 2020				
Federal tax credits	**—**	**33.9**	**—**	**2040**
State net operating loss	**86.1**	**5.2**	**—**	**2030**
State tax credit	**—**	**7.9**	**—**	**2023**
Balance as of December 31, 2020	**$ 86.1**	**$ 47.0**	**$ —**	

2019 *(in millions)*	Gross Value	Deferred Tax Effect	Valuation Allowance	Earliest Year of Expiration
Future tax benefits as of December 31, 2019				
Federal tax credits	**—**	**8.4**	**—**	**2038**
State net operating loss	**174.0**	**10.4**	**—**	**2023**
State tax credit	**—**	**7.3**	**—**	**2019**
Balance as of December 31, 2019	**$ 174.0**	**$ 26.1**	**$ —**	

Unrecognized Tax Benefits

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

(in millions)	2020	2019
Balance at January 1	**$ 13.0**	$ 17.1
Decrease related to tax positions of prior years	**(6.7)**	(4.1)
Balance at December 31	**$ 6.3**	$ 13.0

The amount of unrecognized tax benefits as of both December 31, 2020 and 2019, excludes deferred tax assets related to uncertainty in income taxes of $0.9 million. At December 31, 2020 and 2019, the net amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate for continuing operations was $5.4 million and $12.1 million, respectively.

For the years ended December 31, 2020, 2019, and 2018, we recognized $0.1 million of interest expense, no interest expense, and $0.1 million of interest expense related to unrecognized tax benefits in our income statements, respectively. For the years ended December 31, 2020, 2019, and 2018, we recognized no penalties related to unrecognized tax benefits in our income statements. At December 31, 2020, we had $0.5 million of interest accrued and no penalties accrued related to unrecognized tax benefits on our balance sheets. At December 31, 2019, we had $0.4 million of interest accrued and no penalties accrued related to unrecognized tax benefits on our balance sheets.

Although analysis of our unrecognized tax benefits is ongoing, the potential estimated decrease in the total amounts of unrecognized tax benefits within the next 12 months is approximately $6.2 million associated with statutes of limitations on certain tax years. We do not anticipate any significant increases in the total amounts of unrecognized tax benefits within the next 12 months.

We file income tax returns in the United States federal jurisdiction and state tax returns based on income in our major state operating jurisdictions of Wisconsin, Illinois, Michigan, and Minnesota. We also file tax returns in other state and local jurisdictions with varying statutes of limitations. As of December 31, 2020, we were subject to examination by federal as well as by state or local tax authorities for the 2015 through 2020 tax years in our major operating jurisdictions as follows:

Jurisdiction	Year
Federal	2017-2020
Illinois	2015-2020
Michigan	2015-2020
Minnesota	2016-2020
Wisconsin	2016-2020

NOTE 18—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, 2020			
(in millions)	Level 1	Level 2	Level 3	Total
Derivative assets				
Natural gas contracts	$ 8.0	$ 1.0	$ —	$ 9.0
FTRs	—	—	1.2	1.2
Coal contracts	—	0.4	—	0.4
Total derivative assets	$ 8.0	$ 1.4	$ 1.2	$ 10.6
Investments held in rabbi trust	$ 79.6	$ —	$ —	$ 79.6
Derivative liabilities				
Natural gas contracts	$ 4.0	$ 4.8	$ —	$ 8.8
Coal contracts	—	0.5	—	0.5
Total derivative liabilities	$ 4.0	$ 5.3	$ —	$ 9.3

	December 31, 2019			
(in millions)	Level 1	Level 2	Level 3	Total
Derivative assets				
Natural gas contracts	$ 0.9	$ 2.0	$ —	$ 2.9
FTRs	—	—	1.3	1.3
Coal contracts	—	0.4	—	0.4
Total derivative assets	$ 0.9	$ 2.4	$ 1.3	$ 4.6
Investments held in rabbi trust	$ 85.3	$ —	$ —	$ 85.3
Derivative liabilities				
Natural gas contracts	$ 14.6	$ 0.8	$ —	$ 15.4
Coal contracts	—	0.1	—	0.1
Total derivative liabilities	$ 14.6	$ 0.9	$ —	$ 15.5

The derivative assets and liabilities listed in the tables above include options, swaps, futures, and physical commodity contracts 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.

We hold investments in equity mutual funds in our rabbi trust. These investments are restricted as they can only be withdrawn from the trust to fund participants' benefits under our deferred compensation plan and certain non-qualified pension plans. These investments are included in other long-term assets on our balance sheets. For the years ended December 31, 2020 and 2019, the net unrealized gains included in earnings related to the investments held at the end of the period were $6.3 million and $18.7 million, respectively. The net unrealized gains included in earnings for the year ended December 31, 2018 were not significant. Gains and losses recorded on the investments held in the rabbi trust are recorded in other income, net on our income statements. These investment gains and losses partially offset changes in benefit costs related to deferred compensation, which are included in other operation and maintenance expense.

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

(in millions)	2020	2019	2018
Balance at the beginning of the period	**$ 1.3**	$ 3.0	$ 2.0
Purchases	**4.1**	5.4	9.0
Settlements	**(4.2)**	(7.1)	(8.0)
Balance at the end of the period	**$ 1.2**	$ 1.3	$ 3.0

Fair Value of Financial Instruments

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

	2020		2019	
(in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt, including current portion [1]	**$ 4,109.4**	**$ 4,775.1**	$ 4,098.3	$ 4,460.6

[1] The carrying amount of long-term debt excludes finance lease obligations of $31.3 million and $30.7 million at December 31, 2020 and 2019, respectively.

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

NOTE 19—DERIVATIVE INSTRUMENTS

The following table shows our derivative assets and derivative liabilities, along with their classification on our balance sheets. None of our derivatives are designated as hedging instruments.

	December 31, 2020		December 31, 2019	
(in millions)	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Other current				
Natural gas contracts	**$ 8.4**	**$ 7.9**	$ 2.9	$ 14.8
FTRs	**1.2**	**—**	1.3	—
Coal contracts	**0.2**	**0.3**	0.2	—
Total other current	**9.8**	**8.2**	4.4	14.8
Other long-term				
Natural gas contracts	**0.6**	**0.9**	—	0.6
Coal contracts	**0.2**	**0.2**	0.2	0.1
Total other long-term	**0.8**	**1.1**	0.2	0.7
Total	**$ 10.6**	**$ 9.3**	$ 4.6	$ 15.5

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

	December 31, 2020		December 31, 2019		December 31, 2018	
(in millions)	Volumes	Gains (Losses)	Volumes	Gains (Losses)	Volumes	Gains
Natural gas contracts	**96.2 Dth**	**$ (33.6)**	93.3 Dth	$ (13.1)	96.0 Dth	$ 11.9
Petroleum products contracts	**— gallons**	**—**	— gallons	—	1.8 gallons	0.4
FTRs	**8.3 MWh**	**1.4**	9.1 MWh	7.2	9.3 MWh	12.5
Total		**$ (32.2)**		$ (5.9)		$ 24.8

At December 31, 2020 and 2019, we had posted cash collateral of $10.1 million and $23.0 million, respectively, in our margin accounts.

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

	December 31, 2020		December 31, 2019	
(in millions)	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Gross amount recognized on the balance sheet	**$ 10.6**	**$ 9.3**	$ 4.6	$ 15.5
Gross amount not offset on the balance sheet	**(3.4)**	**(4.0)** [1]	(0.9)	(14.6) [2]
Net amount	**$ 7.2**	**$ 5.3**	$ 3.7	$ 0.9

[1] Includes cash collateral posted of $0.6 million.

[2] Includes cash collateral posted of $13.7 million.

NOTE 20—GUARANTEES

The following table shows our outstanding guarantees:

		Expiration		
(in millions)	Total Amounts Committed at December 31, 2020	Less Than 1 Year	1 to 3 Years	Over 3 Years
Guarantees supporting commodity transactions of subsidiaries [1]	**$ 68.9**	$ 55.9	$ —	$ 13.0
Standby letters of credit [2]	**21.4**	0.1	—	21.3
Other guarantees [3]	**6.6**	—	—	6.6
Total guarantees	**$ 96.9**	$ 56.0	$ —	$ 40.9

(1) Consists of $47.4 million and $21.5 million related to natural gas supply at MERC and MGU, respectively. These amounts are not reflected on our balance sheets.

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

(3) Consists of a guarantee to support PDL's future payment obligations related to one of its previously owned distributed solar generation projects which is covered by a reciprocal guarantee from a third party that is not reflected on our balance sheets.

NOTE 21—EMPLOYEE BENEFITS

Pension and Other Postretirement Employee Benefits

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.

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 Benefits		OPEB Benefits	
(in millions)	**2020**	**2019**	**2020**	**2019**
Change in benefit obligation				
Obligation at January 1	**$ 1,370.1**	$ 1,261.8	**$ 259.1**	$ 284.1
Service cost	**25.3**	23.9	**8.2**	9.1
Interest cost	**45.5**	52.2	**8.8**	12.1
Plan amendments	**—**	—	**—**	(6.8)
Net transfer from affiliates	**0.6**	—	**0.1**	—
Actuarial loss (gain)	**160.9**	138.8	**5.6**	(24.7)
Participant contributions	**—**	—	**4.6**	4.3
Benefit payments	**(115.9)**	(108.4)	**(19.9)**	(18.9)
Transfer	**—**	1.8	**—**	(0.1)
Obligation at December 31	**$ 1,486.5**	$ 1,370.1	**$ 266.5**	$ 259.1
Change in fair value of plan assets				
Fair value at January 1	**$ 1,280.3**	$ 1,098.8	**$ 473.1**	$ 416.5
Actual return on plan assets	**169.5**	237.4	**56.2**	71.0
Employer contributions	**100.7**	50.7	**0.6**	0.2
Net transfer from affiliates	**—**	—	**0.2**	—
Participant contributions	**—**	—	**4.6**	4.3
Benefit payments	**(115.9)**	(108.4)	**(19.9)**	(18.9)
Transfer	**—**	1.8	**—**	—
Fair value at December 31	**$ 1,434.6**	$ 1,280.3	**$ 514.8**	$ 473.1
Funded status at December 31	**$ (51.9)**	$ (89.8)	**$ 248.3**	$ 214.0

In 2020 and 2019, we had actuarial losses related to our pension benefit obligations of $160.9 million and $138.8 million, respectively, which were primarily due to decreases in our discount rates. The discount rate for our pension benefits was 2.74%, 3.44%, and 4.30%, in 2020, 2019, and 2018, respectively.

In 2020, we had an actuarial loss related to our OPEB benefit obligations of $5.6 million, which was primarily due to decreases in our discount rates. The discount rate for our OPEB benefits was 2.56%, 3.39%, and 4.25%, in 2020, 2019, and 2018, respectively. In 2019, we had an actuarial gain related to our OPEB benefit obligation of $24.7 million, which was primarily due to better than expected claims and premiums experience, the use of new mortality tables, and the repeal of certain health insurance related taxes. These gains were partially offset by a decrease in our discount rate as discussed above.

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

	Pension Benefits		OPEB Benefits	
(in millions)	**2020**	**2019**	**2020**	**2019**
Other long-term assets	**$ 32.7**	$ 41.3	**$ 264.4**	$ 229.2
Pension and OPEB obligations	**84.6**	131.1	**16.1**	15.2
Total net (liabilities) assets	**$ (51.9)**	$ (89.8)	**$ 248.3**	$ 214.0

The accumulated benefit obligation for the defined benefit pension plans was $1,336.7 million and $1,241.3 million at December 31, 2020 and 2019, 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)	**2020**	**2019**
Accumulated benefit obligation	**$ 67.0**	$ 462.1
Fair value of plan assets	**27.2**	384.8

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

(in millions)	**2020**	**2019**
Projected benefit obligation	**$ 543.3**	$ 515.9
Fair value of plan assets	**458.7**	384.8

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

(in millions)	**2020**	**2019**
Accumulated benefit obligation	**$ 19.1**	$ 25.1
Fair value of plan assets	**3.0**	9.9

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

	Pension Benefits		OPEB Benefits	
(in millions)	**2020**	**2019**	**2020**	**2019**
Pre-tax accumulated other comprehensive income (loss) [1]				
Net actuarial loss (gain)	**$ 6.2**	$ 13.9	**$ (1.1)**	$ (1.5)
Prior service credits	**—**	—	**(0.1)**	(0.1)
Total	**$ 6.2**	$ 13.9	**$ (1.2)**	$ (1.6)
Net regulatory assets (liabilities) [2]				
Net actuarial loss (gain)	**$ 460.9**	$ 448.9	**$ (152.0)**	$ (143.8)
Prior service costs (credits)	**3.6**	5.3	**(71.9)**	(86.1)
Total	**$ 464.5**	$ 454.2	**$ (223.9)**	$ (229.9)

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

(2) Amounts related to the utilities are recorded as net regulatory assets or liabilities.

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

	Pension Benefits			OPEB Benefits		
(in millions)	2020	2019	2018	2020	2019	2018
Service cost	**$ 25.3**	$ 23.9	$ 27.0	**$ 8.2**	$ 9.1	$ 13.0
Interest cost	**45.5**	52.2	50.0	**8.8**	12.1	14.3
Expected return on plan assets	**(80.9)**	(80.1)	(79.3)	**(32.4)**	(29.6)	(32.1)
Loss (gain) on plan settlement	**11.6**	9.0	(0.1)	**—**	—	—
Amortization of prior service cost (credit)	**1.7**	1.7	1.7	**(14.2)**	(13.3)	(12.8)
Amortization of net actuarial loss (gain)	**56.5**	47.6	49.7	**(10.3)**	(4.0)	1.3
Net periodic benefit cost (credit)	**$ 59.7**	$ 54.3	$ 49.0	**$ (39.9)**	$ (25.7)	$ (16.3)

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

	Pension Benefits		OPEB Benefits	
	2020	2019	2020	2019
Discount rate	**2.74%**	3.44%	**2.56%**	3.39%
Rate of compensation increase	**4.00%**	4.00%	**N/A**	N/A
Interest credit rate	**2.25%**	2.25%	**N/A**	N/A
Assumed medical cost trend rate (Pre 65)	**N/A**	N/A	**5.85%**	6.00%
Ultimate trend rate (Pre 65)	**N/A**	N/A	**5.00%**	5.00%
Year ultimate trend rate is reached (Pre 65)	**N/A**	N/A	**2028**	2028
Assumed medical cost trend rate (Post 65)	**N/A**	N/A	**5.70%**	5.80%
Ultimate trend rate (Post 65)	**N/A**	N/A	**5.00%**	5.00%
Year ultimate trend rate is reached (Post 65)	**N/A**	N/A	**2028**	2028

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

	Pension Costs		
	2020	2019	2018
Discount rate	**3.34%**	4.19%	3.75%
Expected return on assets	**7.00%**	7.25%	7.25%
Rate of compensation increase	**4.00%**	4.00%	4.00%
Interest credit rate	**2.25%**	2.25%	2.25%

	OPEB Costs		
	2020	2019	2018
Discount rate	**3.38%**	4.25%	3.62%
Expected return on assets	**7.00%**	7.25%	7.25%
Assumed medical cost trend rate (Pre 65)	**6.00%**	6.25%	6.50%
Ultimate trend rate (Pre 65)	**5.00%**	5.00%	5.00%
Year ultimate trend rate is reached (Pre 65)	**2028**	2024	2024
Assumed medical cost trend rate (Post 65)	**5.80%**	5.90%	6.00%
Ultimate trend rate (Post 65)	**5.00%**	5.00%	5.00%
Year ultimate trend rate is reached (Post 65)	**2028**	2028	2028

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 2021, the expected return on assets assumption for the pension and OPEB plans is 7.00%.

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

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

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

	December 31, 2020							
	Pension Plan Assets				OPEB Assets			
(in millions)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Asset Class								
Equity securities:								
United States equity	**$ 218.3**	**$ —**	**$ —**	**$ 218.3**	**$ 77.4**	**$ —**	**$ —**	**$ 77.4**
International equity	**171.1**	**—**	**—**	**171.1**	**66.2**	**—**	**—**	**66.2**
Fixed income securities: [1]								
United States bonds	**—**	**292.3**	**—**	**292.3**	**98.4**	**72.4**	**—**	**170.8**
International bonds	**—**	**46.5**	**—**	**46.5**	**—**	**3.8**	**—**	**3.8**
	$ 389.4	**$ 338.8**	**$ —**	**$ 728.2**	**$ 242.0**	**$ 76.2**	**$ —**	**$ 318.2**
Investments measured at net asset value				**$ 706.4**				**$ 196.6**
Total	**$ 389.4**	**$ 338.8**	**$ —**	**$ 1,434.6**	**$ 242.0**	**$ 76.2**	**$ —**	**$ 514.8**

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

	December 31, 2019							
	Pension Plan Assets				OPEB Plan Assets			
(in millions)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Asset Class								
Equity securities:								
United States equity	$ 165.3	$ —	$ —	$ 165.3	$ 54.2	$ —	$ —	$ 54.2
International equity	159.1	0.7	—	159.8	57.6	0.2	—	57.8
Fixed income securities: [1]								
United States bonds	22.6	240.3	—	262.9	79.5	70.5	—	150.0
International bonds	11.2	40.0	—	51.2	14.4	2.8	—	17.2
	$ 358.2	$ 281.0	$ —	$ 639.2	$ 205.7	$ 73.5	$ —	$ 279.2
Investments measured at net asset value				$ 641.1				$ 193.9
Total	$ 358.2	$ 281.0	$ —	$ 1,280.3	$ 205.7	$ 73.5	$ —	$ 473.1

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

Cash Flows

We expect to contribute $0.7 million to the pension plans and $1.3 million to the OPEB plans in 2021, dependent upon various factors affecting us, including our liquidity position and possible tax law changes.

The following table shows the payments, reflecting expected future service, that we expect to make for pension and OPEB over the next 10 years:

(in millions)	Pension Benefits	OPEB Benefits
2021	$ 104.5	$ 16.5
2022	104.4	17.0
2023	100.9	17.5
2024	98.2	17.9
2025	96.0	18.2
2026 through 2030	424.3	90.2

Savings Plans

WEC Energy Group sponsors 401(k) savings plans that allow substantially all of our full-time employees to contribute a portion of their pre-tax and/or after-tax income in accordance with plan-specified guidelines. A percentage of employee contributions are matched by us through a contribution into the employee's savings plan account, up to certain limits. The 401(k) savings plans include an Employee Stock Ownership Plan. Certain employees receive an employer retirement contribution, which amounts are contributed to an employee's savings plan account based on the employee's wages, age, and years of service. Our share of the total costs incurred under all of these plans were $23.3 million, $23.5 million, and $22.1 million in 2020, 2019, and 2018, respectively.

NOTE 22—SEGMENT INFORMATION

Effective December 31, 2020, we changed our measure of segment profitability from operating income to net income. At December 31, 2020, we reported four segments, which are described below.

- The Wisconsin segment includes the electric and natural gas utility operations of WPS.
- The Illinois segment includes the natural gas utility operations of PGL and NSG.
- The other states segment includes the natural gas utility and non-utility operations of MERC and MGU.
- The corporate and other segment includes the operations of the Integrys holding company, the PELLC holding company, and PDL. See Note 3, Disposition, for more information on the sale of our remaining PDL solar facilities.

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, 2020, 2019, and 2018.

	Regulated Operations						
2020 *(in millions)*	**Wisconsin**	**Illinois**	**Other States**	**Total Regulated Operations**	**Corporate and Other**	**Reconciling Eliminations**	**Integrys Holding Consolidated**
External revenues	**$ 1,407.1**	**$1,321.9**	**$ 384.1**	**$ 3,113.1**	**$ 1.5**	**$ —**	**$ 3,114.6**
Other operation and maintenance	**426.3**	**435.4**	**87.0**	**948.7**	**6.4**	**—**	**955.1**
Depreciation and amortization	**174.3**	**196.7**	**33.5**	**404.5**	**0.8**	**—**	**405.3**
Interest expense	**63.5**	**63.5**	**10.2**	**137.2**	**34.1**	**(0.3)**	**171.0**
Income tax expense (benefit)	**54.5**	**66.1**	**13.1**	**133.7**	**(14.7)**	**—**	**119.0**
Net income (loss)	**221.6**	**203.5**	**39.0**	**464.1**	**(17.2)**	**—**	**446.9**
Capital expenditures	**530.7**	**654.6**	**115.0**	**1,300.3**	**—**	**—**	**1,300.3**
Total assets	**5,933.9**	**7,150.8**	**1,318.7**	**14,403.4**	**192.3**	**(61.2)**	**14,534.5**

2019 *(in millions)*	Regulated Operations: Wisconsin	Illinois	Other States	Total Regulated Operations	Corporate and Other	Reconciling Eliminations	Integrys Holding Consolidated
External revenues	$ 1,411.9	$1,357.1	$ 426.0	$ 3,195.0	$ 4.0	$ —	$ 3,199.0
Other operation and maintenance	396.2	461.1	98.5	955.8	7.2	—	963.0
Depreciation and amortization	166.2	181.3	27.5	375.0	1.5	—	376.5
Interest expense	63.4	59.0	8.5	130.9	36.0	(1.1)	165.8
Income tax expense (benefit)	59.1	60.2	13.6	132.9	(28.7)	—	104.2
Net income	184.7	170.3	43.2	398.2	7.3	—	405.5
Capital expenditures	517.8	622.3	138.4	1,278.5	—	—	1,278.5
Total assets	5,641.6	6,587.3	1,216.9	13,445.8	401.0	(56.9)	13,789.9

2018 *(in millions)*	Regulated Operations: Wisconsin	Illinois	Other States	Total Regulated Operations	Corporate and Other	Reconciling Eliminations	Integrys Holding Consolidated
External revenues	$ 1,498.5	$1,400.0	$ 438.2	$ 3,336.7	$ 8.0	$ —	$ 3,344.7
Other operation and maintenance	448.0	472.3	101.0	1,021.3	7.1	—	1,028.4
Depreciation and amortization	141.9	170.3	24.1	336.3	2.4	—	338.7
Interest expense	53.9	51.2	8.7	113.8	37.8	(0.8)	150.8
Income tax expense (benefit)	77.3	51.8	15.9	145.0	(21.6)	—	123.4
Net income (loss)	172.8	147.1	44.1	364.0	(18.7)	—	345.3
Capital expenditures and asset acquisitions	521.4	545.0	102.9	1,169.3	—	—	1,169.3
Total assets	5,217.7	6,162.3	1,127.0	12,507.0	410.0	(71.4)	12,845.6

NOTE 23—COMMITMENTS AND CONTINGENCIES

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

Unconditional Purchase Obligations

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

The following table shows our minimum future commitments related to these purchase obligations as of December 31, 2020, including those of our subsidiaries.

(in millions)	Date Contracts Extend Through	Total Amounts Committed	Payments Due By Period: 2021	2022	2023	2024	2025	Later Years
Electric utility:								
Purchased power	2051	$ 288.0	$ 46.6	$ 41.8	$ 39.6	$ 40.6	$ 43.0	$ 76.4
Coal supply and transportation	2024	51.2	31.0	14.2	5.3	0.7	—	—
Natural gas utility supply and transportation	2048	1,221.2	203.8	184.6	129.7	82.9	69.6	550.6
Total		$ 1,560.4	$ 281.4	$ 240.6	$ 174.6	$ 124.2	$ 112.6	$ 627.0

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 sulfur dioxide, nitrogen oxide, fine particulates, mercury, and GHGs; water intake and

discharges; management 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 older coal-fired power plants and conversion to modern, efficient, natural gas generation, and/or replacement with renewable generation;
- the beneficial use of ash and other products from coal-fired generating units;
- the remediation of former manufactured gas plant sites;
- the reduction of methane emissions across our natural gas distribution system by upgrading infrastructure; and
- the reporting of GHG emissions to comply with federal clean air rules.

Air Quality

National Ambient Air Quality Standards

After completing its review of the 2008 ozone standard, the EPA released a final rule in October 2015, creating a more stringent standard than the 2008 National Ambient Air Quality Standards. The 2015 ozone standard lowered the 8-hour limit for ground-level ozone. In December 2020, the EPA completed its 5-year review of the ozone standard and issued a final decision to retain, without any changes, the existing 2015 standard.

The EPA issued final nonattainment area designations for the 2015 standard in April 2018. The following counties within our service territory were designated as partial nonattainment: Door and Manitowoc. This re-designation was challenged in the D.C. Circuit Court of Appeals in *Clean Wisconsin et al. v. U.S. Environmental Protection Agency.* We expect that any subsequent EPA re-designation, if necessary, would take place in 2021. The State of Wisconsin submitted the "infrastructure" portion of its state implementation plan outlining how it will implement, maintain, and enforce the 2015 ozone standard. The plan is subject to EPA review and approval. Additionally, in January 2021, the Wisconsin Department of Natural Resources issued a notice that it had prepared a draft economic impact analysis for proposed rules related to incorporating the 2015 standards into the state administrative code. We believe we are well positioned to meet the requirements associated with the ozone standard and do not expect to incur significant costs to comply with associated state or federal rules.

In addition to the 2015 ozone standard, in December 2020, the EPA completed its 5-year review of the 2012 standard for particulate matter, including fine particulate matter. The EPA determined that no revisions were necessary to the current standard. All counties within our service territories are in attainment with the 2012 standards; however, we expect that the decision to retain the 2012 standards with no changes will be challenged by certain states and non-governmental organizations.

Climate Change

The ACE rule, effective since September 2019, was vacated by the D.C. Circuit Court of Appeals in January 2021. The ACE rule replaced the CPP and provided existing coal-fired generating units with standards for achieving GHG emission reductions. It is unclear what steps the EPA will take next. The EPA could either revive an updated version of the CPP or draft a new rule to regulate GHG emissions.

In December 2018, the EPA proposed to revise the NSPS for GHG emissions from new, modified, and reconstructed fossil-fueled power plants. In the proposed rule, the EPA determined that the BSER for new, modified, and reconstructed coal units is highly efficient generation that would be equivalent to supercritical steam conditions for larger units and subcritical steam conditions for smaller units. This proposed BSER would replace the determination from the previous rule, which identified BSER as partial carbon capture and storage.

In January 2021, the EPA finalized the NSPS but did not address the BSER as proposed in 2018. Instead, the EPA shifted the focus to finalizing a significant contribution finding for purposes of regulating source categories for GHG emissions. While the EPA confirmed that EGUs remain a listed source category, the EPA concluded that no other source category should be listed. The EPA based its conclusion on the fact that no other source category, except for EGUs, should contribute to GHG emissions above a 3% threshold. BSER may be addressed in a future action by the EPA. The rule became effective March 14, 2021; however, on March 17, 2021 the EPA asked the D.C. Circuit Court of Appeals to vacate and remand the final rule. Despite this uncertainty, WEC Energy Group continues to move forward on the ESG Progress Plan which is heavily focused on reducing GHG emissions.

The ESG Progress Plan, which includes us, includes the retirement of older, fossil-fueled generation, to be replaced with the construction of zero-carbon-emitting renewable generation and natural gas-fired generation. In 2019, WEC Energy Group met and surpassed its original goal to reduce CO_2 emissions by 40% below 2005 levels by 2030. In July 2020, WEC Energy Group announced new goals to reduce CO_2 emissions from its electric generation by 70% below 2005 levels by 2030 and to be net carbon neutral by 2050. WEC Energy Group added a near-term goal in November 2020 to reduce CO_2 emissions by 55% below 2005 levels by 2025. We have already retired approximately 300 MW of coal-fired generation since the beginning of 2018. As part of the ESG Progress Plan, WEC Energy Group expects to retire approximately 1,800 MW of additional fossil-fueled generation by 2025 and to invest in low-cost renewable energy in Wisconsin. WEC Energy Group's plan is to replace a portion of the retired capacity by building and owning a combination of natural gas-fired generation and zero-carbon-emitting renewable generation facilities.

WEC Energy Group also has a goal to decrease the rate of methane emissions from the natural gas distribution lines in its network by 30% per mile by the year 2030 from a 2011 baseline. WEC Energy Group was over half way toward meeting that goal at the end of 2020.

We are required to report our CO_2 equivalent emissions from the electric generating facilities we operate under the EPA Greenhouse Gases Reporting Program. Based upon our preliminary analysis of the data, we estimate that we will report CO_2 equivalent emissions of approximately 5.4 million metric tonnes to the EPA for 2020. The level of CO_2 and other GHG emissions varies from year to year and is dependent on the level of electric generation and mix of fuel sources, which is determined primarily by demand, the availability of the generating units, the unit cost of fuel consumed, and how our units are dispatched by MISO.

We are also required to report CO_2 equivalent emissions related to the natural gas that our natural gas operations distribute and sell. Based upon our preliminary analysis of the data, we estimate that we will report CO_2 equivalent emissions of approximately 17.3 million metric tonnes to the EPA for 2020.

National Emission Standards for Hazardous Air Pollutants – Major Source Classification

In November 2020, the EPA published a final rule to eliminate the "once-in-always-in" policy regarding major and area source classifications under the National Emission Standards for Hazardous Air Pollutants. The final rule revised the definition of "major source" to allow for the reclassification as an area source when the source's potential to emit hazardous air pollutants meets certain criteria. Technical corrections to this final rule were published in December 2020. We do not expect the revisions to the major source classification will have a material impact on our financial condition or results of operations.

Cross-State Air Pollution Rule Update Rule Revision

In 2015, the EPA determined that several upwind states had failed to submit state implementation plans that addressed their "Good Neighbor" obligations (i.e., the states projected NOx emissions significantly contribute to a continuing downwind nonattainment and/or maintenance problem); therefore, by statute, the EPA was required to issue a federal implementation plan. In October 2020, the EPA proposed a CSAPR update rule revision that keeps nine of the 21 CSAPR affected states (including Wisconsin) as a Group 2 NOx ozone season trading program source and found that the prior CSAPR update is sufficient to meet its "Good Neighbor" obligations. No further NOx reductions would be needed within these nine states. We do not expect that the proposed rule, if finalized, will have a material impact on our financial condition or results of operations.

Water Quality

Steam Electric Effluent Limitation Guidelines

The EPA's final 2015 ELG rule took effect in January 2016 and was modified in 2020 to revise the treatment technology requirements related to BATW at existing facilities. The latest compliance date under the ELG rule is December 31, 2023. This rule created new requirements for several types of power plant wastewaters. The new requirement that affects us relates to discharge limits for

BATW. As a result of past capital investments, we believe our fleet is well positioned to meet the existing ELG regulations. Our Weston power plant facility already has advanced wastewater treatment technologies installed that meet many of the discharge limits established by this rule. There will, however, need to be modifications to the BATW systems at Weston Unit 3. Based on engineering cost estimates, we expect that compliance with the ELG rule will require approximately $10 million in capital investment.

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 for our manufactured gas plant sites as of December 31:

(in millions)	2020	2019
Regulatory assets	**$ 524.2**	$ 557.2
Reserves for future environmental remediation	**469.6**	500.2

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 annually. WPS achieved its required renewable energy percentage of 9.74% and met its compliance requirements by constructing various wind parks, a solar park, and by also relying on renewable energy purchases. WPS continues to review its renewable energy portfolio and acquire cost-effective renewables as needed to meet its requirements on an ongoing basis. The PSCW administers the renewable program related to Act 141, and each electric utility in Wisconsin funds the program based on 1.2% of its annual retail operating revenues.

Enforcement and Litigation Matters

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

Manlove Field Matter

In September 2017, the Illinois Department of Natural Resources, Office of Oil and Gas Resource Management, issued a VN to PGL related to a leak of natural gas from a well located at the PGL Manlove Gas Storage Field in December 2016. PGL quickly shut down and permanently plugged the well to contain the leak after it was discovered. The leak resulted in the migration of natural gas from

the well to the Mahomet Aquifer located in central Illinois and impacted residential freshwater wells. PGL has been working with residents potentially impacted by the natural gas leak, and the Illinois state agencies to investigate and remediate the impacts of the natural gas leak to the Mahomet Aquifer. In October 2017, the Illinois AG filed a complaint against PGL alleging certain violations of the Illinois Environmental Protection Act and the Oil and Gas Act. PGL entered into an Agreed Interim Order with the State of Illinois in October 2017 and a First Amended Agreed Interim Order in September 2019 whereby PGL agreed, among other things, to continue actions it was already undertaking proactively, including the submittal of a GMZ application to the IEPA in August 2019. A supplemental filing was sent to the IEPA in December 2019. Proposed modifications to the GMZ application were submitted to the Illinois AG and the IEPA in May 2020. In September 2020, the IEPA sent PGL a letter conditionally approving the GMZ application.

In addition, in December 2017, the IEPA issued a VN to PGL alleging the same violations as the AG. Lastly, in January 2018, the IEPA issued a VN alleging certain violations of Illinois air emission rules arising from the construction and operation of flaring equipment at the leak site. Both of the IEPA VN matters have been referred to the AG for enforcement.

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

Consent Decrees

Wisconsin Public Service Corporation – Weston and Pulliam Power Plants

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

With the retirement of Pulliam Units 7 and 8 in October 2018, WPS completed the mitigation projects required by the Consent Decree and received a completeness letter from the EPA in October 2018. See Note 7, Regulatory Assets and Liabilities, for more information about the retirement. We are working with the EPA on a closeout process for the Consent Decree.

Joint Ownership Power Plants – Columbia and Edgewater

In December 2009, the EPA issued an NOV to Wisconsin Power and Light Company, 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 Company, 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. As a result of the continued implementation of the Consent Decree related to the jointly owned Columbia and Edgewater plants, the Edgewater 4 generating unit was retired in September 2018. See Note 7, Regulatory Assets and Liabilities, for more information about the retirement. Wisconsin Power and Light Company has started the process to close out this Consent Decree.

NOTE 24—SUPPLEMENTAL CASH FLOW INFORMATION

	Year Ended December 31		
(in millions)	**2020**	**2019**	**2018**
Cash paid for interest, net of amount capitalized	**$ 167.6**	$ 155.2	$ 146.1
Cash paid (received) for income taxes, net	**(10.4)**	(47.8)	1.1
Significant non-cash investing and financing transactions:			
Accounts payable related to construction costs	**104.0**	123.3	60.4
Receivable related to corporate-owned life insurance proceeds	**—**	—	7.7
Non-cash equity transfer of WPSI's ownership interest in ATC and related taxes to another subsidiary of WEC Energy Group [(1)]	**—**	—	363.4

(1) See Note 4, Related Parties, for more information on this transaction.

The statements of cash flows include our activity related to cash, cash equivalents, and restricted cash. Our restricted cash primarily consists of the cash held in our rabbi trust, which 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 following table reconciles the cash, cash equivalents, and restricted cash amounts reported within the balance sheets at December 31 to the total of these amounts shown on the statements of cash flows:

(in millions)	2020	2019	2018
Cash and cash equivalents	**$ 6.6**	$ 11.8	$ 24.7
Restricted cash included in other long-term assets	**47.1**	43.5	57.3
Cash, cash equivalents, and restricted cash	**$ 53.7**	$ 55.3	$ 82.0

NOTE 25—REGULATORY ENVIRONMENT

Coronavirus Disease – 2019

The global outbreak of COVID-19 was declared a pandemic by the World Health Organization and the Centers for Disease Control and Prevention. COVID-19 has spread globally, including throughout the United States and, in turn, our service territories. Each of the states in which our regulated utilities operate declared a public health emergency and issued shelter-in-place orders in response to the COVID-19 pandemic. All of the shelter-in-place orders have since expired or been lifted. The PSCW, the ICC, the MPUC, and the MPSC have all issued written orders requiring certain actions to ensure that essential utility services were, and continue to be, available to customers in their respective jurisdictions. A summary of these orders is included below.

Wisconsin

On March 24, 2020, the PSCW issued two orders in response to the COVID-19 pandemic. The first order required all public utilities in the state of Wisconsin, including WPS, to temporarily suspend disconnections, the assessment of late fees, and deposit requirements for all customer classes. In addition, it required utilities to reconnect customers that were previously disconnected, offer deferred payment arrangements to all customers, and streamline the application process for customers applying for utility service.

In the second order issued on March 24, 2020, the PSCW authorized Wisconsin utilities to defer expenditures and certain foregone revenues resulting from compliance with the first order, and expenditures as otherwise incurred to ensure safe, reliable, and affordable access to utility services during the declared public health emergency. The PSCW has affirmed that this authorization for deferral includes the incremental increase in uncollectible expense above what is currently being recovered in rates. As WPS already has a cost recovery mechanism in place to recover uncollectible expense for residential customers, this new deferral only impacts the recovery of uncollectible expense for its commercial and industrial customers. See Note 6, Credit Losses, for information regarding changes to WPS's allowance for credit losses related to COVID-19. As of December 31, 2020, the total amount deferred at WPS related to the COVID-19 pandemic was not significant. The PSCW will review the recoverability and examine the prudency of any deferred amounts in future rate proceedings.

On June 26, 2020, the PSCW issued a written order providing a timeline for the lifting of the temporary provisions required in the first March 24, 2020 order. Utilities were allowed to disconnect commercial and industrial customers and require deposits for new service as of July 25, 2020 and July 31, 2020, respectively. After August 15, 2020, utilities were no longer required to offer deferred payment arrangements to all customers. Additionally, utilities were authorized to reinstate late fees except for the period between the first order and this supplemental order. WPS resumed charging late payment fees in late August 2020. Late payment fees were not charged on outstanding balances that were billed between the first order and late August 2020.

The PSCW extended the moratorium on disconnections of residential customers until November 1, 2020. In accordance with Wisconsin regulations, utilities are generally not allowed to disconnect residential customers for non-payment during the winter moratorium, which began on November 1 and ends on April 15. Utilities are allowed to continue assessing late fees during the winter moratorium.

Illinois

On March 18, 2020, the ICC issued an order to all Illinois utilities, including PGL and NSG, requiring, among other things, a moratorium on disconnections of utility service and a suspension of late fees and penalties during the declared public health emergency. These provisions applied to all utility customer classes. Illinois utilities were also required to temporarily enact more flexible credit and collections procedures.

On June 18, 2020, the ICC issued a written order approving a settlement agreement negotiated by Illinois utilities, ICC staff, and certain intervenors. The key terms of the settlement agreement included the following:

- The moratorium on disconnections and the suspension of late fees and penalties were extended until July 26, 2020.
- Customers disconnected after June 18, 2019 could be reconnected without being assessed a reconnection fee if reconnection was requested prior to August 25, 2020.
- Flexible deferred payment arrangements were required to be offered to residential and commercial and industrial customers for an extended period of time and with reduced down payment requirements.
- Deposit requirements were waived until August 25, 2020 for all residential customers, and were waived for an additional four months for residential customers that verbally expressed financial hardship.
- PGL and NSG were required to establish a bill payment assistance program with approximately $12.0 million and $1.2 million, respectively, available for eligible residential customers to provide relief from high arrearages.

In addition to the above, the settlement agreement approved on June 18, 2020 authorized PGL and NSG to implement a SPC rider for the recovery of incremental direct costs resulting from COVID-19, foregone late fees and reconnection charges, and the costs associated with their bill payment assistance programs. PGL and NSG began recovering costs under the SPC rider on October 1, 2020. Amounts deferred under the SPC rider are being recovered over 36 months and will be subject to review and reconciliation by the ICC. As of December 31, 2020, PGL's and NSG's regulatory assets related to the COVID-19 pandemic were $19.4 million, collectively.

Subsequent to the approval of the June 18, 2020 settlement agreement, and at the request of the ICC, PGL and NSG agreed to extend the moratorium on disconnections for qualified low-income residential customers and residential customers expressing financial hardship through March 31, 2021. The annual winter moratorium in Illinois that generally prohibits PGL and NSG from disconnecting residential customers for non-payment began on December 1 and ends on March 31. Additionally, PGL and NSG voluntarily extended the availability of deferred payment arrangements with reduced down payment requirements to residential and commercial and industrial customers until March 31, 2021.

With the expiration of the winter moratorium approaching, the ICC issued a written order approving a second settlement agreement negotiated by Illinois utilities, ICC staff, and certain intervenors on March 18, 2021. The key terms of this new settlement agreement are as follows:

- Utilities can start sending disconnection notices, on a staggered basis, as of April 1, 2021. Disconnections will follow a staggered schedule based on customer arrears and income levels (e.g. low income versus non-low income customers). Utilities are not allowed to disconnect customers for non-payment prior to June 30, 2021 if the customer's household income is below 300% of the federal poverty level and the customer is on a deferred payment plan.
- Utilities will continue to offer flexible deferred payment arrangements with reduced down payment requirements to residential customers through June 30, 2021. Deferred payment arrangements will vary based on income level.
- Reconnection fees will be waived for eligible low income customers through June 30, 2021. In addition, utilities will continue to exempt eligible low income customers from late payment fees and deposits.
- Each utility will continue, or renew, its bill payment assistance program through 2021. PGL will add an additional $6.0 million to its bill payment assistance program. No additional funding is required for NSG due to the amount still available for assistance from its initial funding.
- Costs related to the provisions in the settlement agreement, including costs related to the bill payment assistance programs, will be recoverable through the SPC rider.

Minnesota

On May 22, 2020, the MPUC issued a written order authorizing Minnesota utilities, including MERC, to track and defer COVID-19 related expenses and certain foregone revenues. The MPUC will review the recoverability and examine the prudency of any deferred

amounts in future rate proceedings. As of December 31, 2020, amounts deferred at MERC related to the COVID-19 pandemic were not significant.

On June 18, 2020, the MPUC verbally ordered Minnesota utilities to temporarily suspend disconnections and waive reconnection fees, service deposits, late fees, interest, and penalties for all residential customers. In addition, utilities were required to immediately reconnect residential customers that were previously disconnected. On August 13, 2020, the MPUC issued a written order affirming these temporary provisions. The order will remain in effect until 60 days after Minnesota's declared peacetime emergency expires. Currently, the peacetime order is set to expire on April 14, 2021, meaning the MPUC's order would expire on June 13, 2021. The expiration date of Minnesota's peacetime emergency, and the corresponding expiration date of the MPUC order, are subject to change. The annual winter moratorium in Minnesota that generally prohibits MERC from disconnecting residential customers for non-payment began on October 15, 2020 and does not end until April 15, 2021.

Prior to the verbal order issued by the MPUC, MERC had voluntarily taken actions to ensure its customers continued to receive utility services during the pandemic. These actions included, but were not limited to, temporarily suspending disconnections and waiving late payment fees for residential and small commercial and industrial customers that entered into payment plans.

Michigan

On April 15, 2020, the MPSC issued a written order requiring Michigan utilities, including MGU, to put certain minimum protections in place during the COVID-19 pandemic. The minimum protections required by the order include the suspension of disconnections, late payment fees, deposits, and reconnection fees for certain vulnerable customers. In addition, utilities are required to extend access to and enhance the flexibility of payment plans to customers financially impacted by COVID-19. The order will remain in effect until further notice from the MPSC.

As required in the MPSC order, MGU filed a response with the MPSC on April 20, 2020 affirming the actions it is taking to protect customers. The actions being taken by MGU provide protections to more customers than required by the MPSC order. These actions include suspending disconnections for all residential customers, waiving deposit requirements for new service, suspending the assessment of late fees for customers that have entered into payment plans, and enhancing payment plan options for all customers.

The April 15, 2020 MPSC order also authorized all Michigan utilities to defer, for potential future recovery, uncollectible expense incurred on or after March 24, 2020 that exceeds the amounts being recovered in rates. On July 23, 2020, the MPSC issued an order denying Michigan utilities' ability to defer additional COVID-19 related expenses and certain foregone revenues. The MPSC indicated that utilities can still seek recovery of these costs and foregone revenues by filing additional information on the specifics of their request. MGU filed comments with the MPSC on November 2, 2020 indicating that they have not experienced any material additional COVID-19 related expenses or foregone revenues, but that it will continue to monitor them and will notify the MPSC if they become material. At December 31, 2020, MGU had not recorded any deferrals related to the COVID-19 pandemic.

Tax Cuts and Jobs Act of 2017

Due to the Tax Legislation, our regulated utilities deferred for return to ratepayers, through future refunds, bill credits, riders, or reductions in other regulatory assets, the estimated tax benefit of $1,085 million that resulted from the revaluation of deferred taxes. The Tax Legislation also reduced the corporate federal tax rate from a maximum of 35% to a 21% rate, effective January 1, 2018. WPS and MGU have received written orders from the PSCW and the MPSC addressing the refunding of certain of these tax benefits to ratepayers in Wisconsin and Michigan, respectively. The ICC has approved the VITA in Illinois, and the MPUC addressed the impacts to MERC in its 2018 rate order. See the Variable Income Tax Adjustment Rider discussion and the 2018 Minnesota Rate Order discussion below for more information. A summary of the Wisconsin and Michigan orders is outlined below.

Wisconsin

In May 2018, the PSCW issued an order regarding the benefits associated with the Tax Legislation. The PSCW order required WPS's electric utility operations to use 40% of the current 2018 and 2019 tax benefits to reduce certain regulatory assets. The remaining 60% was to be returned to electric customers in the form of bill credits. For WPS's natural gas utility operations, the PSCW indicated that 100% of the current 2018 and 2019 tax benefits should be returned to natural gas customers in the form of bill credits. Regarding the net tax benefit associated with the revaluation of deferred taxes, amortization required in accordance with normalization accounting was used to reduce certain regulatory assets for WPS's electric utility operations and was deferred for its natural gas utility operations. The timing and method of returning the remaining net tax benefit associated with the revaluation of

deferred taxes was addressed in WPS's rate order issued by the PSCW in December 2019. See the 2020 and 2021 Rates discussion below for more information.

Michigan

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

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

The third filing was filed in October 2018 and addressed the remaining impacts of the Tax Legislation on base rates – most notably the re-measurement of deferred tax balances. MGU proposed providing a volumetric bill credit, subject to reconciliation and true up, to return these remaining impacts of the Tax Legislation to customers. The MPSC issued an order approving a settlement in May 2019. The settlement order provides for volumetric bill credits to MGU's customers effective June 1, 2019. The bill credits will remain in effect until MGU's next rate proceeding.

Wisconsin Public Service Corporation

2020 and 2021 Rates

In March 2019, WPS filed an application with the PSCW to increase its retail electric and natural gas rates, effective January 1, 2020. In August 2019, WPS filed an application with the PSCW for approval of a settlement agreement entered into with certain intervenors to resolve several outstanding issues in its rate case. In December 2019, the PSCW issued a written order that approved the settlement agreement without material modification and addressed the remaining outstanding issues that were not included in the settlement agreement. The new rates became effective January 1, 2020. The final order reflects the following:

2020 Effective rate increase	
Electric [1] [2]	$ 15.8 million / 1.6%
Gas [3]	$ 4.3 million / 1.4%
ROE	10.0%
Common equity component average on a financial basis	52.5%

[1] Amount is net of certain deferred tax benefits from the Tax Legislation that were utilized to reduce near-term rate impact. The rate order reflects the majority of the unprotected deferred tax benefits from the Tax Legislation being amortized over two years. Approximately $11 million of tax benefits were amortized in 2020 and approximately $39 million are being amortized in 2021. Unprotected deferred tax benefits by their nature are eligible to be returned to customers in a manner and timeline determined to be appropriate by the PSCW.

[2] The rate order is net of $21 million of refunds related to WPS's 2018 earnings sharing mechanism. These refunds will be made to customers evenly over two years, with half returned in 2020 and the remainder being returned in 2021.

[3] Amount is net of certain deferred tax benefits from the Tax Legislation that were utilized to reduce near-term rate impact. The rate order reflects all of the unprotected deferred tax benefits from the Tax Legislation being amortized evenly over four years, which results in approximately $5 million of previously deferred tax benefits being amortized each year. Unprotected deferred tax benefits by their nature are eligible to be returned to customers in a manner and timeline determined to be appropriate by the PSCW.

The rate order allows WPS to collect the previously deferred revenue requirement for ReACT™ costs above the authorized $275.0 million level. The total cost of the ReACT™ project was $342 million. This regulatory asset will be collected from customers over eight years.

WPS will continue having an earnings sharing mechanism through 2021. The earnings sharing mechanism was modified from its previous structure to one that is consistent with other Wisconsin investor-owned utilities. Under the new earnings sharing

mechanism, if WPS earns above its authorized ROE: (i) WPS will retain 100.0% of earnings for the first 25 basis points above the authorized ROE; (ii) 50.0% of the next 50 basis points is refunded to customers; and (iii) 100.0% of any remaining excess earnings is refunded to customers. In addition, the rate order also requires WPS to maintain residential and small commercial electric and natural gas customer fixed charges at previously authorized rates and to maintain the status quo for its electric market-based rate programs for large industrial customers through 2021.

2018 and 2019 Rates

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

In addition to freezing base rates, the settlement agreement extended and expanded the electric real-time market pricing program options for large commercial and industrial customers. Additionally, the agreement allowed WPS to extend, through 2019, the deferral for the revenue requirement of ReACT™ costs above the authorized $275.0 million level and other deferrals related to its electric real-time market pricing program and network transmission expenses.

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

Solar Generation Projects

In May 2018, WPS, along with an unaffiliated utility, filed an application with the PSCW for approval to acquire ownership interests in two solar projects in Wisconsin. Badger Hollow I is located in Iowa County, Wisconsin, and Two Creeks is located in Manitowoc County, Wisconsin. The PSCW approved the acquisition of these two projects in April 2019. Commercial operation was achieved in November 2020 for Two Creeks, and is targeted for the second quarter of 2021 for Badger Hollow I. WPS owns 100 MW of Two Creeks and will own 100 MW of Badger Hollow I for a total of 200 MW. WPS's share of the cost of both projects is estimated to be approximately $260 million.

Acquisition of a Wind Energy Generation Facility in Wisconsin

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

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

North Shore Gas Company 2021 Rate Case

On October 15, 2020, NSG filed a request with the ICC to increase its natural gas rates. NSG's request is targeting a rate increase of $7.6 million (8.5%) and reflects a 10.0% ROE and a common equity component average of 52.5%. The proposed natural gas rate increase is primarily driven by NSG's ongoing significant investment in its distribution system since its last rate review that resulted in revised base rates effective January 1, 2015. New rates are expected to be effective in September 2021.

Illinois Proceedings

In December 2015, the ICC ordered a series of stakeholder workshops to evaluate PGL's SMP, which were completed in March 2016. In July 2016, the ICC initiated a proceeding to review, among other things, the planning, reporting, and monitoring of the program, including the target end date for the program, and issued a final order in January 2018. The order did not have a significant impact

on PGL's existing SMP design and execution. An appeal related to the final order was filed by the Illinois AG in April 2018. In June 2019, the Illinois Appellate Court issued its ruling affirming the ICC's final order. The appeal period has since expired for this ruling.

Qualifying Infrastructure Plant Rider

In July 2013, Illinois Public Act 98-0057, The Natural Gas Consumer, Safety & Reliability Act, became law. This law provides natural gas utilities with a cost recovery mechanism that allows collection, through a surcharge on customer bills, of prudently incurred costs to upgrade Illinois natural gas infrastructure. In January 2014, the ICC approved a QIP rider for PGL, which is in effect through 2023.

PGL's QIP rider is subject to an annual reconciliation whereby costs are reviewed for accuracy and prudency. In March 2021, PGL filed its 2020 reconciliation with the ICC, which, along with the 2019, 2018, 2017, and 2016 reconciliations, are still pending. In July 2019, the ICC approved a settlement of the 2015 reconciliation, which included a rate base reduction of $7.0 million and a $7.3 million refund to ratepayers. In February 2018, PGL agreed to a settlement of the 2014 reconciliation, which included a rate base reduction of $5.4 million and a $4.7 million refund to ratepayers.

As of December 31, 2020, there can be no assurance that all costs incurred under PGL's QIP rider during the open reconciliation years will be deemed recoverable by the ICC.

Variable Income Tax Adjustment Rider

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

Minnesota Energy Resources Corporation

2018 Minnesota Rate Order

In October 2017, MERC initiated a rate proceeding with the MPUC. In December 2018, the MPUC issued a final written order for MERC. The order authorized a retail natural gas rate increase of $3.1 million (1.26%). The rates reflect a 9.7% ROE and a common equity component average of 50.9%. The final rates were implemented on July 1, 2019. The final approved rate increase was lower than the interim rates collected from customers during 2018 and through June 30, 2019. Therefore, MERC refunded $8.2 million to its customers during the second half of 2019.

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

Michigan Gas Utilities Corporation

2021 Rate Application

In February 2020, MGU provided notification to the MPSC of its intent to file an application requesting an increase to its natural gas rates to be effective January 1, 2021. However, MGU decided that it would delay its filing of the rate case as a result of the COVID-19 pandemic.

In May 2020, MGU filed an application with the MPSC requesting approval to defer $5.0 million of depreciation and interest expense during 2021 related to capital investments made by MGU since its last rate case. In July 2020, the MPSC issued a written order approving MGU's request. The deferral of these costs will help to mitigate the impacts from delaying the filing of the rate case.

On March 22, 2021, MGU filed a request with the MPSC to increase its natural gas rates. MGU's request is targeting a rate increase of $15.1 million (10.7%) and reflects a 10.2% ROE and a common equity component of 52.5%. The proposed natural gas rate increase is primarily driven by MGU's significant investment in capital infrastructure since its last rate review that resulted in revised base rates effective January 1, 2016. New rates are expected to be effective in January 2022.

NOTE 26—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, 2017	$ (1.4)	$ (16.1)	$ (17.5)
Other comprehensive income before reclassifications	—	(2.2)	(2.2)
Amounts reclassified out of accumulated other comprehensive loss	0.6	5.1	5.7
Cumulative effect adjustment from adoption of ASU 2018-02 [1]	(0.2)	(3.0)	(3.2)
Net 2018 other comprehensive income	0.4	(0.1)	0.3
Balance at December 31, 2018	(1.0)	(16.2)	(17.2)
Other comprehensive loss before reclassifications	—	2.3	2.3
Amounts reclassified out of accumulated other comprehensive loss	0.6	5.0	5.6
Net 2019 other comprehensive income (loss)	0.6	7.3	7.9
Balance at December 31, 2019	(0.4)	(8.9)	(9.3)
Other comprehensive loss before reclassifications	**—**	**(0.2)**	**(0.2)**
Amounts reclassified out of accumulated other comprehensive loss	**0.4**	**5.5**	**5.9**
Net 2020 other comprehensive income	**0.4**	**5.3**	**5.7**
Balance at December 31, 2020	**$ —**	**$ (3.6)**	**$ (3.6)**

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

NOTE 27—OTHER INCOME, NET

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

(in millions)	2020	2019	2018
Non-service components of net periodic benefit costs	**$ 13.5**	$ 8.5	$ 4.4
Gains (losses) on investments held in rabbi trust [1]	**12.7**	21.2	(1.8)
AFUDC – Equity	**12.0**	6.0	4.6
Interest income from parent	**0.7**	2.8	4.6
Other, net	**3.3**	17.1	17.8
Total other income, net	**$ 42.2**	$ 55.6	$ 29.6

[1] See Note 18, Fair Value Measurements, for more information on the investments held in our rabbi trust.

NOTE 28—NEW ACCOUNTING PRONOUNCEMENTS

Cloud Computing

In August 2018, the FASB issued ASU 2018-15, Customer's Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract. The standard allows entities who are customers in hosting arrangements that are service contracts to apply the existing internal-use software guidance to determine which implementation costs to capitalize as an asset related to the service contract and which costs to expense. The guidance specifies classification for capitalizing implementation costs and related amortization expense within the financial statements and requires additional disclosures. The adoption of ASU 2018-15, effective January 1, 2020, did not have a significant impact on our financial statements and related disclosures.

Disclosure Requirements for Defined Benefit Plans

In August 2018, the FASB issued ASU 2018-14, Disclosure Framework: Changes to the Disclosure Requirements for Defined Benefit Plans. The pronouncement modifies the disclosure requirements for defined benefit pension and OPEB plans. The guidance removes disclosures that are no longer considered cost beneficial, clarifies the specific requirements of disclosures and adds disclosure requirements identified as relevant. The modifications affect annual period disclosures and must be applied on a retrospective basis

to all periods presented. We adopted the disclosure provisions of ASU 2018-14, effective December 31, 2020. These disclosure modifications are included in Note 21, Employee Benefits.

Simplifying the Accounting for Income Taxes

In December 2019, the FASB issued ASU 2019-12, Simplifying the Accounting for Income Taxes. The new standard removes certain exceptions for performing intraperiod allocation and calculating income taxes in interim periods and also adds guidance to reduce complexity in certain areas, including recognizing deferred taxes for tax goodwill and allocating taxes to members of a consolidated group. The adoption of ASU 2019-12, effective January 1, 2021, did not have a significant impact on our financial statements and related disclosures.

Reference Rate Reform

In March 2020, the FASB issued ASU No. 2020-04, Reference Rate Reform (Topic 848): Facilitation of the Effects of Reference Rate Reform on Financial Reporting, which provides optional expedients and exceptions for applying GAAP to contracts, hedging relationships, and other transactions affected by reference rate reform if certain criteria are met. The amendments apply only to contracts, hedging relationships, and other transactions that reference the LIBOR or another reference rate expected to be discontinued because of reference rate reform. The amendments are effective for all entities as of March 12, 2020 through December 31, 2022. We are currently evaluating the impact this guidance may have on our financial statements and related disclosures.