MINNESOTA ENERGY RESOURCES CORPORATION

FINANCIAL STATEMENTS
FOR THE YEAR ENDED DECEMBER 31, 2018

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GLOSSARY OF TERMS AND ABBREVIATIONS

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

Subsidiaries and Affiliates	
Integrys	Integrys Holding, Inc.
WBS	WEC Business Services LLC
WEC Energy Group	WEC Energy Group, Inc.
WPS	Wisconsin Public Service Corporation

Federal and State Regulatory Agencies	
EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
MPUC	Minnesota Public Utilities Commission

Accounting Terms	
ASU	Accounting Standards Update
FASB	Financial Accounting Standards Board
GAAP	Generally Accepted Accounting Principles
OPEB	Other Postretirement Employee Benefits

Environmental Terms	
CO_2	Carbon Dioxide

Measurements	
Dth	Dekatherm

Other Terms and Abbreviations	
AIA	Affiliated Interest Agreement
ROE	Return on Equity
Tax Legislation	Tax Cuts and Jobs Act of 2017

FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

A. INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Shareholder of Minnesota Energy Resources Corporation:

Milwaukee, Wisconsin

We have audited the accompanying financial statements of Minnesota Energy Resources Corporation (the "Company"), which comprise the balance sheets and statements of capitalization as of December 31, 2018 and 2017, and the related statements of income, equity, and cash flows for each of the three years in the period ended December 31, 2018, and the related notes to the financial statements.

Management's Responsibility for the Financial Statements

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

Auditors' Responsibility

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

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

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

Opinion

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of Minnesota Energy Resources Corporation as of December 31, 2018 and 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018, in accordance with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP

Milwaukee, Wisconsin
March 29, 2019

MINNESOTA ENERGY RESOURCES CORPORATION

B. INCOME STATEMENTS

Year Ended December 31 *(in millions)*	2018	2017	2016
Operating revenues	**$ 289.8**	$ 272.0	$ 248.6
Operating expenses			
Cost of sales	**163.4**	151.6	128.5
Other operation and maintenance	**65.6**	65.0	71.7
Depreciation and amortization	**11.6**	13.1	11.4
Property and revenue taxes	**6.6**	10.9	9.0
Total operating expenses	**247.2**	240.6	220.6
Operating income	**42.6**	31.4	28.0
Other income (expense)	**0.1**	0.1	(0.5)
Interest expense	**4.9**	4.6	4.8
Other expense	**(4.8)**	(4.5)	(5.3)
Income before income taxes	**37.8**	26.9	22.7
Income tax expense (benefit)	**10.4**	(0.5)	9.7
Net income	**$ 27.4**	$ 27.4	$ 13.0

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

MINNESOTA ENERGY RESOURCES CORPORATION

C. BALANCE SHEETS

At December 31 *(in millions, except share amounts)*	2018	2017
Assets		
Current assets		
Cash and cash equivalents	**$ 1.5**	$ 1.0
Accounts receivable and unbilled revenues, net of reserves of $2.6 and $2.5, respectively	**47.1**	41.6
Accounts receivable from related parties	**3.5**	0.1
Materials, supplies, and inventories		
Natural gas in storage	**13.0**	10.0
Materials and supplies	**0.2**	0.2
Amounts recoverable from customers	**15.5**	21.5
Other	**1.6**	5.4
Current assets	**82.4**	79.8
Long-term assets		
Property, plant, and equipment, net of accumulated depreciation of $157.3 and $153.4, respectively	**434.1**	378.0
Regulatory assets	**28.7**	36.6
Goodwill	**127.7**	127.7
Other	**9.3**	8.9
Long-term assets	**599.8**	551.2
Total assets	**$ 682.2**	$ 631.0
Liabilities and Equity		
Current liabilities		
Accounts payable	**$ 40.3**	$ 42.8
Accounts payable to related parties	**7.5**	3.0
Short-term debt to parent	**44.0**	41.7
Accrued taxes	**9.5**	10.5
Customer credit balances	**10.7**	8.8
Other	**11.5**	8.6
Current liabilities	**123.5**	115.4
Long-term liabilities		
Long-term debt	**119.2**	119.2
Deferred income taxes	**75.8**	74.6
Regulatory liabilities	**91.4**	80.5
Other	**9.0**	17.4
Long-term liabilities	**295.4**	291.7
Commitments and contingencies (Note 12)		
Common stock – without par value, 1,000 shares authorized; 100 shares issued and outstanding	**133.4**	121.4
Retained earnings	**129.9**	102.5
Total common shareholder's equity	**263.3**	223.9
Total liabilities and equity	**$ 682.2**	$ 631.0

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

MINNESOTA ENERGY RESOURCES CORPORATION

D. STATEMENTS OF CASH FLOWS

Year Ended December 31 *(in millions)*	2018	2017	2016
Operating activities			
Net income	**$ 27.4**	$ 27.4	$ 13.0
Reconciliation to cash provided by operating activities			
Depreciation and amortization	**11.6**	13.1	11.4
Deferred income taxes, net	**1.1**	9.8	18.0
Change in –			
Accounts receivable and unbilled revenues	**(8.9)**	(0.3)	(6.7)
Materials, supplies, and inventories	**(3.0)**	0.2	4.8
Amounts recoverable from customers	**6.0**	(8.7)	(4.0)
Prepaid taxes	**2.2**	5.1	(5.1)
Other current assets	**2.1**	(1.1)	(0.3)
Accounts payable	**8.3**	12.5	2.4
Other current liabilities	**3.3**	1.4	(3.3)
Other, net	**10.0**	(4.3)	2.8
Net cash provided by operating activities	**60.1**	55.1	33.0
Investing activities			
Capital expenditures	**(69.0)**	(48.5)	(34.3)
Payments for assets transferred from WBS	**(4.9)**	(3.0)	(9.6)
Net cash used in investing activities	**(73.9)**	(51.5)	(43.9)
Financing activities			
Short-term debt to parent, net	**2.3**	5.3	9.8
Repayment of long-term debt to parent	**—**	(78.0)	(29.0)
Issuance of long-term debt	**—**	120.0	—
Return of capital to parent	**(10.0)**	(50.0)	—
Equity contribution from parent	**22.0**	—	31.0
Other, net	**—**	(0.8)	—
Net cash provided by (used in) financing activities	**14.3**	(3.5)	11.8
Net change in cash and cash equivalents	**0.5**	0.1	0.9
Cash and cash equivalents at beginning of year	**1.0**	0.9	—
Cash and cash equivalents at end of year	**$ 1.5**	$ 1.0	$ 0.9

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

MINNESOTA ENERGY RESOURCES CORPORATION

E. STATEMENTS OF EQUITY

(in millions)	Common Stock	Retained Earnings	Total Common Shareholder's Equity
Balance at December 31, 2015	$ 140.4	$ 62.1	$ 202.5
Net income	—	13.0	13.0
Equity contribution from parent	31.0	—	31.0
Balance at December 31, 2016	$ 171.4	$ 75.1	$ 246.5
Net income	—	27.4	27.4
Return of capital to parent	(50.0)	—	(50.0)
Balance at December 31, 2017	$ 121.4	$ 102.5	$ 223.9
Net income	**—**	**27.4**	**27.4**
Equity contribution from parent	**22.0**	**—**	**22.0**
Return of capital to parent	**(10.0)**	**—**	**(10.0)**
Balance at December 31, 2018	**$ 133.4**	**$ 129.9**	**$ 263.3**

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

MINNESOTA ENERGY RESOURCES CORPORATION

F. STATEMENTS OF CAPITALIZATION

At December 31 *(in millions)*			2018	2017
Common shareholder's equity (see accompanying statement)			**$ 263.3**	$ 223.9
Long-term debt	**Interest Rate**	**Year Due**		
Senior Notes (unsecured)	3.11%	2027	**40.0**	40.0
	3.41%	2032	**40.0**	40.0
	4.01%	2047	**40.0**	40.0
Total			**120.0**	120.0
Unamortized debt issuance costs			**(0.8)**	(0.8)
Total long-term debt			**119.2**	119.2
Total long-term capitalization			**$ 382.5**	$ 343.1

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

MINNESOTA ENERGY RESOURCES CORPORATION

G. NOTES TO FINANCIAL STATEMENTS
December 31, 2018

NOTE 1—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) Nature of Operations—As used in these notes, the term “financial statements” includes the income statements, balance sheets, statements of cash flows, statements of equity, and statements of capitalization, unless otherwise noted. In this report, when we refer to "us," "we," "our," or "ours," we are referring to Minnesota Energy Resources Corporation.

We are primarily a natural gas utility company that distributes, sells, and transports natural gas to customers in Minnesota. We also have non-utility operations related to servicing appliances for customers. We are subject to the jurisdiction of, and regulation by, the MPUC, which has general supervisory and regulatory powers over public utilities in Minnesota. In addition, we are subject to the standards of conduct and affiliate rules of the FERC. We are an indirect, wholly owned subsidiary of WEC Energy Group.

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

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

(d) Operating Revenues—The following discussion includes our significant accounting policies related to operating revenues, including our adoption of ASU 2014-09, Revenues from Contracts with Customers. For additional required disclosures on disaggregation of operating revenues as required by this ASU, see Note 3, Operating Revenues.

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

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

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

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

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

Revenues from Contracts with Customers

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 our tariffs. 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. Our 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 our tariffs, which have been approved by the MPUC. 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.

Our tariffs include various rate mechanisms that allow us to recover or refund changes in prudently incurred costs from rate case-approved amounts. Our rates include a one-for-one recovery mechanism for natural gas commodity costs. We defer any difference between actual natural gas costs incurred and costs recovered through rates as a current asset or liability. The deferred balance is returned to or recovered from customers at intervals throughout the year.

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 primarily from servicing appliances for our customers. These contracts customarily have a duration of one year or less and consist of a single performance obligation satisfied over time. We use a time-based output method to recognize revenues monthly for the service fee.

Other Operating Revenues

Alternative Revenues

Alternative revenues are created from programs authorized by regulators that allow us 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 our alternative revenue programs:

- Our rates include a decoupling mechanism, which allows us to recover or refund the differences between actual and authorized margins for certain customer classes.
- Our rates include a conservation improvement program rider, which includes a financial incentive for meeting energy savings goals.

(e) Materials, Supplies, and Inventories—We record substantially all materials, supplies, and natural gas in storage inventories using the weighted-average cost method of accounting.

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

Recovery or refund of regulatory assets and liabilities is based on specific periods determined by the MPUC or occurs over the normal operating period of the assets and liabilities to which they relate. If at any reporting date a previously recorded regulatory asset is no longer probable of recovery, the regulatory asset is reduced to the amount considered probable of recovery with the reduction charged to expense in the reporting period the determination is made. See Note 4, Regulatory Assets and Liabilities, for more information.

(g) Property, Plant, and Equipment—We record property, plant, and equipment at cost. Cost includes material, labor, overhead, and capitalized interest. 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 as approved by the MPUC. Our annual utility composite depreciation rates were 1.95%, 2.51%, and 2.53% for 2018, 2017, and 2016, respectively.

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

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

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

See Note 5, Property, Plant, and Equipment, for more information.

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

(i) Goodwill—Goodwill represents the excess of the cost of an acquisition over the fair value of the identifiable net assets acquired. At December 31, 2018 and 2017, we had gross goodwill of $144.3 million and accumulated goodwill impairment losses of $16.6 million, resulting in a net goodwill balance of $127.7 million.

Goodwill is subject to an annual impairment test. Interim impairment tests are performed when impairment indicators are present. Our reporting unit containing goodwill as of July 1, 2018, performed an annual goodwill impairment test during the third quarter of 2018. No impairments resulted from this test. The carrying amount of the reporting unit's goodwill is considered not recoverable if the carrying amount of the reporting unit exceeds the reporting unit's fair value. An impairment loss is recorded for the excess of the carrying amount of goodwill over its implied fair value.

(j) Stock-Based Compensation—Our employees participate in the WEC Energy Group stock-based compensation plans. In accordance with the WEC Energy Group shareholder approved WEC Energy Group 1993 Omnibus Stock Incentive Plan, Amended and Restated Effective as of January 1, 2016, WEC Energy Group provides long-term incentives through its equity interests to its non-

employee directors, officers, and other key employees. The plan provides for the granting of stock options, restricted stock, performance shares, and other stock-based awards. Awards may be paid in WEC Energy Group common stock, cash, or a combination thereof. Stock-based compensation expense related to these awards is allocated to us based on the outstanding awards held by our employees and our allocation of labor costs. For the years ended December 31, 2018, 2017, and 2016, we recorded stock-based compensation expense of $1.0 million, $0.7 million, and $0.5 million, respectively.

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

(k) Common Equity—We do not have any restrictions imposed on us that affect our ability to pay dividends to the sole holder of our common stock, Integrys. We are prohibited from loaning funds to WEC Energy Group, Integrys, or their other subsidiaries.

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

Investment tax credits associated with regulated operations are deferred and amortized over the life of the assets. We and our subsidiary are included in WEC Energy Group's consolidated federal and state income tax returns. In accordance with our tax allocation agreement with WEC Energy Group, we are allocated income tax payments and refunds based on our separate tax computation. See Note 8, Income Taxes, for more information.

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

(m) Fair Value Measurements—Fair value is the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date (exit price).

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

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

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

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

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

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

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

See Note 9, Fair Value Measurements, for more information.

(n) Derivative Instruments—We use derivatives as part of our risk management program to manage the risks associated with the price volatility of 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 the MPUC.

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 of our natural gas-related physical and financial contracts that qualify as derivatives, the MPUC allows the effects of fair value accounting to be offset to regulatory assets and liabilities.

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

Derivative accounting rules provide the option to present certain asset and liability derivative positions net on the balance sheets and to net the related cash collateral against these net derivative positions. We elected not to net these items. On our balance sheets, cash collateral provided to others is reflected in other current assets. See Note 10, Derivative Instruments, for more information.

(o) Employee Benefits—The costs of pension and OPEB plans are expensed over the periods during which employees render service. These costs are distributed among WEC Energy Group's subsidiaries based on current employment status and actuarial calculations, as applicable. The MPUC allows recovery in rates for the net periodic benefit cost calculated under GAAP. See Note 11, Employee Benefits, for more information.

(p) Customer Deposits and Credit Balances—When customers apply for new service, they may be required to provide a deposit for the service. We use a credit scoring system as one of the methods to determine whether a deposit is necessary. Customer deposits are recorded within other current liabilities on our balance sheets.

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.

(q) 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 manufactured gas plant sites. See Note 12, Commitments and Contingencies, for more information.

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.

We 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 MPUC approval.

We review our estimated costs of remediation annually for our manufactured gas plant site. We adjust the liability and related regulatory asset, as appropriate, to reflect the new cost estimates. Any material changes in cost estimates are adjusted throughout the year.

(r) Customer Concentrations of Credit Risk—The geographic concentration of our customers in our service territory 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. As a result, we did not have any significant concentrations of credit risk at December 31, 2018. In addition, there were no customers that accounted for more than 10% of our revenues for the year ended December 31, 2018.

(s) Subsequent Events—Subsequent events were evaluated for potential recognition or disclosure through March 29, 2019, which is the date the financial statements were available to be issued.

NOTE 2—RELATED PARTIES

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

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

Following WEC Energy Group's acquisition of Integrys on June 29, 2015, Integrys Business Support, LLC (IBS) changed its name to WEC Business Services LLC, and a new AIA (Non-WBS AIA) went into effect. The Non-WBS AIA included WEC Energy Group and the former Wisconsin Energy Corporation subsidiaries. It governed the provision and receipt of services by WEC Energy Group's subsidiaries, except that WBS continued to provide services to Integrys and its subsidiaries only under the existing WBS AIAs. WBS provided services to WEC Energy Group and the former Wisconsin Energy Corporation subsidiaries under interim WBS AIAs. The Non-WBS AIA included no other significant changes from the prior Non-IBS AIA. The MPUC and all other relevant state commissions approved the Non-WBS AIA or granted appropriate waivers related to the Non-WBS AIA.

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

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

A new AIA took effect January 1, 2017. The new agreement replaced the previous agreements. The pricing methodology and services under this new agreement are substantially identical to those under the agreements that were replaced.

The following table shows activity associated with related party transactions:

(in millions)	2018	2017	2016
Transactions with WBS [1]			
Billings to WBS	**$ 2.6**	$ 0.9	$ —
Billings from WBS [2]	**20.4**	26.0	22.4
Interest expense on debt to parent	**0.4**	2.2	4.6

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

(2) Includes $4.9 million, $3.0 million, and $9.6 million for the transfer of certain software assets to us for the years ended December 31, 2018, 2017, and 2016, respectively. The year ended December 31, 2017 included $3.0 million of cash paid related to pension trust assets transferred to us in conjunction with the Integrys pension plan split. Effective January 1, 2017, the Integrys Energy Group Retirement Plan was split into six separate plans. As a result, we now have our own pension plan. While the split did not impact our pension benefit obligation, federal regulations required a different allocation of assets among the new plans. Assets were transferred into our plan in January 2017.

See Note 6, Short-Term Debt To Parent, and Note 11, Employee Benefits, for additional disclosures on related party transactions.

NOTE 3—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. Natural gas revenues are further disaggregated by customer class. Each customer class has different expectations of service, natural gas and demand requirements, and are impacted by regulatory activities within Minnesota.

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

(in millions)	Natural Gas Operating Revenues
Year ended December 31, 2018	
Natural gas utility revenues from contracts with customers	$ 280.9
Other non-utility revenues	16.1
Total revenues from contracts with customers	297.0
Other operating revenues	(7.2)
Total natural gas operating revenues	$ 289.8

Revenues from Contracts with Customers

Natural Gas Utility Operating Revenues

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

(in millions)	Natural Gas Utility Operating Revenues
Year Ended December 31, 2018	
Residential	$ 171.5
Commercial and industrial	104.3
Total retail revenues	275.8
Transport	11.7
Other utility revenues *	(6.6)
Total natural gas utility operating revenues	$ 280.9

* 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)	Year Ended December 31, 2018
Appliance service revenues	$ 15.9
Other	0.2
Total other non-utility operating revenues	$ 16.1

Other Operating Revenues

Other operating revenues consist primarily of the following:

(in millions)	Year Ended December 31, 2018
Alternative revenues *	**$ (8.2)**
Late payment charges	**1.0**
Total other operating revenues	**$ (7.2)**

* 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, as discussed in Note 1(d), Operating Revenues.

NOTE 4—REGULATORY ASSETS AND LIABILITIES

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

(in millions)	2018	2017	See Note
Regulatory assets [1] [2]			
Pension and OPEB costs [3]	**$ 20.8**	$ 20.3	11
Natural gas costs recoverable through rate adjustments [4]	**13.5**	19.7	1(d)
Environmental remediation costs [5]	**4.7**	9.4	12
Energy efficiency program [6]	**2.0**	1.8	
Decoupling	**—**	4.4	14
Other, net	**3.2**	2.5	
Total regulatory assets	**$ 44.2**	$ 58.1	
Balance sheet presentation			
Amounts recoverable from customers	**$ 15.5**	$ 21.5	
Regulatory assets	**28.7**	36.6	
Total regulatory assets	**$ 44.2**	$ 58.1	

[1] Based on prior and current rate treatment, we believe it is probable that we will continue to recover from customers the regulatory assets in this table.

[2] As of December 31, 2018, we had $7.7 million of regulatory assets not earning a return. The regulatory assets not earning a return primarily relate to certain environmental remediation costs, the recovery of which depends on the timing of the actual expenditure, as well as our energy efficiency program. The other regulatory assets in the table either earn a return or the cash has not yet been expended, in which case the regulatory assets are offset by liabilities.

[3] 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.

[4] Represents natural gas costs that will be recovered from customers in the future.

[5] As of December 31, 2018, we had made cash expenditures of $4.0 million related to these environmental remediation costs. The remaining $0.7 million represents our estimated future cash expenditures.

[6] Represents amounts recoverable from customers related to a program designed to meet energy efficiency standards.

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

(in millions)	2018	2017	See Note
Regulatory liabilities			
Removal costs [1]	**$ 42.3**	$ 41.4	
Income tax related items [2]	**39.0**	38.5	8
Interim rate refund	**5.1**	—	14
Energy efficiency program [3]	**4.5**	0.6	
Decoupling	**2.4**	—	14
Other, net	**2.6**	0.6	
Total regulatory liabilities	**$ 95.9**	$ 81.1	
Balance sheet presentation			
Other current liabilities	**$ 4.5**	$ 0.6	
Regulatory liabilities	**91.4**	80.5	
Total regulatory liabilities	**$ 95.9**	$ 81.1	

[1] Represents amounts collected from customers to cover the future cost of property, plant, and equipment removals that are not legally required.

[2] For information on the regulatory treatment of the impacts of the Tax Legislation, see Note 14, Regulatory Environment.

[3] Represents amounts refundable to customers related to a program designed to meet energy efficiency standards.

NOTE 5—PROPERTY, PLANT, AND EQUIPMENT

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

(in millions)	2018	2017
Natural gas - distribution, storage, and transmission	**$ 513.3**	$ 469.7
Other utility property, plant, and equipment	**59.2**	54.3
Less: Accumulated depreciation	**157.3**	153.4
Net	**415.2**	370.6
Construction work in progress	**18.9**	7.4
Total property, plant, and equipment	**$ 434.1**	$ 378.0

NOTE 6—SHORT-TERM DEBT TO PARENT

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

(in millions, except for percentages)	2018	2017
Short-term debt to parent:		
Amount outstanding at December 31	**$ 44.0**	$ 41.7
Weighted-average interest rate on amounts outstanding at December 31	**2.90%**	1.63%

Our average amount of short-term borrowings based on daily outstanding balances during 2018, was $16.2 million with a weighted-average interest rate during the period of 2.45%.

(in millions)	December 31, 2018
Revolving short-term notes payable to parent	**$ 75.0**
Less:	
Short-term debt to parent outstanding	**44.0**
Available capacity under existing agreement	**$ 31.0**

Our short-term borrowing capacity with Integrys is $75.0 million. Short-term borrowings bear interest computed at the average stated interest rate payable on commercial paper issued by WEC Energy Group. Short-term debt is callable by Integrys at any time.

NOTE 7—LONG-TERM DEBT

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

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

(in millions)	Payments
2019	$ —
2020	—
2021	—
2022	—
2023	—
Thereafter	120.0
Total	$ 120.0

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

NOTE 8—INCOME TAXES

Income Tax Expense

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

(in millions)	2018	2017	2016
Current tax expense (benefit)	**$ 9.3**	$ (10.3)	$ (8.3)
Deferred income taxes, net	**1.1**	9.8	18.0
Total income tax expense (benefit)	**$ 10.4**	$ (0.5)	$ 9.7

Statutory Rate Reconciliation

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

	2018		2017*		2016	
(in millions)	Amount	Effective Tax Rate	Amount	Effective Tax Rate	Amount	Effective Tax Rate
Expected tax at statutory federal tax rates	**$ 7.9**	**21.0 %**	$ 9.4	35.0 %	$ 7.9	35.0%
State income taxes net of federal tax benefit	**3.0**	**8.0 %**	3.0	11.2 %	1.5	6.6%
Federal excess deferred tax amortization	**(0.7)**	**(1.9)%**	—	— %	—	—%
Tax Legislation	**—**	**— %**	(12.8)	(47.6)%	—	—%
Other, net	**0.2**	**0.4 %**	(0.1)	(0.5)%	0.3	1.1%
Total income tax expense (benefit)	**$ 10.4**	**27.5 %**	$ (0.5)	(1.9)%	$ 9.7	42.7%

* The net impact of Tax Legislation in the amount of $11.6 million is represented in both the Tax Legislation and state income taxes net of federal tax benefit lines above.

Deferred Income Tax Assets and Liabilities

On December 22, 2017, the Tax Legislation was signed into law. For businesses, the Tax Legislation reduced the corporate federal tax rate from a maximum of 35% to a 21% rate effective January 1, 2018. In December 2017, we recorded a net tax benefit related to the remeasurement of our deferred taxes in the amount of $50 million. Accordingly, the tax benefit related to our regulated operations was recorded as both an increase to regulatory liabilities as well as a decrease to certain existing regulatory assets at December 31, 2017. The effects of the Tax Legislation related to our non-utility operations resulted in the recording of an income tax benefit of $11.6 million for the year ended December 31, 2017. This tax benefit was primarily due to a re-measurement of deferred tax assets and liabilities.

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

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

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

(in millions)	2018	2017
Deferred tax assets		
Tax gross up - regulatory items	**$ 11.0**	$ 11.1
Other	**6.9**	3.5
Total deferred tax assets	**$ 17.9**	$ 14.6
Deferred tax liabilities		
Property-related	**$ 86.3**	$ 75.7
Regulatory deferrals	**1.2**	8.8
Employee benefits and compensation	**5.9**	4.5
Other	**0.3**	0.2
Total deferred tax liabilities	**93.7**	89.2
Deferred tax liability, net	**$ 75.8**	$ 74.6

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

At December 31, 2018, we had no significant federal deferred tax assets related to tax benefit carryforwards. At December 31, 2017, we had $0.1 million of federal tax credit carryforwards resulting in deferred tax assets of $0.1 million.

At December 31, 2018 and 2017, we had no significant state deferred tax assets related to tax benefit carryforwards.

Unrecognized Tax Benefits

We had no unrecognized tax benefits at December 31, 2018 and 2017.

We do not expect any unrecognized tax benefits to affect our effective tax rate in periods after December 31, 2018.

For the years ended December 31, 2018, 2017, and 2016, we recognized no interest or penalties related to unrecognized tax benefits in our income statements. At December 31, 2018 and 2017, we had no interest accrued and 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.

Our primary tax jurisdictions include federal and the state of Minnesota. With a few exceptions, we are no longer subject to federal income tax examinations by the United States Internal Revenue Service for years prior to 2015. At December 31, 2018, we were subject to examination by the Minnesota taxing authority for tax years 2014 through 2018.

NOTE 9—FAIR VALUE MEASUREMENTS

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

	December 31, 2018			
(in millions)	Level 1	Level 2	Level 3	Total
Derivative assets				
Natural gas contracts	**$ 0.1**	**$ —**	**$ —**	**$ 0.1**
Derivative liabilities				
Natural gas contracts	**0.1**	**0.6**	**—**	**0.7**

	December 31, 2017			
(in millions)	Level 1	Level 2	Level 3	Total
Derivative assets				
Natural gas contracts	$ 0.1	$ —	$ —	$ 0.1
Derivative liabilities				
Natural gas contracts	0.4	—	—	0.4

The derivative assets and liabilities listed in the tables above include natural gas purchase contracts, options, and futures used to manage volatility in natural gas supply costs. See Note 10, Derivative Instruments, for more information.

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:

	2018		2017	
(in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	**$ 119.2**	**$ 111.3**	$ 119.2	$ 118.9

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

NOTE 10—DERIVATIVE INSTRUMENTS

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

	December 31, 2018		December 31, 2017	
(in millions)	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Other current				
Natural gas contracts	**$ 0.1**	**$ 0.7**	$ 0.1	$ 0.4

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

	December 31, 2018		December 31, 2017		December 31, 2016	
(in millions)	Volume	Gains	Volume	Losses	Volume	Losses
Natural gas contracts	7.0 Dth	$ 0.9	6.9 Dth	$ (1.2)	9.1 Dth	$ (4.1)

At December 31, 2018 and 2017, we had posted cash collateral of $0.3 million and $0.9 million, respectively, in our margin accounts.

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

	December 31, 2018		December 31, 2017	
(in millions)	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Gross amount recognized on the balance sheet	**$ 0.1**	**$ 0.7**	$ 0.1	$ 0.4
Gross amount not offset on the balance sheet	**(0.1)**	**(0.2)** [1]	(0.1)	(0.4) [2]
Net amount	**$ —**	**$ 0.5**	$ —	$ —

[1] Includes cash collateral posted of $0.1 million.

[2] Includes cash collateral posted of $0.3 million.

NOTE 11—EMPLOYEE BENEFITS

Pension and Other Postretirement Employee Benefits

Through December 31, 2016, we participated in the Integrys Energy Group retirement plan, a noncontributory, qualified pension plan sponsored by WBS. We were responsible for our share of the plan assets and obligations. Effective January 1, 2017, the Integrys Energy Group Retirement Plan was split into six separate plans. As a result, we now have our own pension plan. While the split did not impact our pension benefit obligation, federal regulations required a different allocation of assets among the new plans. Assets were transferred into our plan in January 2017. During 2017, we paid $3.0 million related to pension trust assets transferred to us in conjunction with the Integrys pension plan split. We also participate in an unfunded, non-qualified retirement plan sponsored by WPS. In addition, we maintain an unfunded, non-qualified Supplemental Employee Retirement Plan.

We offer OPEB plans to employees, which are sponsored by WPS. We are responsible for our share of the plan assets and obligations for all of these plans. Our balance sheets reflect only the liabilities associated with our past and current employees and our share of the plan assets. WEC Energy Group also offers medical, dental, and life insurance benefits to our active employees and their dependents. We expense the allocated costs of these benefits as incurred.

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

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

The following table shows information relating to our share of the plans' benefit obligations and fair value of assets. Amounts presented are as of December 31:

	Pension Costs		OPEB Costs	
(in millions)	2018	2017	2018	2017
Benefit obligation	**$ 40.7**	$ 46.1	**$ 5.2**	$ 6.6
Fair value of plan assets	**44.6**	51.1	**2.8**	3.3
Funded status	**$ 3.9**	$ 5.0	**$ (2.4)**	$ (3.3)

The amount of contributions and benefit payments for the years ended December 31 was as follows:

	Pension Costs		OPEB Costs	
(in millions)	**2018**	**2017**	**2018**	**2017**
Employer contributions	**$ —**	$ —	**$ —**	$ 0.1
Participant contributions	**—**	—	**0.2**	0.2
Benefit payments	**(3.6)**	(2.6)	**(0.6)**	(1.0)

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

	Pension Costs		OPEB Costs	
(in millions)	**2018**	**2017**	**2018**	**2017**
Other long-term assets	**$ 4.0**	$ 5.1	**$ —**	$ —
Other long-term liabilities	**0.1**	0.1	**2.4**	3.3
Total net assets (liabilities)	**$ 3.9**	$ 5.0	**$ (2.4)**	$ (3.3)

The accumulated benefit obligation for the qualified pension plans was $40.1 million and $46.0 million at December 31, 2018 and 2017, respectively.

The following table shows information for pension plans with an accumulated benefit obligation in excess of plan assets. There were no plan assets related to these pension plans. Amounts presented are as of December 31:

(in millions)	**2018**	**2017**
Projected benefit obligation	**$ 0.1**	$ 0.2
Accumulated benefit obligation	**0.1**	0.2

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

	Pension Costs		OPEB Costs	
(in millions)	**2018**	**2017**	**2018**	**2017**
Net regulatory assets				
Net actuarial loss	**$ 17.5**	$ 16.2	**$ 3.3**	$ 4.5
Prior service credits	**—**	—	**(0.6)**	(0.4)
Total	**$ 17.5**	$ 16.2	**$ 2.7**	$ 4.1

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

(in millions)	**Pension Costs**	**OPEB Costs**
Net actuarial loss	$ 1.1	$ 0.3
Prior service credits	—	(0.1)
Total 2019 – estimated amortization	$ 1.1	$ 0.2

The amount of net periodic benefit cost recognized (including amounts capitalized to our balance sheets) for the years ended December 31 was as follows:

	Pension Costs			OPEB Costs		
(in millions)	**2018**	**2017**	**2016**	**2018**	**2017**	**2016**
Net periodic benefit (credit) cost	**$ (0.2)**	$ (0.2)	$ 0.3	**$ 0.5**	$ 0.5	$ 0.5

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

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

	Year Ended December 31, 2017			Year Ended December 31, 2016		
(in millions)	2017 Annual Report Income Statement	Impact of ASU 2017-07	Income Statement After Adoption	2017 Annual Report Income Statement	Impact of ASU 2017-07	Income Statement After Adoption
Operating expenses						
Other operation and maintenance	$ 64.9	$ 0.1	$ 65.0	$ 72.1	$ (0.4)	$ 71.7
Other expense						
Other income (expense)	—	0.1	0.1	(0.1)	(0.4)	(0.5)

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

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

	Pension		OPEB	
	2018	2017	2018	2017
Discount rate	**4.25%**	3.60%	**4.14%**	3.42%
Rate of compensation increase	**4.00%**	4.00%	**N/A**	N/A
Assumed medical cost trend rate (Pre 65)	**N/A**	N/A	**6.25%**	6.50%
Ultimate trend rate (Pre 65)	**N/A**	N/A	**5.00%**	5.00%
Year ultimate trend rate is reached (Pre 65)	**N/A**	N/A	**2024**	2024
Assumed medical cost trend rate (Post 65)	**N/A**	N/A	**5.90%**	6.00%
Ultimate trend rate (Post 65)	**N/A**	N/A	**5.00%**	5.00%
Year ultimate trend rate is reached (Post 65)	**N/A**	N/A	**2028**	2028

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

	Pension Costs		OPEB Costs	
	2018	2017	2018	2017
Discount rate	**3.74%**	4.20%	**3.42%**	**3.74%**
Expected return on assets	**7.25%**	7.25%	**7.25%**	**7.25%**
Rate of compensation increase	**4.00%**	4.00%	**N/A**	**N/A**
Assumed medical cost trend rate (Pre 65)	**N/A**	N/A	**6.50%**	**7.00%**
Ultimate trend rate (Pre 65)	**N/A**	N/A	**5.00%**	**5.00%**
Year ultimate trend rate is reached (Pre 65)	**N/A**	N/A	**2024**	**2021**
Assumed medical cost trend rate (Post 65)	**N/A**	N/A	**6.00%**	**7.00%**
Ultimate trend rate (Post 65)	**N/A**	N/A	**5.00%**	**5.00%**
Year ultimate trend rate is reached (Post 65)	**N/A**	N/A	**2028**	**2021**

WEC Energy Group consults with its investment advisors on an annual basis to help forecast expected long-term returns on plan assets by reviewing historical returns as well as calculating expected total trust returns using the weighted-average of long-term market returns for each of the major target asset categories utilized in the fund. For 2019, the expected return on assets assumption for the pension and OPEB plans is 7.25%.

Plan Assets

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

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

Our pension plan's assets are invested in a corporate pension trust with a target asset allocation of 45% equity investments, 45% fixed income investments, and 10% private equity and real estate investments. Our largest OPEB trust has a target asset allocation of 45% equity investments and 55% fixed income 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(m), Fair Value Measurements, for more information regarding the fair value hierarchy and the classification of fair value measurements based on the types of inputs used.

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

	December 31, 2018							
	Pension Plan Assets				OPEB 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	**$ 5.5**	**$ —**	**$ —**	**$ 5.5**	**$ 0.3**	**$ —**	**$ —**	**$ 0.3**
International Equity	**5.6**	**—**	**—**	**5.6**	**0.4**	**—**	**—**	**0.4**
Fixed income securities: *								
United States Bonds	**1.1**	**8.3**	**—**	**9.4**	**0.2**	**0.5**	**—**	**0.7**
International Bonds	**0.2**	**1.5**	**—**	**1.7**	**—**	**0.1**	**—**	**0.1**
	$ 12.4	**$ 9.8**	**$ —**	**$ 22.2**	**$ 0.9**	**$ 0.6**	**$ —**	**$ 1.5**
Investments measured at net asset value				**$ 22.4**				**$ 1.3**
Total	**$ 12.4**	**$ 9.8**	**$ —**	**$ 44.6**	**$ 0.9**	**$ 0.6**	**$ —**	**$ 2.8**

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

	December 31, 2017							
	Pension Plan Assets				OPEB Plan Assets			
(in millions)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Asset class								
Cash and cash equivalents	$ —	$ 1.6	$ —	$ 1.6	$ —	$ 0.1	$ —	$ 0.1
Equity securities:								
United States Equity	7.0	—	—	7.0	0.5	—	—	0.5
International Equity	7.1	—	—	7.1	0.5	—	—	0.5
Fixed income securities: *								
United States Bonds	1.3	9.2	—	10.5	0.2	0.6	—	0.8
International Bonds	0.2	1.5	—	1.7	—	0.1		0.1
Private Equity and Real Estate	—	4.5	0.9	5.4	—	0.2	—	0.2
	$ 15.6	$ 16.8	$ 0.9	$ 33.3	$ 1.2	$ 1.0	$ —	$ 2.2
Investments measured at net asset value				$ 17.8				$ 1.1
Total	$ 15.6	$ 16.8	$ 0.9	$ 51.1	$ 1.2	$ 1.0	$ —	$ 3.3

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

The following table sets forth a reconciliation of changes in the fair value of pension plan assets categorized as Level 3 in the fair value hierarchy:

(in millions)	Private Equity and Real Estate Pension
Beginning balance at January 1, 2018	**$ 0.9**
Purchases	**0.2**
Transfers out of level 3	**(1.1)**
Ending balance at December 31, 2018	**$ —**

(in millions)	Private Equity and Real Estate Pension
Beginning balance at January 1, 2017	$ —
Purchases	0.9
Ending balance at December 31, 2017	$ 0.9

Cash Flows

We do not expect to make any contributions to our pension and OPEB plans in 2019. Contributions to our pension and OPEB plans are dependent on various factors affecting us, including our liquidity position and the effects of the new Tax Legislation.

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

(in millions)	Pension	OPEB
2019	$ 3.1	$ 0.6
2020	2.6	0.6
2021	2.5	0.5
2022	2.5	0.5
2023	2.8	0.5
2024 through 2028	13.3	2.5

Savings Plans

WEC Energy Group sponsors a 401(k) savings plan that allows substantially all of our full-time employees to contribute a portion of their pre-tax and/or after-tax income in accordance with plan-specified guidelines. A percentage of employee contributions are matched by us through a contribution into the employee's savings plan account, up to certain limits. The 401(k) savings plan includes an Employee Stock Ownership Plan. Certain employees receive an employer retirement contribution, which amounts are contributed to an employee's savings plan account based on the employee's wages, age, and years of service. Our share of the total costs incurred under all of these plans was $1.8 million in both 2018 and 2017, and $1.7 million 2016.

NOTE 12—COMMITMENTS AND CONTINGENCIES

We 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

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

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

			Payments Due By Period					
(in millions)	Date Contracts Extend Through	Total Amounts Committed	2019	2020	2021	2022	2023	Later Years
Natural gas supply and transportation	**2043**	**$ 493.4**	**$ 51.7**	**$ 54.3**	**$ 39.8**	**$ 32.8**	**$ 19.0**	**$ 295.8**

Environmental Matters

Consistent with other companies in the natural gas utility 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 greenhouse gas emissions 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 protection of wetlands and waterways, threatened and endangered species, and cultural resources associated with utility construction projects;
- the reporting of CO_2 emissions to comply with federal clean air rules; and
- the remediation of former manufactured gas plant sites.

Air Quality

Environmental Protection Agency Greenhouse Gases Reporting Program

We are required to report our CO_2 equivalent emissions related to the natural gas that we distribute and sell under the EPA Greenhouse Gases Reporting Program. For 2017, we reported CO_2 equivalent emissions of approximately 2.3 million metric tonnes to the EPA. Based upon our preliminary analysis of the data, we estimate that we will report CO_2 equivalent emissions of approximately 2.6 million metric tonnes to the EPA for 2018.

Land Quality

Manufactured Gas Plant Remediation

We have identified a site at which a predecessor company owned or operated a manufactured gas plant or stored manufactured gas. We are responsible for the environmental remediation of this site. We are also working with the Minnesota Pollution Control Agency on our investigation, monitoring, and remediation.

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 a regulatory asset for costs associated with this site.

We have established the following regulatory asset and reserve related to our manufactured gas plant site as of December 31:

(in millions)	2018	2017
Regulatory asset	**$ 4.7**	$ 9.4
Reserve for future remediation *	**0.7**	7.4

* The reserve for future remediation is included in other long-term liabilities on our balance sheets.

Enforcement and Litigation Matters

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

NOTE 13—SUPPLEMENTAL CASH FLOW INFORMATION

(in millions)	2018	2017	2016
Cash (paid) for interest, net of amount capitalized	**$ (5.0)**	$ (4.0)	$ (5.6)
Cash (paid) received for income taxes, net	**(7.1)**	15.1	2.9
Significant non-cash transactions:			
Accounts payable related to construction costs	**0.7**	7.1	3.7

NOTE 14—REGULATORY ENVIRONMENT

Tax Cuts and Jobs Act of 2017

In December 2017, we deferred for return to ratepayers, through future refunds or bill credits, the estimated tax benefit of $38 million related to the Tax Legislation that was signed into law in December 2017. This tax benefit resulted from the revaluation of deferred taxes. The Tax Legislation also reduced the corporate federal tax rate from a maximum of 35% to a 21% rate, effective January 1, 2018. The MPUC addressed the impacts from the Tax Legislation in its 2018 rate order. See the 2018 Rate Case discussion below for more information.

2018 Rate Case

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

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

The final order addressed the various impacts of the Tax Legislation, including the remeasurement of deferred tax balances. All of the impacts from the Tax Legislation will be included in base rates. The order also approved the continued use of our decoupling mechanism for residential customers. Effective January 1, 2019, our small commercial and industrial customers will no longer be included in the decoupling mechanism. Our request for a property tax tracker was also approved. The property tax tracker recovers or refunds the difference between our actual property tax expense and the amounts included in rates retroactive to January 1, 2008.

2016 Rate Order

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

Gas Utility Infrastructure Cost Rider

In April 2018, we filed an application with the MPUC to establish a rider under Minnesota statute §216B.1635 to begin recovering approximately $12 million of capital investments and $3 million of operating and maintenance expenses related to gas utility infrastructure costs (GUIC). Statute §216B.1635 allows recovery of GUIC incurred to replace or modify natural gas facilities (including costs incurred for surveys, assessments, and other work necessary to determine the need for replacement or modification) to the extent the work is required by state, federal, or other government agencies and exceeds the costs included in base rates. In February 2019, the MPUC issued a final written order approving our use of the GUIC rider to start recovering in 2019 the costs noted above. As we requested, the rider will be subject to an annual true-up.

Natural Gas Extension Project

In response to anticipated growth and customer demand, we are expanding our natural gas distribution system in and around the city of Rochester, Minnesota (Rochester Project). The estimated cost of this project is $44 million, excluding allowance for funds used during construction. In October 2015, we filed an application with the MPUC to recover a portion of the costs of the Rochester Project pursuant to Minnesota's new Natural Gas Extension Project statute through a rider. The rider allows recovery of one-third of the revenue deficiency in excess of the amounts included in base rates in a non-rate case year for eligible natural gas extension projects. In a rate case year, any revenue deficiency for these projects would be collected entirely through base rates. In May 2017, the MPUC issued a final order approving recovery of the cost of the Rochester Project, up to the initial estimate of $44 million, as well as the future use of the rider. Construction of the Rochester Project began in 2017. We are projecting a revenue deficiency related to the Rochester project in 2019 and, consistent with the commission's May 2017 order, we filed for approval in February 2018 to recover the 2019 revenue deficiency through the implementation of the rider starting January 1, 2019. We expect to receive an order from the MPUC related to the implementation of the rider later in 2019.

NOTE 15—NEW ACCOUNTING PRONOUNCEMENTS

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. For lessors however, accounting for leases was largely unchanged from previous provisions of GAAP.

We have finalized our inventory of leases and did not identify any leases that were significant, documented our technical accounting issues, and implemented required changes to internal controls and processes as a result of the new lease guidance. In addition, we continue to finalize the related financial disclosures that will be incorporated into our annual report for the year ended December 31, 2019.

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

- We did not reassess whether any expired or existing contracts were leases or contained leases.
- We did not reassess the lease classification for any expired or existing leases.
- 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, access or cross another entity's land for a specified purpose. This new guidance permits an entity to elect a transitional practical

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

In July 2018, the FASB issued ASU 2018-11, Leases (Topic 842): Targeted Improvements, which amends ASU 2016-02 and allows entities the option to initially apply Topic 842 at the adoption date and recognize a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption, if required. We used the optional transition method to apply the new guidance as of January 1, 2019, rather than as of the earliest period presented. We do not expect the adoption of Topic 842 to result in us recording any significant right of use assets or related lease liabilities related to operating leases, and we had no capital leases upon adoption. We did not require a cumulative-effect adjustment upon adoption of Topic 842, and the new guidance is not expected to have any impact on future net income or cash flows.

Financial Instruments Credit Losses

In June 2016, the FASB issued ASU 2016-13, Measurement of Credit Losses on Financial Instruments. This guidance is effective for fiscal years beginning after December 15, 2021, including interim periods within those fiscal years. This ASU introduces a new impairment model known as the current expected credit loss model. The ASU requires a financial asset measured at amortized cost to be presented at the net amount expected to be collected. Previously, recognition of the full amount of credit losses was generally delayed until the loss was probable of occurring. We are currently assessing the effects this guidance may have on our financial statements.

Cloud Computing

In August 2018, the FASB issued ASU 2018-15, Customer’s Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract. The standard allows entities who are customers in hosting arrangements that are service contracts to apply the existing internal-use software guidance to determine which implementation costs to capitalize as an asset related to the service contract and which costs to expense. The guidance specifies classification for capitalizing implementation costs and related amortization expense within the financial statements and requires additional disclosures. This guidance is effective for fiscal years beginning after December 15, 2020, and interim periods within fiscal years beginning after December 15, 2021. Early adoption is permitted and can be applied either retrospectively or prospectively. We are currently evaluating the transition methods and the impact the adoption of this standard may have on our financial statements.