WEC ENERGY GROUP, INC.
Form 10-Q
May 03, 2019

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, DC 20549

FORM 10-Q

(Mark One)
[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended March 31, 2019

OR
[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the transition period from ________________ to ___________________

Commission File Number	Registrant; State of Incorporation; Address; and Telephone Number	IRS Employer Identification No.
001-09057	WEC ENERGY GROUP, INC. (A Wisconsin Corporation) 231 West Michigan Street P. O. Box 1331 Milwaukee, WI 53201 414-221-2345	39-1391525

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	Trading Symbol	Name of Each Exchange on Which Registered
Common Stock, $.01 Par Value	WEC	New York Stock Exchange

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes [X]   No [ ]

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files).

Yes [X]   No [ ]

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

Large accelerated filer [X]	Accelerated filer [ ]
Non-accelerated filer [ ]	Smaller reporting company [ ]
	Emerging growth company [ ]

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act).

Yes [ ] No [X]

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date (March 31, 2019):

Common Stock, $.01 Par Value, 315,438,398 shares outstanding

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WEC ENERGY GROUP, INC.
QUARTERLY REPORT ON FORM 10-Q
For the Quarter Ended March 31, 2019
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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
ATC Holdco	ATC Holdco LLC
Bishop Hill III	Bishop Hill Energy III LLC
Bluewater	Bluewater Natural Gas Holding, LLC
Coyote Ridge	Coyote Ridge Wind, LLC
Integrys	Integrys Holding, Inc.
MERC	Minnesota Energy Resources Corporation
MGU	Michigan Gas Utilities Corporation
NSG	North Shore Gas Company
PGL	The Peoples Gas Light and Coke Company
UMERC	Upper Michigan Energy Resources Corporation
Upstream	Upstream Wind Energy LLC
WE	Wisconsin Electric Power Company
We Power	W.E. Power, LLC
WG	Wisconsin Gas LLC
WPS	Wisconsin Public Service Corporation

Federal and State Regulatory Agencies

EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
ICC	Illinois Commerce Commission
IRS	United States Internal Revenue Service
MDEQ	Michigan Department of Environmental Quality
MPSC	Michigan Public Service Commission
MPUC	Minnesota Public Utilities Commission
PSCW	Public Service Commission of Wisconsin
SEC	United States Securities and Exchange Commission
WDNR	Wisconsin Department of Natural Resources

Accounting Terms

AFUDC	Allowance for Funds Used During Construction
ASU	Accounting Standards Update
FASB	Financial Accounting Standards Board
GAAP	United States Generally Accepted Accounting Principles
LIFO	Last-In, First-Out
OPEB	Other Postretirement Employee Benefits

Environmental Terms

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

Measurements

Dth	Dekatherm
MW	Megawatt
MWh	Megawatt-hour

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Other Terms and Abbreviations

2007 Junior Notes	WEC Energy Group, Inc.'s 2007 Junior Subordinated Notes Due 2067
ALJ	Administrative Law Judge
ERGS	Elm Road Generating Station
Exchange Act	Securities Exchange Act of 1934, as amended
FTR	Financial Transmission Rights
MISO	Midcontinent Independent System Operator, Inc.
OCPP	Oak Creek Power Plant
OC 5	Oak Creek Power Plant Unit 5
OC 6	Oak Creek Power Plant Unit 6
OC 7	Oak Creek Power Plant Unit 7
OC 8	Oak Creek Power Plant Unit 8
PIPP	Presque Isle Power Plant
QIP	Qualifying Infrastructure Plant
ROE	Return on Equity
SMP	Natural Gas System Modernization Program
SMRP	System Modernization and Reliability Project
SSR	System Support Resource
Tax Legislation	Tax Cuts and Jobs Act of 2017
Tilden	Tilden Mining Company

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING INFORMATION

In this report, we make statements concerning our expectations, beliefs, plans, objectives, goals, strategies, and future events or performance. These statements are "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Exchange Act. Readers are cautioned not to place undue reliance on these forward-looking statements. Forward-looking statements may be identified by reference to a future period or periods or by the use of terms such as "anticipates," "believes," "could," "estimates," "expects," "forecasts," "goals," "guidance," "intends," "may," "objectives," "plans," "possible," "potential," "projects," "seeks," "should," "targets," "will," or variations of these terms.

Forward-looking statements include, among other things, statements concerning management's expectations and projections regarding earnings, completion of capital projects, sales and customer growth, rate actions and related filings with regulatory authorities, environmental and other regulations and associated compliance costs, legal proceedings, dividend payout ratios, effective tax rates, pension and OPEB plans, fuel costs, sources of electric energy supply, coal and natural gas deliveries, remediation costs, environmental matters, liquidity and capital resources, and other matters.

Forward-looking statements are subject to a number of risks and uncertainties that could cause our actual results to differ materially from those expressed or implied in the statements. These risks and uncertainties include those described in risk factors as set forth in this report and our 2018 Annual Report on Form 10-K, and those identified below:

- Factors affecting utility operations such as catastrophic weather-related damage, environmental incidents, unplanned facility outages and repairs and maintenance, and electric transmission or natural gas pipeline system constraints;

- Factors affecting the demand for electricity and natural gas, including political developments, unusual weather, changes in economic conditions, customer growth and declines, commodity prices, energy conservation efforts, and continued adoption of distributed generation by customers;

- The timing, resolution, and impact of rate cases and negotiations, including recovery of deferred and current costs and the ability to earn a reasonable return on investment, and other regulatory decisions impacting our regulated operations;

- The ability to obtain and retain customers, including wholesale customers, due to increased competition in our electric and natural gas markets from retail choice and alternative electric suppliers, and continued industry consolidation;

- The timely completion of capital projects within budgets, as well as the recovery of the related costs through rates;

- The impact of federal, state, and local legislative and/or regulatory changes, including changes in rate-setting policies or procedures, deregulation and restructuring of the electric and/or natural gas utility industries, transmission or distribution system operation, the approval process for new construction, reliability standards, pipeline integrity and safety standards, allocation of energy assistance, energy efficiency mandates, and tax laws that affect our ability to use production tax credits and investment tax credits;

- The remaining uncertainty surrounding the Tax Legislation enacted in December 2017, including implementing regulations and IRS interpretations, the amount to be returned to our ratepayers, and any further impact on our and our subsidiaries’ credit ratings;

-

Federal and state legislative and regulatory changes relating to the environment, including climate change and other environmental regulations impacting generation facilities and renewable energy standards, the enforcement of these laws and regulations, changes in the interpretation of regulations or permit conditions by regulatory agencies, and the recovery of associated remediation and compliance costs;

- Factors affecting the implementation of our generation reshaping plan, including related regulatory decisions, the cost of materials, supplies, and labor, and the feasibility of competing projects;

- Increased pressure on us by investors and other stakeholder groups to take more aggressive action to reduce future GHG emissions in order to limit future global temperature increases;

- The risks associated with changing commodity prices, particularly natural gas and electricity, and the availability of sources of fossil fuel, natural gas, purchased power, materials needed to operate environmental controls at our electric generating facilities,

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or water supply due to high demand, shortages, transportation problems, nonperformance by electric energy or natural gas suppliers under existing power purchase or natural gas supply contracts, or other developments;

- Changes in credit ratings, interest rates, and our ability to access the capital markets, caused by volatility in the global credit markets, our capitalization structure, and market perceptions of the utility industry, us, or any of our subsidiaries;

- Costs and effects of litigation, administrative proceedings, investigations, settlements, claims, and inquiries;

- Restrictions imposed by various financing arrangements and regulatory requirements on the ability of our subsidiaries to transfer funds to us in the form of cash dividends, loans or advances, that could prevent us from paying our common stock dividends, taxes, and other expenses, and meeting our debt obligations;

- The risk of financial loss, including increases in bad debt expense, associated with the inability of our customers, counterparties, and affiliates to meet their obligations;

- Changes in the creditworthiness of the counterparties with whom we have contractual arrangements, including participants in the energy trading markets and fuel suppliers and transporters;

- The direct or indirect effect on our business resulting from terrorist attacks and cyber security intrusions, as well as the threat of such incidents, including the failure to maintain the security of personally identifiable information, the associated costs to protect our utility assets, technology systems, and personal information, and the costs to notify affected persons to mitigate their information security concerns and to comply with state notification laws;

- The financial performance of ATC and its corresponding contribution to our earnings, as well as the ability of ATC and Duke-American Transmission Company to obtain the required approvals for their transmission projects;

- The investment performance of our employee benefit plan assets, as well as unanticipated changes in related actuarial assumptions, which could impact future funding requirements;

- Factors affecting the employee workforce, including loss of key personnel, internal restructuring, work stoppages, and collective bargaining agreements and negotiations with union employees;

- Advances in technology, and related legislation or regulation supporting the use of that technology, that result in competitive disadvantages and create the potential for impairment of existing assets;

- The risk associated with the values of goodwill and other intangible assets and their possible impairment;

- Potential business strategies to acquire and dispose of assets or businesses, which cannot be assured to be completed timely, if at all, or within budgets, and legislative or regulatory restrictions or caps on non-utility acquisitions, investments or projects, including the State of Wisconsin's public utility holding company law;

- The timing and outcome of any audits, disputes, and other proceedings related to taxes;

- The ability to maintain effective internal controls in accordance with Section 404 of the Sarbanes-Oxley Act, while both integrating and continuing to consolidate our enterprise systems;

- The effect of accounting pronouncements issued periodically by standard-setting bodies; and

- Other considerations disclosed elsewhere herein and in other reports we file with the SEC or in other publicly disseminated written documents.

We expressly disclaim any obligation to publicly update or revise any forward-looking statements, whether as a result of new information, future events, or otherwise.

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PART I. FINANCIAL INFORMATION

ITEM 1. FINANCIAL STATEMENTS

WEC ENERGY GROUP, INC.

CONDENSED CONSOLIDATED INCOME STATEMENTS (Unaudited)	Three Months Ended March 31	
(in millions, except per share amounts)	2019	2018
Operating revenues	$2,377.4	$2,286.5
Operating expenses		
Cost of sales	1,009.6	972.1
Other operation and maintenance	550.6	511.9
Depreciation and amortization	226.4	208.6
Property and revenue taxes	48.0	48.8
Total operating expenses	1,834.6	1,741.4
Operating income	542.8	545.1
Equity in earnings of transmission affiliates	36.1	32.8
Other income, net	30.9	7.5
Interest expense	124.4	106.7
Other expense	(57.4)	(66.4)
Income before income taxes	485.4	478.7
Income tax expense	65.0	88.3
Net income	420.4	390.4
Preferred stock dividends of subsidiary	0.3	0.3
Net income attributed to common shareholders	$420.1	$390.1
Earnings per share		
Basic	$1.33	$1.24
Diluted	$1.33	$1.23
Weighted average common shares outstanding		
Basic	315.5	315.5
Diluted	316.7	316.9

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

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WEC ENERGY GROUP, INC.

CONDENSED CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (Unaudited)	Three Months Ended March 31	
(in millions)	2019	2018
Net income	$420.4	$390.4
Other comprehensive (loss) income, net of tax		
Derivatives accounted for as cash flow hedges		
Derivative losses, net of tax	(1.2)	—
Reclassification of net gains to net income, net of tax	(0.3)	(0.2)
Cash flow hedges, net	(1.5)	(0.2)
Defined benefit plans		
Amortization of pension and OPEB costs included in net periodic benefit cost, net of tax	0.1	1.9
Other comprehensive (loss) income, net of tax	(1.4)	1.7
Comprehensive income	419.0	392.1
Preferred stock dividends of subsidiary	0.3	0.3
Comprehensive income attributed to common shareholders	$418.7	$391.8

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

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WEC ENERGY GROUP, INC.

CONDENSED CONSOLIDATED BALANCE SHEETS (Unaudited) (in millions, except share and per share amounts)	March 31, 2019	December 31, 2018
Assets		
Current assets		
Cash and cash equivalents	$30.6	$ 84.5
Accounts receivable and unbilled revenues, net of reserves of $163.2 and $149.2, respectively	1,430.1	1,280.9
Materials, supplies, and inventories	330.1	548.2
Prepayments	167.2	256.8
Other	50.3	77.2
Current assets	2,008.3	2,247.6
Long-term assets		
Property, plant, and equipment, net of accumulated depreciation and amortization of $8,589.0 and $8,636.6, respectively	22,193.3	22,000.9
Regulatory assets	4,009.8	3,805.1
Equity investment in transmission affiliates	1,670.6	1,665.3
Goodwill	3,052.8	3,052.8
Other	802.3	704.1
Long-term assets	31,728.8	31,228.2
Total assets	$33,737.1	$ 33,475.8
Liabilities and Equity		
Current liabilities		
Short-term debt	$1,145.2	$ 1,440.1
Current portion of long-term debt	366.0	365.0
Accounts payable	674.1	876.4
Accrued payroll and benefits	125.9	185.4
Other	578.7	464.8
Current liabilities	2,889.9	3,331.7
Long-term liabilities		
Long-term debt	10,326.7	9,994.0
Deferred income taxes	3,459.9	3,388.1
Deferred revenue, net	514.5	520.4
Regulatory liabilities	4,274.3	4,251.6
Environmental remediation liabilities	631.8	616.4
Pension and OPEB obligations	418.1	422.8
Other	1,109.8	1,108.1
Long-term liabilities	20,735.1	20,301.4
Commitments and contingencies (Note 20)		
Common shareholders' equity		
Common stock – $0.01 par value; 325,000,000 shares authorized; 315,438,398 and 315,523,192 shares outstanding, respectively	3.2	3.2
Additional paid in capital	4,213.2	4,250.1

Retained earnings	5,772.1	5,538.2
Accumulated other comprehensive loss	(4.0)	(2.6)
Common shareholders' equity	9,984.5	9,788.9
Preferred stock of subsidiary	30.4	30.4
Noncontrolling interests	97.2	23.4
Total liabilities and equity	$33,737.1	$ 33,475.8

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

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WEC ENERGY GROUP, INC.

CONDENSED CONSOLIDATED STATEMENTS OF CASH FLOWS (Unaudited)	Three Months Ended March 31	
(in millions)	2019	2018
Operating Activities		
Net income	$420.4	$390.4
Reconciliation to cash provided by operating activities		
Depreciation and amortization	226.4	208.6
Deferred income taxes and investment tax credits, net	17.2	17.0
Contributions and payments related to pension and OPEB plans	(4.2)	(5.3)
Equity income in transmission affiliates, net of distributions	(1.9)	7.1
Change in –		
Accounts receivable and unbilled revenues	(124.3)	(60.1)
Materials, supplies, and inventories	218.3	163.0
Other current assets	125.1	81.3
Accounts payable	(204.3)	(170.9)
Other current liabilities	54.6	128.6
Other, net	8.4	134.3
Net cash provided by operating activities	735.7	894.0
Investing Activities		
Capital expenditures	(358.8)	(439.6)
Acquisition of Upstream, net of cash and restricted cash acquired of $9.2	(268.2)	—
Capital contributions to transmission affiliates	(3.4)	(12.8)
Proceeds from the sale of assets	10.6	0.8
Proceeds from the sale of investments held in rabbi trust	0.1	16.5
Other, net	13.1	(0.7)
Net cash used in investing activities	(606.6)	(435.8)
Financing Activities		
Exercise of stock options	32.6	2.1
Purchase of common stock	(70.7)	(15.8)
Dividends paid on common stock	(186.2)	(174.2)
Issuance of long-term debt	350.0	—
Retirement of long-term debt	(13.3)	(12.6)
Change in short-term debt	(294.9)	(244.3)
Other, net	(3.6)	(0.3)
Net cash used in financing activities	(186.1)	(445.1)
Net change in cash, cash equivalents, and restricted cash	(57.0)	13.1
Cash, cash equivalents, and restricted cash at beginning of period	146.1	58.6
Cash, cash equivalents, and restricted cash at end of period	$89.1	$71.7

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

WEC ENERGY GROUP, INC.

CONDENSED CONSOLIDATED STATEMENTS OF EQUITY
(Unaudited)

	WEC Energy Group Common Shareholders' Equity							
(in millions, except per share amounts)	Common Stock	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Common Shareholders' Equity	Preferred Stock of Subsidiary	Non-controlling Interests	Total Equity
Balance at December 31, 2018	$3.2	$4,250.1	$5,538.2	$ (2.6)	$ 9,788.9	$ 30.4	$ 23.4	$9,842.7
Net income attributed to common shareholders	—	—	420.1	—	420.1	—	—	420.1
Other comprehensive loss	—	—	—	(1.4)	(1.4)	—	—	(1.4)
Common stock dividends of $0.59 per share	—	—	(186.2)	—	(186.2)	—	—	(186.2)
Exercise of stock options	—	32.6	—	—	32.6	—	—	32.6
Purchase of common stock	—	(70.7)	—	—	(70.7)	—	—	(70.7)
Acquisition of a noncontrolling interest	—	—	—	—	—	—	69.0	69.0
Capital contributions from noncontrolling interest	—	—	—	—	—	—	4.8	4.8
Stock-based compensation and other	—	1.2	—	—	1.2	—	—	1.2
Balance at March 31, 2019	$3.2	$4,213.2	$5,772.1	$ (4.0)	$ 9,984.5	$ 30.4	$ 97.2	$10,112.1

	WEC Energy Group Common Shareholders' Equity							
(in millions, except per share amounts)	Common Stock	Additional Paid In Capital	Retained Earnings	Accumulated Other Comprehensive Income	Total Common Shareholders' Equity	Preferred Stock of Subsidiary	Non-controlling Interests	Total Equity
Balance at December 31, 2017	$3.2	$4,278.5	$5,176.8	$ 2.9	$ 9,461.4	$ 30.4	$ —	$9,491.8
Net income attributed to common shareholders	—	—	390.1	—	390.1	—	—	390.1
Other comprehensive income	—	—	—	1.7	1.7	—	—	1.7
Common stock dividends of $0.5525 per share	—	—	(174.2)	—	(174.2)	—	—	(174.2)
Exercise of stock options	—	2.1	—	—	2.1	—	—	2.1
Purchase of common stock	—	(15.8)	—	—	(15.8)	—	—	(15.8)
Stock-based compensation and other	—	2.5	—	—	2.5	—	—	2.5
Balance at March 31, 2018	$3.2	$4,267.3	$5,392.7	$ 4.6	$ 9,667.8	$ 30.4	$ —	$9,698.2

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

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WEC ENERGY GROUP, INC.
NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS (Unaudited)
March 31, 2019

NOTE 1—GENERAL INFORMATION

WEC Energy Group serves approximately 1.6 million electric customers and 2.9 million natural gas customers, and owns approximately 60% of ATC.

As used in these notes, the term "financial statements" refers to the condensed 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 "the Company," "us," "we," "our," or "ours," we are referring to WEC Energy Group and all of its subsidiaries.

On our financial statements, we consolidate our majority-owned subsidiaries and reflect noncontrolling interests for the portion of entities that we do not own as a component of consolidated equity separate from the equity attributable to our shareholders. The noncontrolling interests that we reported as equity on our balance sheet as of March 31, 2019 related to the minority interests at Bishop Hill III, Coyote Ridge, and Upstream held by third parties. We completed the acquisition of an 80% membership interest in Upstream during January 2019. See Note 2, Acquisitions, for more information.

We use the equity method to account for investments in companies we do not control but over which we exercise significant influence regarding their operating and financial policies. As a result of our limited voting rights, we account for ATC and ATC Holdco as equity method investments. See Note 17, Investment in Transmission Affiliates, for more information.

We have prepared the unaudited interim financial statements presented in this Form 10-Q pursuant to the rules and regulations of the SEC and GAAP. Accordingly, these financial statements do not include all of the information and footnotes required by GAAP for annual financial statements. These financial statements should be read in conjunction with the consolidated financial statements and footnotes in our Annual Report on Form 10-K for the year ended December 31, 2018. Financial results for an interim period may not give a true indication of results for the year. In particular, the results of operations for the three months ended March 31, 2019, are not necessarily indicative of expected results for 2019 due to seasonal variations and other factors.

In management's opinion, we have included all adjustments, normal and recurring in nature, necessary for a fair presentation of our financial results.

NOTE 2—ACQUISITIONS

All the acquisitions discussed below were accounted for as asset acquisitions.

Acquisition of a Wind Generation Facility in Nebraska

In January 2019, we completed the acquisition of an 80% membership interest in Upstream, a commercially operational 202.5 MW wind generating facility, for $268.2 million, which included transactions costs and is net of cash and restricted cash acquired of $9.2 million. Upstream is located in Antelope County, Nebraska and supplies energy to the Southwest Power Pool. Upstream's revenue will be substantially fixed over a 10-year period through an agreement with an unaffiliated third party. Under the Tax Legislation, our investment in Upstream qualifies for production tax credits and 100% bonus depreciation. Upstream is included in the non-utility energy infrastructure segment.

Acquisition of a Wind Generation Facility in South Dakota

In December 2018, we acquired an 80% ownership interest in Coyote Ridge, a 97.5 MW wind generating facility under construction in Brookings County, South Dakota, for $61.6 million, which included transaction costs. This wind generating facility is expected to be in service by the end of 2019. Upon completion, we expect our total investment in Coyote Ridge to be $145 million. The project has a 12-year offtake agreement with an unaffiliated third party for all of the energy produced by the facility. Under the Tax Legislation, our investment in Coyote Ridge is expected to qualify for production tax credits and 100% bonus depreciation. We are entitled to 99% of the tax benefits related to this facility for the first 11 years of commercial operation, after which we will be entitled to tax benefits equal to our ownership interest. Coyote Ridge is included in the non-utility energy infrastructure segment.

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Acquisition of a Wind Energy Generation Facility in Illinois

In August 2018, we completed the acquisition of an 80% membership interest in a commercially operational 132 MW wind generating facility located in Henry County, Illinois, known as Bishop Hill III, for $144.7 million, which included transaction costs and was net of restricted cash acquired of $4.5 million. In December 2018, we completed the acquisition of an additional 10% membership interest in Bishop Hill III, for $18.2 million. Bishop Hill III has a 22-year offtake agreement with an unaffiliated third party for all of the energy produced by the facility. Under the Tax Legislation, our investment in Bishop Hill III qualifies for production tax credits and 100% bonus depreciation. Bishop Hill III is included in the non-utility energy infrastructure segment.

Acquisition of a Wind Energy Generation Facility in Wisconsin

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

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

NOTE 3—OPERATING REVENUES

For more information about our significant accounting policies related to operating revenues, see Note 1(d), Operating Revenues, in our 2018 Annual Report on Form 10-K.

Disaggregation of Operating Revenues

The following tables present our operating revenues disaggregated by revenue source. We do not have any revenues associated with our electric transmission segment. We disaggregate revenues into categories that depict how the nature, amount, timing, and uncertainty of revenues and cash flows are affected by economic factors. For our segments, revenues are further disaggregated by electric and natural gas operations and then by customer class. Each customer class within our electric and natural gas operations have different expectations of service, energy and demand requirements, and are impacted by regulatory activities within their jurisdictions.

(in millions)	Wisconsin	Illinois	Other States	Total Utility Operations	Non-Utility Energy Infrastructure	Corporate and Other	Reconciling Eliminations	WEC Energy Group Consolidated
Three Months Ended March 31, 2019								
Electric	$ 1,061.8	$ —	$ —	$ 1,061.8	$ —	$ —	$ —	$ 1,061.8
Natural gas	564.9	544.6	185.2	1,294.7	16.4	—	(14.7)	1,296.4
Total regulated revenues	1,626.7	544.6	185.2	2,356.5	16.4	—	(14.7)	2,358.2
Other non-utility revenues	—	0.1	4.1	4.2	13.3	1.5	(0.7)	18.3
Total revenues from contracts with customers	1,626.7	544.7	189.3	2,360.7	29.7	1.5	(15.4)	2,376.5
Other operating revenues	6.7	(8.2)	(4.1)	(5.6)	98.1	0.2	(91.8)	0.9

Total operating revenues	$ 1,633.4	$ 536.5	$ 185.2	$ 2,355.1	$ 127.8	$ 1.7	$ (107.2)	$ 2,377.4

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(in millions)	Wisconsin	Illinois	Other States	Total Utility Operations	Non-Utility Energy Infrastructure	Corporate and Other	Reconciling Eliminations	WEC Energy Group Consolidated
Three Months Ended March 31, 2018								
Electric	$ 1,067.7	$—	$—	$ 1,067.7	$ —	$ —	$ —	$ 1,067.7
Natural gas	518.0	507.6	172.7	1,198.3	14.9	—	(2.5)	1,210.7
Total regulated revenues	1,585.7	507.6	172.7	2,266.0	14.9	—	(2.5)	2,278.4
Other non-utility revenues	—	—	3.9	3.9	7.1	1.3	(0.7)	11.6
Total revenues from contracts with customers	1,585.7	507.6	176.6	2,269.9	22.0	1.3	(3.2)	2,290.0
Other operating revenues	3.4	(0.3)	(6.7)	(3.6)	96.1	0.1	(96.1)	(3.5)
Total operating revenues	$ 1,589.1	$ 507.3	$ 169.9	$ 2,266.3	$ 118.1	$ 1.4	$ (99.3)	$ 2,286.5

Revenues from Contracts with Customers

Electric Utility Operating Revenues

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

	Electric Utility Operating Revenues Three Months Ended March 31	
(in millions)	2019	2018
Residential	$ 406.7	$ 384.3
Small commercial and industrial	333.9	330.7
Large commercial and industrial	212.3	203.9
Other	7.8	7.7
Total retail revenues	960.7	926.6
Wholesale	47.7	54.9
Resale	40.8	73.8
Steam	10.1	9.7
Other utility revenues	2.5	2.7
Total electric utility operating revenues	$ 1,061.8	$ 1,067.7

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
Three Months Ended March 31, 2019				
Residential	$ 383.9	$ 354.0	$ 125.2	$ 863.1
Commercial and industrial	199.7	116.2	72.0	387.9

Total retail revenues	583.6	470.2	197.2	1,251.0
Transport	21.9	87.2	11.1	120.2
Other utility revenues *	(40.6)	(12.8)	(23.1)	(76.5)
Total natural gas utility operating revenues	$ 564.9	$ 544.6	$ 185.2	$ 1,294.7

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(in millions)	Wisconsin	Illinois	Other States	Total Natural Gas Utility Operating Revenues
Three Months Ended March 31, 2018				
Residential	$ 356.7	$ 332.6	$ 123.2	$ 812.5
Commercial and industrial	187.9	109.4	64.7	362.0
Total retail revenues	544.6	442.0	187.9	1,174.5
Transport	21.0	77.7	9.9	108.6
Other utility revenues *	(47.6)	(12.1)	(25.1)	(84.8)
Total natural gas utility operating revenues	$ 518.0	$ 507.6	$ 172.7	$ 1,198.3

* Includes amounts refunded to customers for purchased gas adjustment costs.

Other Non-Utility Operating Revenues

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

(in millions)	Three Months Ended March 31 2019	2018
We Power revenues	$ 6.4	$ 6.4
Appliance service revenues	4.1	3.9
Distributed renewable solar project revenues	1.5	1.3
Wind generation revenues	6.2	—
Other	0.1	—
Total other non-utility operating revenues	$ 18.3	$ 11.6

As part of the construction of the We Power electric generating units, we capitalized interest during construction, which is included in property, plant, and equipment. As allowed by the PSCW, we collected carrying costs from WE's utility customers during construction. The equity portion of these carrying costs was recorded as deferred revenue, and we continually amortize the deferred revenues over the life of the related lease term that We Power has with WE. During both the three months ended March 31, 2019 and 2018, we recorded $6.4 million of revenue related to these deferred carrying costs, which were included in the contract liability balance at the beginning of the period. This contract liability is presented as deferred revenue, net on our balance sheets.

In January 2019, we completed the acquisition of an 80% membership interest in Upstream. Upstream's revenue will be substantially fixed over a 10-year period through an agreement with an unaffiliated third party. See Note 2, Acquisitions, for more information on this acquisition. We recognize revenue as energy is produced and delivered to the customer within the production month.

Other Operating Revenues

Other operating revenues consist primarily of the following:

Three Months
Ended March 31

(in millions)	2019	2018
Alternative revenues *	$(19.7)	$(16.1)
Late payment charges	13.2	11.4
Rental revenues	7.4	1.2
Total other operating revenues	$0.9	$(3.5)

* Negative amounts can result from alternative revenues being reversed to revenues from contracts with customers as the customer is billed for these alternative revenues. Negative amounts can also result from revenues to be refunded to customers subject to decoupling mechanisms and wholesale true-ups.

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NOTE 4—REGULATORY ASSETS AND LIABILITIES

The following regulatory assets and liabilities were reflected on our balance sheets at March 31, 2019 and December 31, 2018. For more information on our regulatory assets and liabilities, see Note 5, Regulatory Assets and Liabilities, in our 2018 Annual Report on Form 10-K.

(in millions)	March 31, 2019	December 31, 2018
Regulatory assets		
Pension and OPEB costs	$ 1,173.8	$ 1,193.5
Plant retirements *	1,027.9	832.3
Environmental remediation costs	697.6	687.1
Income tax related items	384.8	369.1
SSR	317.9	316.7
Asset retirement obligations	223.4	185.4
Uncollectible expense	47.6	38.7
Electric transmission costs	41.7	58.1
We Power generation	36.1	43.0
Energy efficiency programs	11.3	14.0
Other, net	75.0	117.9
Total regulatory assets	$ 4,037.1	$ 3,855.8
Balance sheet presentation		
Other current assets	$ 27.3	$ 50.7
Regulatory assets	4,009.8	3,805.1
Total regulatory assets	$ 4,037.1	$ 3,855.8

* On March 31, 2019, the PIPP generating units were retired by WE. See Note 5, Property, Plant, and Equipment, for more information on the retirement of the PIPP units.

(in millions)	March 31, 2019	December 31, 2018
Regulatory liabilities		
Income tax related items	$ 2,401.2	$ 2,406.6
Removal costs	1,330.8	1,329.6
Pension and OPEB costs	235.7	238.3
Mines deferral	129.1	120.8
Energy costs refundable through rate adjustments	103.0	39.6
Decoupling	51.0	30.5
Energy efficiency programs	45.7	31.7
Earnings sharing mechanisms	29.9	30.0
Uncollectible expense	29.5	30.5
Derivatives	9.0	16.4
Other, net	13.3	14.4
Total regulatory liabilities	$ 4,378.2	$ 4,288.4
Balance sheet presentation		
Other current liabilities	$ 103.9	$ 36.8
Regulatory liabilities	4,274.3	4,251.6
Total regulatory liabilities	$ 4,378.2	$ 4,288.4

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NOTE 5—PROPERTY, PLANT, AND EQUIPMENT

We have evaluated future plans for our older and less efficient fossil fuel generating units and have retired several plants within the Wisconsin segment. In addition, a severance liability was recorded in other current liabilities on our balance sheets related to these plant retirements.

(in millions)	
Severance liability at December 31, 2018	$15.7
Severance payments	(1.7)
Total severance liability at March 31, 2019	$14.0

Presque Isle Power Plant

Pursuant to MISO's April 2018 approval of the retirement of the PIPP, these units were retired on March 31, 2019. Also on March 31, 2019, UMERC's new natural gas-fired generation in the Upper Peninsula of Michigan began commercial operation. The carrying value of the PIPP units was $172.1 million at March 31, 2019. This amount included the net book value of $183.1 million, which was classified as a regulatory asset on our balance sheet. In addition, an $11.0 million cost of removal reserve related to the PIPP units remained classified as a regulatory liability at March 31, 2019. WE will amortize this regulatory asset on a straight-line basis using the composite depreciation rates approved by the PSCW before the units were retired.

NOTE 6—COMMON EQUITY

Stock-Based Compensation

During the first quarter of 2019, the Compensation Committee of our Board of Directors awarded the following stock-based compensation awards to our directors, officers, and certain other key employees:

Award Type	Number of Awards
Stock options [(1)]	476,418
Restricted shares [(2)]	73,571
Performance units	148,036

(1) Stock options awarded had a weighted-average exercise price of $68.18 and a weighted-average grant date fair value of $8.60 per option.

(2) Restricted shares awarded had a weighted-average grant date fair value of $68.18 per share.

Restrictions

Our ability as a holding company to pay common stock dividends primarily depends on the availability of funds received from our utility subsidiaries, We Power, and ATC Holding. 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 UMERC and MGU, are prohibited from loaning funds to us, either directly or indirectly. See Note 10, Common Equity, in our 2018 Annual Report on Form 10-K for additional information on these and other restrictions.

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

Common Stock Dividends

On April 18, 2019, our Board of Directors declared a quarterly cash dividend of $0.59 per share, payable on June 1, 2019, to shareholders of record on May 14, 2019.

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NOTE 7—SHORT-TERM DEBT AND LINES OF CREDIT

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

(in millions, except percentages)	March 31, 2019	December 31, 2018
Commercial paper		
Amount outstanding	$1,145.2	$1,440.1
Weighted-average interest rate on amounts outstanding	2.75 %	2.92 %

Our average amount of commercial paper borrowings based on daily outstanding balances during the three months ended March 31, 2019, was $1,487.0 million with a weighted-average interest rate during the period of 2.81%.

The information in the table below relates to our revolving credit facilities used to support our commercial paper borrowing programs, including available capacity under these facilities:

(in millions)	Maturity	March 31, 2019
WEC Energy Group	October 2022	$ 1,200.0
WE	October 2022	500.0
WPS	October 2022	400.0
WG	October 2022	350.0
PGL	October 2022	350.0
Total short-term credit capacity		$ 2,800.0
Less:		
Letters of credit issued inside credit facilities		$ 3.0
Commercial paper outstanding		1,145.2
Available capacity under existing agreements		$ 1,651.8

NOTE 8—LONG-TERM DEBT

In March 2019, we issued $350.0 million of 3.10% Senior Notes due March 8, 2022. We used the net proceeds to repay short-term debt, and for working capital and other general corporate purposes.

NOTE 9—LEASES

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

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

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

We did not elect the practical expedient allowing entities to account for the nonlease components in lease contracts as part of the single lease component to which they were related. Instead, in accordance with Accounting Standards

Codification 842-10-15-31, our policy is to account for each lease component separately from the nonlease components of the contract.

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

In January 2018, the FASB issued ASU 2018-01, Leases (Topic 842): Land Easement Practical Expedient for Transition to Topic 842, which is an amendment to ASU 2016-02. Land easements (also commonly referred to as rights of way) represent the right to use,

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access or cross another entity's land for a specified purpose. This new guidance permits an entity to elect a transitional practical expedient, to be applied consistently, to not evaluate under Topic 842 land easements that were already in existence or had expired at the time of the entity's adoption of Topic 842. Once Topic 842 is adopted, an entity is required to apply Topic 842 prospectively to all new (or modified) land easements to determine whether the arrangement should be accounted for as a lease. We elected this practical expedient, resulting in none of our land easements being treated as leases upon our adoption of Topic 842.

In July 2018, the FASB issued ASU 2018-11, Leases (Topic 842): Targeted Improvements, which amends ASU 2016-02 and allows entities the option to initially apply Topic 842 at the adoption date and recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption, if required. We used the optional transition method to apply the new guidance as of January 1, 2019, rather than as of the earliest period presented. We did not require a cumulative-effect adjustment upon adoption of Topic 842.

Right of use assets and related lease liabilities related to our operating leases that were recorded upon adoption of Topic 842 were $49.0 million and $48.8 million, respectively. Regarding our finance lease, while the adoption of Topic 842 changed the classification of expense related to this lease on a prospective basis, it had no impact on the total amount of lease expense recorded, and did not impact the lease asset and related liability amounts recorded on our balance sheets.

Obligations Under Operating Leases

We have recorded right of use assets and lease liabilities associated with the following operating leases.

- Leases of office space, primarily related to several floors we are leasing in the Aon Center office building in Chicago, Illinois, though April 2029.
- Land we are leasing related to our Rothschild biomass plant through June 2051, and also land leases related to several non-utility solar facilities through various months in 2033 and 2034.
- Rail cars we are leasing to transport coal to various generating facilities through February 2021.

The operating leases generally require us to pay property taxes, insurance premiums, and operating and maintenance costs associated with the leased property. Many of our leases contain options to renew past the initial term, as set forth in the lease agreement.

Obligations Under Finance Lease

In 1997, we entered into a 25-year power purchase contract with an unaffiliated independent power producer. The contract, for 236 MWs of firm capacity from a natural gas-fired cogeneration facility, includes zero minimum energy requirements. When the contract expires in 2022, we may, at our option and with proper notice, renew for another ten years, purchase the generating facility at fair market value, or allow the contract to expire. We originally recorded this leased facility and corresponding obligation on our balance sheets at the estimated fair value of the plant's electric generating facilities. Minimum lease payments are a function of the 236 MWs of firm capacity we receive from the plant and the fixed monthly capacity rate published in the lease.

Prior to our adoption of Topic 842 on January 1, 2019, we accounted for this finance lease under Topic 980-840, Regulated Operations – Leases, as follows:

- We recorded our minimum lease payments as purchased power expense on our income statement.
- We recorded the difference between the minimum lease payments and the sum of imputed interest and amortization costs calculated under finance lease accounting rules as a deferred regulatory asset on our balance sheets.

In conjunction with our adoption of Topic 842, while the timing of expense recognition related to this finance lease did not change, classification of the lease expense changed as follows:

- Effective January 1, 2019, the minimum lease payments under the power purchase contract were no longer classified within purchased power expense, but were instead recorded as a component of depreciation and amortization and interest expense in accordance with Topic 980-842, Regulated Operations – Leases.
- In order to ensure the timing of lease expense did not change for this finance lease upon adoption of Topic 842, and still resembled the expense recognition pattern of an operating lease, the amortization of the right of use assets was modified from what would typically be recorded for a finance lease under Topic 980-842.

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- We continue to record the difference between the minimum lease payments and the sum of imputed interest and unadjusted amortization costs calculated under the finance lease accounting rules as a deferred regulatory asset on our balance sheets.

Due to the timing and the amounts of the minimum lease payments, the regulatory asset increased to $78.5 million in 2009, at which time the regulatory asset began to be reduced to zero over the remaining life of the contract. The total obligation under the finance lease was $22.1 million at March 31, 2019, and will decrease to zero over the remaining life of the contract.

Amounts Recognized in the Financial Statements

The components of lease expense and supplemental cash flow information related to our leases for the quarters ended March 31 are as follows:

(in millions)	2019	2018
Finance/capital lease expense (1)	$2.0	$1.9
Operating lease expense (2)	1.4	1.4
Short-term lease expense (2)	—	0.1
Total lease expense	$3.4	$3.4
Other information		
Cash paid for amounts included in the measurement of lease liabilities		
Operating cash flows from finance/capital lease (3)	$0.9	$1.9
Operating cash flows from operating leases	$1.7	$1.7
Financing cash flows from finance lease (3)	$1.2	$—
Non-cash activity - right of use assets obtained in exchange for operating lease liabilities	$49.0	
Remaining lease term – finance lease	3.2 years	
Weighted-average remaining lease term – operating leases	13.2 years	
Discount rate – finance lease (4)	15.8 %	
Weighted average discount rate – operating leases (4)	4.6 %	

(1) For the quarter ended March 31, 2019, finance lease expense included amortization of right of use assets in the amount of $1.1 million (included in depreciation and amortization expense) and interest on lease liabilities of $0.9 million (included in interest expense). For the quarter ended March 31, 2018, total finance lease expense related to the long-term power purchase agreement was included in cost of sales.

(2) Operating lease expense was included as a component of operation and maintenance for the quarters ended March 31, 2019 and 2018.

(3) Prior to our adoption of Topic 842 on January 1, 2019, all cash flows related to the finance lease were recorded as a component of operating cash flows.

(4) Because our operating leases do not provide an implicit rate of return, we used the fully collateralized incremental borrowing rates based upon information available for similarly rated companies in determining the present value of

lease payments for our operating leases. For our financing lease, the rate implicit in the lease was readily determinable.

The following table summarizes our finance lease right of use asset, which was included in property, plant and equipment on our balance sheets:

(in millions)	March 31, 2019	December 31, 2018
Long-term power purchase commitment	$ 140.3	$ 140.3
Accumulated amortization	(122.3)	(120.9)
Total finance lease right of use asset/capital lease asset	$ 18.0	$ 19.4

Right of use assets related to operating leases were $48.2 million at March 31, 2019, and were included in other long-term assets on our balance sheets.

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Future minimum lease payments under our operating leases and our finance lease, and the present value of our net minimum lease payments as of March 31, 2019, were as follows:

(in millions)	Total Operating Leases	Power Purchase Commitment
Nine months ended December 31, 2019	$ 4.5	$ 6.2
2020	7.1	8.8
2021	5.1	9.4
2022	5.1	4.2
2023	5.2	—
2024	5.1	—
Thereafter	33.0	—
Total minimum lease payments	65.1	28.6
Less: Interest	(17.3)	(6.5)
Present value of minimum lease payments	47.8	22.1
Less: Short-term lease liabilities	(4.1)	(5.2)
Long-term lease liabilities	$ 43.7	$ 16.9

Short-term and long-term lease liabilities related to operating leases were included in other current liabilities and other long-term liabilities on the balance sheets, respectively.

At December 31, 2018, short-term and long-term liabilities under our capital lease were $4.9 million and $18.4 million, respectively. Short-term and long-term lease liabilities related to our finance/capital lease were included in current portion of long-term debt and long-term debt on the balance sheets, respectively.

Significant Judgments and Other Information

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

As of May 3, 2019, we have not entered into any material operating leases that have not yet commenced.

NOTE 10—MATERIALS, SUPPLIES, AND INVENTORIES

Our inventory consisted of:

(in millions)	March 31, 2019	December 31, 2018
Materials and supplies	$ 230.7	$ 226.6
Fossil fuel	60.4	88.7
Natural gas in storage	39.0	232.9
Total	$ 330.1	$ 548.2

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. For interim periods, the difference between current projected replacement cost and the LIFO cost for quantities of natural gas temporarily withdrawn from storage is recorded as a temporary LIFO liquidation debit or credit. At March 31, 2019, we had a temporary LIFO liquidation credit of $40.2 million recorded within other current liabilities on our balance sheet. Due to seasonality requirements, PGL and NSG expect these interim reductions in LIFO layers to be replenished by year end.

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

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NOTE 11—INCOME TAXES

The provision for income taxes 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:

	Three Months Ended March 31, 2019		Three Months Ended March 31, 2018	
(in millions)	Amount	Effective Tax Rate	Amount	Effective Tax Rate
Statutory federal income tax	$101.9	21.0 %	$100.5	21.0 %
State income taxes net of federal tax benefit	31.0	6.4 %	29.9	6.2 %
Tax repairs	(29.6)	(6.1)%	(25.5)	(5.3)%
Wind production tax credits	(13.4)	(2.8)%	(3.8)	(0.8)%
Federal excess deferred tax amortization	(13.2)	(2.7)%	(15.5)	(3.2)%
Excess tax benefits – stock options	(7.2)	(1.5)%	(0.9)	(0.2)%
Other	(4.5)	(0.9)%	3.6	0.7 %
Total income tax expense	$65.0	13.4 %	$88.3	18.4 %

The effective tax rate of 13.4% for the first quarter of 2019, differs from the United States statutory federal income tax rate of 21%, primarily due to the flow through of tax repairs in connection with the Wisconsin rate settlement, wind production tax credits generated from recent acquisitions of wind generation facilities in our non-utility energy infrastructure segment, and the impact of the Tax Legislation, partially offset by state income taxes.

The effective tax rate of 18.4% for the first quarter of 2018, differs from the United States statutory federal income tax rate of 21%, primarily due to the flow through of tax repairs in connection with the Wisconsin rate settlement and the impact of the Tax Legislation, partially offset by state income taxes.

The Tax Legislation, signed into law in December 2017, required our regulated utilities to remeasure their deferred income taxes and we began to amortize the resulting excess deferred income taxes beginning in 2018 in accordance with normalization requirements (see federal excess deferred tax amortization line above). See Note 22, Regulatory Environment, for more information about the Wisconsin rate settlement.

NOTE 12—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 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 financial 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

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quoted market prices received from counterparties and/or observable inputs for similar instruments. Transactions valued using these inputs are classified in Level 2. Certain derivatives are categorized in Level 3 due to the significance of unobservable or internally-developed inputs.

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

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:

	March 31, 2019			
(in millions)	Level 1	Level 2	Level 3	Total
Derivative assets				
Natural gas contracts	$6.0	$—	$—	$6.0
FTRs	—	—	3.1	3.1
Coal contracts	—	1.2	—	1.2
Total derivative assets	$6.0	$ 1.2	$ 3.1	$10.3
Investments held in rabbi trust	$74.0	$—	$—	$74.0
Derivative liabilities				
Natural gas contracts	$0.9	$—	$—	$0.9
Coal contracts	—	0.1	—	0.1
Interest rate swaps	—	3.7	—	3.7
Total derivative liabilities	$0.9	$ 3.8	$—	$4.7

	December 31, 2018			
(in millions)	Level 1	Level 2	Level 3	Total
Derivative assets				
Natural gas contracts	$6.3	$ 1.8	$—	$8.1
FTRs	—	—	7.4	7.4
Coal contracts	—	0.4	—	0.4
Total derivative assets	$6.3	$ 2.2	$ 7.4	$15.9
Investments held in rabbi trust	$65.0	$—	$—	$65.0
Derivative liabilities				
Natural gas contracts	$4.7	$ 0.8	$—	$5.5
Coal contracts	—	0.1	—	0.1
Interest rate swaps	—	2.3	—	2.3
Total derivative liabilities	$4.7	$ 3.2	$—	$7.9

The derivative assets and liabilities listed in the tables above include options, swaps, futures, physical commodity contracts, and other instruments used to manage market risks related to changes in commodity prices and interest rates. They also include FTRs, which are used to manage electric transmission congestion costs in the MISO Energy and Operating Reserves Markets.

We hold investments in the Integrys rabbi trust. These investments are restricted as they can only be withdrawn from the trust to fund participants' benefits under the Integrys deferred compensation plan and certain Integrys non-qualified pension plans. These investments are included in other long-term assets on our balance sheets. For the three months ended March 31, 2019 and 2018, the net unrealized gains (losses) included in earnings related to the investments held at the end of the period were $8.6 million and $(3.1) million, respectively.

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

	Three Months Ended March 31	
(in millions)	2019	2018
Balance at the beginning of the period	$7.4	$4.4
Settlements	(4.3)	(2.9)
Balance at the end of the period	$3.1	$1.5

Fair Value of Financial Instruments

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

	March 31, 2019		December 31, 2018	
(in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Preferred stock of subsidiary	$30.4	$ 28.3	$30.4	$ 28.3
Long-term debt, including current portion *	10,670.6	11,257.5	10,335.7	10,554.9

* The carrying amount of long-term debt excludes finance and capital lease obligations of $22.1 million and $23.3 million at March 31, 2019 and December 31, 2018, respectively.

The fair values of our long-term debt and preferred stock are categorized within Level 2 of the fair value hierarchy.

NOTE 13—DERIVATIVE INSTRUMENTS

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

We record derivative instruments on our balance sheets as an asset or liability 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.

None of our derivatives are designated as hedging instruments, with the exception of our interest rate swaps, which have been designated as cash flow hedges. The following table shows our derivative assets and derivative liabilities:

	March 31, 2019		December 31, 2018	
(in millions)	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Other current				
Natural gas contracts	$5.1	$ 0.9	$7.7	$ 5.3

FTRs	3.1	—	7.4	—
Coal contracts	1.0	0.1	0.2	0.1
Interest rate swaps	—	0.7	—	0.4
Total other current *	$9.2	$ 1.7	$ 15.3	$ 5.8
Other long-term				
Natural gas contracts	$0.9	$ —	$ 0.4	$ 0.2
Coal contracts	0.2	—	0.2	—
Interest rate swaps	—	3.0	—	1.9
Total other long-term *	$1.1	$ 3.0	$ 0.6	$ 2.1
Total	$10.3	$ 4.7	$ 15.9	$ 7.9

* On our balance sheets, we classify derivative assets and liabilities as other current or other long-term based on the maturities of the underlying contracts.

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Realized gains (losses) on derivatives not designated as hedging instruments are primarily recorded in cost of sales on the income statements. Our estimated notional sales volumes and realized gains (losses) were as follows:

	Three Months Ended March 31, 2019		Three Months Ended March 31, 2018	
(in millions)	Volumes	Gains (Losses)	Volumes	Gains (Losses)
Natural gas contracts	56.1 Dth	$ (0.5)	48.1 Dth	$ (5.2)
Petroleum products contracts	— gallons	—	2.1 gallons	0.5
FTRs	8.1 MWh	2.3	8.2 MWh	3.7
Total		$ 1.8		$ (1.0)

On our balance sheets, the amounts recognized for the right to reclaim cash collateral or the obligation to return cash collateral are not offset against the fair value amounts recognized for derivative instruments executed with the same counterparty under the same master netting arrangement. At March 31, 2019 and December 31, 2018, we had posted cash collateral of $3.0 million and $2.7 million, respectively, in our margin accounts. These amounts were recorded on our balance sheets in other current assets. At December 31, 2018, we had also received cash collateral of $0.2 million in our margin accounts. This amount was recorded on our balance sheet in other current liabilities. We had not received any cash collateral at March 31, 2019.

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

	March 31, 2019		December 31, 2018	
(in millions)	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Gross amount recognized on the balance sheet	$ 10.3	$ 4.7	$ 15.9	$ 7.9
Gross amount not offset on the balance sheet	(0.9)	(0.9)	(4.0) (1)	(4.9) (2)
Net amount	$ 9.4	$ 3.8	$ 11.9	$ 3.0

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

(2) Includes cash collateral posted of $1.1 million.

Cash Flow Hedges

Effective January 1, 2019, we adopted ASU 2017-12, Targeted Improvements to Accounting for Hedging Activities. The amendments in this update expand the strategies that qualify for hedge accounting, amend the presentation and disclosure requirements related to hedging activities, and provide overall targeted improvements to simplify hedge accounting in certain situations. The adoption of this standard did not have a significant impact on our financial statements.

As of March 31, 2019, we had two interest rate swaps with a combined notional value of $250.0 million to hedge the variable interest rate risk associated with our 2007 Junior Notes. The swaps provide a fixed interest rate of 4.9765% on $250.0 million of the $500.0 million of outstanding 2007 Junior Notes through November 15, 2021. As these swaps qualified for cash flow hedge accounting treatment, the related gains and losses are being deferred in accumulated other comprehensive income (OCI) and are being amortized to interest expense as interest is accrued on the 2007 Junior Notes.

We previously entered into forward interest rate swap agreements to mitigate the interest rate exposure associated with the issuance of long-term debt related to the acquisition of Integrys. These swap agreements were settled in 2015, and we continue to amortize amounts out of accumulated OCI into interest expense over the periods in which the interest costs are recognized in earnings.

The table below shows the amounts related to these cash flow hedges recorded in OCI and in earnings, along with our total interest expense on the income statements:

	Three Months Ended March 31	
(in millions)	2019	2018
Derivative losses recognized in OCI	$ (1.6)	$ —
Net derivative gains reclassified from accumulated OCI to interest expense	0.4	0.6
Total interest expense line item on the income statements	124.4	106.7

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We estimate that during the next twelve months, $1.5 million will be reclassified from accumulated OCI as a reduction to interest expense.

NOTE 14—GUARANTEES

The following table shows our outstanding guarantees:

(in millions)	Total Amounts Committed at March 31, 2019	Expiration: Less Than 1 Year	Expiration: 1 to 3 Years	Expiration: Over 3 Years
Guarantees				
Guarantees supporting commodity transactions of subsidiaries [1]	$ 7.1	$7.1	$ —	$—
Standby letters of credit [2]	102.8	5.7	1.1	96.0
Surety bonds [3]	9.2	8.9	0.3	—
Other guarantees [4]	11.0	—	0.9	10.1
Total guarantees	$ 130.1	$21.7	$ 2.3	$106.1

(1) Includes $5.6 million and $1.5 million to support the business operations of Bluewater and UMERC, respectively.

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

(3) Primarily for workers compensation self-insurance programs and obtaining various licenses, permits, and rights-of-way. These amounts are not reflected on our balance sheets.

(4) Consists of $11.0 million related to other indemnifications, for which a liability of $10.1 million related to workers compensation coverage was recorded on our balance sheets.

NOTE 15—EMPLOYEE BENEFITS

The following tables show the components of net periodic pension and OPEB costs for our benefit plans.

	Pension Costs Three Months Ended March 31	
(in millions)	2019	2018
Service cost	$11.3	$12.0
Interest cost	30.6	28.3
Expected return on plan assets	(48.7)	(49.6)
Loss on plan settlement	0.8	0.4
Amortization of prior service cost	0.6	0.7
Amortization of net actuarial loss	19.0	23.1
Net periodic benefit cost	$13.6	$14.9

OPEB Costs

(in millions)	Three Months Ended March 31 2019	2018
Service cost	$4.4	$6.2
Interest cost	6.5	7.5
Expected return on plan assets	(13.7)	(14.9)
Amortization of prior service credit	(3.9)	(3.8)
Amortization of net actuarial (gain) loss	(0.7)	0.3
Net periodic benefit credit	$(7.4)	$(4.7)

During the three months ended March 31, 2019, we made contributions and payments of $3.6 million related to our pension plans and $0.6 million related to our OPEB plans. We expect to make contributions and payments of $8.4 million related to our pension

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plans and $6.1 million related to our OPEB plans during the remainder of 2019, dependent upon various factors affecting us, including our liquidity position and the effects of the new Tax Legislation.

NOTE 16—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 for the three months ended March 31, 2019. We had no changes to the carrying amount of goodwill during the three months ended March 31, 2019.

(in millions)	Wisconsin	Illinois	Other States	Non-Utility Energy Infrastructure	Total
Goodwill balance *	$ 2,104.3	$758.7	$183.2	$ 6.6	$3,052.8

*We had no accumulated impairment losses related to our goodwill as of March 31, 2019.

NOTE 17—INVESTMENT IN TRANSMISSION AFFILIATES

We own approximately 60% of 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. We also own approximately 75% of ATC Holdco, a separate entity formed in December 2016 to invest in transmission-related projects outside of ATC's traditional footprint. The following tables provide a reconciliation of the changes in our investments in ATC and ATC Holdco:

	Three Months Ended March 31, 2019		
(in millions)	ATC	ATC Holdco	Total
Balance at beginning of period	$1,625.3	$40.0	$1,665.3
Add: Earnings (loss) from equity method investment	36.5	(0.4)	36.1
Add: Capital contributions	3.0	0.4	3.4
Less: Distributions	34.2	—	34.2
Balance at end of period	$1,630.6	$40.0	$1,670.6

	Three Months Ended March 31, 2018		
(in millions)	ATC	ATC Holdco	Total
Balance at beginning of period *	$1,515.8	$37.6	$1,553.4
Add: Earnings (loss) from equity method investment	33.4	(0.6)	32.8
Add: Capital contributions	12.0	0.8	12.8
Less: Other	0.1	—	0.1
Balance at end of period	$1,561.1	$37.8	$1,598.9

* Distributions of $39.9 million, received in the first quarter of 2018, were approved and recorded as a receivable from ATC in other current assets at December 31, 2017.

We pay ATC for network transmission and other related services it provides. In addition, we provide a variety of operational, maintenance, and project management work for ATC, which is reimbursed by ATC. We are required to pay the cost of needed transmission infrastructure upgrades for new generation projects while the projects are under construction. ATC reimburses us for these costs when the new generation is placed in service.

In connection with UMERC's construction of the new natural gas-fired generation in the Upper Peninsula of Michigan, UMERC was required to pay ATC for the costs of the transmission infrastructure upgrades needed for the new generation. ATC owns these transmission assets and will reimburse UMERC for these costs in 2019, as the new generation has now been placed in service. At March 31, 2019 and December 31, 2018, the amounts to be reimbursed to UMERC related to the transmission infrastructure upgrades were $32.4 million and $29.4 million, respectively.

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The following table summarizes our significant related party transactions with ATC:

(in millions)	Three Months Ended March 31 2019	2018
Charges to ATC for services and construction	$4.0	$4.6
Charges from ATC for network transmission services	87.1	84.5

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

(in millions)	March 31, 2019	December 31, 2018
Accounts receivable for services provided to ATC	$ 2.0	$ 3.4
Accounts payable for services received from ATC	29.0	28.2

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

(in millions)	Three Months Ended March 31 2019	2018
Income statement data		
Operating revenues	$177.7	$165.4
Operating expenses	90.4	84.9
Other expense, net	28.8	27.6
Net income	$58.5	$52.9

(in millions)	March 31, 2019	December 31, 2018
Balance sheet data		
Current assets	$87.8	$ 87.2
Noncurrent assets	5,012.7	4,928.8
Total assets	$5,100.5	$ 5,016.0
Current liabilities	$571.1	$ 640.0
Long-term debt	2,164.1	2,014.0
Other noncurrent liabilities	288.6	295.3
Shareholders' equity	2,076.7	2,066.7
Total liabilities and shareholders' equity	$5,100.5	$ 5,016.0

NOTE 18—SEGMENT INFORMATION

We use operating income to measure segment profitability and to allocate resources to our businesses. At March 31, 2019