INTEGRYS HOLDING, INC.

FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2022

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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.
WPS	Wisconsin Public Service Corporation
WRPC	Wisconsin River Power Company

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

Accounting Terms	
AFUDC	Allowance for Funds Used During Construction
ARO	Asset Retirement Obligation
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
BTA	Best Technology Available
CAA	Clean Air Act
CASAC	Clean Air Scientific Advisory Committee
CO_2	Carbon Dioxide
ELG	Steam Electric Effluent Limitation Guidelines
GHG	Greenhouse Gas
NAAQS	National Ambient Air Quality Standards
NOPP	Notice of Planned Participation
NOV	Notice of Violation

NOx	Nitrogen Oxide
PCB	Polychlorinated Biphenyls
PM	Particulate Matter
WOTUS	Waters of the United States
WPDES	Wisconsin Pollutant Discharge Elimination System

Measurements

Dth	Dekatherm
MW	Megawatt
MWh	Megawatt-hour
µg/m3	Micrograms Per Cubic Meter

Other Terms and Abbreviations

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
Darien	Darien Solar-Battery Park
ESG Progress Plan	WEC Energy Group's Capital Investment Plan for Efficiency, Sustainability, and Growth for 2023-2027
Forward Wind	Forward Wind Energy Center
FTR	Financial Transmission Right
GCRM	Gas Cost Recovery Mechanism
ITC	Investment Tax Credit
MISO	Midcontinent Independent System Operator, Inc.
MISO Energy Markets	MISO Energy and Operating Reserves Market
MRP	Main Replacement Program
Omnibus Stock Incentive Plan	WEC Energy Group Omnibus Stock Incentive Plan, Amended and Restated, Effective as of May 6, 2021
Paris	Paris Solar-Battery Park
PTC	Production Tax Credit
QIP	Qualifying Infrastructure Plant
Red Barn	Red Barn Wind Park
RICE	Reciprocating Internal Combustion Engine
ROE	Return on Equity
SIP	State Implementation Plan
SPC	COVID-19 Special Purpose Charge
Supreme Court	United States Supreme Court
Tax Legislation	Tax Cuts and Jobs Act of 2017
TPTFA	Third-Party Transaction Fee Adjustment
Two Creeks	Two Creeks Solar Park
Whitewater	Whitewater Cogeneration Facilities

FINANCIAL STATEMENTS AND NOTES

A. INDEPENDENT AUDITOR'S REPORT

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

Opinion

We have audited the consolidated financial statements of Integrys Holding, Inc. and subsidiaries (the "Company"), which comprise the consolidated balance sheets as of December 31, 2022 and 2021, 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, 2022, and the related notes to the consolidated financial statements (collectively referred to as the "financial statements").

In our opinion, the accompanying financial statements present fairly, in all material respects, the financial position of the Company as of December 31, 2022 and 2021, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2022, in accordance with accounting principles generally accepted in the United States of America.

Basis for Opinion

We conducted our audits in accordance with auditing standards generally accepted in the United States of America (GAAS). Our responsibilities under those standards are further described in the Auditor's Responsibilities for the Audit of the Financial Statements section of our report. We are required to be independent of the Company and to meet our other ethical responsibilities, in accordance with the relevant ethical requirements relating to our audits. We believe that the audit evidence we have obtained is sufficient and appropriate to provide a basis for our audit opinion.

Responsibilities of Management for the Financial Statements

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

In preparing the financial statements, management is required to evaluate whether there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for one year after the date that the financial statements are available to be issued.

Auditor's Responsibilities for the Audit of the Financial Statements

Our objectives are to obtain reasonable assurance about whether the financial statements as a whole are free from material misstatement, whether due to fraud or error, and to issue an auditor's report that includes our opinion. Reasonable assurance is a high level of assurance but is not absolute assurance and therefore is not a guarantee that an audit conducted in accordance with GAAS will always detect a material misstatement when it exists. The risk of not detecting a material misstatement resulting from fraud is higher than for one resulting from error, as fraud may involve collusion, forgery, intentional omissions, misrepresentations, or the override of internal control. Misstatements are considered material if there is a substantial likelihood that, individually or in the aggregate, they would influence the judgment made by a reasonable user based on the financial statements.

In performing an audit in accordance with GAAS, we:

- Exercise professional judgment and maintain professional skepticism throughout the audit.
- Identify and assess the risks of material misstatement of the financial statements, whether due to fraud or error, and design and perform audit procedures responsive to those risks. Such procedures include examining, on a test basis, evidence regarding the amounts and disclosures in the financial statements.
- Obtain an understanding of internal control relevant to the audit 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, no such opinion is expressed.
- Evaluate the appropriateness of accounting policies used and the reasonableness of significant accounting estimates made by management, as well as evaluate the overall presentation of the financial statements.
- Conclude whether, in our judgment, there are conditions or events, considered in the aggregate, that raise substantial doubt about the Company's ability to continue as a going concern for a reasonable period of time.

We are required to communicate with those charged with governance regarding, among other matters, the planned scope and timing of the audit, significant audit findings, and certain internal control-related matters that we identified during the audit.

/s/ DELOITTE & TOUCHE LLP

Milwaukee, Wisconsin
March 29, 2023

INTEGRYS HOLDING, INC.

B. CONSOLIDATED INCOME STATEMENTS

Year Ended December 31 *(in millions)*	2022	2021	2020
Operating revenues	**$ 4,294.7**	$ 3,712.7	$ 3,114.6
Operating expenses			
Cost of sales	**2,029.2**	1,544.9	974.0
Other operation and maintenance	**920.6**	926.3	955.1
Depreciation and amortization	**471.6**	444.9	405.3
Property and revenue taxes	**104.4**	89.9	85.5
Total operating expenses	**3,525.8**	3,006.0	2,419.9
Operating income	**768.9**	706.7	694.7
Other income, net	**49.5**	67.5	42.2
Interest expense	**170.6**	160.1	171.0
Loss on debt extinguishment	**—**	20.6	—
Other expense	**(121.1)**	(113.2)	(128.8)
Income before income taxes	**647.8**	593.5	565.9
Income tax expense	**162.2**	111.4	119.0
Net income	**$ 485.6**	$ 482.1	$ 446.9

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

INTEGRYS HOLDING, INC.

C. CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

Year Ended December 31 *(in millions)*	2022	2021	2020
Net income	**$ 485.6**	$ 482.1	$ 446.9
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
Defined benefit plans			
Pension and OPEB adjustments arising during the period, net of tax expense of $1.0, $0.5, $—, respectively	**(2.7)**	1.3	(0.2)
Amortization of pension and OPEB costs included in net periodic benefit cost, net of tax expense of $—, $—, and $2.0, respectively	**—**	—	5.5
Defined benefit plans, net	**(2.7)**	1.3	5.3
Other comprehensive income (loss), net of tax	**(2.7)**	1.3	5.7
Comprehensive income	**$ 482.9**	$ 483.4	$ 452.6

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)*	2022	2021
Assets		
Current assets		
Cash and cash equivalents	**$ 0.8**	$ 6.5
Accounts receivable and unbilled revenues, net of reserves of $129.0 and $125.3, respectively	**939.0**	741.2
Accounts receivable from related parties	**60.4**	52.7
Notes receivable from parent	**115.0**	5.3
Materials, supplies, and inventories	**375.6**	305.2
Prepaid taxes	**53.6**	40.1
Other prepayments	**16.8**	15.3
Amounts recoverable from customers	**35.7**	89.8
Other	**106.4**	66.1
Current assets	**1,703.3**	1,322.2
Long-term assets		
Property, plant, and equipment, net of accumulated depreciation and amortization of $4,253.1 and $4,098.1, respectively	**12,089.9**	11,490.0
Regulatory assets	**1,212.4**	1,295.8
Goodwill	**635.8**	635.8
Pension and OPEB assets	**474.1**	454.5
Other	**219.0**	209.1
Long-term assets	**14,631.2**	14,085.2
Total assets	**$ 16,334.5**	$ 15,407.4
Liabilities and Equity		
Current liabilities		
Short-term debt	**$ 495.3**	$ 637.5
Accounts payable	**570.8**	492.2
Accounts payable to related parties	**113.4**	89.1
Accrued taxes	**80.8**	96.1
Customer credit balances	**131.6**	88.0
Other	**256.1**	160.5
Current liabilities	**1,648.0**	1,563.4
Long-term liabilities		
Long-term debt	**4,687.4**	4,277.0
Deferred income taxes	**1,757.9**	1,666.6
Deferred ITCs	**108.8**	108.2
Regulatory liabilities	**1,344.9**	1,474.9
Environmental remediation liabilities	**442.0**	470.9
AROs	**345.6**	343.1
Other	**175.6**	162.6
Long-term liabilities	**8,862.2**	8,503.3
Commitments and contingencies (Note 23)		
Common shareholder's equity		
Common stock – $0.01 par value; 10,000 shares authorized, 1,020 shares issued and outstanding	**—**	—
Additional paid in capital	**2,303.9**	2,303.2
Retained earnings	**3,525.4**	3,039.8
Accumulated other comprehensive loss	**(5.0)**	(2.3)
Common shareholder's equity	**5,824.3**	5,340.7
Total liabilities and equity	**$ 16,334.5**	$ 15,407.4

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)*	2022	2021	2020
Operating activities			
Net income	**$ 485.6**	$ 482.1	$ 446.9
Reconciliation to cash provided by operating activities			
Depreciation and amortization	**471.6**	444.9	405.3
Deferred income taxes and ITCs, net	**70.4**	177.2	136.1
Contributions and payments related to pension and OPEB plans	**(1.9)**	(52.4)	(101.3)
Net gain on disposition of assets	**(60.6)**	(4.2)	—
Change in –			
Accounts receivable and unbilled revenues, net	**(215.4)**	(172.2)	61.3
Materials, supplies, and inventories	**(70.4)**	(50.5)	5.7
Amounts recoverable from customers	**54.1**	(69.9)	0.9
Collateral on deposit	**(59.5)**	2.3	12.9
Other current assets	**(17.9)**	0.4	(2.2)
Accounts payable	**97.7**	62.0	(62.8)
Accrued taxes	**(15.3)**	22.6	14.3
Customer credit balances	**43.6**	0.6	(6.3)
Amounts refundable to customers	**39.9**	(28.0)	(18.7)
Other current liabilities	**10.2**	6.0	(10.1)
Other, net	**(17.3)**	(61.9)	(96.5)
Net cash provided by operating activities	**814.8**	759.0	785.5
Investing activities			
Capital expenditures	**(1,017.2)**	(1,021.2)	(1,300.3)
Payments for assets transferred from WBS	**—**	(16.0)	—
Proceeds from the sale of assets, net of cash divested	**61.9**	7.9	10.3
Proceeds from the sale of investments held in rabbi trust	**15.4**	18.7	56.2
Purchase of investments held in rabbi trust	**—**	—	(37.8)
Short-term notes receivable from parent, net	**(109.7)**	(5.3)	166.9
Payments for ATC's construction costs that will be reimbursed	**(5.5)**	(4.4)	(1.9)
Reimbursement for ATC's construction costs	**10.0**	—	—
Other, net	**8.4**	4.7	8.1
Net cash used in investing activities	**(1,036.7)**	(1,015.6)	(1,098.5)
Financing activities			
Retirement of long-term debt	**—**	(578.6)	(300.0)
Issuance of long-term debt	**400.0**	715.0	310.0
Change in short-term debt	**(142.2)**	216.0	236.0
Short-term debt to parent, net	**—**	(68.1)	68.1
Payments for debt extinguishment and issuance costs	**(3.2)**	(24.5)	(2.7)
Other, net	**(0.1)**	(0.8)	—
Net cash provided by financing activities	**254.5**	259.0	311.4
Net change in cash, cash equivalents, and restricted cash	**32.6**	2.4	(1.6)
Cash, cash equivalents, and restricted cash at beginning of year	**56.1**	53.7	55.3
Cash, cash equivalents, and restricted cash at end of year	**$ 88.7**	$ 56.1	$ 53.7

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)	Common Stock	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Common Shareholder's Equity
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
Net income	—	—	482.1	—	482.1
Other comprehensive income	—	—	—	1.3	1.3
Other	—	0.7	—	—	0.7
Balance at December 31, 2021	$ —	$ 2,303.2	$ 3,039.8	$ (2.3)	$ 5,340.7
Net income	—	—	**485.6**	—	**485.6**
Other comprehensive loss	—	—	—	**(2.7)**	**(2.7)**
Other	—	**0.7**	—	—	**0.7**
Balance at December 31, 2022	**$ —**	**$ 2,303.9**	**$ 3,525.4**	**$ (5.0)**	**$ 5,824.3**

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

G. NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2022

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 also included the operations of PDL prior to the sale of its remaining solar facilities in the fourth quarter of 2020. See Note 3, Dispositions, for more information on the sale of these 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 WPS's tariffs, 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.

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 WPS 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. Under normal circumstances, 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. However, as a result of the extreme weather in the Midwest in February 2021, the cost of gas purchased for our natural gas customers was temporarily driven significantly higher than our normal winter weather expectations. See Note 25, Regulatory Environment, for more information on the recovery of these high natural gas costs.

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 both environmental cleanup costs and energy conservation and management program costs. Finally, PGL's rates include a rider for pass through of income tax expense changes resulting from the Tax Legislation and a cost recovery mechanism for the Safety Modernization Program costs, and similarly, the rates of MERC and MGU include riders to recover costs incurred to replace or modify certain natural gas facilities. Effective January 1, 2023, the MERC riders were discontinued, with recovery of these costs now included in interim rates. See Note 25, Regulatory Environment, for more information.

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

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

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.
- 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 their 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.

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.

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

(in millions)	2022	2021
Natural gas in storage	**$ 239.6**	$ 197.2
Materials and supplies	**95.2**	78.4
Fossil fuel	**40.8**	29.6
Total	**$ 375.6**	$ 305.2

PGL and NSG price natural gas storage injections at the calendar year average of the costs of natural gas supply purchased. Withdrawals from storage are priced on the LIFO cost method. Inventories stated on a LIFO basis represented approximately 29% and 40% of total inventories at December 31, 2022 and 2021, respectively. The estimated replacement cost of natural gas in inventory at December 31, 2022 and 2021, exceeded the LIFO cost by $98.3 million and $114.2 million, respectively. In calculating these replacement amounts, PGL and NSG used a Chicago city-gate natural gas price per Dth of $3.41 at December 31, 2022, and $3.67 at December 31, 2021.

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 ratemaking 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	2022	2021	2020
WPS	**2.67 %**	2.66 %	2.63 %
PGL	**3.13 %**	3.12 %	3.16 %
NSG	**2.43 %**	2.52 %	2.48 %
MERC	**2.56 %**	2.58 %	2.47 %
MGU	**2.75 %**	2.70 %	2.67 %

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 2022, WPS's average AFUDC retail rate was 7.55%, and its average AFUDC wholesale rate was 5.49%. The other utilities did not record significant AFUDC for 2022, 2021, or 2020.

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

(in millions)	2022	2021	2020
AFUDC – Debt	**$ 2.4**	$ 3.6	$ 4.7
AFUDC – Equity	**6.3**	9.1	12.0

(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 as the excess of the carrying amount of the goodwill over its fair value. For our indefinite-lived intangible assets, an impairment loss is recognized when the carrying amount of an asset is not recoverable and exceeds its fair

value. An impairment loss is measured as the excess of the carrying amount of the intangible assets over its fair value. No impairment losses were recorded for our indefinite-lived intangible assets during the years ended December 31, 2022, 2021, and 2020. See Note 11, Goodwill and 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. 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 is fair value. 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 over its fair value.

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 and Note 8, Property, Plant, and Equipment 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) Stock-Based Compensation—Our employees participate in the WEC Energy Group stock-based compensation plans. In accordance with the 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. In addition to those shares of WEC Energy Group common stock that were subject to awards outstanding as of May 6, 2021, 9.0 million shares of WEC Energy Group common stock are reserved for issuance under the plan.

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 six months of the grant date except in connection with certain termination of employment events following 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:

	2022	2021	2020
Stock options granted	**47,299**	60,431	66,500
Estimated weighted-average fair value per stock option	**$ 14.71**	$ 13.20	$ 10.82
Assumptions used to value the options:			
Risk-free interest rate	**0.2% – 1.6%**	0.1% – 0.9%	1.6% – 1.9%
Dividend yield	**3.2 %**	2.9 %	3.0 %
Expected volatility	**21.0 %**	21.0 %	16.0 %
Expected life (years)	**8.7**	8.7	8.6

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. All grants of performance units are settled in cash and are accounted for as liability awards accordingly. Performance units accrue forfeitable dividend equivalents in the form of additional performance units. 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.

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. Under the terms of awards granted prior to 2023, participants may earn between 0% and 175% of the performance unit award based on WEC Energy Group's total shareholder return. Pursuant to the plan terms governing these awards, these percentages can be adjusted upwards or downwards by up to 10% based on WEC Energy Group's performance against additional performance measures, if any, adopted by the Compensation Committee.

The WEC Energy Group Performance Unit Plan was amended and restated, effective January 1, 2023. In accordance with the amended plan, the Compensation Committee selected multiple performance measures that will be weighted to determine the ultimate payout for the awards granted in 2023. The ultimate number of units awarded will be based on WEC Energy Group's total shareholder return compared to the total shareholder return of a peer group of companies over three years (55%), and WEC Energy Group's performance against the weighted average authorized ROE of all of its utility subsidiaries (45%). In addition, the Compensation Committee selected the level of WEC Energy Group's stock price to earnings ratio compared to its peer companies as

a performance measure that can increase the payout by up to 25%. In no event can the performance unit payout be greater than 200% of the target award.

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

(m) Leases—We recognize a right of use asset and lease liability for operating and finance leases with a term of greater than one year. As a policy election, we account for each lease component separately from the nonlease components of a contract.

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 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.

See Note 16, Leases, for more information.

(n) 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. PTCs are recognized in the period in which such credits are generated. The amount of the credit is based upon power production from our qualifying generation facilities. 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 upon the benefit for loss method, where attributes are realized when WEC Energy Group is able to realize them. 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.

(o) 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 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, such as FTRs, are categorized in Level 3 due to the significance of unobservable or internally-developed inputs. Our FTRs are valued using MISO auction prices.

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

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

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

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

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

(q) 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.

(r) 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.

(s) 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.

(t) 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.

(u) 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, 2022. In addition, there were no customers that accounted for more than 10% of our revenues for the year ended December 31, 2022.

(v) Subsequent Events—Subsequent events were evaluated for potential recognition or disclosure through March 29, 2023, which is the date the financial statements were available to be issued.

NOTE 2—ACQUISITIONS

In accordance with Topic 805: Clarifying the Definition of a Business (ASU 2017-01), transactions are evaluated and are accounted for as acquisitions (or disposals) of assets or businesses, and transaction costs are capitalized in asset acquisitions.

Acquisition of Electric Generation Facilities in Wisconsin

Effective January 1, 2023, WPS, along with WE, completed the acquisition of Whitewater, a commercially operational 236.5 MW dual fueled (natural gas and low sulfur fuel oil) combined cycle electrical generation facility in Whitewater, Wisconsin. WPS's share of the cost of this facility was approximately $36.3 million for 50% of the capacity, which excludes working capital and transaction costs.

In January 2022, WPS, along with an unaffiliated utility, received PSCW approval to acquire Red Barn, a utility-scale wind-powered electric generating facility. The project will be located in Grant County, Wisconsin and once constructed, WPS will own 82 MW of this project. WPS's share of the cost of this project is estimated to be $160 million, with commercial operation expected to begin in the first half of 2023, at which time the transaction is expected to close. Red Barn is expected to qualify for PTCs.

NOTE 3—DISPOSITIONS

Illinois Segment - Sale of Certain Real Estate by The Peoples Gas Light and Coke Company

In May 2022, we sold approximately 11 acres of real estate owned by PGL that was no longer being utilized in its operations, for $55.1 million. The real estate was located in Chicago, Illinois. As a result of the sale, a pre-tax gain in the amount of $54.5 million was recorded within other operation and maintenance expense on our income statement. The book value of the real estate included in the sale was not material and, therefore, was not presented as held for sale.

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.

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). As required by FERC regulations for centralized service companies, WBS renders services at cost. Services provided by any regulated subsidiary of WEC Energy Group to another regulated subsidiary or WBS are provided at cost, and any services provided by a regulated subsidiary to a nonregulated subsidiary of WEC Energy Group are provided at the greater of cost or fair market value.

WPS pays ATC, a for-profit, transmission-only company regulated by the FERC for cost of service and certain state regulatory commissions for routing and siting of transmission projects, 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, 2022	December 31, 2021
Accounts receivable		
Services provided to ATC	**$ 0.5**	$ 0.9
Amounts due from ATC for transmission infrastructure upgrades [(1)]	**3.3**	8.4
Accounts payable		
Services received from ATC	**9.1**	8.9

[(1)] The transmission infrastructure upgrades were primarily related to the construction of WPS's renewable energy projects.

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

(in millions)	2022	2021	2020
Transactions with WE			
Natural gas related sales to WE from WPS [1]	**$ 3.3**	$ 2.9	$ 1.5
Charges to WE from WPS for services and other items [2]	**10.7**	9.4	8.3
Charges from WE to WPS for services and other items [2]	**13.3**	11.8	12.5
Transactions with UMERC			
Natural gas related sales to UMERC from WPS [1]	**4.0**	2.6	2.0
Charges to UMERC from WPS for services and other items [2]	**3.7**	3.1	4.4
Transactions with Bluewater			
Storage service fees charged to WPS [3]	**10.7**	10.3	10.6
Other operating fees charged to WPS [3]	**2.3**	1.0	0.7
Natural gas related sales to Bluewater from WPS [1]	**1.9**	1.9	1.9
Transactions with WBS			
Charges to WBS for services and other items [2]	**39.4**	35.6	51.9
Charges from WBS for services and other items [2]	**205.3**	226.3 [5]	228.1
Transactions with Parent			
Interest income on short-term borrowings	**1.4**	—	0.7
Transactions with ATC			
Charges to ATC for services and construction	**9.6**	8.0	11.9
Charges from ATC for network transmission services	**109.5**	107.0	107.4
Net refund from ATC related to FERC ROE orders	**—**	2.3	3.3
Transactions with WRPC			
Rental payments to WRPC [4]	**1.9**	1.9	1.9
Charges to WRPC for operations	**0.4**	0.6	1.2
Charges from WRPC for services	**2.6**	2.4	2.6

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

[2] Includes amounts charged for services, pass through costs, asset and liability transfers, and other items in accordance with the approved AIA.

[3] WPS has a long-term service agreement with a wholly owned subsidiary of Bluewater that was previously approved by the PSCW. Bluewater owns natural gas storage facilities in Michigan and provides a portion of WPS's current storage needs.

[4] WPS has an agreement with WRPC whereby it receives 50% of the energy generated from WRPC's hydroelectric power generation facilities.

[5] Includes $15.5 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, 2022 and 2021, we had a short-term note receivable from WEC Energy Group of $115.0 million and $5.3 million, respectively. 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, 2022						
Electric	**$ 1,316.5**	**$ —**	**$ —**	**$ 1,316.5**	**$ —**	**$ 1,316.5**
Natural gas	**465.5**	**1,883.7**	**601.8**	**2,951.0**	**—**	**2,951.0**
Total regulated revenues	**1,782.0**	**1,883.7**	**601.8**	**4,267.5**	**—**	**4,267.5**
Other non-utility revenues	**—**	**—**	**18.7**	**18.7**	**—**	**18.7**
Total revenues from contracts with customers	**1,782.0**	**1,883.7**	**620.5**	**4,286.2**	**—**	**4,286.2**
Other operating revenues	**3.2**	**7.2**	**(2.0)**	**8.4**	**0.1**	**8.5**
Total operating revenues	**$ 1,785.2**	**$ 1,890.9**	**$ 618.5**	**$ 4,294.6**	**$ 0.1**	**$ 4,294.7**

(in millions)	Wisconsin	Illinois	Other States	Total Utility Operations	Corporate and Other	Integrys Holding Consolidated
Year ended December 31, 2021						
Electric	$ 1,176.7	$ —	$ —	$ 1,176.7	$ —	$ 1,176.7
Natural gas	338.8	1,630.3	494.0	2,463.1	—	2,463.1
Total regulated revenues	1,515.5	1,630.3	494.0	3,639.8	—	3,639.8
Other non-utility revenues	—	—	17.8	17.8	—	17.8
Total revenues from contracts with customers	1,515.5	1,630.3	511.8	3,657.6	—	3,657.6
Other operating revenues	5.4	42.5	7.2	55.1	—	55.1
Total operating revenues	$ 1,520.9	$ 1,672.8	$ 519.0	$ 3,712.7	$ —	$ 3,712.7

(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

Revenues from Contracts with Customers

Electric Utility Operating Revenues

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

	Year Ended December 31		
(in millions)	**2022**	**2021**	**2020**
Residential	**$ 460.4**	$ 423.5	$ 420.0
Small commercial and industrial	**413.8**	376.2	353.6
Large commercial and industrial	**293.3**	256.6	220.0
Other	**8.8**	8.4	8.4
Total retail revenues	**1,176.3**	1,064.7	1,002.0
Wholesale	**95.4**	86.7	95.1
Resale	**27.3**	11.4	19.6
Other utility revenues	**17.5**	13.9	20.2
Total electric utility operating revenues	**$ 1,316.5**	$ 1,176.7	$ 1,136.9

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, 2022				
Residential	**$ 271.8**	**$ 1,297.4**	**$ 391.3**	**$ 1,960.5**
Commercial and industrial	**175.1**	**408.8**	**218.7**	**802.6**
Total retail revenues	**446.9**	**1,706.2**	**610.0**	**2,763.1**
Transportation	**20.1**	**259.8**	**34.5**	**314.4**
Other utility revenues [(1) (2)]	**(1.5)**	**(82.3)**	**(42.7)**	**(126.5)**
Total natural gas utility operating revenues	**$ 465.5**	**$ 1,883.7**	**$ 601.8**	**$ 2,951.0**

(in millions)	**Wisconsin**	**Illinois**	**Other States**	**Total Natural Gas Utility Operating Revenues**
Year Ended December 31, 2021				
Residential	$ 202.0	$ 1,017.9	$ 241.2	$ 1,461.1
Commercial and industrial	122.0	302.1	129.9	554.0
Total retail revenues	324.0	1,320.0	371.1	2,015.1
Transportation	19.4	231.2	31.8	282.4
Other utility revenues [(1) (3)]	(4.6)	79.1	91.1	165.6
Total natural gas utility operating revenues	$ 338.8	$ 1,630.3	$ 494.0	$ 2,463.1

(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
Transportation	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

(1) Includes the revenues subject to the purchased gas recovery mechanisms of our utilities.

(2) During 2022, our Illinois and Minnesota utilities continued to recover natural gas costs they under-collected from their customers in 2021 related to the extreme weather experienced in February 2021. As these amounts are billed to customers, they are reflected in retail revenues with an offsetting decrease in other utility revenues.

(3) During 2021, in addition to costs related to the extreme weather event experienced in February 2021, we incurred higher natural gas costs as a result of an increase in the price of natural gas.

See Note 25, Regulatory Environment, for more information

Other Non-Utility Operating Revenues

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

	Year Ended December 31		
(in millions)	**2022**	**2021**	**2020**
Appliance service revenues	**$ 18.7**	$ 17.8	$ 17.1
Distributed renewable solar project revenues	**—**	—	1.4
Total other non-utility operating revenues	**$ 18.7**	$ 17.8	$ 18.5

Other Operating Revenues

Other operating revenues consist primarily of the following:

	Year Ended December 31		
(in millions)	**2022**	**2021**	**2020**
Late payment charges [1]	**$ 38.0**	$ 35.8	$ 20.9
Rental revenues	**1.0**	0.6	0.8
Alternative revenues [2]	**(30.5)**	18.7	39.1
Total other operating revenues	**$ 8.5**	$ 55.1	$ 60.8

(1) The increase in late payment charges during 2021, compared with 2020, was a result of the expiration of various regulatory orders from our utility commissions in response to the COVID-19 pandemic, which included the suspension of late payment charges during a designated time period. See Note 25, Regulatory Environment, for more information.

(2) 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, conservation improvement rider true-ups, and certain late payment charges, as discussed in Note 1(d), Operating Revenues.

NOTE 6—CREDIT LOSSES

We have included tables below that show our gross third-party receivable balances and the related allowance for credit losses at December 31, 2022 and 2021, by reportable segment.

(in millions)	**Wisconsin**	**Illinois**	**Other States**	**Integrys Holding Consolidated**
December 31, 2022				
Accounts receivable and unbilled revenues	**$ 279.5**	**$ 624.1**	**$ 164.4**	**$ 1,068.0**
Allowance for credit losses	**11.7**	**111.0**	**6.3**	**129.0**
Accounts receivable and unbilled revenues, net [1]	**$ 267.8**	**$ 513.1**	**$ 158.1**	**$ 939.0**
Total accounts receivable, net – past due greater than 90 days [1]	**$ 8.4**	**$ 52.9**	**$ 1.9**	**$ 63.2**
Past due greater than 90 days – collection risk mitigated by regulatory mechanisms [1]	**95.5 %**	**100.0 %**	**— %**	**96.4 %**

(in millions)	Wisconsin	Illinois	Other States	Integrys Holding Consolidated
December 31, 2021				
Accounts receivable and unbilled revenues	$ 237.7	$ 523.1	$ 105.7	$ 866.5
Allowance for credit losses	11.1	105.4	8.8	125.3
Accounts receivable and unbilled revenues, net [(1)]	$ 226.6	$ 417.7	$ 96.9	$ 741.2
Total accounts receivable, net – past due greater than 90 days [(1)]	$ 8.0	$ 36.6	$ 3.4	$ 48.0
Past due greater than 90 days – collection risk mitigated by regulatory mechanisms [(1)]	97.3 %	100.0 %	— %	92.5 %

(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, 2022, $644.7 million, or 68.7%, of our net accounts receivable and unbilled revenues balance had regulatory protections in place to mitigate the exposure to credit losses.

A rollforward of the allowance for credit losses by reportable segment for the years ended December 31, 2022, 2021, and 2020, is included below:

Year Ended December 31, 2022 *(in millions)*	Wisconsin	Illinois	Other States	Integrys Holding Consolidated
Balance at January 1, 2022	**$ 11.1**	**$ 105.4**	**$ 8.8**	**$ 125.3**
Provision for credit losses	**8.4**	**33.0**	**2.6**	**44.0**
Provision for credit losses deferred for future recovery or refund	**0.1**	**33.2**	**—**	**33.3**
Write-offs charged against the allowance	**(12.8)**	**(82.5)**	**(6.4)**	**(101.7)**
Recoveries of amounts previously written off	**4.9**	**21.9**	**1.3**	**28.1**
Balance at December 31, 2022	**$ 11.7**	**$ 111.0**	**$ 6.3**	**$ 129.0**

On a consolidated basis, there was an increase in the allowance for credit losses during the year ended December 31, 2022. We believe that the high energy costs that customers are seeing, which have been driven by high natural gas prices, contributed to higher past due accounts receivable balances and a related increase in the allowance for credit losses. The increase was substantially offset by customer write-offs related to collection practices returning to pre-pandemic levels, including the restoration of our ability to disconnect customers. After a customer is disconnected for a period of time without payment on their account, we will write off that customer balance.

Year Ended December 31, 2021 *(in millions)*	Wisconsin	Illinois	Other States	Integrys Holding Consolidated
Balance at January 1, 2021	$ 18.3	$ 111.6	$ 6.4	$ 136.3
Provision for credit losses	6.2	25.6	3.7	35.5
Provision for credit losses deferred for future recovery or refund	(7.0)	3.5	—	(3.5)
Write-offs charged against the allowance	(10.0)	(52.6)	(2.5)	(65.1)
Recoveries of amounts previously written off	3.6	17.3	1.2	22.1
Balance at December 31, 2021	$ 11.1	$ 105.4	$ 8.8	$ 125.3

The allowance for credit losses decreased during the year ended December 31, 2021, primarily related to normal collection practices resuming in April 2021 for WPS and in June 2021 for our Illinois utilities. Across all of our reportable segments, higher year-over-year natural gas prices drove an increase in gross accounts receivable balances, partially offsetting the decrease in the allowance for credit losses attributed to collection efforts.

Year Ended December 31, 2020 *(in millions)*	Wisconsin	Illinois	Other States	Total Utility Operations	Corporate and Other	Integrys Holding Consolidated
Balance at January 1, 2020	$ 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 allowance for credit losses increased during the year ended December 31, 2020, 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 received, we were unable to disconnect any of our Wisconsin and Illinois customers during the year ended December 31, 2020.

NOTE 7—REGULATORY ASSETS AND LIABILITIES

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

(in millions)	2022	2021	See Note
Regulatory assets [1] [2]			
Environmental remediation costs [3]	**$ 500.1**	$ 521.9	23
Pension and OPEB costs [4]	**232.1**	298.6	21
AROs	**128.6**	152.2	1(k), 10
Derivatives	**83.2**	25.1	1(p)
Income tax related items	**65.8**	55.9	17
Uncollectible expense	**52.9**	42.6	6
Plant retirement related items	**43.1**	50.2	
MERC extraordinary natural gas costs [5]	**35.1**	59.7	25
Invested capital tax rider [6]	**25.9**	23.9	
Energy costs recoverable through rate adjustments	**17.5**	72.9	1(d), 25
Energy efficiency programs [7]	**14.7**	12.4	
ReACT™	**13.0**	15.6	25
Other, net	**36.1**	54.6	
Total regulatory assets	**$ 1,248.1**	$ 1,385.6	
Balance sheet presentation			
Amounts recoverable from customers	**$ 35.7**	$ 89.8	
Regulatory assets	**1,212.4**	1,295.8	
Total regulatory assets	**$ 1,248.1**	$ 1,385.6	

(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 $10.2 million and $12.6 million at December 31, 2022 and 2021, respectively.

(2) As of December 31, 2022, we had $185.0 million of regulatory assets not earning a return and $7.1 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, MERC's extraordinary natural gas costs, certain environmental remediation costs, our invested capital tax rider, and unamortized loss on reacquired debt. 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, 2022, we had made cash expenditures of $58.1 million related to these environmental remediation costs. The remaining $442.0 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 the extraordinary natural gas costs MERC incurred during February 2021 that are being recovered over 27 months, beginning in September 2021. See Note 25, Regulatory Environment, for more information on our recovery efforts associated with these costs.

(6) 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.

(7) Represents amounts recoverable from customers related to programs at our utilities designed to meet energy efficiency standards.

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

(in millions)	2022	2021	See Note
Regulatory liabilities			
Income tax related items	**$ 782.0**	$ 805.8	17
Removal costs [1]	**318.8**	333.7	
Pension and OPEB benefits [2]	**157.2**	216.7	21
Energy costs refundable through rate adjustments	**50.8**	13.4	1(d)
Derivatives	**31.3**	59.8	1(p)
Decoupling	**20.2**	0.2	1(d)
Energy efficiency programs [3]	**9.2**	1.1	
Earnings sharing mechanism	**3.0**	26.7	25
Electric transmission costs [4]	**0.2**	19.7	
Other, net	**26.3**	12.0	
Total regulatory liabilities	**$ 1,399.0**	$ 1,489.1	
Balance sheet presentation			
Other current liabilities	**$ 54.1**	$ 14.2	
Regulatory liabilities	**1,344.9**	1,474.9	
Total regulatory liabilities	**$ 1,399.0**	$ 1,489.1	

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

(4) 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. During 2022, WPS amortized $19.0 million of its transmission regulatory liabilities to offset certain 2022 revenue deficiencies, as approved by the PSCW in order to forego filing for 2022 base rate increases. See Note 25, Regulatory Environment, for more information.

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 $36.6 million at December 31, 2022, representing book value less cost of removal and accumulated depreciation. This amount was classified as a regulatory asset on our balance sheet at December 31, 2022 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. The amortization is included in depreciation and amortization in the income statement. WPS also 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.

Edgewater Unit 4

The Edgewater 4 generating unit was retired on September 28, 2018. The net book value of the generating unit was $3.2 million at December 31, 2022, representing book value less cost of removal and accumulated depreciation. This amount was classified as a regulatory asset on our balance sheet at December 31, 2022 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. The amortization is included in depreciation and amortization in the income statement. WPS also 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.

NOTE 8—PROPERTY, PLANT, AND EQUIPMENT

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

(in millions)	2022	2021
Electric – generation	**$ 2,736.5**	$ 2,816.7
Electric – distribution	**2,184.9**	2,076.3
Natural gas – distribution, storage, and transmission	**9,674.6**	9,202.6
Property, plant, and equipment to be retired, net	**273.1**	277.0
Other	**1,042.6**	1,021.2
Less: Accumulated depreciation	**4,095.0**	4,098.1
Net	**11,816.7**	11,295.7
CWIP	**273.2**	194.3
Total property, plant, and equipment	**$ 12,089.9**	$ 11,490.0

Severance Liability for Plant Retirements

We have severance liabilities related to past and future plant retirements recorded in other current liabilities on our balance sheets. Activity related to these severance liabilities for the years ended December 31 was as follows:

(in millions)	2022	2021
Severance liability at January 1 [(1)]	$ 1.6	$ —
Severance expense	**1.1**	1.6
Severance payments	**—**	—
Other	**—**	—
Total severance liability at December 31	**$ 2.7**	$ 1.6

(1) There was no severance liability in 2020.

Plant to be Retired

Columbia Units 1 and 2

As a result of a MISO ruling received in June 2021, retirement of the jointly-owned Columbia generating units 1 and 2 became probable. Columbia generating units 1 and 2 are expected to be retired by June 2026. The net book value of WPS's ownership share of unit 1 and unit 2 was $84.0 million and $189.1 million, respectively, at December 31, 2022, which does not include deferred taxes. These amounts were classified as plant to be retired within property, plant, and equipment on our balance sheet. These units are included in rate base, and WPS continues to depreciate them on a straight-line basis using the composite depreciation rates approved by the PSCW.

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, 2022 was as follows:

(in millions, except for percentages and MW)	Weston Unit 4	Columbia Energy Center Units 1 and 2	Forward Wind	Two Creeks	Badger Hollow I [2]
Ownership	70.0 %	27.5 %	44.6 %	66.7 %	66.7 %
WPS's share of capacity (MW) [1]	387.3	311.1	61.5	100.0	100.0
In-service date	2008	1975 and 1978	2008	2020	2021
Property, plant, and equipment	$ 612.1	$ 426.1	$ 119.3	$ 136.8	$ 146.2
Accumulated depreciation	$ (213.0)	$ (159.7)	$ (53.9)	$ (9.7)	$ (4.9)
CWIP	$ 1.2	$ 6.8	$ 0.2	$ 0.1	$ —

[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 2023 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 is based on nameplate capacity, which is the amount of energy a turbine should produce at optimal wind speeds. Capacity for Two Creeks and Badger Hollow I 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 2021 for Badger Hollow I.

WPS, along with WE and an unaffiliated utility, received PSCW approval to construct Paris, a utility-scale solar-powered electric generating facility with a battery energy storage system. The project will be located in Kenosha County, Wisconsin and once fully constructed, WPS will own 15%, or 30 MW of solar generation and 17 MW of battery storage of this project. Commercial operation of the solar facility is targeted for 2023. The CWIP balance for Paris was $34.4 million as of December 31, 2022.

WPS, along with WE and an unaffiliated utility, received PSCW approval to construct Darien, a utility-scale solar-powered electric generating facility with a battery energy storage system. The project will be located in Rock and Walworth counties, Wisconsin and once fully constructed, WPS will own 15%, or 37 MW of solar generation and 12 MW of battery storage of this project. Commercial operation of the solar facility is targeted for 2024. The CWIP balance for Darien was $1.6 million as of December 31, 2022.

WPS, along with WE, received PSCW approval to construct a natural gas-fired generation facility at our existing Weston power plant site in northern Wisconsin. The new facility will consist of seven RICE units. Once constructed, WPS will own 50%, or 64 MW of this project. Commercial operation is targeted for 2023. The CWIP balance for the Weston RICE units was $60.2 million as of December 31, 2022.

Effective January 1, 2023, WPS, along with WE, completed the acquisition of Whitewater, a commercially operational 236.5 MW dual fueled (natural gas and low sulfur fuel oil) combined cycle electrical generation facility in Whitewater, Wisconsin. WPS's share of the cost of this facility was $36.3 million, or 50% of the capacity, which excludes transaction costs and working capital. See Note 2, Acquisitions, for more information.

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 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 ratemaking 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)	2022	2021	2020
Balance as of January 1	**$ 343.1**	$ 433.7	$ 397.3
Accretion	**12.4**	18.1	17.6
Additions and revisions to estimated cash flows	**2.5**	(92.7) [1]	47.5 [2]
Liabilities settled	**(12.4)**	(16.0)	(28.7)
Balance as of December 31	**$ 345.6**	$ 343.1	$ 433.7

[1] AROs decreased $152.0 million in 2021, due to revisions made to estimated cash flows primarily for changes in the cost to retire natural gas distribution pipe at PGL. Also in 2021, AROs increased $50.7 million due to new natural gas distribution lines being placed into service at PGL and NSG. AROs increased $10.8 million due to the legal requirement to dismantle, at retirement, the Badger Hollow I solar generation project.

[2] 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.

NOTE 11—GOODWILL AND 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, 2022. We had no changes to the carrying amount of goodwill during the years ended December 31, 2022 and 2021.

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

During the third quarter of 2022, annual impairment tests were completed at all of our reporting units that carried a goodwill balance as of July 1, 2022. No impairments resulted from these tests.

Intangible Assets

At December 31, 2022 and 2021, we had $13.4 million and $5.7 million, respectively, of indefinite-lived intangible assets. During 2022, we purchased additional spectrum frequencies for $7.7 million. The spectrum frequencies enable the utilities to transmit data and voice communications over a wavelength dedicated to us throughout our service territories. We also have $5.7 million of other indefinite-lived intangible assets, primarily related to a MGU trade name from a previous acquisition. These indefinite-lived intangible assets are included in other long-term assets on our balance sheets.

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)	2022	2021	2020
Stock options	**$ 3.7**	$ 3.7	$ 3.4
Restricted stock	**4.1**	3.4	4.0
Performance units	**10.4**	1.1	10.7
Stock-based compensation expense	**$ 18.2**	$ 8.2	$ 18.1
Related tax benefit	**$ 5.0**	$ 2.3	$ 5.0

Stock-based compensation costs capitalized during 2022, 2021, and 2020 were not significant.

Stock Options

The following is a summary of our employees' WEC Energy Group stock option activity during 2022:

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, 2022	231,024	$ 76.82		
Granted	**47,299**	**$ 96.04**		
Exercised	**(65,627)**	**$ 68.34**		
Transferred	**4,959**	**$ 88.16**		
Forfeited	**(654)**	**$ 91.49**		
Outstanding as of December 31, 2022	**217,001**	**$ 83.78**	**7.0**	**$ 2.3**
Exercisable as of December 31, 2022	**103,497**	**$ 73.87**	**5.9**	**$ 2.1**

The aggregate intrinsic value of outstanding and exercisable options in the above table represents the total pre-tax intrinsic value that would have been received by the option holders had they exercised all of their options on December 31, 2022. This is calculated as the difference between WEC Energy Group's closing stock price on December 31, 2022, 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, 2022, 2021, and 2020 was $2.1 million, $1.1 million, and $2.2 million, respectively. Cash received by WEC Energy Group from exercises of its options by our employees was $4.5 million, $1.8 million, and $3.3 million during the years ended December 31, 2022, 2021, and 2020, respectively. The actual tax benefit from option exercises for the same periods was approximately $0.6 million, $0.3 million, and $0.6 million, respectively.

As of December 31, 2022, we expected to recognize approximately $1.4 million of unrecognized compensation cost related to unvested and outstanding WEC Energy Group stock options over the next 1.6 years on a weighted-average basis.

During the first quarter of 2023, the Compensation Committee awarded 27,735 non-qualified WEC Energy Group stock options with an exercise price of $93.69 and a weighted-average grant date fair value of $19.58 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 2022:

Restricted Shares	Number of Shares	Weighted-Average Grant Date Fair Value
Outstanding and unvested as of January 1, 2022	7,412	$ 87.25
Granted	**4,481**	**$ 96.04**
Released	**(5,398)**	**$ 86.38**
Transferred	**319**	**$ 90.72**
Forfeited	**(505)**	**$ 93.78**
Outstanding and unvested as of December 31, 2022	**6,309**	**$ 93.89**

The intrinsic value of WEC Energy Group restricted stock held by our employees that was released was $0.5 million, $0.4 million, and $0.5 million for the years ended December 31, 2022, 2021, and 2020, respectively. The actual tax benefit from released restricted shares for the same years was $0.1 million each year.

As of December 31, 2022, we expected to recognize approximately $1.6 million of unrecognized compensation cost related to unvested and outstanding WEC Energy Group restricted stock over the next 1.7 years on a weighted-average basis.

During the first quarter of 2023, the Compensation Committee awarded 4,135 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 $93.69 per share.

Performance Units

During 2022, 2021, and 2020, the Compensation Committee awarded 19,433; 18,231; and 21,172 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 $2.6 million, $3.5 million, and $4.7 million were settled during 2022, 2021, and 2020, respectively. The actual tax benefit from the distribution of performance units for the same years was approximately $0.7 million, $0.7 million, and $1.0 million, respectively.

At December 31, 2022, our employees held 41,119 WEC Energy Group performance units, including dividend equivalents. A liability of $2.4 million was recorded on our balance sheet at December 31, 2022 related to these outstanding units. As of December 31, 2022, we expected to recognize approximately $6.4 million of unrecognized compensation cost related to unvested and outstanding WEC Energy Group performance units over the next 1.7 years on a weighted-average basis.

During the first quarter of 2023, performance units held by our employees with an intrinsic value of $1.1 million were settled. The actual tax benefit from the distribution of these awards was $0.3 million. In January 2023, the Compensation Committee also awarded 17,985 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 53.0%. 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, 2022, restricted net assets of our consolidated subsidiaries totaled approximately $3.5 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, 2022 and 2021.

	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)	2022	2021
Commercial paper		
Amount outstanding at December 31	**$ 495.3**	$ 637.5
Average interest rate on amounts outstanding at December 31	**4.64 %**	0.22 %

Our average amount of commercial paper borrowings based on daily outstanding balances during 2022, was $286.9 million with a weighted-average interest rate during the period of 2.03%.

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, 2022, both companies were in compliance with their respective financial covenants.

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

(in millions)	Maturity	2022
Revolving credit facility (WPS)	September 2026	$ 400.0
Revolving credit facility (PGL)	September 2026	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		$ 495.3
Letters of credit issued inside credit facilities		1.3
Available capacity under existing credit agreements		$ 653.4

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)			2022	2021
Long-term debt	**Interest Rate**	**Year Due**		
WPS Senior Notes (unsecured)	5.35%	2025	**300.0**	—
	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
	2.85%	2051	**450.0**	450.0
Integrys Junior Notes (unsecured) [(1)]	6.00%	2073	**221.4**	221.4
PGL First and Refunding Mortgage Bonds (secured) [(2)]	2.64%	2024	**75.0**	75.0
	5.23%	2027	**100.0**	—
	3.87%	2028	**150.0**	150.0
	2.20%	2028	**200.0**	200.0
	2.96%	2029	**275.0**	275.0
	3.90%	2030	**50.0**	50.0
	1.98%	2030	**200.0**	200.0
	3.06%	2031	**50.0**	50.0
	4.00%	2033	**50.0**	50.0
	3.98%	2042	**100.0**	100.0
	3.96%	2043	**220.0**	220.0
	4.21%	2044	**200.0**	200.0
	3.65%	2046	**50.0**	50.0
	3.65%	2046	**150.0**	150.0
	3.77%	2047	**100.0**	100.0
NSG First Mortgage Bonds (secured) [(3)]	3.43%	2027	**28.0**	28.0
	2.20%	2028	**25.0**	25.0
	3.87%	2028	**50.0**	50.0
	3.96%	2043	**54.0**	54.0
MERC Senior Notes (unsecured)	2.69%	2025	**50.0**	50.0
	3.11%	2027	**40.0**	40.0
	2.07%	2028	**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**	60.0
	3.11%	2027	**30.0**	30.0
	3.41%	2032	**30.0**	30.0
	4.01%	2047	**30.0**	30.0
Total			**4,683.4**	4,283.4
Unamortized debt issuance costs			**(36.4)**	(36.2)
Unamortized discount, net and other			**(1.5)**	(1.5)
Total long-term debt [(4)]			**$ 4,645.5**	$ 4,245.7

(1) The terms of our 2013 6.00% Junior Notes, due August 1, 2073, provide that, effective August 2023, they will bear interest at a variable rate, which we expect to be based off of Secured Overnight Financing Rate, 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 $100 million of 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 $41.9 million at December 31, 2022 and $31.3 million at December 31, 2021.

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.

Wisconsin Public Service Corporation

In November 2022, WPS issued $300.0 million of 5.35% Senior Notes due November 10, 2025, and used the net proceeds to repay short-term debt and for other corporate purposes.

The Peoples Gas Light and Coke Company

In December 2022, PGL issued $100.0 million of 5.23% Bonds, Series MMM due December 1, 2027, and used the net proceeds for general corporate purposes, including capital expenditures and the refinancing of short-term debt.

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, 2022:

(in millions)	Payments
2023	$ —
2024	75.0
2025	410.0
2026	—
2027	198.0
Thereafter	4,000.4
Total	$ 4,683.4

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, 2022, we were in compliance with our covenants related to our long-term debt obligations.

NOTE 16—LEASES

Obligations Under Finance Leases

In accordance with ASC Subtopic 980-842, Regulated Operations – Leases, the expense recognition pattern of our finance leases discussed below resembles that of an operating lease. The difference between the minimum lease payments and the sum of imputed interest and unadjusted amortization costs calculated under Topic 842 is deferred as a regulatory asset on our balance sheets in accordance with Subtopic 980-842.

Land Leases – Utility Solar Generation

WPS, along with WE and an unaffiliated utility, has entered into various land leases related to its investments in utility-scale solar generation. Each lease has an initial term and one or more optional extensions. WPS expects the optional extensions to be exercised, and, as a result, all of the land leases are being amortized over an extended term of approximately 50 years. Once a solar project achieves commercial operation, the lease liability is remeasured to reflect the final total acres being leased. WPS's payments related to these leases are being recovered through rates.

Amounts Recognized in the Financial Statements and Other Information

Lease expense and cash payments related to WPS's finance leases were not significant in 2022, 2021, or 2020. Other information related to these leases for the years ended December 31 are as follows:

Other information *(dollar amounts in millions)*	**2022**	**2021**	**2020**
Non-cash activities:			
Right of use assets obtained in exchange for finance lease liabilities	**$ 10.2**	$ 2.6	$ —
Reduction of right of use asset and finance lease liability due to a remeasurement	**$ —**	$ (2.9)	$ —
Weighted average remaining lease term	**49.0 years**	49.6 years	50.0 years
Weighted average discount rate [(1)]	**3.9 %**	3.3 %	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 and obligations at December 31:

(in millions)	**2022**	**2021**	**Balance Sheet Location**
Right of use assets			
Finance lease right of use assets, net [(1)]	**$ 38.0**	$ 28.4	Property, plant, and equipment, net
Lease obligations			
Long-term finance lease liabilities	**$ 41.9**	$ 31.3	Long-term debt

(1) Amounts are net of accumulated amortization of $2.2 million and $1.5 million at December 31, 2022 and 2021, respectively.

Future minimum lease payments under WPS's finance leases and the present value of its net minimum lease payments as of December 31, 2022, were as follows:

(in millions)	**Total Finance Leases**
2023	$ 1.2
2024	1.3
2025	1.3
2026	1.3
2027	1.4
Thereafter	101.7
Total minimum lease payments	108.2
Less: Interest	(66.3)
Present value of minimum lease payments	41.9
Less: Short-term lease liabilities	—
Long-term lease liabilities	$ 41.9

As of March 29, 2023, we have not entered into any material leases that have not yet commenced.

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)	2022	2021	2020
Current tax expense (benefit)	**$ 96.7**	$ (26.9)	$ 9.6
Deferred income taxes, net	**69.7**	141.3	111.3
ITCs, net	**(4.2)**	(3.0)	(1.9)
Total income tax expense	**$ 162.2**	$ 111.4	$ 119.0

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:

	2022		2021		2020	
(in millions)	Amount	Effective Tax Rate	Amount	Effective Tax Rate	Amount	Effective Tax Rate
Statutory federal income tax	**$ 136.0**	**21.0 %**	$ 124.6	21.0 %	$ 118.8	21.0 %
State income taxes net of federal tax benefit	**44.4**	**6.9 %**	40.2	6.8 %	37.9	6.7 %
Federal excess deferred tax amortization [1]	**(12.6)**	**(2.0)%**	(12.8)	(2.2)%	(12.4)	(2.2)%
ITCs, net	**(4.2)**	**(0.7)%**	(3.0)	(0.5)%	(1.9)	(0.3)%
Federal excess deferred tax amortization – Wisconsin unprotected [2]	**(3.8)**	**(0.6)%**	(33.0)	(5.6)%	(12.7)	(2.2)%
AFUDC – Equity	**(1.2)**	**(0.2)%**	(1.9)	(0.2)%	(2.5)	(0.4)%
Uncertain tax positions	**—**	**— %**	(5.8)	(1.0)%	(6.6)	(1.2)%
Deferred ITCs recognized from PDL solar sale	**—**	**— %**	—	— %	(6.5)	(1.1)%
Other, net	**3.6**	**0.6 %**	3.1	0.5 %	4.9	0.7 %
Total income tax expense	**$ 162.2**	**25.0 %**	$ 111.4	18.8 %	$ 119.0	21.0 %

(1) 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.

(2) 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.

Deferred Income Tax Assets and Liabilities

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

(in millions)	2022	2021
Deferred tax assets		
Tax gross up – regulatory items	**$ 227.5**	$ 233.6
Future tax benefits	**14.7**	21.7
Other	**81.4**	67.8
Total deferred tax assets	**323.6**	323.1
Deferred tax liabilities		
Property-related	**$ 1,863.8**	$ 1,750.0
Employee benefits and compensation	**131.4**	114.6
Regulatory deferrals	**45.3**	78.9
Other	**41.0**	46.2
Total deferred tax liabilities	**2,081.5**	1,989.7
Deferred tax liability, net	**$ 1,757.9**	$ 1,666.6

Consistent with ratemaking 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, 2022 and 2021 are summarized in the tables below:

2022 *(in millions)*	Gross Value	Deferred Tax Effect	Valuation Allowance	Earliest Year of Expiration
Future tax benefits as of December 31, 2022				
Federal tax credits	**—**	**3.5**	**—**	**2042**
State net operating loss	**72.6**	**4.3**	**—**	**2031**
State tax credit	**—**	**6.9**	**—**	**2024**
Balance as of December 31, 2022	**$ 72.6**	**$ 14.7**	**$ —**	

2021 *(in millions)*	Gross Value	Deferred Tax Effect	Valuation Allowance	Earliest Year of Expiration
Future tax benefits as of December 31, 2021				
Federal tax credits	—	8.7	—	2041
State net operating loss	72.0	4.3	—	2031
State tax credit	—	8.7	—	2024
Balance as of December 31, 2021	$ 72.0	$ 21.7	**$ —**	

Unrecognized Tax Benefits

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

(in millions)	2022	2021	2020
Balance at January 1	**$ 0.1**	$ 6.3	$ 13.0
Decrease related to tax positions of prior years	**—**	(6.2)	(6.7)
Balance at December 31	**$ 0.1**	$ 0.1	$ 6.3

The amount of unrecognized tax benefits at both December 31, 2022 and 2021, excludes deferred tax assets related to uncertainty in income taxes of $0.1 million. At both December 31, 2022 and 2021, the net amount of unrecognized tax benefits that, if recognized, would impact the effective tax rate for continuing operations was $0.

Interest accrued related to unrecognized tax benefits is as follows:

(in millions)	2022	2021	2020
Balance as of January 1	$ —	$ 0.5	$ 0.4
Interest expense (income) related to unrecognized tax benefits	—	(0.5)	0.1
Balance as of December 31	**$ —**	$ —	$ 0.5

For the years ended December 31, 2022, 2021, and 2020, we recognized no penalties related to unrecognized tax benefits in our income statements. At December 31, 2022 and 2021, we had no penalties accrued related to unrecognized tax benefits on our balance sheets.

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, 2022, we were subject to examination by federal as well as by state or local tax authorities for the 2017 through 2022 tax years in our major operating jurisdictions as follows:

Jurisdiction	Year
Federal	2019-2022
Illinois	2017-2022
Michigan	2018-2022
Minnesota	2018-2022
Wisconsin	2018-2022

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, 2022			
(in millions)	Level 1	Level 2	Level 3	Total
Derivative assets				
Natural gas contracts	**$ 13.4**	**$ 9.5**	**$ —**	**$ 22.9**
FTRs	**—**	**—**	**4.1**	**4.1**
Coal contracts	**—**	**1.9**	**—**	**1.9**
Total derivative assets	**$ 13.4**	**$ 11.4**	**$ 4.1**	**$ 28.9**
Investments held in rabbi trust	**$ 50.9**	**$ —**	**$ —**	**$ 50.9**
Derivative liabilities				
Natural gas contracts	**$ 47.1**	**$ 12.4**	**$ —**	**$ 59.5**

	December 31, 2021			
(in millions)	Level 1	Level 2	Level 3	Total
Derivative assets				
Natural gas contracts	$ 31.3	$ 9.5	$ —	$ 40.8
FTRs	—	—	1.4	1.4
Coal contracts	—	15.3	—	15.3
Total derivative assets	$ 31.3	$ 24.8	$ 1.4	$ 57.5
Investments held in rabbi trust	$ 79.6	$ —	$ —	$ 79.6
Derivative liabilities				
Natural gas contracts	$ 5.1	$ 5.4	$ —	$ 10.5

The derivative assets and liabilities listed in the tables above include options, 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. We recorded $12.7 million of net unrealized losses in earnings related to the investments held at the end of the period during the year ended December 31, 2022. For the years ended December 31, 2021 and 2020, the net unrealized gains included in earnings related to the investments held at the end of the period were $16.0 million and $6.3 million, respectively. 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)	2022	2021	2020
Balance at the beginning of the period	**$ 1.4**	$ 1.2	$ 1.3
Purchases	**11.7**	3.1	4.1
Settlements	**(9.0)**	(2.9)	(4.2)
Balance at the end of the period	**$ 4.1**	$ 1.4	$ 1.2

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:

	2022		2021	
(in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt [1]	**$ 4,645.5**	**$ 3,924.2**	$ 4,245.7	$ 4,667.5

[1] The carrying amount of long-term debt excludes finance lease obligations of $41.9 million and $31.3 million at December 31, 2022 and 2021, respectively.

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

NOTE 19—DERIVATIVE INSTRUMENTS

Derivative assets and liabilities are included in the other current and other long-term line items on our balance sheets. The following table shows our derivative assets and derivative liabilities. None of the derivatives shown below were designated as hedging instruments.

	December 31, 2022		December 31, 2021	
(in millions)	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Current				
Natural gas contracts	**$ 22.9**	**$ 53.3**	$ 37.6	$ 9.7
FTRs	**4.1**	**—**	1.4	—
Coal contracts	**1.4**	**—**	11.6	—
Total current	**28.4**	**53.3**	50.6	9.7
Long-term				
Natural gas contracts	**—**	**6.2**	3.2	0.8
Coal contracts	**0.5**	**—**	3.7	—
Total long-term	**0.5**	**6.2**	6.9	0.8
Total	**$ 28.9**	**$ 59.5**	$ 57.5	$ 10.5

Realized gains and losses on derivatives are recorded in cost of sales upon settlement; however, they may be subsequently deferred for future rate recovery or refund as the gains and losses are included in our utilities' fuel and natural gas cost recovery mechanisms. Our estimated notional sales volumes and realized gains and losses were as follows for the years ended:

	December 31, 2022		December 31, 2021		December 31, 2020	
(in millions)	Volumes	Gains	Volumes	Gains	Volumes	Gains (Losses)
Natural gas contracts	**92.2 Dth**	**$ 193.3**	97.3 Dth	$ 74.4	96.2 Dth	$ (33.6)
FTRs	**7.8 MWh**	**2.5**	7.0 MWh	8.7	8.3 MWh	1.4
Total		**$ 195.8**		$ 83.1		$ (32.2)

At December 31, 2022 and 2021, we had posted cash collateral of $67.3 million and $7.9 million, respectively. We had also received cash collateral of $12.9 million at December 31, 2021.

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

	December 31, 2022		December 31, 2021	
(in millions)	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Gross amount recognized on the balance sheet	**$ 28.9**	**$ 59.5**	$ 57.5	$ 10.5
Gross amount not offset on the balance sheet	**(14.3)**	**(48.0)** [1]	(11.4) [2]	(5.7) [3]
Net amount	**$ 14.6**	**$ 11.5**	$ 46.1	$ 4.8

[1] Includes cash collateral posted of $33.7 million.

[2] Includes cash collateral received of $6.1 million.

[3] Includes cash collateral posted of $0.4 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
Standby letters of credit [1]	**$ 21.3**	$ —	$ 0.2	$ 21.1
Other guarantees [2]	**6.0**	—	—	6.0
Total guarantees	**$ 27.3**	$ —	$ 0.2	$ 27.1

[1] 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.

[2] 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. This amount 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 the 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)	**2022**	**2021**	**2022**	**2021**
Change in benefit obligation				
Obligation at January 1	**$ 1,377.4**	$ 1,486.5	**$ 260.5**	$ 266.5
Service cost	**20.0**	25.4	**7.8**	8.5
Interest cost	**40.8**	39.8	**7.5**	7.0
Plan amendments	**—**	—	**—**	(3.5)
Net transfer (to) from affiliates	**(0.1)**	—	**0.3**	(0.1)
Actuarial gain	**(354.6)**	(57.7)	**(62.2)**	(0.8)
Participant contributions	**—**	—	**3.5**	3.9
Benefit payments	**(143.5)**	(116.6)	**(18.6)**	(21.0)
Obligation at December 31	**$ 940.0**	$ 1,377.4	**$ 198.8**	$ 260.5
Change in fair value of plan assets				
Fair value at January 1	**$ 1,507.0**	$ 1,434.6	**$ 541.0**	$ 514.8
Actual return on plan assets	**(233.2)**	138.0	**(74.6)**	42.0
Employer contributions	**0.7**	51.0	**1.3**	1.3
Net transfer from affiliates	**—**	—	**—**	—
Participant contributions	**—**	—	**3.5**	3.9
Benefit payments	**(143.5)**	(116.6)	**(18.6)**	(21.0)
Fair value at December 31	**$ 1,131.0**	$ 1,507.0	**$ 452.6**	$ 541.0
Funded status at December 31	**$ 191.0**	$ 129.6	**$ 253.8**	$ 280.5

In 2022 and 2021, we had actuarial gains related to our pension benefit obligations of $354.6 million and $57.7 million, both of which were primarily driven by changes in our discount rates. The discount rate for our pension benefits was 5.48%, 3.00%, and 2.74%, in 2022, 2021, and 2020, respectively.

In 2022, we had an actuarial gain related to our OPEB benefit obligations of $62.2 million, which was primarily due to changes in our discount rates. The actuarial gain related to our OPEB benefit obligations was not significant for 2021. The discount rate for our OPEB benefits was 5.50% and 2.91% in 2022 and 2021, respectively.

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)	**2022**	**2021**	**2022**	**2021**
Pension and OPEB assets	**$ 207.7**	$ 158.7	**$ 266.4**	$ 295.8
Other long-term liabilities	**16.7**	29.1	**12.6**	15.3
Total net assets	**$ 191.0**	$ 129.6	**$ 253.8**	$ 280.5

The accumulated benefit obligation for the defined benefit pension plans was $876.5 million and $1,253.9 million at December 31, 2022 and 2021, 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)	**2022**	**2021**
Accumulated benefit obligation	**$ 45.0**	$ 62.9
Fair value of plan assets	**32.8**	43.1

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)	2022	2021
Projected benefit obligation	**$ 49.6**	$ 72.2
Fair value of plan assets	**32.8**	43.1

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)	2022	2021
Accumulated benefit obligation	**$ 20.0**	$ 18.1
Fair value of plan assets	**7.4**	2.8

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

	Pension Benefits		OPEB Benefits	
(in millions)	2022	2021	2022	2021
Pre-tax accumulated other comprehensive income (loss) [1]				
Net actuarial loss (gain)	**$ 8.1**	$ 4.2	**$ (1.1)**	$ (1.0)
Prior service credits	**—**	—	**—**	(0.1)
Total	**$ 8.1**	$ 4.2	**$ (1.1)**	$ (1.1)
Net regulatory assets (liabilities) [2]				
Net actuarial loss (gain)	**$ 229.7**	$ 300.4	**$ (86.8)**	$ (146.9)
Prior service costs (credits)	**0.2**	1.9	**(41.3)**	(55.1)
Total	**$ 229.9**	$ 302.3	**$ (128.1)**	$ (202.0)

[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) (including amounts capitalized to our balance sheets) for the years ended December 31 were as follows:

	Pension Benefits			OPEB Benefits		
(in millions)	2022	2021	2020	2022	2021	2020
Service cost	**$ 20.0**	$ 25.4	$ 25.3	**$ 7.8**	$ 8.5	$ 8.2
Interest cost	**40.8**	39.8	45.5	**7.5**	7.0	8.8
Expected return on plan assets	**(94.2)**	(89.4)	(80.9)	**(37.3)**	(36.0)	(32.4)
Plan settlement/curtailment	**2.2**	3.4	11.6	**—**	(6.4)	—
Amortization of prior service cost (credit)	**1.7**	1.7	1.7	**(13.8)**	(14.0)	(14.2)
Amortization of net actuarial loss (gain)	**37.2**	52.7	56.5	**(10.4)**	(11.8)	(10.3)
Net periodic benefit cost (credit)	**$ 7.7**	$ 33.6	$ 59.7	**$ (46.2)**	$ (52.7)	$ (39.9)

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	
	2022	**2021**	**2022**	**2021**
Discount rate	**5.48%**	3.00%	**5.50%**	2.91%
Rate of compensation increase	**4.00%**	4.00%	**N/A**	N/A
Interest credit rate	**4.00%**	2.25%	**N/A**	N/A
Assumed medical cost trend rate (Pre 65)	**N/A**	N/A	**6.50%**	5.70%
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	**2031**	2028
Assumed medical cost trend rate (Post 65)	**N/A**	N/A	**6.00%**	5.60%
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	**2031**	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 Benefits		
	2022	**2021**	**2020**
Discount rate	**3.35%**	2.79%	3.34%
Expected return on plan assets	**7.00%**	7.00%	7.00%
Rate of compensation increase	**4.00%**	4.00%	4.00%
Interest credit rate	**2.34%**	2.25%	2.25%

	OPEB Benefits		
	2022	**2021**	**2020**
Discount rate	**2.91%**	2.70%	3.38%
Expected return on plan assets	**7.00%**	7.00%	7.00%
Assumed medical cost trend rate (Pre 65)	**5.70%**	5.85%	6.00%
Ultimate trend rate (Pre 65)	**5.00%**	5.00%	5.00%
Year ultimate trend rate is reached (Pre 65)	**2028**	2028	2028
Assumed medical cost trend rate (Post 65)	**5.60%**	5.70%	5.80%
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 trust. For 2023, 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.

WEC Energy Group's 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 payment cash flows and risk analyses of appropriate investments. They are intended to reduce risk, provide long-term financial stability for the plans and maintain funded levels which meet long-term plan obligations while preserving sufficient liquidity for near-term benefit payments.

Our pension trust target asset allocations are 40% equity investments, 45% fixed income investments, and 15% private equity and real estate investments. Our two OPEB trusts have the same target asset allocations of 45% equity investments, 45% fixed income investments, and 10% real estate investments. Equity securities include investments in large-cap, mid-cap, and small-cap companies.

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(o), 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, 2022							
	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	**$ 116.0**	**$ —**	**$ —**	**$ 116.0**	**$ 50.7**	**$ —**	**$ —**	**$ 50.7**
International equity	**101.2**	**—**	**—**	**101.2**	**47.9**	**—**	**—**	**47.9**
Fixed income securities: [1]								
United States bonds	**—**	**215.8**	**—**	**215.8**	**87.5**	**58.4**	**—**	**145.9**
International bonds	**—**	**39.0**	**—**	**39.0**	**—**	**5.5**	**—**	**5.5**
	$ 217.2	**$ 254.8**	**$ —**	**$ 472.0**	**$ 186.1**	**$ 63.9**	**$ —**	**$ 250.0**
Investments measured at net asset value:								
Equity securities				**233.7**				**102.7**
Fixed income securities				**87.5**				**43.4**
Other				**337.8**				**56.5**
Total				**$ 1,131.0**				**$ 452.6**

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

	December 31, 2021							
	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	$ 217.0	$ —	$ —	$ 217.0	$ 74.2	$ —	$ —	$ 74.2
International equity	166.2	—	—	166.2	61.3	—	—	61.3
Fixed income securities: [1]								
United States bonds	—	289.9	—	289.9	112.1	77.5	—	189.6
International bonds	—	47.6	—	47.6	—	6.0	—	6.0
	$ 383.2	$ 337.5	$ —	$ 720.7	$ 247.6	$ 83.5	$ —	$ 331.1
Investments measured at net asset value:								
Equity securities				363.5				121.9
Fixed income securities				110.9				75.6
Other				311.9				12.4
Total				$ 1,507.0				$ 541.0

[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 $0.8 million to the pension plans and $1.5 million to the OPEB plans in 2023, 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
2023	$ 80.8	$ 17.5
2024	81.1	17.8
2025	80.1	18.1
2026	80.0	18.5
2027	75.0	18.7
2028-2032	338.9	89.4

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, in which amounts are contributed to an employee's savings plan account based on the employee's wages, age, and years of service. Total costs incurred under all of these plans were $25.2 million, $24.6 million, and $23.3 million in 2022, 2021, and 2020, respectively.

NOTE 22—SEGMENT INFORMATION

We use net income to measure segment profitability and to allocate resources to our businesses. At December 31, 2022, 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 and the PELLC holding company. It also included the operations of PDL prior to the sale of its remaining solar facilities in the fourth quarter of 2020. See Note 3, Dispositions, for more information on the sale of these 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, 2022, 2021, and 2020.

	Regulated Operations						
2022 *(in millions)*	**Wisconsin**	**Illinois**	**Other States**	**Total Regulated Operations**	**Corporate and Other**	**Reconciling Eliminations**	**Integrys Holding Consolidated**
External revenues	**$ 1,785.2**	**$1,890.9**	**$ 618.5**	**$ 4,294.6**	**$ 0.1**	**$ —**	**$ 4,294.7**
Other operation and maintenance	**362.5**	**459.2**	**98.5**	**920.2**	**0.4**	**—**	**920.6**
Depreciation and amortization	**199.8**	**230.9**	**40.9**	**471.6**	**—**	**—**	**471.6**
Interest expense	**70.5**	**73.8**	**13.9**	**158.2**	**13.6**	**(1.2)**	**170.6**
Income tax expense (benefit)	**72.2**	**83.1**	**13.1**	**168.4**	**(6.2)**	**—**	**162.2**
Net income (loss)	**235.0**	**226.9**	**39.7**	**501.6**	**(16.0)**	**—**	**485.6**
Capital expenditures	**433.8**	**483.2**	**100.2**	**1,017.2**	**—**	**—**	**1,017.2**
Total assets	**6,708.8**	**7,770.9**	**1,617.9**	**16,097.6**	**344.8**	**(107.9)**	**16,334.5**

2021 *(in millions)*	Regulated Operations: Wisconsin	Illinois	Other States	Total Regulated Operations	Corporate and Other	Reconciling Eliminations	Integrys Holding Consolidated
External revenues	$ 1,520.9	$1,672.8	$ 519.0	$ 3,712.7	$ —	$ —	$ 3,712.7
Other operation and maintenance	406.4	433.5	90.4	930.3	(4.0)	—	926.3
Depreciation and amortization	188.6	218.1	38.1	444.8	0.1	—	444.9
Interest expense	64.7	66.6	6.2	137.5	22.7	(0.1)	160.1
Loss on debt extinguishment	—	—	—	—	20.6	—	20.6
Income tax expense (benefit)	31.2	79.3	11.5	122.0	(10.6)	—	111.4
Net income (loss)	231.1	223.0	35.8	489.9	(7.8)	—	482.1
Capital expenditures	389.7	535.2	96.3	1,021.2	—	—	1,021.2
Total assets	6,235.7	7,532.3	1,485.3	15,253.3	226.7	(72.6)	15,407.4

2020 *(in millions)*	Regulated Operations: 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

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

WPS 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, 2022, including those of our subsidiaries.

(in millions)	Date Contracts Extend Through	Total Amounts Committed	Payments Due By Period: 2023	2024	2025	2026	2027	Later Years
Electric utility:								
Purchased power	2050	$ 220.0	$ 50.1	$ 51.4	$ 46.3	$ 42.6	$ 18.0	$ 11.6
Coal supply and transportation	2030	306.9	119.4	80.4	64.1	12.0	7.6	23.4
Natural gas utility supply and transportation	2048	1,487.9	233.7	215.1	185.6	145.1	135.4	573.0
Total		$ 2,014.8	$ 403.2	$ 346.9	$ 296.0	$ 199.7	$ 161.0	$ 608.0

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, NOx, 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, biodiversity including 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

Cross State Air Pollution Rule – Good Neighbor Plan

The proposed rule to address the 2015 ozone NAAQS, resulting in more stringent regulation of ozone-season NOx emissions from electric utility generating units in 26 states, is expected to take effect in 2023. Based on a review of our existing units' 2020 and 2021 actual ozone season emissions and projected future emissions versus proposed NOx ozone season allocations, we anticipate that we should be able to comply with the expanded rule requirements without procuring additional allowances on the open market.

Our planned RICE units in Wisconsin are not subject to this rule as proposed as each unit is less than 25 MW. We note that, to the extent we use RICE engines for natural gas distribution operations, those engines may be subject to the emission limits and operational requirements of the rule beginning in 2026. In June 2022, we submitted comments on this proposed rule seeking clarification of its applicability, as well as other items, and we will closely monitor the final rule for any changes from the proposed rule.

National Ambient Air Quality Standards

Ozone

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 NAAQS. The 2015 ozone standard lowered the 8-hour limit for ground-level ozone. In November 2022, the EPA's 2022 CASAC Ozone Review Panel issued a draft report supporting a previously issued EPA staff-written Integrated Science Assessment for ozone which supported the reconsideration of the 2015 standard. The EPA had planned a proposed rule in April 2023, but the CASAC review is expected to slow the process.

In June 2021, the EPA published its final action to revise the nonattainment area designations and/or boundaries for 13 counties associated with six nonattainment areas, including several in Illinois and Wisconsin. Under the new designations, the partial nonattainment areas of Sheboygan, Door, and Manitowoc counties were also expanded.

In February 2022, revisions to the Wisconsin Administrative Code to adopt the 2015 standard were finalized. The amended regulations adopted the standard and incorporated by reference the federal air pollution monitoring requirements related to the standard. The WDNR submitted the rule updates as a SIP revision to the EPA in April 2022, which the EPA proposed to approve in August 2022.

We believe that we are well positioned to meet the requirements associated with the 2015 ozone standard and do not expect to incur significant costs to comply with the associated state and federal rules.

Particulate Matter

In December 2020, the EPA completed its 5-year review of the 2012 annual and 24-hour standards for fine PM and determined that no revisions were necessary to the current annual standard of 12 $\mu g/m^3$ or the 24-hour standard of 35 $\mu g/m^3$. Under the Biden Administration's policy review, the EPA concluded that the scientific evidence and information from the December 2020 determination supports revising the level of the annual standard for the PM NAAQS to below the current level of 12 $\mu g/m^3$, while retaining the 24-hour standard. In January 2023, the EPA announced its proposed decision to revise the primary (health-based) annual PM2.5 standard from its current level of 12 $\mu g/m^3$ to within the range of 9 to 10 $\mu g/m^3$. The EPA also proposed not to change the current secondary (welfare-based) annual PM2.5 standard, primary and secondary 24-hour PM2.5 standards, and primary and secondary PM10 standards. The EPA is also taking comments on the full range (between 8 and 11 $\mu g/m^3$) included in the CASAC's latest report. We anticipate the final rule to be released in late 2023. All counties within our service territories are in attainment with the current 2012 standards. If the EPA lowers the annual standard to 10 or 11 $\mu g/m^3$, our generating facilities within our service territories should remain in attainment. If the EPA lowers it to below 10 $\mu g/m^3$, there could be some nonattainment areas that may affect permitting of some smaller ancillary equipment located at our facilities. After finalization of the rule, the WDNR will need to draft a SIP and submit for the EPA's approval.

Climate Change

The ACE rule, which replaced the Clean Power Plan, was vacated by the D.C. Circuit Court of Appeals in January 2021. In October 2021, the Supreme Court agreed to review the D.C. Circuit Court's ruling vacating the EPA's ACE rule and in June 2022, the Supreme Court issued its decision. The Supreme Court found that the EPA may regulate GHGs under section 111 of the CAA but cannot rely on generation shifting to lower carbon emitting sources to do so. We expect a new GHG replacement rule for existing sources to be proposed in April 2023.

In January 2021, the EPA finalized a rule to revise the New Source Performance Standards for GHG emissions from new, modified, and reconstructed fossil-fueled power plants; however, it was vacated by the D.C. Circuit Court of Appeals in April 2021. Based on an updated EPA regulatory timeline, we expect a new rule to be proposed in April 2023. We continue to move forward on the ESG Progress Plan, which is heavily focused on reducing GHG emissions.

The EPA released proposed regulations for the Greenhouse Gas Reporting Rule, 40 Code of Federal Regulations Part 98, in June 2022. The proposed revisions could impact the reporting required of our local natural gas distribution companies and underground natural gas storage facilities with updates to emission factors for equipment counts and increased disclosure for large release events. We expect the final rule in 2023, pending the EPA's review and consideration of public comments.

The ESG Progress Plan includes the retirement of older, fossil-fueled generation, to be replaced with zero-carbon-emitting renewables and clean natural gas-fueled generation. We have already retired approximately 300 MW of coal-fired generation since the beginning of 2018. Through its ESG Progress Plan, WEC Energy Group expects to retire approximately 1,600 MW of additional fossil-fueled generation by the end of 2026, which includes the planned retirement by June 2026 of jointly-owned Columbia Units 1-2. See Note 8, Property, Plant, and Equipment, for more information on the timing of the retirements. In May 2021, WEC Energy Group announced goals to achieve reductions in carbon emissions from its electric generation fleet by 60% by the end of 2025 and by 80% by the end of 2030, both from a 2005 baseline. WEC Energy Group expects to achieve these goals by making operating refinements, retiring less efficient generating units, and executing its capital plan. Over the longer term, the target for WEC Energy Group's generation fleet is net-zero CO_2 emissions by 2050.

WEC Energy Group also continues to reduce methane emissions by improving its natural gas distribution systems and has set a target across its natural gas distribution operations to achieve net-zero methane emissions by the end of 2030. WEC Energy Group plans to achieve its net-zero goal through an effort that includes both continuous operational improvements and equipment upgrades, as well as the use of renewable natural gas throughout its natural gas utility systems.

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 5.8 million metric tonnes to the EPA for 2022. 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 18.1 million metric tonnes to the EPA for 2022.

Water Quality

Clean Water Act Cooling Water Intake Structure Rule

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

In 2016, the WDNR initiated a state rulemaking process to incorporate the federal Section 316(b) requirements into the Wisconsin Administrative Code. This new state rule, NR 111, became effective in June 2020, and the WDNR will apply it when establishing BTA requirements for cooling water intake structures at existing facilities. These BTA requirements are incorporated into WPDES permits for our facilities.

We have received interim BTA determinations for Weston Units 2, 3, and 4. In addition, we believe that existing technology installed at the Weston facility will result in a final BTA determination during the WPDES permit reissuance in 2023.

As a result of past capital investments completed to address Section 316(b) compliance, we believe our fleet overall is well positioned to continue to meet this regulation and do not expect to incur significant additional compliance costs.

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. This rule created new requirements for several types of power plant wastewaters. The new requirement that affects us relates to discharge limits for BATW. 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 facility modifications to meet water permit requirements for the BATW system at Weston Unit 3, which is expected to be completed by December 2023. Based on existing contracts and engineering cost estimates, we expect that compliance with the ELG rule will require approximately $10 million in capital investment. The BATW modifications do not require PSCW approval prior to construction. This ELG required project is on track for completion by the WPDES permit deadline in December 2023.

In March 2023, the EPA issued a pre-publication version of a supplemental ELG rule. The rule would replace the existing 2020 ELG Rule and, as proposed, would establish stricter limitations on: 1) BATW; 2) flue gas desulfurization wastewater; 3) coal combustion residual leachate and 4) legacy wastewaters. If the supplemental ELG rule is finalized as proposed, the BATW requirement would remain unchanged and the Weston 3 project would continue to be compliant. We are continuing to evaluate the proposed rule to determine what, if any, impacts it may have on our operations. The 2020 ELG Rule will continue to be implemented and enforced while the EPA pursues this rulemaking process.

In March 2023, the EPA also issued a pre-publication version of a final rule reopening the NOPP deadline to enter the cessation of coal subcategory. Under this subcategory, utilities are able to retire coal units or convert them to natural gas-fired units by December 31, 2028 instead of making capital investments to add the necessary treatment technology. The new NOPP deadline will be 90 days after publication in the *Federal Register.*

Waters of the United States

In January 2023, the EPA and the United States Army Corps of Engineers together released a final rule revising the definition of WOTUS, effective March 20, 2023. The final rule states that it is based on the pre-2015 definition of "waters of the United States." The pre-2015 approach involves applying factors established through case law and agency precedents to determine whether a wetland or surface drainage feature is subject to federal jurisdiction.

The recent rulemaking could be affected by a significant pending Supreme Court case involving WOTUS determination. In January 2022, the Supreme Court granted certiorari in a case, *Sackett v. Environmental Protection Agency*, to evaluate the proper test for determining whether wetlands are WOTUS. A decision by the Supreme Court is expected in spring 2023.

At this point, our projects requiring federal permits are moving ahead, but we are monitoring these recent developments to better understand potential future impacts. The *Sackett* case, once decided, should provide some clarity regarding the definition of WOTUS. We will continue to monitor this litigation and any subsequent agency action.

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)	2022	2021
Regulatory assets	**$ 500.1**	$ 521.9
Reserves for future environmental remediation	**442.0**	470.9

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% by constructing various wind parks, solar parks, 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 WPS funds the program, along with other utilities, 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.

Consent Decrees

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 and expect that process to begin in 2023.

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 Company, 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 Company, 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 started the process to close out this Consent Decree in early 2023.

NOTE 24—SUPPLEMENTAL CASH FLOW INFORMATION

	Year Ended December 31		
(in millions)	**2022**	**2021**	**2020**
Cash paid for interest, net of amount capitalized	**$ 163.5**	$ 161.6	$ 167.6
Cash paid (received) for income taxes, net	**122.8**	(85.8)	(10.4)
Significant non-cash investing and financing transactions:			
Accounts payable related to construction costs	**76.1**	67.0	104.0
Increase in receivable related to insurance proceeds	**—**	4.3	—
Liabilities accrued for software licensing agreement	**3.9**	—	—

The statements of cash flows include our activity related to cash, cash equivalents, and restricted cash. Our restricted cash consists of the following:

- 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.
- Cash used by WPS for the purchase of a natural gas-fired cogeneration facility located in Whitewater, Wisconsin. This cash was included in other long-term assets at December 31, 2022. See Note 2, Acquisitions, for more information on the purchase of this facility.

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)	**2022**	**2021**	**2020**
Cash and cash equivalents	**$ 0.8**	$ 6.5	$ 6.6
Restricted cash included in other long-term assets	**87.9**	49.6	47.1
Cash, cash equivalents, and restricted cash	**$ 88.7**	$ 56.1	$ 53.7

NOTE 25—REGULATORY ENVIRONMENT

Recovery of Natural Gas Costs

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 significantly higher than our normal winter weather expectations. All of our utilities have regulatory mechanisms in place for recovering all prudently incurred gas costs.

In March 2021, WPS filed its revised natural gas rate sheets with the PSCW reflecting approximately $28 million of natural gas costs in excess of the benchmark set in its GCRM. WPS recovered these excess costs over a period of three months, beginning in April 2021.

PGL and NSG incurred approximately $131 million and $10 million, respectively, of natural gas costs in February 2021 in excess of the amounts included in their rates. These costs were recovered over a period of 12 months, which started on April 1, 2021. PGL's and NSG's natural gas costs were reviewed for prudency by the ICC as part of their annual natural gas cost reconciliation. On January 5, 2023, the ICC issued written orders approving each company's 2021 reconciliation.

In February 2021, MERC incurred approximately $75 million of natural gas costs in excess of the benchmark set in its GCRM. In August 2021, the MPUC issued a written order approving a joint proposal filed by MERC and four other Minnesota utilities to recover their respective excess natural gas costs. In accordance with the order, MERC recovered $10 million of these costs through its annual natural gas true-up process over a period of 12 months, and the remaining $65 million was to be recovered over a period of 27 months, both beginning in September 2021. Recovery of these costs and the issue of prudence was referred to a contested-case proceeding. In October 2022, the MPUC issued a written order approving a settlement agreement entered into by MERC and various parties related to the recovery of the extraordinary natural gas costs incurred in February 2021. Under the settlement agreement, MERC agreed to not seek recovery of $3 million of these costs. MERC will continue to recover the remaining $62 million of extraordinary natural gas costs over the previously approved 27-month recovery period.

Natural gas costs incurred at MGU in excess of the amount included in its respective rates were not significant.

Coronavirus Disease – 2019

In response to the COVID-19 pandemic, the PSCW, the ICC, the MPUC, and the MPSC all issued written orders requiring certain actions to ensure that essential utility services were available to customers in their respective jurisdictions. A summary of these orders is included below.

Wisconsin

In March 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 in March 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. In December 2021, the PSCW approved a motion to end all COVID-related deferrals as of December 31, 2021. At December 31, 2022, WPS did not have any amounts deferred related to the COVID-19 pandemic as the rate order it received from the PSCW in December 2022 did not allow recovery of these costs.

In June 2020, the PSCW issued a written order providing a timeline for the lifting of the temporary provisions required in the first March 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.

Subsequent to the June 2020 order, 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 customarily begins on November 1 and ends on April 15 of each year. Utilities were allowed to continue assessing late payment fees during the winter moratorium. On April 5, 2021, the PSCW issued a written order indicating that it would not extend the moratorium on disconnections further; therefore, utilities could begin disconnecting residential customers for non-payment after April 15, 2021. The order also allowed WPS to resume charging late payment fees on the full balance of all outstanding arrears, regardless of the associated dates the service was provided, after April 15, 2021. WPS continues to offer flexible payment arrangements to low-income residential customers prior to disconnecting service.

Illinois

In March 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.

In June 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 in June 2020 authorized PGL and NSG to implement a SPC rider for certain costs incurred between March 1, 2020 and December 31, 2021. The SPC rider allows for recovery of incremental direct costs resulting from COVID-19, foregone late fees and reconnection charges, and the costs associated with the 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, 2022, PGL's and NSG's remaining regulatory assets related to the COVID-19 pandemic were $9.5 million, collectively.

Subsequent to the approval of the June 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 customarily begins on December 1 and ends on March 31 of each year.

In March 2021, the ICC issued a written order approving a second settlement agreement negotiated by Illinois utilities, ICC staff, and certain intervenors. The key terms of this new settlement agreement were as follows:

- Utilities could start sending disconnection notices, on a staggered basis, as of April 1, 2021. Disconnections were done on a staggered schedule based on customer arrears and income levels. Utilities were not allowed to disconnect customers for non-payment prior to June 30, 2021 if the customer's household income was below 300% of the federal poverty level and the customer was on a deferred payment plan.
- Utilities were required to continue offering flexible deferred payment arrangements with reduced down payment requirements to residential customers through June 30, 2021.
- Reconnection fees were 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 was required to continue, or renew, its bill payment assistance program through 2021. In addition to the $12.0 million PGL initially funded, PGL was required to fund an additional $6.0 million to its bill payment assistance program. No additional funding was required for NSG due to the amount still available for assistance from its initial funding. PGL's and NSG's bill payment assistance programs ended in April 2021 and August 2021, respectively, as all of their respective funds were exhausted.

- Costs related to the provisions in the settlement agreement, including costs related to the bill payment assistance programs, were recoverable through the SPC rider.

Minnesota

In May 2020, the MPUC issued a written order authorizing Minnesota utilities, including MERC, to track and defer COVID-19 related expenses and certain foregone revenues. Costs incurred at MERC related to the COVID-19 pandemic were not significant, and at December 31, 2022, MERC did not have any amounts deferred.

In June 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. In August 2020, the MPUC issued a written order affirming these temporary provisions. Prior to the June 2020 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.

In March 2021, the MPUC issued an order requiring Minnesota utilities to file a transition plan to resume collections and disconnections. MERC filed its transition plan in April 2021, and it was subsequently deemed complete. In accordance with the transition plan, MERC resumed disconnections on August 2, 2021. MERC will not disconnect residential customers with past due balances if the customer has a pending application or has been deemed eligible for a financial assistance program. In addition, MERC continues to offer flexible deferred payment arrangements to residential customers. For customers who entered, or were complying with, a payment arrangement, MERC did not impose any service deposits, down payments, interest, late payment fees, or reconnections fees through April 30, 2022.

Michigan

In April 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 included the suspension of disconnections, late payment fees, deposits, and reconnection fees for certain vulnerable customers. In addition, utilities were required to extend access to and enhance the flexibility of payment plans to customers financially impacted by COVID-19.

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

The April 2020 MPSC order also authorized all Michigan utilities to defer, for potential future recovery, uncollectible expense incurred on or after March 24, 2020 that exceeded the amounts being recovered in rates. MGU did not record any deferrals related to the COVID-19 pandemic as it did not experience any significant COVID-19 related expenses.

In June 2021, MGU worked with MPSC staff to develop a transition plan to resume collections and disconnections, while continuing to assist customers in managing their arrears balances. In accordance with the agreed upon transition plan, MGU resumed pre-pandemic collection activities and residential service disconnections on August 2, 2021. Flexible deferred payment arrangements continue to be available to customers.

Wisconsin Public Service Corporation

2023 and 2024 Rates

In April 2022, WPS filed a request with the PSCW to increase its retail electric and natural gas rates. WPS's request was updated in July 2022 to reflect new developments that impacted the original proposal. The requested increase in electric rates was driven by capital investments in new wind, solar, and battery storage; capital investments in natural gas generation; and changes in wholesale business with other utilities. Many of these investments have already been approved by the PSCW. The requested increase in natural gas rates primarily related to capital investments that have been made to maintain and improve safety and reliability.

In September 2022, WPS entered into a settlement agreement with certain intervenors to resolve most of the outstanding issues in its rate case; however, the PSCW declined to approve the settlement agreement. In December 2022, the PSCW issued a final written order approving electric and natural gas base rate increases, effective January 1, 2023. The final order reflects the following:

2023 base rate increase	
Electric	$120.5 million / 9.8%
Gas	$ 26.4 million / 7.1%
ROE	9.8%
Common equity component average on a financial basis	53.0%

In addition to the above, the final order includes the following terms:

- WPS will keep its current earnings sharing mechanism, under which, if it earns above its authorized ROE: (i) WPS will retain 100.0% of earnings for the first 15 basis points above the authorized ROE; (ii) 50.0% of the next 60 basis points will be required to be refunded to ratepayers; and (iii) 100.0% of any remaining excess earnings will be required to be refunded to ratepayers.
- WPS is required to complete an analysis of alternative recovery scenarios for generating units that will be retired prior to the end of their useful life.
- WPS will not propose any changes to its real time pricing rates for large commercial and industrial electric customers through the end of 2024.
- WPS will lower monthly residential and small commercial electric customer fixed charges by $3.33 from currently authorized rates.
- WPS will offer an additional voluntary renewable energy pilot for commercial and industrial customers.
- WPS will work with PSCW staff and other interested parties to develop alternative low income assistance programs. WPS, along with WE, will also collectively contribute $4.0 million to the Keep Wisconsin Warm Fund.
- WPS is required to implement escrow accounting treatment for pension and OPEB costs in 2023 and 2024.
- WPS is authorized to file a limited electric rate case re-opener for 2024 to address changes to revenue requirements associated with generation projects that are expected to be placed into service in 2023 and 2024 and future plant retirements.

2022 Rates

In March 2021, WPS filed an application with the PSCW for the approval of certain accounting treatments that allowed it to maintain its electric and natural gas base rates through 2022 and forego filing a rate case for one year. In connection with the request, WPS also entered into an agreement, dated March 23, 2021, with various stakeholders. Pursuant to the terms of the agreement, the stakeholders fully supported the application. In September 2021, the PSCW issued a written order approving the application.

The final order reflected the following:

- WPS amortized, in 2022, certain previously deferred balances to offset approximately half of its forecasted revenue deficiency.
- WPS was able to defer any increases in tax expense due to changes in tax law that occurred in 2021 and/or 2022.
- WPS maintained its earnings sharing mechanism for 2022, with modification. The earnings sharing mechanism was modified to authorize WPS to retain 100% of the first 15 basis points of earnings above its authorized ROE. The earnings sharing mechanism otherwise remained as previously authorized.

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 were effective January 1, 2020. The final order reflected 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 impacts. The rate order reflected 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 were 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 was net of $21 million of refunds related to WPS's 2018 earnings sharing mechanism. These refunds were made to customers evenly over two years, with half returned in 2020 and the remainder returned in 2021.

(3) Amount is net of certain deferred tax benefits from the Tax Legislation that were utilized to reduce near-term rate impacts. The rate order reflected 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.

WPS's rate order allows it to collect the previously deferred revenue requirement for ReACT™ costs above the authorized $275 million level. The total cost of the ReACT™ project was $342 million. This regulatory asset is being collected from customers over eight years.

The PSCW approved WPS continuing to have an earnings sharing mechanism through 2021. The earnings sharing mechanism was modified from its previous structure to one that was consistent with other Wisconsin investor-owned utilities. Under this earnings sharing mechanism, if WPS earned above its authorized ROE: (i) WPS retained 100.0% of earnings for the first 25 basis points above the authorized ROE; (ii) 50.0% of the next 50 basis points were required to be refunded to customers; and (iii) 100.0% of any remaining excess earnings were required to be refunded to customers. In addition, the rate order also required 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.

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

2023 Rate Case

On January 6, 2023, PGL and NSG filed requests with the ICC to increase their natural gas rates. They are requesting incremental rate increases of $194.7 million (13.0%) and $18.7 million (7.8%), respectively. The requested rate increases are primarily driven by capital investments made to strengthen the safety and reliability of each utility's natural gas distribution system. PGL is also seeking to recover costs incurred to upgrade its natural gas storage field and operations facilities and to continue improving customer service.

Both companies are requesting an ROE of 9.90% and a common equity component average of 54.0%. PGL is not seeking an extension of the QIP rider. Instead, PGL will return to the traditional rate making process to recover the costs of necessary infrastructure improvements. See the Qualifying Infrastructure Plant Rider section below for more information on the QIP rider.

An ICC decision is anticipated in the fourth quarter of 2023, with any rate adjustments expected to be effective January 1, 2024.

Third-Party Transaction Fee Adjustment Rider

In accordance with the Climate and Equitable Jobs Act that was signed into law in Illinois, effective September 15, 2021, Illinois utilities are prohibited from charging customers a fee when they elect to pay for service with a credit card. Utilities are now required to incur these expenses and seek recovery through a rate proceeding or by establishing a recovery mechanism. In December 2021, the ICC approved the use of a TPTFA rider for PGL. The TPTFA rider allows PGL to recover the costs incurred for these third-party transaction fees. PGL began recovering costs under the rider on February 1, 2022. Amounts deferred under the rider will be recovered over a period of 12 months and will be subject to an annual reconciliation whereby costs will be reviewed by the ICC for accuracy and prudency. NSG recovers costs related to these third-party transaction fees through its base rates, effective September 15, 2021.

North Shore Gas Company 2021 Rate Order

In October 2020, NSG filed a request with the ICC to increase its natural gas rates. In September 2021, the ICC issued a written order authorizing a rate increase of $4.1 million (4.5%). The rate increase reflects a 9.67% ROE and a common equity component average

of 51.58%. The natural gas rate increase was 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 28, 2015. The new rates were effective September 15, 2021.

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 will not seek an extension of the rider beyond 2023.

PGL's QIP rider is subject to an annual reconciliation whereby costs are reviewed for accuracy and prudency. In March 2023, PGL filed its 2022 reconciliation with the ICC, which, along with the reconciliations from 2016 through 2021, are still pending. There can be no assurance that all costs incurred under PGL's QIP rider during the open reconciliation years, which include 2016 through 2022, will be deemed recoverable by the ICC.

Minnesota Energy Resources Corporation

2023 Rate Case

On November 1, 2022, MERC initiated a rate proceeding with the MPUC to increase its retail natural gas base rates by $40.3 million (9.9%). MERC's request reflects a 10.3% ROE and a common equity component average of 53.0%. The proposed retail natural gas rate increase is primarily driven by increased capital investments as well as inflationary pressure on operating costs. In December 2022, the MPUC approved MERC's request for interim rates totaling $37.0 million, subject to refund. The interim rates went into effect on January 1, 2023.

Michigan Gas Utilities Corporation

2023 Rate Case

On March 3, 2023, MGU filed a request with the MPSC to increase its retail natural gas base rates by $19.1 million (9.1%). MGU's request reflects a 10.4% ROE and a common equity component average of 51.4%. The proposed natural gas rate increase is primarily driven by capital investments made to strengthen the safety and reliability of MGU's natural gas distribution system and to provide service to additional customers. Inflationary pressure on operating costs also contributed to the proposed rate increase.

As part of MGU's rate application, it also requested changes to its MRP rider. The changes include updates for projects that are expected to be placed in service during 2023 and 2024 and included in MGU's base rates, updates to remaining project costs to address inflation, and an extension of the rider for two additional years (new expiration of 2029).

An MPSC decision is anticipated in the fourth quarter of 2023, with any rate adjustments expected to be effective January 1, 2024.

2021 Rate Order

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 helped to mitigate the impacts from delaying the filing of the rate case.

In March 2021, MGU filed its request with the MPSC to increase its natural gas rates. In July 2021, MGU filed with the MPSC, a settlement agreement it reached with certain intervenors, which the MPSC approved in a written order in September 2021. The order authorized a rate increase of $9.3 million (6.35%) and reflected a 9.85% ROE and a common equity component average of 51.5%. The natural gas rate increase was 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. The order also allowed MGU to implement a rider for its MRP

that provides recovery of and return on planned capital investment related to pipeline replacements to maintain system safety and reliability between 2023 and 2027, without having to file a rate case. All costs recovered through the rider are subject to a prudency review by the MPSC. The new rates became effective January 1, 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, 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)
Other comprehensive income before reclassifications	—	1.3	1.3
Net 2021 other comprehensive income	—	1.3	1.3
Balance at December 31, 2021	—	(2.3)	(2.3)
Other comprehensive loss before reclassifications	**—**	**(2.7)**	**(2.7)**
Net 2022 other comprehensive loss	**—**	**(2.7)**	**(2.7)**
Balance at December 31, 2022	**$ —**	**$ (5.0)**	**$ (5.0)**

NOTE 27—OTHER INCOME, NET

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

(in millions)	2022	2021	2020
Non-service components of net periodic benefit costs	**$ 53.3**	$ 36.8	$ 13.5
Gains (losses) on investments held in rabbi trust [(1)]	**(12.6)**	18.6	12.7
AFUDC – Equity	**6.3**	9.1	12.0
Other, net	**2.5**	3.0	4.0
Total other income, net	**$ 49.5**	$ 67.5	$ 42.2

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

NOTE 28—NEW ACCOUNTING PRONOUNCEMENTS

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 to provide relief 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 London Interbank Offered Rate or another reference rate expected to be discontinued because of reference rate reform. Under ASU No. 2020-04, this relief was effective for all entities beginning March 12, 2020 through December 31, 2022. In December 2022, the FASB issued ASU No. 2022-06, Reference Rate Reform (Topic 848): Deferral of the Sunset Date of Topic 848, which extends the relief for applying GAAP to contracts, hedging relationships, and other transactions affected by reference rate reform to December 31, 2024. We are currently evaluating the impact this guidance may have on our financial statements and related disclosures.

Government Assistance

In November 2021, the FASB issued ASU No. 2021-10, Government Assistance (Topic 832). The amendments in this update increase the transparency surrounding government assistance by requiring disclosure of: (i) the types of assistance received; (ii) an entity's accounting for the assistance; and (iii) the effect of the assistance on the entity's financial statements. The update was effective for annual periods beginning after December 15, 2021. The adoption of ASU No. 2021-10, effective for our fiscal year ending on December 31, 2022, did not have a significant impact on our financial statements and related disclosures.