NORTH SHORE GAS COMPANY

ANNUAL REPORT
FOR THE YEAR ENDED DECEMBER 31, 2015

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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. (previously known as Integrys Energy Group, Inc.)
NSG	North Shore Gas Company
PELLC	Peoples Energy, LLC
PGL	The Peoples Gas Light and Coke Company
WBS	WEC Business Services LLC
WEC Energy Group	WEC Energy Group, Inc.

Federal and State Regulatory Agencies

EPA	United States Environmental Protection Agency
FERC	Federal Energy Regulatory Commission
ICC	Illinois Commerce Commission
SEC	Securities and Exchange Commission

Accounting Terms

ARO	Asset Retirement Obligation
ASC	Accounting Standards Codification
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
GHG	Greenhouse Gas

Measurements

Btu	British Thermal Unit(s)
Dth	Dekatherm(s) (One Dth equals one million Btu)
MDth	One thousand Dekatherms

Other Terms and Abbreviations

GCRM	Gas Cost Recovery Mechanism
Merger Agreement	Agreement and Plan of Merger, dated as of June 22, 2014, between Integrys Energy Group, Inc. and Wisconsin Energy Corporation
N/A	Not Applicable
ROE	Return on Equity

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." 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, effective tax rate, pension and OPEB plans, natural gas deliveries, remediation costs, 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 and those identified below:

- Factors affecting utility operations such as catastrophic weather-related damage, environmental incidents, unplanned repairs and maintenance, and natural gas pipeline system constraints;
- Factors affecting the demand for natural gas, including political developments, unusual weather, changes in economic conditions, customer growth and declines, commodity prices, and energy conservation efforts;
- 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 business;
- The ability to obtain and retain customers due to increased competition in our natural gas markets from retail choice, 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 regulatory changes, including changes in rate-setting policies or procedures, tax law changes, including the extension of bonus depreciation, deregulation and restructuring of the natural gas utility industry, transmission or distribution system operation, the approval process for new construction, pipeline integrity and safety standards, allocation of energy assistance, and energy efficiency mandates;
- Federal and state legislative and regulatory changes relating to the environment, the enforcement of these laws and regulations, changes in the interpretation of permit conditions by regulatory agencies, and the recovery of associated remediation and compliance costs;
- The risks associated with changing commodity prices, particularly natural gas, and the availability of sources of natural gas, transportation problems, nonperformance by natural gas suppliers under existing 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 or us;
- 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 certain affiliates to transfer funds to us in the form of loans or advances;
- 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;

- The direct or indirect effect on our business resulting from terrorist incidents, the threat of terrorist incidents, and cyber intrusion, including the failure to maintain the security of personally identifiable information, the associated costs to protect our assets and personal information, and the costs to notify affected persons to mitigate their information security concerns;

- The investment performance of Integrys's and PELLC's 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;

- The terms and conditions of the governmental and regulatory approvals of WEC Energy Group's acquisition of Integrys that could reduce anticipated benefits and the ability to successfully integrate the operations of the combined company;

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

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

- Other considerations disclosed elsewhere herein and in other reports WEC Energy Group files with the SEC.

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.

BUSINESS

A. INTRODUCTION

In this report, when we refer to "us," "we," "our," or "ours," we are referring to NSG. The term "utility" refers to our regulated activities, while the term "non-utility" refers to our activities that are not regulated. References to "Notes" are to the Notes to the Financial Statements included in this Annual Report.

We are a natural gas utility company that began operations in 1900. We are an Illinois corporation and are wholly owned by PELLC, which is an indirect wholly owned subsidiary of WEC Energy Group, Inc.

For more information about our natural gas utility operations, including financial and geographic information, see Note 17, Segment Information, and Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations.

Merger

On June 29, 2015, Wisconsin Energy Corporation acquired 100% of the outstanding common shares of Integrys and changed its name to WEC Energy Group, Inc. In this report, when we refer to the "WEC Merger," we are referring to this acquisition. For additional information on this merger, see Note 2, Merger.

Available Information

WEC Energy Group's annual and periodical filings with the SEC are available, free of charge, through its Internet website www.wecenergygroup.com, as soon as reasonably practicable after they are filed with or furnished to the SEC.

WEC Energy Group has adopted a written code of ethics, referred to as its Code of Business Conduct. We are an indirect wholly owned subsidiary of WEC Energy Group, and as such, all of our directors, executive officers and employees, including our principal executive officer, principal financial officer and principal accounting officer, have a responsibility to comply with WEC Energy Group's Code of Business Conduct. WEC Energy Group has posted its Code of Business Conduct in the "Governance" section on its website, www.wecenergygroup.com. WEC Energy Group has not provided any waiver to the Code for any director, executive officer or other employee. Any amendments to, or waivers for directors and executive officers from, the Code of Business Conduct will be disclosed on WEC Energy Group's website or in a current report on Form 8-K.

B. NATURAL GAS UTILITY OPERATIONS

We provide natural gas utility service to residential, commercial and industrial, and transportation customers located within the northern suburbs of Chicago.

Operating Statistics

The following table shows certain operating statistics for the past three years:

	2015	2014	2013
Operating revenues ***(in millions)***			
Residential	**$ 138.5**	$ 216.5	$ 157.2
Commercial and industrial	**24.5**	41.1	28.9
Total retail revenues	**163.0**	257.6	186.1
Transport	**26.1**	29.1	21.2
Other operating revenues	**5.5**	0.1	(1.1)
Total	**$ 194.6**	$ 286.8	$ 206.2
Customers – end of year ***(in thousands)***			
Residential	**133.1**	133.6	137.7
Commercial and industrial	**9.2**	9.4	9.7
Transport	**16.5**	15.5	11.3
Total customers	**158.8**	158.5	158.7
Customers – average ***(in thousands)***	**158.7**	158.9	158.5

Natural Gas Supply

We manage a portfolio of natural gas supply contracts, storage contracts, and pipeline transportation services designed to meet varying customer use patterns with safe, reliable natural gas supplies at the best value.

Our natural gas supply requirements are met through a combination of fixed price purchases, index price purchases, contracted storage, a peak-shaving facility, and natural gas supply call options. We contract for fixed-term firm natural gas supply each year to meet the demand of firm system sales customers. To supplement natural gas supply and manage risk, we purchase additional natural gas supply on the monthly and daily spot markets.

For more information on our natural gas utility supply and transportation contracts, see Note 13, Commitments and Contingencies.

We contract with PGL, a related party, and other underground storage service providers for storage services. Storage allows us to manage significant changes in daily natural gas demand and to purchase steady levels of natural gas on a year-round basis, thus providing a hedge against supply cost volatility. We contract with interstate pipelines and another service provider to purchase firm transportation services. Interstate pipelines and one local distribution company's pipeline interconnect with our utility system. We believe that having multiple pipelines that serve our service territory benefits our customers by improving reliability, providing access to a diverse supply of natural gas, and fostering competition among these service providers. These benefits can lead to favorable conditions for us when negotiating new agreements for transportation and storage services. We further reduce our supply cost volatility through the use of financial instruments, such as commodity swaps and options, as part of our hedging program. We hedge between 25% and 50% of natural gas purchases, with a target of 37.5%.

We had adequate capacity to meet all firm natural gas demand obligations during 2015 and expect to have adequate capacity to meet all firm demand obligations during 2016. Our forecasted design peak-day throughput is 4.5 million therms for the 2015 through 2016 heating season.

Seasonality

Since the majority of our customers use natural gas for heating, customer use is sensitive to weather and is generally higher during the winter months. Accordingly, we are subject to variations in earnings and working capital throughout the year as a result of changes in weather.

Our working capital needs are met by cash generated from operations and debt (both long-term and short-term). The seasonality of natural gas revenues causes the timing of cash collections to be concentrated from January through June. A portion of the winter natural gas supply needs is typically purchased and stored from April through November. Also, planned capital spending on our natural gas distribution facilities is concentrated in April through November. Because of these timing differences, the cash flow from customers is typically supplemented with temporary increases in short-term borrowings (from external sources) during the late summer and fall. Short-term debt is typically reduced over the January through June period.

Competition

Although our rates are regulated by the ICC, we still face varying degrees of competition from other entities and other forms of energy available to consumers. Absent extraordinary circumstances, potential competitors are not allowed to construct competing natural gas distribution systems in our service territory due to a judicial doctrine known as the "first in the field." In addition, we believe it would be impractical to construct competing duplicate distribution facilities due to the high cost of installation.

Since 2002, all our natural gas customers have had the opportunity to choose a natural gas supplier other than us. As a result, we offer natural gas transportation service to enable customers to directly manage their energy costs. Transportation customers purchase natural gas directly from third-party natural gas suppliers and use our distribution system to transport the natural gas to their facilities. We still earn a distribution charge for transporting the natural gas for these customers. As such, the loss of revenue associated with the cost of natural gas that our transportation customers purchase from third-party suppliers has little impact on our net income, as it is offset by an equal reduction to natural gas costs.

An interstate pipeline may seek to provide transportation service directly to end users, which would bypass our natural gas transportation service. However, we have a bypass rate approved by the ICC, which allows us to negotiate rates with customers that are potential bypass candidates to help ensure that such customers use our transportation service.

C. REGULATION

In addition to the specific regulations noted below, we are also subject to regulations, where applicable, of the EPA, the Illinois Environmental Protection Agency, and the United States Army Corps of Engineers.

Rates

Our natural gas rates are regulated by the ICC, which has general supervisory and regulatory powers over public utilities in Illinois.

Embedded within our rates is an amount to recover natural gas costs. We operate under a GCRM as approved by the ICC. Generally, the GCRM allows for dollar-for-dollar recovery of prudently incurred natural gas costs. For a summary of the significant mechanisms we had in place in 2015 that allowed us to recover or refund changes in prudently incurred costs from rate case-approved amounts, see Note 1(d), Revenues and Customer Receivables.

For information on how our rates are set, see Note 16, Regulatory Environment. Orders from the ICC can be viewed at https://www.icc.illinois.gov/. The material and information contained on this website is not intended to be a part of, nor is it incorporated by reference into, this Annual Report.

Other Natural Gas Regulations

Almost all of the natural gas we distribute is transported to our distribution systems by interstate pipelines. The pipelines' transportation and storage services are regulated by the FERC under the Natural Gas Act and the Natural Gas Policy Act of 1978. In addition, the Pipeline and Hazardous Materials Safety Administration and the ICC are responsible for monitoring and enforcing requirements governing our natural gas safety compliance programs for our pipelines under United States Department of Transportation regulations. These regulations include 49 Code of Federal Regulations (CFR) Part 192 (Transportation of Natural and Other Gas by Pipeline: Minimum Federal Safety Standards) and 49 CFR Part 195 (Transportation of Hazardous Liquids by Pipeline).

We are required to provide service and grant credit (with applicable deposit requirements) to customers in the northern suburbs of Chicago. The Illinois Public Utilities Act and ICC Administrative Code restrictions generally do not allow us to discontinue service during winter moratorium months to residential heating customers who do not pay their bills. The Federal and Illinois governments have programs that provide for a limited amount of funding for assistance to our low-income customers.

D. ENVIRONMENTAL COMPLIANCE

See Note 13, Commitments and Contingencies, for more information on our environmental matters.

E. EMPLOYEES

As of December 31, 2015, we had 167 employees, which were substantially all full-time. Approximately 121 of our total employees were represented by Local 2285 of International Brotherhood of Electrical Workers, AFL CIO. The current Local 2285 collective bargaining agreement expires on June 30, 2019.

RISK FACTORS

We are subject to a variety of risks, many of which are beyond our control, that may adversely affect our business, financial condition, and results of operations. You should carefully consider the following risk factors, as well as the other information included in this report, when making an investment decision.

Risks Related to Legislation and Regulation

Our business is significantly impacted by governmental regulation.

We are subject to significant state, local, and federal governmental regulation, including regulation by the ICC. This regulation significantly influences our operating environment and may affect our ability to recover costs from utility customers. Many aspects of our operations are regulated, including, but not limited to: the rates we charge our retail natural gas customers; participation in the interstate natural gas pipeline capacity market; standards of service; issuance of debt securities; short-term debt obligations; construction and operation of facilities; transactions with affiliates; and billing practices. Our significant level of regulation imposes restrictions on our operations and causes us to incur substantial compliance costs. Failure to comply with any applicable rules or regulations may lead to customer refunds, penalties, and other payments, which could materially and adversely affect our results of operations and financial condition.

The rates, including adjustments determined under riders, we are allowed to charge our customers for retail services have the most significant impact on our financial condition, results of operations, and liquidity. Rate regulation is based on providing an opportunity to recover prudently incurred costs and earn a reasonable rate of return on invested capital. However, our ability to obtain rate adjustments in the future is dependent on regulatory action, and there is no assurance that our regulators will consider all of our costs to have been prudently incurred. In addition, our rate proceedings may not always result in rates that fully recover our costs or provide for a reasonable ROE. We defer certain costs and revenues as regulatory assets and liabilities for future recovery or refund to customers, as authorized by our regulators. Future recovery of regulatory assets is not assured, and is subject to review and approval by our regulators. If recovery of regulatory assets is not approved or is no longer deemed probable, these costs would be recognized in current period expense and could have a material adverse impact on our results of operations, cash flows, and financial condition.

We believe we have obtained the necessary permits, approvals, authorizations, certificates, and licenses for our existing operations, have complied with all of their associated terms, and that our business is conducted in accordance with applicable laws. These permits, approvals, authorizations, certificates, and licenses may be revoked or modified by the agencies that granted them if facts develop that differ significantly from the facts assumed when they were issued. In addition, discharge permits and other approvals and licenses are often granted for a term that is less than the expected life of the associated facility. Licenses and permits may require periodic renewal, which may result in additional requirements being imposed by the granting agency. In addition, existing regulations may be revised or reinterpreted by federal, state, and local agencies, or these agencies may adopt new laws and regulations that apply to us. We cannot predict the impact on our business and operating results of any such actions by these agencies. Changes in regulations, interpretations of regulations, or the imposition of new regulations could influence our operating environment, may result in substantial compliance costs, or may require us to change our business operations.

If we are unable to obtain, renew, or comply with these governmental permits, approvals, authorizations, certificates, or licenses, or if we are unable to recover any increased costs of complying with additional requirements or any other associated costs in customer rates in a timely manner, our results of operations and financial condition could be materially and adversely affected.

We may face significant costs to comply with existing and future environmental laws and regulations.

Our operations are subject to numerous federal and state environmental laws and regulations. These laws and regulations govern, among other things, air emissions (including CO_2 and methane), water quality, wastewater discharges, and management of hazardous, toxic, and solid wastes and substances. We incur significant costs to comply with these environmental requirements, including costs associated with environmental monitoring and permits at our facilities. In addition, if we fail to comply with environmental laws and regulations, even if caused by factors beyond our control, that failure may result in the assessment of civil or criminal penalties and fines.

Existing environmental laws and regulations may be revised or new laws or regulations may be adopted at the federal or state level that could result in significant additional expenditures for our distribution systems, including, without limitation, costs to further limit GHG emissions from our operations; operating restrictions on our facilities; and increased compliance costs. For example, the EPA has adopted a final rule that would expand traditional federal jurisdiction over navigable waters and related wetlands for permitting and other regulatory matters; however, this rule has been stayed.

We are also subject to significant liabilities related to the investigation and remediation of environmental impacts at certain of our current and former facilities, and at third-party owned sites. We accrue liabilities and defer costs (recorded as regulatory assets) incurred in connection with our former manufactured gas plant sites. These costs include all costs incurred to date that we expect to recover, management's best estimates of future costs for investigation and remediation, and related legal expenses, and are net of amounts recovered by or that may be recovered from insurance or other third parties. Due to the potential for imposition of stricter standards and greater regulation in the future, as well as the possibility that other potentially responsible parties may not be financially able to contribute to cleanup costs, conditions may change or additional contamination may be discovered, our remediation costs could increase, and the timing of our capital and/or operating expenditures in the future may accelerate or could vary from the amounts currently accrued.

In the event we are not able to recover all of our environmental expenditures and related costs from our customers in the future, our results of operations and financial condition could be adversely affected. Further, increased costs recovered through rates could contribute to reduced demand for natural gas, which could adversely affect our results of operations, cash flows, and financial condition.

Litigation over environmental issues and claims of various types, including property damage, personal injury, common law nuisance, and citizen enforcement of environmental requirements, has increased generally throughout the United States. In particular, personal injury, property damage, and other claims for damages alleged to have been caused by environmental impacts and alleged exposure to hazardous materials have become more frequent. In addition to claims relating to our current facilities, we may also be subject to potential liability in connection with the environmental condition of facilities that we previously owned and operated, regardless of whether the liabilities arose before, during, or after the time we owned or operated these facilities. If we fail to comply with environmental laws and regulations or cause (or caused) harm to the environment or persons, that failure or harm may result in the assessment of civil penalties and damages against us. The incurrence of a material environmental liability or a material judgment in any action for personal injury or property damage related to environmental matters could have a significant adverse effect on our results of operations and financial condition.

We may face significant costs to comply with the regulation of greenhouse gas emissions.

Our natural gas delivery systems may generate fugitive gas as a result of normal operations and as a result of excavation, construction, and repair of natural gas delivery systems. Fugitive gas typically vents to the atmosphere and consists primarily of methane. CO_2 is also a byproduct of natural gas consumption. As a result, future legislation to regulate GHG emissions could increase the price of natural gas, restrict the use of natural gas, and adversely affect our ability to operate our natural gas facilities. A significant increase in the price of natural gas may increase rates for our natural gas customers, which could reduce natural gas demand.

Risks Related to the Operation of Our Business

Our operations are subject to risks arising from the reliability of our natural gas distribution facilities, natural gas infrastructure facilities, and other facilities.

Our financial performance depends on the successful operation of our natural gas distribution facilities. The operation of these facilities involves many risks, including operator error and the breakdown or failure of equipment or processes. Potential breakdown or failure may occur due to severe weather; catastrophic events (i.e., fires, earthquakes, explosions, tornadoes, floods, droughts, pandemic health events, etc.); transportation disruptions; accidents; employee labor disputes; construction delays or cost overruns; shortages of or delays in obtaining equipment, material, and/or labor; performance below expected levels; operating limitations that may be imposed by environmental or other regulatory requirements; terrorist attacks; or cyber security threats. Any of these events could lead to substantial financial losses.

Insurance, warranties, performance guarantees, or recovery through the regulatory process may not cover any or all of these lost revenues or increased expenses, which could adversely affect our results of operations and cash flows.

Our operations are subject to various conditions that can result in fluctuations in natural gas sales to customers, including customer growth and general economic conditions in our service areas, varying weather conditions, and energy conservation efforts.

Our results of operations and cash flows are affected by the demand for natural gas, which can vary greatly based upon:

- *Fluctuations in customer growth and general economic conditions in our service areas.* Customer growth and energy use can be negatively impacted by population declines as well as economic factors in our service territories, including job losses, decreases in income, and business closings. Our natural gas operations are impacted by economic cycles and the competitiveness of the commercial and industrial customers we serve. Any economic downturn or disruption of financial markets could adversely affect the financial condition of our customers and demand for their products. These risks could directly influence the demand for natural gas. We could also be exposed to greater risks of accounts receivable write-offs if customers are unable to pay their bills.
- *Weather conditions*. Demand for natural gas peaks in the winter heating season. As a result, our overall results may fluctuate substantially on a seasonal basis. In addition, milder temperatures during the winter heating season may result in lower revenues and net income.
- *Our customers' continued focus on energy conservation and ability to meet their own energy needs*. Customers could voluntarily reduce their consumption of natural gas in response to decreases in their disposable income, increases in natural gas prices, and individual conservation efforts through the use of more energy efficient technologies. Conservation of energy can be influenced by certain federal and state programs that are intended to influence how consumers use energy.

As part of our planning process, we estimate the impacts of changes in customer growth and general economic conditions, weather, and customer energy conservation efforts, but risks still remain. Any of these matters, as well as any regulatory delay in adjusting rates as a result of reduced sales from effective conservation measures or the adoption of new technologies, could adversely impact our results of operations and financial condition.

Our operations are subject to risks beyond our control, including but not limited to, cyber security intrusions, terrorist attacks, acts of war, or unauthorized access to personally identifiable information.

We face the risk of terrorist and cyber intrusions, both threatened and actual, against our natural gas distribution infrastructure, our information and technology systems, and network infrastructure, including that of third parties on which we rely, any of which could result in a full or partial disruption of our ability to purchase or distribute natural gas or cause environmental repercussions. Any operational disruption or environmental repercussions could result in a significant decrease in our revenues or significant reconstruction or remediation costs, which could materially and adversely affect our results of operations, financial condition, and cash flows.

We operate in an industry that requires the use of sophisticated information technology systems and network infrastructure, which control an interconnected system of distribution and transmission systems shared with third parties. A successful physical or cyber security intrusion may occur despite our security measures or those that we require our vendors to take. Successful cyber intrusions, including those targeting the electronic control systems used at our natural gas transmission, distribution, and storage systems, could disrupt our operations and result in loss of service to customers. These intrusions may cause additional maintenance expenses. The risk of such intrusions may also increase our capital and operating costs as a result of having to implement increased security measures for protection of our information technology and infrastructure.

We face on-going threats to our assets and technology systems. Despite the implementation of strong security measures, all assets and systems are potentially vulnerable to disability, failures, or unauthorized access due to human error or physical or cyber intrusions. If our assets or systems were to fail, be physically damaged, or be breached and were not recovered in a timely manner, we may be unable to perform critical business functions, and sensitive and other data could be compromised.

Our business requires the collection and retention of personally identifiable information of our customers and employees, who expect that we will adequately protect such information. Security breaches may expose us to a risk of loss or misuse of confidential and proprietary information. A significant theft, loss, or fraudulent use of personally identifiable information may lead to potentially large costs to notify and protect the impacted persons, and/or could cause us to become subject to significant litigation, costs, liability, fines, or penalties, any of which could materially and adversely impact our results of operations as well as our reputation with customers and regulators, among others. In addition, we may be required to incur significant costs associated with governmental actions in response to such intrusions or to strengthen our information and electronic control systems. We may also need to obtain additional insurance coverage related to the threat of such intrusions.

The costs of repairing damage to our facilities, protecting personally identifiable information, and notifying impacted persons, as well as related legal claims, may not be recoverable in rates, may exceed the insurance limits on our insurance policies, or, in some cases, may not be covered by insurance.

Transporting, distributing, and storing natural gas involves numerous risks that may result in accidents and other operating risks and costs.

Inherent in natural gas distribution activities are a variety of hazards and operational risks, such as leaks, accidental explosions, including third party damages, and mechanical problems, which could materially and adversely affect our results of operations, financial condition, and cash flows. In addition, these risks could result in serious injury to employees and non-employees, loss of human life, significant damage to property, environmental pollution, impairment of operations, and substantial losses to us. The location of natural gas pipelines and storage facilities near populated areas, including residential areas, commercial business centers, and industrial sites, could increase the level of damages resulting from these risks. These activities may subject us to litigation or administrative proceedings from time to time, which could result in substantial monetary judgments, fines, or penalties against us, or be resolved on unfavorable terms.

We may fail to attract and retain an appropriately qualified workforce.

We operate in an industry that requires many of our employees to possess unique technical skill sets. Events such as an aging workforce without appropriate replacements, the mismatch of skill sets to future needs, or the unavailability of contract resources may lead to operating challenges or increased costs. These operating challenges include lack of resources, loss of knowledge, and a lengthy time period associated with skill development. In addition, current and prospective employees may determine that they do not wish to work for us. Failure to hire and obtain replacement employees, including the ability to transfer significant internal historical knowledge and expertise to the new employees, may adversely affect our ability to manage and operate our business. If we are unable to successfully attract and retain an appropriately qualified workforce, our results of operations could be adversely affected.

Failure of our counterparties to meet their obligations, including obligations under natural gas supply and transportation agreements, could have an adverse impact on our results of operations.

We are exposed to the risk that counterparties to various arrangements who owe us money, natural gas, or other commodities or services will not be able to perform their obligations. Should the counterparties to these arrangements fail to perform, we may be required to replace the underlying commitment at current market prices or we may be unable to meet all of our customers' natural gas requirements unless or until alternative supply arrangements are put in place. In such event, we may incur losses, and our results of operations, financial position, or liquidity could be adversely affected.

We have entered into several natural gas supply and transportation agreements with non-affiliated companies, and continue to look for additional opportunities to enter into these agreements. Revenues are dependent on the continued performance by the purchasers of their obligations under the natural gas supply and transportation agreements. Although we have a comprehensive credit evaluation process and contractual protections, it is possible that one or more purchasers could fail to perform their obligations under the natural gas supply and transportation agreements. If this were to occur, we would expect that any operating and other costs that were initially allocated to a defaulting customer's natural gas and transportation agreement would be reallocated among our retail customers. To the extent there is any regulatory delay in adjusting rates, a customer default under a natural gas and transportation agreement could have a negative impact on our results of operations and cash flows.

Risks Related to Economic and Market Volatility

Our business is dependent on our ability to successfully access capital markets.

We rely on access to credit and capital markets to support our capital requirements, including expenditures for our utility infrastructure and to comply with future regulatory requirements, to the extent not satisfied by the cash flow generated by our operations. We have historically secured funds from a variety of sources, including the issuance of short-term and long-term debt securities. Successful implementation of our long-term business strategies, including capital investment, is dependent upon our, WEC Energy Group's, or PGL's ability to access the capital markets, including the banking and commercial paper markets, on competitive terms and rates.

Access to the credit and capital markets could be limited, or our cost of capital significantly increased, due to any of the following risks and uncertainties:

- A rating downgrade;
- An economic downturn or uncertainty;
- Prevailing market conditions;
- Concerns over foreign economic conditions;
- Changes in tax policy;
- War or the threat of war; and
- The overall health and view of the utility and financial institution industries.

If any of these risks or uncertainties limit access to the credit and capital markets or significantly increase our cost of capital, it could limit our ability to implement, or increase the costs of implementing, our business plan, which, in turn, could materially and adversely affect our results of operations, cash flows, and financial condition.

A downgrade in our or WEC Energy Group's credit ratings could negatively affect our ability to access capital at reasonable costs and/or require the posting of collateral.

There are a number of factors that impact our credit ratings, including, but not limited to, capital structure, regulatory environment, the ability to cover liquidity requirements, and other requirements for capital. We could experience a downgrade in ratings if the rating agencies determine that the level of business or financial risk of us or the utility industry has deteriorated. Changes in rating methodologies by the rating agencies could also have a negative impact on credit ratings.

Any downgrade by the rating agencies could:

- Require the payment of higher interest rates in future financings and possibly reduce the pool of creditors;
- Limit the availability of adequate credit support for our operations; and
- Trigger collateral requirements in various contracts.

Fluctuating commodity prices could negatively impact our natural gas utility operations.

The margins and liquidity requirements of our business are impacted by changes in the forward and current market prices of natural gas.

The cost of natural gas may increase because of disruptions in the supply of natural gas due to a curtailment in production or distribution, international market conditions, the demand for natural gas, and the availability of shale gas and potential regulations affecting its accessibility. We receive dollar-for-dollar recovery of prudently incurred natural gas costs.

Changes in commodity prices could result in:

- Higher working capital requirements, particularly related to natural gas inventory, accounts receivable, and cash collateral postings;
- Reduced profitability to the extent that reduced margins, increased bad debt, and interest expense are not recovered through rates;
- Higher rates charged to our customers, which could impact our competitive position; and
- Reduced demand for natural gas, which could impact margins and operating expenses.

The use of derivative contracts could result in financial losses.

We use derivative instruments such as swaps, options, futures, and forwards to manage commodity price exposure. We could recognize financial losses as a result of volatility in the market value of these contracts or if a counterparty fails to perform. These risks are managed through risk management policies, which might not work as planned and cannot entirely eliminate the risks associated with these activities. In addition, derivative contracts entered into for hedging purposes might not offset the underlying exposure being hedged as expected, resulting in financial losses. In the absence of actively quoted market prices and pricing information from external sources, the value of these financial instruments can involve management's judgment or use of estimates. Changes in the underlying assumptions or use of alternative valuation methods could affect the value of the reported fair value of these contracts.

We may experience poor investment performance of benefit plan holdings due to changes in assumptions and market conditions.

We have significant obligations related to pension and OPEB plans. If WEC Energy Group is unable to successfully manage our benefit plan assets and medical costs, our cash flows, financial condition, or results of operations could be adversely impacted.

Our cost of providing these plans is dependent upon a number of factors, including actual plan experience, changes made to the plans, and assumptions concerning the future. Types of assumptions include earnings on plan assets, discount rates, the level of interest rates used to measure the required minimum funding levels of the plans, future government regulation, estimated withdrawals by retirees, and our required or voluntary contributions to the plans. Plan assets are subject to market fluctuations and may yield returns that fall below projected return rates. In addition, medical costs for both active and retired employees may increase at a rate that is significantly higher than we currently anticipate. Our funding requirements could be impacted by a decline in the market value of plan assets, changes in interest rates, changes in demographics (including the number of retirements), or changes in life expectancy assumptions.

We may be unable to obtain insurance on acceptable terms or at all, and the insurance coverage we do obtain may not provide protection against all significant losses.

Our ability to obtain insurance, as well as the cost and coverage of such insurance, could be affected by developments affecting our business; international, national, state, or local events; and the financial condition of insurers. Insurance coverage may not continue to be available at all or at rates or terms similar to those presently available to us. In addition, our insurance may not be sufficient or effective under all circumstances and against all hazards or liabilities to which we may be subject. Any losses for which we are not fully insured or that are not covered by insurance at all could materially adversely affect our results of operations, cash flows, and financial position.

Risks Related to the WEC Merger

The WEC Merger may not achieve its anticipated results, and WEC Energy Group may be unable to integrate operations as expected.

The Merger Agreement was entered into with the expectation that the merger would result in various benefits, including, among other things, cost savings and operating efficiencies. Achieving the anticipated benefits of the merger is subject to a number of uncertainties, including whether the businesses of WEC Energy Group can be integrated in an efficient, effective, and timely manner.

It is possible that the integration process could take longer than anticipated and could result in the loss of valuable employees; the disruption of ongoing businesses, processes, and systems; or inconsistencies in standards, controls, procedures, practices, policies, and compensation arrangements, any of which could adversely affect WEC Energy Group's ability to achieve the anticipated benefits of the transaction as and when expected. WEC Energy Group may have difficulty addressing possible differences in corporate cultures and management philosophies. Failure to achieve the anticipated benefits of the merger could result in increased costs or decreases in the amount of expected revenues and could adversely affect our future business, financial condition, operating results, and prospects.

PROPERTIES

Most of our principal plants and properties, other than mains, services, meters, and regulators are located on property owned in fee. Substantially all natural gas mains are located under public streets, alleys, and highways, or under property owned by others under grants of easements. Meters and house regulators in use and a portion of services are located on the premises being served. Certain portions of the transmission system are located on land held pursuant to leases, easements, or permits.

Natural Gas Facilities

At December 31, 2015, the majority of our natural gas properties were located in Illinois and consisted of the following:

- Approximately 2,400 miles of natural gas distribution mains,
- Approximately 30 miles of natural gas transmission mains located in Illinois and Wisconsin,
- Approximately 144,000 natural gas lateral services,
- 5 natural gas distribution and transmission gate stations, and
- A peak-shaving facility that can store the equivalent of approximately 80 MDth in liquefied petroleum gas located in Illinois.

General

Substantially all of our utility plant is subject to the first mortgage lien of our mortgage indenture for the benefit of bondholders.

NORTH SHORE GAS COMPANY
COMPARATIVE FINANCIAL DATA AND OTHER STATISTICS

As of or for Year Ended December 31 *(in millions)*	**2015**	2014	2013	2012	2011
Operating revenues	**$ 194.6**	$ 286.8	$ 206.2	$ 162.3	$ 201.4
Net income	**12.7**	11.1	12.3	8.2	9.9
Total assets [1] [2]	**457.4**	466.6	453.3	434.9	426.7
Long-term debt (excluding current portion) [1]	**81.5**	81.4	81.4	27.7	73.7

[1] In the fourth quarter of 2015, we early implemented ASU 2015-03, Simplifying the Presentation of Debt Issuance Costs. As a result, debt issuance costs previously reported as other long-term assets were reclassified to offset long-term debt for all periods presented. Amounts reclassified were $0.6 million in 2014, $0.6 million in 2013, $0.3 million in 2012, and $0.9 million in 2011.

[2] In the fourth quarter of 2015, we early implemented ASU 2015-17, Balance Sheet Classification of Deferred Taxes. As a result, current deferred income taxes previously reported as current assets were reclassified to offset long-term deferred income tax liabilities. Amounts reclassified were $1.6 million in 2014 and $1.0 million in 2012. No reclassifications were needed for 2013 or 2011.

MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

CORPORATE DEVELOPMENTS

Introduction

We are a natural gas utility and an indirect wholly owned subsidiary of WEC Energy Group. We purchase, store, distribute, sell, and transport natural gas to customers in the northern suburbs of Chicago, Illinois.

Corporate Strategy

Our goal is to create long-term value for WEC Energy Group's stockholders and our customers by focusing on the following:

Reliability

We plan to continue making capital investments to strengthen the reliability of our natural gas distribution network.

Operating Efficiency

We continually look for ways to optimize the operating efficiency of our company. We are committed to integrating resources and finding the best and most efficient processes, while meeting all applicable legal and regulatory requirements.

Financial Discipline

A strong adherence to financial discipline is essential to earning our authorized ROE and maintaining a strong balance sheet, stable cash flows, and quality credit ratings.

Exceptional Customer Care

Our approach is driven by an intense focus on delivering exceptional customer care every day. We strive to provide the best value for our customers by embracing constructive change, leveraging our capabilities and expertise, and using creative solutions to meet or exceed our customers' expectations.

RESULTS OF OPERATIONS

Earnings

(in millions)	Year Ended December 31 2015	2014	2013
Operating income	**$ 23.8**	$ 21.8	$ 23.7
Other income, net	**0.6**	0.3	—
Interest expense	**3.5**	3.6	3.8
Other expense	**(2.9)**	(3.3)	(3.8)
Income before income taxes	**20.9**	18.5	19.9
Income tax expense	**8.2**	7.4	7.6
Net income	**$ 12.7**	$ 11.1	$ 12.3

2015 Compared with 2014

We recognized earnings of $12.7 million in 2015, compared with $11.1 million in 2014. The primary driver of the $1.6 million increase in earnings was an approximate $2 million after-tax increase in margins due to our rate orders, effective January 28, 2015, and updated effective February 26, 2015.

2014 Compared with 2013

We recognized earnings of $11.1 million in 2014, compared with $12.3 million in 2013. The primary drivers of the $1.2 million decrease in earnings were:

- A $2.8 million after-tax increase in operating expenses, excluding items directly offset in margins, driven by an increase in natural gas distribution costs.

- An approximate $1 million after-tax negative impact due to a reversal in 2013 of reserves established in 2012 against a regulatory asset related to decoupling. See Note 16, Regulatory Environment, for more information.

These decreases were partially offset by:

- An approximate $2 million after-tax increase in margins due to our rate orders, effective June 27, 2013, and updated effective January 1, 2014.

- An approximate $1 million after-tax increase from the combined effect of colder weather year over year, the impact of higher weather-normalized sales volumes, and the impact of our decoupling mechanism.

Operating Income

Natural gas utility margins are defined as natural gas utility operating revenues less the cost of natural gas purchased for resale. Management believes that natural gas utility margins provide a more meaningful basis for evaluating natural gas utility operations than natural gas utility revenues, since prudently incurred natural gas commodity costs are passed through to our customers in current rates. There was an approximate 37% decrease and a 43% increase in the average per-unit cost of natural gas sold during 2015 and 2014, respectively, which had no impact on margins.

	Year Ended December 31		
(in millions)	**2015**	**2014**	**2013**
Operating revenues	**$ 194.6**	$ 286.8	$ 206.2
Cost of natural gas	**92.6**	177.5	114.9
Total natural gas margins	**102.0**	109.3	91.3
Other operation and maintenance	**64.5**	74.6	55.3
Depreciation and amortization	**11.9**	11.1	10.5
Property and revenue taxes	**1.8**	1.8	1.8
Operating income	**$ 23.8**	$ 21.8	$ 23.7

The following tables provide information on sales volumes by customer class and weather statistics:

	Therms *(in millions)*		
Natural Gas Sales Volumes	**2015**	**2014**	**2013**
Customer Class			
Residential	**172.7**	210.1	196.8
Commercial and industrial	**35.1**	44.0	39.8
Total retail	**207.8**	254.1	236.6
Transport	**134.1**	146.9	138.3
Total sales in therms	**341.9**	401.0	374.9

	Degree Days		
Weather *	**2015**	**2014**	**2013**
Heating (6,160 Normal)	**6,107**	7,021	6,573

* Normal heating degree days are based on a 12-year moving average of monthly total heating degree days at Chicago's O'Hare Airport.

NSG recovers certain operating expenses directly through separate riders, resulting in no impact on operating income as increases in operating expenses are offset by equal increases in margins. The following table shows the impact of these riders on margins and operating expenses.

(in millions)	2015	2014	2013
Environmental cleanup costs	**$ 10.6**	$ 16.8	$ 2.0
Energy efficiency program	**2.8**	5.1	5.9
Bad debt rider	**0.8**	2.2	0.9
Total increase in margins and operating expenses	**$ 14.2**	$ 24.1	$ 8.8

2015 Compared with 2014

Operating Income

Operating income increased $2.0 million, driven by an approximate $3.0 million net increase in margins due to our rate orders, effective January 28, 2015, and updated effective February 26, 2015.

2014 Compared with 2013

Operating income decreased $1.9 million, driven by:

- A $3.8 million increase in natural gas distribution costs, primarily driven by cross bore inspections performed during 2014.

- The approximate $2 million year-over-year negative impact on margins of a reversal in 2013 of reserves established in 2012 against a regulatory asset related to decoupling. The reversal was recorded after the Illinois Appellate Court issued an opinion in March 2013 that affirmed the ICC's order approving the decoupling mechanism. See Note 16, Regulatory Environment, for more information.

These decreases were partially offset by:

- An approximate $3 million net increase in margins due to our rate orders, effective June 27, 2013, and updated effective January 1, 2014. See Note 16, Regulatory Environment, for more information.

- An approximate $1 million net increase in margins from the combined effect of colder weather year over year, the impact of higher weather-normalized sales volumes, and the impact of our decoupling mechanism. Margins for certain customer classes in both years were sensitive to volume and other variances as they were not covered by the decoupling mechanism. See Note 16, Regulatory Environment, for more information on our decoupling mechanism.

Other Expense

	Year Ended December 31		
(in millions)	2015	2014	2013
Other income, net	**$ 0.6**	$ 0.3	$ —
Interest expense	**3.5**	3.6	3.8
Other expense	**$ (2.9)**	$ (3.3)	$ (3.8)

There was no significant changes in other expense for the periods presented.

Income Tax Expense

	Year Ended December 31		
	2015	2014	2013
Effective Tax Rate	**39.2%**	40.0%	38.2%

2015 Compared with 2014

There were no significant changes in the effective tax rate for 2015.

2014 Compared with 2013

Our effective tax rate increased in 2014. In 2013, we reduced the provision for income taxes by $0.4 million due to the reversal of a regulatory liability. Deferred income taxes that had been recorded in prior years were reversed as a result of the treatment of scheduled income tax rate changes in Illinois in our final 2013 rate order.

For information on changes in the deferred income tax balances, see Note 11, Income Taxes.

LIQUIDITY AND CAPITAL RESOURCES

Cash Flows

The following summarizes our cash flows during 2015, 2014, and 2013:

(in millions)	**2015**	**2014**	**2013**	**Change in 2015 Over 2014**	**Change in 2014 Over 2013**
Cash provided by (used in):					
Operating activities	**$ 58.4**	$ 21.0	$ 21.5	$ 37.4	$ (0.5)
Investing activities	**(31.4)**	(31.4)	(33.8)	—	2.4
Financing activities	**(27.3)**	10.6	12.4	(37.9)	(1.8)

Operating Activities

2015 Compared with 2014

Net cash provided by operating activities increased $37.4 million in 2015, driven by:

- A $14.9 million increase in cash due to lower payments for operating and maintenance costs in 2015.
- A $9.1 million decrease in cash paid in 2015 related to the timing of payments for environmental remediation activities.
- A $5.1 million decrease in contributions to pension and OPEB plans.
- A $3.5 million net increase in cash related to lower payments for natural gas, partially offset by lower overall collections from customers in 2015. This net increase in cash was primarily due to the impact of lower commodity prices in 2015.
- A $2.8 million increase in cash from higher prepayments from customers participating in our budget billing program, driven by the warmer winter in 2015.

2014 Compared with 2013

Net cash provided by operating activities decreased $0.5 million in 2014, driven by:

- An $80.9 million decrease in cash due to higher costs of natural gas in 2014. Additional cash was used in 2014 due to higher natural gas prices and higher sales volumes, partially driven by the colder weather.
- A $21.8 million decrease in cash due to higher payments for operating and maintenance costs in 2014. The increase in operating and maintenance costs was partially driven by higher natural gas distribution costs related to cross bore inspections and various other expenses.
- A $3.1 million increase in contributions to pension and OPEB plans.

These decreases in cash were partially offset by:

- A $97.7 million increase in cash collections from customers, mainly due to higher natural gas prices and higher sales volumes, partially driven by the colder weather in 2014. Our 2014 rate increase and higher recoveries from customers under certain riders also contributed to the increase in cash collections.

- A $1.7 million increase in cash from customer prepayments and credit balances. In 2013, cash received in relation to amounts billed was lower because customer prepayments had grown during an unusually warm 2012.

Investing Activities

2015 Compared with 2014

There were no significant changes in net cash related to investing activities in 2015.

2014 Compared with 2013

Net cash used for investing activities decreased $2.4 million in 2014, partially driven by a $1.1 million decrease in cash used to fund capital expenditures.

Financing Activities

2015 Compared with 2014

Net cash related to financing activities decreased $37.9 million in 2015, driven by:

- A $30.3 million net decrease in cash driven by $19.8 million of repayments in 2015 related to a note payable to PGL, compared with $10.5 million of borrowings from PGL in 2014.

- A $7.5 million payment of dividends to our parent, PELLC, in 2015.

2014 Compared with 2013

Net cash provided by financing activities decreased $1.8 million in 2014, driven by:

- A $7.5 million net decrease in cash in 2014 related to long-term debt. In 2013, we received cash proceeds from the issuance of long-term debt of $54.0 million, which was partially offset by cash used in 2013 for the repayment of long-term debt in the amount of $46.5 million.

- A $6.8 million decrease in cash due to lower borrowings in 2014 related to a notes payable to PGL.

These decreases in cash were partially offset by $12.0 million of dividends paid to our parent, PELLC, in 2013.

Significant Financing Activities

For information on our long-term debt, see Note 10, Long-Term Debt.

Capital Resources and Requirements

Liquidity

Management prioritizes the use of capital and debt capacity, determines cash management policies, uses risk management strategies to hedge the impact of volatile commodity prices, and makes decisions regarding capital requirements in order to manage our liquidity and capital resource needs. We plan to meet our capital requirements for the period 2016 through 2018 primarily through internally generated funds (net of forecasted dividend payments to our parent), debt financings, and equity infusions from our parent. We plan to keep debt to equity ratios at levels that can support current credit ratings and corporate growth.

We have the ability to borrow up to $50.0 million from Integrys and up to $50.0 million from PGL. At December 31, 2015, we had $28.8 million of borrowings outstanding with PGL and no borrowings outstanding with Integrys.

At December 31, 2015, we were in compliance with all covenants related to outstanding long-term debt. We expect to be in compliance with all such debt covenants for the foreseeable future. See Note 10, Long-Term Debt, for more information on our long-term debt agreements.

Working Capital

As of December 31, 2015, our current liabilities exceeded our current assets by $30.5 million. We do not expect this to have an impact on our liquidity. We have access to the capital markets to finance our construction programs.

Capital Requirements

Contractual Obligations

The following table shows our contractual obligations as of December 31, 2015.

(in millions)	Total Amounts Committed	Payments Due By Period 2016	2017 to 2018	2019 to 2020	Later Years
Long-term debt principal and interest payments [1]	$ 151.3	$ 3.1	$ 6.2	$ 6.2	$ 135.8
Natural gas supply and transportation purchase obligations [2]	50.6	21.6	23.4	2.8	2.8
Purchase orders [3]	16.2	12.8	3.4	—	—
Pension and other postretirement funding obligations [4]	0.6	0.2	0.4	—	—
Total contractual cash obligations	**$ 218.7**	**$ 37.7**	**$ 33.4**	**$ 9.0**	**$ 138.6**

(1) Represents bonds issued. We record all principal obligations on the balance sheet.

(2) Natural gas supply and transportation purchase obligations under various contracts for the procurement of gas supply and associated transportation related to utility operations.

(3) Includes obligations related to normal business operations and large construction obligations.

(4) Obligations for pension and OPEB benefit plans cannot reasonably be estimated beyond 2018.

The table above does not reflect estimated future payments related to the manufactured gas plant remediation liability of $45.0 million at December 31, 2015, as the amount and timing of payments are uncertain. We expect to incur costs annually to remediate these sites. See Note 13, Commitments and Contingencies, for more information about environmental liabilities.

AROs in the amount of $17.0 million are not included in the above table. Settlement of these liabilities cannot be determined with certainly, but we believe the majority of these liabilities will be settled beyond 2020. See Note 7, Asset Retirement Obligations, for more information.

Obligations for utility operations have historically been included as part of the rate-making process and therefore are generally recoverable from customers.

Capital Expenditures and Significant Capital Projects

We have several capital projects that will require significant capital expenditures over the next three years and beyond. All projected capital requirements are subject to periodic review and may vary significantly from estimates, depending on a number of factors. These factors include environmental requirements, regulatory restraints and requirements, changes in tax laws and regulations, acquisition and development opportunities, market volatility, and economic trends. Our estimated capital expenditures for the next three years are as follows:

(in millions)		
2016	$	20.4
2017		21.5
2018		22.0
Total	$	63.9

The majority of spending consists of upgrading our natural gas pipe distribution system.

Common Stock Matters

For information related to our common stock matters, see Note 8, Common Equity.

Investments in Outside Trusts

We use outside trusts to fund our pension and certain OPEB obligations. These trusts had investments of approximately $57.1 million as of December 31, 2015. These trusts hold investments that are subject to the volatility of the stock market and interest rates. We contributed $0.4 million, $5.5 million, and $2.4 million to our pension and OPEB plans in 2015, 2014, and 2013, respectively. Future contributions to the plans will be dependent upon many factors, including the performance of existing plan assets and long-term discount rates. For additional information, see Note 12, Employee Benefits.

FACTORS AFFECTING RESULTS, LIQUIDITY, AND CAPITAL RESOURCES

Market Risks and Other Significant Risks

We are exposed to market and other significant risks as a result of the nature of our business and the environment in which we operate. These risks, described in further detail below, include but are not limited to:

Regulatory Recovery

We account for our regulated operations in accordance with accounting guidance under the Regulated Operations Topic of the FASB ASC. Our rates are determined by the ICC. See Business – C. Regulation, for more information.

Regulated entities are allowed to defer certain costs that would otherwise be charged to expense, if the regulated entity believes the recovery of these costs is probable. We record regulatory assets pursuant to specific orders or by a generic order issued by the ICC. Recovery of these deferred costs in future rates is subject to the review and approval by the ICC. We assume the risks and benefits of ultimate recovery of these items in future rates. If the recovery of these costs is not approved by the ICC, the costs are charged to income in the current period. In general, our regulatory assets are recovered over a period of one to three years. The ICC can impose liabilities on a prospective basis for amounts previously collected from customers and for amounts that are expected to be refunded to customers. We record these items as regulatory liabilities. As of December 31, 2015, our regulatory assets totaled $81.3 million and our regulatory liabilities totaled $18.1 million.

Prior to the WEC Merger (for a discussion of the merger see Note 2, Merger), Integrys initiated an IT project with the goal of improving the customer experience at its subsidiaries, including us. Specifically, the project is expected to provide functional and technological benefits to the billing, call center, and credit collection functions. As of December 31, 2015, none of the costs have been disallowed in rate proceedings. We will be required to obtain approval for the recovery of additional costs incurred through the completion of this long-term project. See Note 16, Regulatory Environment, for additional information regarding recent and pending rate proceedings, orders, and investigations involving us.

Natural Gas Costs

In the normal course of providing natural gas utility service, we are subject to market fluctuations in the costs of natural gas. We manage our natural gas supply costs through a portfolio of short and long-term procurement contracts with various suppliers for the purchase of natural gas. In addition, we manage the risk of price volatility through natural gas hedging programs.

Embedded within our utility rates are amounts to recover natural gas costs. We have a GCRM in place that allows us to recover or refund all or a portion of the changes in prudently incurred natural gas costs from rate case-approved amounts.

Higher natural gas costs can increase our working capital requirements, and lead to increased energy efficiency investments by our customers to reduce utility usage. Higher natural gas costs combined with slower economic conditions also expose us to greater risks of accounts receivable write-offs as more customers are unable to pay their bills. See Note 1(d), Revenues and Customer Receivables, for more information on our rider that allows for cost recovery or refund of uncollectible expense.

Weather

Our utility rates are based upon estimated normal temperatures. Our natural gas revenues are unfavorably sensitive to above normal temperatures during the winter heating season. We have a decoupling mechanism in place that helps reduce the impacts of weather. Our decoupling mechanism allows us to recover or refund certain differences between actual and authorized margins. A summary of actual weather information in our service territories during 2015, 2014, and 2013, as measured by degree days, may be found in Management's Discussion and Analysis of Financial Condition and Results of Operations – Results of Operations.

Marketable Securities Return

We use various trusts to fund our pension and OPEB obligations. These trusts invest in debt and equity securities. Changes in the market prices of these assets can affect future pension and OPEB expenses. Additionally, future contributions can also be affected by the investment returns on trust fund assets. We believe that the financial risks associated with investment returns would be partially mitigated through future rate actions by the ICC.

The fair value of our trust fund assets and expected long-term returns were approximately:

(in millions)		As of December 31, 2015	Expected Return on Assets in 2016
Pension trust funds	$	**38.0**	7.25%
OPEB trust funds	$	**19.1**	7.25%

Fiduciary oversight of the pension and OPEB trust fund investments is the responsibility of an Investment Trust Policy Committee. The Committee works with external actuaries and investment consultants on an ongoing 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 asset allocations are determined utilizing projected benefit payment cash flows and risk analyses of appropriate investments. The targeted asset allocations 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. Investment strategies utilize a wide diversification of asset types and qualified external investment managers.

WEC Energy Group consults with its investment advisors on an annual basis to help us forecast expected long-term returns on plan assets by reviewing actual historical returns and 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.

Economic Conditions

We have natural gas utility operations that serve customers in Illinois. As such, we are exposed to market risks in the regional midwest economy. In addition, any economic downturn or disruption of national or international markets could adversely affect the financial condition of our customers and demand for their products, which could affect their demand for our services.

Inflation

We continue to monitor the impact of inflation, especially with respect to the costs of medical plans, construction costs, and regulatory and environmental compliance in order to minimize its effects in future years through pricing strategies, productivity improvements, and cost reductions. We do not believe the impact of general inflation will have a material impact on our future results of operations.

For additional information concerning risk factors, including market risks, see the Cautionary Statement Regarding Forward-Looking Information at the beginning of this report and Risk Factors.

Industry Restructuring

Since 2002, we have provided all of our customers with the option to choose an alternative retail natural gas supplier. We are not required by the ICC or state law to make this option available to customers, but since this option is currently provided to customers, we would need ICC approval to eliminate it.

We offer natural gas transportation service to customers that select an alternative retail natural gas supplier. Transportation customers purchase natural gas directly from an alternative retail natural gas supplier and use our distribution system to transport the natural gas to their facilities. We still earn a distribution charge when we transport natural gas for these customers. As such, the loss of revenue associated with the natural gas that transportation customers purchase from an alternative retail natural gas supplier has little impact on our net income, since it is offset by an equal reduction to natural gas costs.

Other Matters

Decoupling

In 2012, the Illinois Attorney General and Citizens Utility Board appealed the ICC's authority to approve our permanent decoupling mechanism. As a result, revenues collected under this mechanism were potentially subject to refund. In 2012, we established offsetting reserves equal to decoupling amounts accrued. In March 2013, the Illinois Appellate Court affirmed the ICC's authority to approve the permanent decoupling mechanism. Therefore, the reserves recorded in 2012 were reversed in the first quarter of 2013. In June 2013, the Illinois Attorney General and Citizens Utility Board petitioned the Illinois Supreme Court to review the Illinois Appellate Court's decision. In January 2015, the Illinois Supreme Court affirmed the ICC's authority to approve the permanent decoupling mechanism. As a result, decoupling amounts recorded in 2014 were refunded to customers in 2015 as planned, and decoupling amounts in the future will continue to be accrued.

See Note 16, Regulatory Environment, for more information on our decoupling mechanism.

Bonus Depreciation Provisions

The Protecting Americans from Tax Hikes Act of 2015 was signed into law on December 18, 2015. This act extended 50% bonus depreciation to assets placed in service during 2015 through 2017, 40% bonus depreciation to assets placed in service during 2018, and 30% bonus depreciation to assets placed in service during 2019. Bonus depreciation is an additional amount of deductible depreciation that is awarded above and beyond what would normally be available.

Critical Accounting Policies and Estimates

Preparation of financial statements and related disclosures in compliance with GAAP requires the application of appropriate technical accounting rules and guidance, as well as the use of estimates. The application of these policies necessarily involves judgments regarding future events, including the likelihood of success of particular projects, legal and regulatory challenges, and anticipated recovery of costs. These judgments, in and of themselves, could materially impact the financial statements and disclosures based on varying assumptions. In addition, the financial and operating environment may also have a significant effect, not only on the operation of our business, but on our results reported through the application of accounting measures used in preparing the financial statements and related disclosures, even if the nature of the accounting policies applied have not changed.

The following is a list of accounting policies that are most significant to the portrayal of our financial condition and results of operations and that require management's most difficult, subjective, or complex judgments.

Pension and Other Postretirement Employee Benefits

The costs of providing non-contributory defined pension benefits and OPEB, described in Note 12, Employee Benefits, are dependent on numerous factors resulting from actual plan experience and assumptions of future experience.

Pension and OPEB costs are impacted by actual employee demographics (including age, compensation levels, and employment periods), the level of contributions made to the plans, and earnings on plan assets. Pension and OPEB costs may also be significantly affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets, mortality and discount rates, and expected health care cost trends. Changes made to the plan provisions may also impact current and future pension and OPEB costs.

Pension and OPEB plan assets are primarily made up of equity and fixed income investments. Fluctuations in actual equity and fixed income market returns, as well as changes in general interest rates, may result in increased or decreased benefit costs in future periods. We believe that such changes in costs would be recovered or refunded through the rate-making process.

The following table shows how a given change in certain actuarial assumptions would impact the projected benefit obligation and the reported net periodic pension cost. Each factor below reflects an evaluation of the change based on a change in that assumption only.

Actuarial Assumption ***(in millions, except percentages)***	**Percentage-Point Change in Assumption**	**Impact on Projected Benefit Obligation**	**Impact on 2015 Pension Cost**
Discount rate	(0.5)	$ 5.6	$ 0.5
Discount rate	0.5	(4.9)	(0.4)
Rate of return on plan assets	(0.5)	N/A	0.2
Rate of return on plan assets	0.5	N/A	(0.2)

The following table shows how a given change in certain actuarial assumptions would impact the accumulated OPEB obligation and the reported net periodic OPEB cost. Each factor below reflects an evaluation of the change based on a change in that assumption only.

Actuarial Assumption ***(in millions, except percentages)***	**Percentage-Point Change in Assumption**	**Impact on Postretirement Benefit Obligation**	**Impact on 2015 Postretirement Benefit Cost**
Discount rate	(0.5)	$ 1.1	$ 0.1
Discount rate	0.5	(1.0)	(0.1)
Health care cost trend rate	(0.5)	(0.8)	(0.2)
Health care cost trend rate	0.5	0.9	0.2
Rate of return on plan assets	(0.5)	N/A	0.1
Rate of return on plan assets	0.5	N/A	(0.1)

In the fourth quarter of 2014, the Society of Actuaries published a new set of mortality tables, which updated life expectancy assumptions. We have adjusted the tables to better reflect our plan-specific mortality experience and other general assumptions. We have incorporated the revised mortality tables into the projected pension and OPEB obligations at December 31, 2015.

The discount rates are selected based on hypothetical bond portfolios consisting of noncallable (or callable with make-whole provisions), noncollateralized, high-quality corporate bonds with maturities between 0 and 30 years. The bonds are generally rated "Aa" with a minimum amount outstanding of $50.0 million. From the hypothetical bond portfolios, a single rate is determined that equates the market value of the bonds purchased to the discounted value of the plans' expected future benefit payments.

We establish our expected return on assets based on consideration of historical and projected asset class returns, as well as the target allocations of the benefit trust portfolios. The assumed long-term rate of return on pension plan assets was 7.75% in 2015 and 8.00% in both 2014 and 2013, respectively. The actual rate of return on pension plan assets, net of fees, was (3.6)%, 6.4%, and 15.2%, in 2015, 2014, and 2013, respectively.

In selecting assumed health care cost trend rates, past performance and forecasts of health care costs are considered. For more information on health care cost trend rates and a table showing future payments that we expect to make for our pension and OPEB obligations, see Note 12, Employee Benefits.

Regulatory Accounting

We follow the guidance under the Regulated Operations Topic of the FASB ASC. Our financial statements reflect the effects of the rate-making principles followed by the ICC. Certain items that would otherwise be immediately recognized as revenues and expenses are deferred as regulatory assets and regulatory liabilities for future recovery or refund to customers, as authorized by the ICC. Future recovery of regulatory assets is not assured, and is generally subject to review by the ICC in rate proceedings for matters such as prudence and reasonableness. Once approved, the regulatory assets and liabilities are amortized into earnings over the rate recovery period. If recovery or refund of costs is not approved or is no longer considered probable, these regulatory assets or liabilities are recognized in current period earnings. Management regularly assesses whether these regulatory assets and liabilities are probable of future recovery or refund by considering factors such as changes in the regulatory environment, and our earnings.

The application of the Regulated Operations Topic of the FASB ASC would be discontinued if all or a separable portion of our natural gas utility operations no longer meet the criteria for application. Our regulatory assets and liabilities would be written off as a charge to income as an unusual or infrequently occurring item in the period in which discontinuation occurred. As of December 31, 2015, we had $81.3 million in regulatory assets and $18.1 million in regulatory liabilities. See Note 5, Regulatory Assets and Liabilities, for more information.

Unbilled Revenues

We record operating revenues when natural gas is delivered to our customers. However, the determination of natural gas sales to individual customers is based upon the reading of their meters, which occurs on a systematic basis throughout the month. At the end of each month, amounts of natural gas delivered to customers since the date of their last meter reading are estimated and corresponding unbilled revenues are calculated. This unbilled revenue is estimated each month based upon throughput volumes, recorded sales, estimated customer usage by class, weather factors, and applicable customer rates. Significant fluctuations in natural gas demand for the unbilled period or changes in the composition of customer classes could impact the accuracy of the unbilled revenue estimate. Total operating revenues during 2015 of approximately $194.6 million included accrued revenues of $12.4 million as of December 31, 2015.

Income Tax Expense

We are required to estimate income taxes for each of the jurisdictions in which we operate as part of the process of preparing financial statements. This process involves estimating current income tax liabilities together with assessing temporary differences resulting from differing treatment of items, such as depreciation, for income tax and accounting purposes. These differences result in deferred income tax assets and liabilities, which are included within our balance sheets. We also assess the likelihood that our deferred income tax assets will be recovered through future taxable income. To the extent we believe that realization is not likely, we establish a valuation allowance, which is offset by an adjustment to income tax expense in our income statements.

Uncertainty associated with the application of tax statutes and regulations and the outcomes of tax audits and appeals requires that judgments and estimates be made in the accrual process and in the calculation of effective tax rates. Only income tax benefits that meet the "more likely than not" recognition threshold may be recognized or continue to be recognized. Unrecognized tax benefits are re-evaluated quarterly and changes are recorded based on new information, including the issuance of relevant guidance by the courts or tax authorities and developments occurring in the examinations of our tax returns.

Significant management judgment is required in determining our provision for income taxes, deferred income tax assets and liabilities, the liability for unrecognized tax benefits, and any valuation allowance recorded against deferred income tax assets. The assumptions involved are supported by historical data, reasonable projections, and interpretations of applicable tax laws and regulations across multiple taxing jurisdictions. Significant changes in these assumptions could have a material impact on our financial condition and results of operations. See Note 1(j), Income Taxes, and Note 11, Income Taxes, for a discussion of accounting for income taxes.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

See Management's Discussion and Analysis of Financial Condition and Results of Operations – Factors Affecting Results, Liquidity, and Capital Resources – Market Risks and Other Significant Risks, as well as Note 1(m), Derivative Instruments, and Note 1(l), Fair Value Measurements, for information concerning potential market risks to which we are exposed.

FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

A. INDEPENDENT AUDITORS' REPORT

INDEPENDENT AUDITORS' REPORT

To the Board of Directors of North Shore Gas Company:

We have audited the accompanying financial statements of North Shore Gas Company (the "Company"), which comprise the balance sheets and statements of capitalization as of December 31, 2015 and 2014, and the related statements of income, common shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2015, 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 North Shore Gas Company as of December 31, 2015 and 2014, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2015, in accordance with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP

Milwaukee, WI
March 17, 2016

NORTH SHORE GAS COMPANY

B. INCOME STATEMENTS

Year Ended December 31 ***(in millions)***	**2015**	**2014**	**2013**
Operating revenues	**$ 194.6**	$ 286.8	$ 206.2
Operating Expenses			
Cost of natural gas	**92.6**	177.5	114.9
Other operation and maintenance	**64.5**	74.7	55.3
Depreciation and amortization	**11.9**	11.1	10.5
Property and revenue taxes	**1.8**	1.7	1.8
Total operating expenses	**170.8**	265.0	182.5
Operating income	**23.8**	21.8	23.7
Other income, net	**0.6**	0.3	—
Interest expense	**3.5**	3.6	3.8
Other expense	**(2.9)**	(3.3)	(3.8)
Income before income taxes	**20.9**	18.5	19.9
Income tax expense	**8.2**	7.4	7.6
Net income	**$ 12.7**	$ 11.1	$ 12.3

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

NORTH SHORE GAS COMPANY

C. BALANCE SHEETS

At December 31 *(in millions, except share amounts)*	2015	2014
Assets		
Current assets		
Cash and cash equivalents	**$ 0.3**	$ 0.6
Accounts receivable and unbilled revenues, net of reserves of $1.5 and $2.7, respectively	**28.1**	56.3
Receivables from related parties	**0.2**	—
Materials, supplies, and inventories:		
Natural gas in storage, primarily at LIFO	**9.4**	7.7
Materials and supplies	**1.7**	1.8
Liquid propane	**0.7**	0.7
Prepaid taxes	**0.7**	5.5
Other current assets	**0.8**	2.6
Current assets	**41.9**	75.2
Long-term assets		
Property, plant, and equipment, net of accumulated depreciation of $189.2 and $185.7, respectively	**336.8**	312.8
Regulatory assets	**78.6**	78.6
Other long-term assets	**0.1**	—
Long-term assets	**415.5**	391.4
Total assets	**$ 457.4**	$ 466.6
Liabilities and Shareholder's Equity		
Current liabilities		
Accounts payable	**$ 19.0**	$ 21.1
Payables to related parties	**2.4**	3.9
Derivative liabilities	**4.0**	8.1
Notes payable to related parties	**28.8**	48.6
Customer credit balances	**6.2**	3.2
Other current liabilities	**12.0**	12.9
Current liabilities	**72.4**	97.8
Long-term liabilities		
Long-term debt	**81.5**	81.4
Deferred income taxes	**88.0**	85.6
Deferred investment tax credits	**2.8**	2.8
Environmental remediation liabilities	**45.0**	38.0
Pension and OPEB obligations	**20.3**	21.1
Asset retirement obligations	**17.0**	14.8
Other long-term liabilities	**19.9**	19.8
Long-term liabilities	**274.5**	263.5
Commitments and contingencies (Note 13)		
Common stock, without par value, 5,000,000 shares authorized; 3,625,887 shares issued and outstanding	**25.0**	25.0
Retained earnings	**85.5**	80.3
Total liabilities and shareholder's equity	**$ 457.4**	$ 466.6

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

NORTH SHORE GAS COMPANY

D. STATEMENTS OF CAPITALIZATION

At December 31 *(in millions, except share amounts)*				2015	2014
Common stock equity					
Common stock, without par value, 5,000,000 shares authorized, 3,625,887 shares issued and outstanding				**$ 25.0**	$ 25.0
Retained earnings				**85.5**	80.3
Total common stock equity				**110.5**	105.3
Long-term debt					
First Mortgage Bonds					
	Series	Interest Rate	Year Due		
	P	3.43%	2027	**28.0**	28.0
	Q	3.96%	2043	**54.0**	54.0
Total first mortgage bonds				**82.0**	82.0
Unamortized debt issuance costs				**(0.5)**	(0.6)
Total long-term debt				**81.5**	81.4
Total capitalization				**$ 192.0**	$ 186.7

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

NORTH SHORE GAS COMPANY

E. STATEMENTS OF CASH FLOWS

Year Ended December 31 ***(in millions)***	**2015**	**2014**	**2013**
Operating activities			
Net income	**$ 12.7**	$ 11.1	$ 12.3
Reconciliation to cash provided by operating activities			
Depreciation and amortization	**12.4**	11.8	11.1
Contributions to pension and OPEB plans	**(0.4)**	(5.5)	(2.4)
Deferred income taxes and investment tax credits, net	**2.4**	5.9	9.5
Change in -			
Accounts receivable and unbilled revenues	**29.1**	17.1	(10.7)
Materials, supplies, and inventories	**(1.6)**	0.7	0.4
Prepaid taxes	**4.8**	0.1	(4.9)
Other current assets	**1.7**	(1.4)	0.7
Accounts payable	**(6.1)**	(3.0)	11.6
Customer credit balances	**3.0**	(0.1)	(1.7)
Other current liabilities	**1.4**	1.0	(1.6)
Other, net	**(1.0)**	(16.7)	(2.8)
Net cash provided by operating activities	**58.4**	21.0	21.5
Investing activities			
Capital expenditures	**(31.4)**	(31.9)	(33.0)
Other, net	**—**	0.5	(0.8)
Net cash used for investing activities	**(31.4)**	(31.4)	(33.8)
Financing activities			
Change in notes payable to related parties	**(19.8)**	10.5	17.3
Issuance of long-term debt	**—**	—	54.0
Repayment of long-term debt	**—**	—	(46.5)
Payments of dividend to parent	**(7.5)**	—	(12.0)
Other, net	**—**	0.1	(0.4)
Net cash (used for) provided by financing activities	**(27.3)**	10.6	12.4
Net change in cash and cash equivalents	**(0.3)**	0.2	0.1
Cash and cash equivalents at beginning of year	**0.6**	0.4	0.3
Cash and cash equivalents at end of year	**$ 0.3**	$ 0.6	$ 0.4

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

NORTH SHORE GAS COMPANY

F. STATEMENTS OF EQUITY

(in millions)	Common Stock	Retained Earnings	Total Common Shareholder's Equity
Balance at December 31, 2012	$ 24.9	$ 68.9	$ 93.8
Net income	—	12.3	12.3
Payments of dividend to parent	—	(12.0)	(12.0)
Balance at December 31, 2013	$ 24.9	$ 69.2	$ 94.1
Net income	—	11.1	11.1
Other	0.1	—	0.1
Balance at December 31, 2014	$ 25.0	$ 80.3	$ 105.3
Net income	**—**	**12.7**	**12.7**
Payments of dividend to parent	**—**	**(7.5)**	**(7.5)**
Balance at December 31, 2015	**$ 25.0**	**$ 85.5**	**$ 110.5**

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

G. NOTES TO FINANCIAL STATEMENTS
December 31, 2015

NOTE 1—SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

(a) General Information—On June 29, 2015, Wisconsin Energy Corporation acquired Integrys and changed its name to WEC Energy Group, Inc. See Note 2, Merger, for more information on this acquisition.

As used in these notes, the term "financial statements" includes the income statements, balance sheets, statements of capitalization, statements of cash flows, and statements of equity, unless otherwise noted.

We are a natural gas utility company that purchases, stores, distributes, sells, and transports natural gas to customers in the northern suburbs of Chicago. We are subject to the jurisdiction of, and regulation by, the ICC, which has general supervisory and regulatory powers over public utilities in Illinois. We are also subject to the jurisdiction of the FERC, which regulates the interstate services we provide.

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

(b) Reclassifications—As a result of the WEC Merger, we adopted the financial statement presentation policies of WEC Energy Group. The previously reported items below were reclassified to conform to the current period presentation. Only material reclassifications are quantified below.

Income Statements

- Payroll taxes of $0.8 million and $0.7 million for the years ended December 31, 2014 and 2013, respectively, were reclassified from taxes other than income taxes to other operation and maintenance. The taxes other than income taxes line item was also renamed to property and revenue taxes.

Balance Sheets

- Current regulatory assets of $11.3 million and $9.2 million were reclassified to accounts receivable and long-term regulatory assets, respectively, at December 31, 2014.

- Current regulatory liabilities of $1.7 million and $9.8 million were reclassified to other current liabilities and other long-term liabilities, respectively, at December 31, 2014.

- During the fourth quarter of 2015, we early implemented ASU 2015-03, Simplifying the Presentation of Debt Issuance Costs. As a result, debt issuance costs of $0.6 million, previously reported as other long-term assets, were reclassified to offset long-term debt on the December 31, 2014 balance sheet.

- During the fourth quarter of 2015, we also early implemented ASU 2015-17, Balance Sheet Classification of Deferred Taxes. Since we adopted this ASU on a retrospective basis, we reclassified current deferred income tax assets of $1.6 million to offset long-term deferred income tax liabilities on the December 31, 2014 balance sheet.

Statements of Cash Flows

- Various line items within the operating, investing, and financing activities sections were reclassified; however, there was no impact on the total cash flows of these sections.

(c) Cash and Cash Equivalents—Cash and cash equivalents include marketable debt securities acquired three months or less from maturity.

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

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

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

- Our rates included 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.

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

- Our rates included a rider for cost recovery or refund of uncollectible expense based on the difference between actual uncollectible write-offs and the amounts recovered in rates.

- Our rates included a decoupling mechanism, which allows us to recover or refund differences between actual and authorized margins. See Note 16, Regulatory Environment, for more information.

We provide regulated natural gas service to customers in the northern suburbs of Chicago, Illinois. The geographic concentration of our customers did not contribute significantly to our overall exposure to credit risk. We periodically review customers' credit ratings, financial statements, and historical payment performance and require them to provide collateral or other security as needed. Our credit risk exposure is mitigated by our rider for uncollectible expense discussed above. As a result, we did not have any significant concentrations of credit risk at December 31, 2015. In addition, there were no customers that accounted for more than 10% of our revenues for the year ended December 31, 2015.

(e) Materials, Supplies, and Other Inventories

Inventories consist of materials and supplies, natural gas in storage, and liquid propane. Materials and supplies and liquid propane inventory are priced at average cost. We 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 Last-in, First-out (LIFO) cost method. The estimated replacement cost of our natural gas in inventory at December 31, 2015, and December 31, 2014, exceeded the LIFO cost by approximately $8.4 million and $12.6 million, respectively. In calculating these replacement amounts, we used a Chicago city-gate natural gas price per Dth of $2.48 at December 31, 2015, and $3.04 at December 31, 2014.

(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 revenue associated with certain costs or liabilities that have been deferred and are expected to be recovered through rates charged to customers. Regulatory liabilities represent amounts that are expected to be refunded to customers in future rates or amounts that are collected in rates for future costs. Recovery or refund of regulatory assets and liabilities is based on specific periods determined by the regulators or occurs over the normal operating period of the assets and liabilities to which they relate. If at any reporting date a previously recorded regulatory asset is no longer probable of recovery, the regulatory asset is reduced to the amount considered probable of recovery with the reduction charged to expense in the reporting period the determination is made. See Note 5, 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 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 ICC. Our annual utility composite depreciation rates were 2.45% in 2015, and 2.44% in 2014 and 2013, respectively.

See Note 6, Property, Plant, and Equipment, for more information.

(h) Asset Retirement Obligations—We recognize, at fair value, legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development, and normal operation of the assets. A liability is recorded, when incurred, for these obligations as long as the fair value can be reasonably estimated, even if the timing or method of settling the obligation is unknown. The associated retirement costs are capitalized as part of the related long-lived asset and are depreciated over the useful life of the asset. The AROs are accreted to their present value each period using the credit-adjusted risk-free interest rate associated with the expected settlement dates of the AROs. This rate is determined when the obligation is incurred. Subsequent changes resulting from revisions to the timing or the amount of the original estimate of undiscounted cash flows are recognized as an increase or a decrease to the carrying amount of the liability and the associated retirement costs. We recognize regulatory assets or liabilities for the timing differences between when we recover an ARO in rates and when we recognize the associated retirement costs. See Note 7, Asset Retirement Obligations, for more information.

(i) 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 13, 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 ICC approval.

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

(j) Income Taxes—We are included in the consolidated United States income tax return filed by Integrys for all tax periods up to and including the tax year ended June 29, 2015. For all tax periods after June 29, 2015, we are included within the WEC Energy Group consolidated return. We are party to a tax allocation arrangement with Integrys and its consolidated subsidiaries for all tax periods up to and including June 29, 2015, and are a party to a tax allocation arrangement with WEC Energy Group and its consolidated subsidiaries for tax periods ending after June 29, 2015.

Deferred income taxes have been recorded to recognize the expected future tax consequences of events that have been included in the financial statements by using currently enacted tax rates for the differences between the income tax basis of assets and liabilities and the basis reported in the financial statements. We record valuation allowances for deferred income tax assets unless it is more likely than not that the benefit will be realized in the future. We defer certain adjustments made to income taxes that will impact future rates and record regulatory assets or liabilities related to these adjustments.

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

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

See Note 11, Income Taxes, for more information regarding our accounting for income taxes.

(k) Employee Benefits—The costs of pension and OPEB plans are expensed over the periods during which employees render service. The benefit costs associated with employee benefit plans are allocated among WEC Energy Group's subsidiaries based on current employment status and actuarial calculations, as applicable. Our regulators allow recovery in rates for the net periodic benefit cost calculated under GAAP. See Note 12, Employee Benefits, for more information.

(l) 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.

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

We conduct a thorough review of fair value hierarchy classifications on a quarterly basis.

See Note 14, Fair Value Measurements, for more information.

(m) 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. Regulated hedging programs are approved by the ICC.

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 energy-related physical and financial contracts that qualify as derivatives, the ICC 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. Gains and losses on derivative instruments are primarily recorded in cost of natural gas on the income statements. Cash flows from derivative activities are presented in the same category as the item being hedged within operating activities on our statements of cash flows.

Derivative accounting rules provide the option to present certain asset and liability derivative positions net on the balance sheets and to net the related cash collateral against these net derivative positions. We elected not to net these items. See Note 15, Derivative Instruments, for more information.

(n) 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 reflected within other current liabilities on the 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 the balance sheets.

(o) Subsequent Events—Subsequent events were evaluated for potential recognition or disclosure through March 17, 2016, which is the date the financial statements were available to be issued.

NOTE 2—MERGER

On June 29, 2015, the WEC Merger was completed, and Integrys became a wholly owned subsidiary of Wisconsin Energy Corporation. Wisconsin Energy Corporation then changed its name to WEC Energy Group, Inc. The merger was subject to the approvals of various government agencies, including the ICC. Approvals were obtained from all agencies subject to several conditions. The ICC order includes a base rate freeze for us for two years after the close of the merger. This base rate freeze does not impact our ability to adjust rates through our various riders or our GCRM.

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

NOTE 3—RELATED PARTIES

We routinely enter into transactions with related parties, including WEC Energy Group and its subsidiaries. The following agreements result in related party receivables and payables.

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 the WEC Merger on June 29, 2015, Integrys Business Support, LLC (IBS) changed its name to WBS, and a new affiliated interest agreement (Non-WBS AIA) went into effect. The new Non-WBS AIA includes WEC Energy Group and the legacy Wisconsin Energy Corporation subsidiaries. It governs the provision and receipt of services by WEC Energy Group's subsidiaries, except that WBS will continue to provide services to Integrys and its subsidiaries, including us, only under the existing WBS affiliated interest agreements (WBS AIAs). WBS will provide services to WEC Energy Group and the legacy Wisconsin Energy Corporation subsidiaries under new interim WBS affiliated interest agreements (interim WBS AIAs). The Non-WBS AIA includes no other significant changes from the prior Non-IBS affiliated interest agreement. The ICC and all other relevant state commissions have approved the Non-WBS AIA or granted appropriate waivers related to the Non-WBS AIA.

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

WBS provides several categories of services (including financial, human resources, and administrative services) to us pursuant to the WBS AIAs, which have been approved, or from which we have been granted appropriate waivers, by the appropriate regulators, including the ICC. As required by FERC regulations for centralized service companies, WBS renders services at cost. The ICC 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 ICC approval. Recovery of allocated costs is addressed in our rate cases.

We had no other significant related party transactions during the year ended December 31, 2015. The following table shows activity associated with our other related party transactions for the years ended December 31, 2014 and 2013.

(in millions)	2014	2013
Natural gas sales to Integrys Energy Services *	$ 0.5	$ —
Interest expense to Integrys and PGL	0.2	0.1

* Integrys sold Integrys Energy Services's retail energy business in November 2014.

We manage our liquidity in part by maintaining adequate financing commitments with related parties. We have the ability to borrow up to $50.0 million from Integrys and to loan to or borrow from PGL up to $50.0 million. At December 31, 2015 and 2014, our short-term notes payable balance with PGL was $28.8 million and $48.6 million, respectively.

NOTE 4—SUPPLEMENTAL CASH FLOW INFORMATION

	Year Ended December 31		
(in millions)	2015	2014	2013
Cash paid for interest, net of amount capitalized	**$ 3.2**	$ 3.2	$ 3.4
Cash paid for income taxes, net of refunds	**0.4**	1.9	2.5
Significant non-cash transactions			
Accounts payable related to construction costs	**3.2**	3.7	2.3

NOTE 5—REGULATORY ASSETS AND LIABILITIES

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

(in millions)	2015	2014	See Note
Regulatory assets (1)			
Environmental remediation costs (2)	**$ 46.8**	$ 48.9	13
Unrecognized pension and OPEB costs (3)	**17.3**	19.5	12
Derivatives	**5.4**	9.9	1(m)
AROs	**4.9**	5.5	7
Uncollectible expense (4)	**1.8**	1.1	1(d)
Rate case costs (5)	**1.2**	1.9	
Other	**3.9**	3.1	
Total regulatory assets	**$ 81.3**	$ 89.9	
Balance Sheet Presentation			
Current assets (6)	**$ 2.7**	$ 11.3	
Regulatory assets	**78.6**	78.6	
Total regulatory assets	**$ 81.3**	$ 89.9	

(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 the table above.

(2) As of December 31, 2015, we had not yet made cash expenditures for $45.0 million of these environmental remediation costs. The recovery of these costs depends on the timing of the actual expenditures.

(3) Represents the unrecognized future pension and OPEB costs resulting from actuarial gains and losses on defined benefit and OPEB plans.

(4) Represents amounts recoverable from customers related to our uncollectible expense true-up mechanism. This mechanism allows us to recover or refund the difference between actual uncollectible write-offs and the amounts recovered in rates.

(5) Amounts were recoverable over a four-year period for 2010 rates and a two-year period for 2012 and 2013 rates.

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

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

(in millions)	2015	2014	See Note
Regulatory liabilities			
Removal costs [1]	**$ 6.6**	$ 5.5	
Unrecognized OPEB costs [2]	**4.2**	0.9	12
Natural gas costs refundable through rate adjustments [3]	**2.8**	1.7	1(d)
Decoupling	**1.1**	4.2	16
Derivatives	**1.1**	2.6	1(m)
Other	**2.3**	4.5	
Total regulatory liabilities	**$ 18.1**	$ 19.4	
Balance Sheet Presentation			
Other current liabilities	**$ 2.8**	$ 1.7	
Other long-term liabilities	**15.3**	17.7	
Total regulatory liabilities	**$ 18.1**	$ 19.4	

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

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

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

NOTE 6—PROPERTY, PLANT, AND EQUIPMENT

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

(in millions)	2015	2014
Total utility plant	**$ 521.6**	$ 494.1
Less: Accumulated depreciation	**189.2**	185.7
Net	**332.4**	308.4
Construction work in progress	**4.4**	4.4
Total property, plant, and equipment	**$ 336.8**	$ 312.8

NOTE 7—ASSET RETIREMENT OBLIGATIONS

We have recorded AROs primarily for the removal of natural gas distribution mains and service pipes (including asbestos and polychlorinated biphenyls [PCBs]), asbestos and PCBs in buildings, and the removal of above ground storage tanks. We establish regulatory assets and liabilities to record the differences between ongoing expense recognition under the ARO accounting rules and the rate-making practices for retirement costs authorized by the ICC.

The following table shows changes to our AROs:

(in millions)	2015	2014	2013
Balance as of January 1	**$ 14.8**	$ 14.5	$ 17.2
Accretion	**0.9**	0.9	1.0
Additions and revisions to estimated cash flows	**1.9** *	—	(3.4) *
Liabilities settled	**(0.6)**	(0.6)	(0.3)
Balance as of December 31	**$ 17.0**	$ 14.8	$ 14.5

* We revised the AROs recorded for our natural gas distribution pipes primarily due to changes in the weighted average cost to retire pipe.

NOTE 8—COMMON EQUITY

Various laws, regulations, and financial covenants impose restrictions on our ability to pay dividends to the sole holder of our common stock, PELLC. We are prohibited from loaning funds to WEC Energy Group or its subsidiaries, with the exception of PGL.

Our long-term debt obligations contain provisions and covenants restricting the payment of cash dividends and the purchase or redemption of capital stock. As of December 31, 2015, these covenants resulted in total restricted retained earnings of $6.9 million.

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

PELLC may provide equity contributions to us, we may request ICC authorization to issue additional common stock to PELLC, and/or we may pay dividends to PELLC in order to maintain utility common equity levels consistent with our current rate order. See Note 16, Regulatory Environment, for more information on our rate order.

NOTE 9—PREFERRED STOCK

We have 160,000 shares of preferred stock with a $100 par value authorized for issuance, of which none were issued and outstanding at December 31, 2015.

NOTE 10—LONG-TERM DEBT

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

Our First Mortgage Bonds are subject to the terms and conditions of our First Mortgage Indenture dated April 1, 1955, as supplemented. Under the terms of the Indenture, substantially all our property is pledged as collateral for these outstanding debt securities.

Our long-term debt obligations contain covenants related to payment of principal and interest when due and various financial reporting obligations.

The following table shows the future maturities and sinking fund requirements of our long-term debt outstanding as of December 31, 2015:

(in millions)	Payments
2016	$ —
2017	—
2018	—
2019	—
2020	—
Thereafter	82.0
Total	$ 82.0

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

NOTE 11—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)	2015	2014	2013
Current tax expense	**$ 5.8**	$ 1.5	$ (1.9)
Deferred income taxes, net	**2.4**	5.8	9.4
Investment tax credit, net	**—**	0.1	0.1
Total income tax expense	**$ 8.2**	$ 7.4	$ 7.6

Statutory Rate Reconciliation

The following table presents a reconciliation of the difference between the effective tax rate and the amount computed by applying the statutory federal tax rate to income before taxes.

	2015		2014		2013	
(in millions)	Amount	Effective Tax Rate	Amount	Effective Tax Rate	Amount	Effective Tax Rate
Expected tax at statutory federal tax rates	**$ 7.3**	**35.0%**	$ 6.5	35.0%	$ 7.0	35.0%
State income taxes net of federal tax benefit	**0.8**	**3.6**	1.0	5.4	0.8	4.0
Other, net	**0.1**	**0.6**	(0.1)	(0.4)	(0.2)	(0.8)
Total income tax expense	**$ 8.2**	**39.2%**	$ 7.4	40.0%	$ 7.6	38.2%

Deferred Income Tax Assets and Liabilities

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

(in millions)	2015	2014
Total deferred tax assets	**$ 5.7**	$ 5.3
Deferred tax liabilities		
Plant-related	**$ 89.4**	$ 85.0
Regulatory deferrals	**3.6**	5.7
Other	**0.7**	0.2
Total deferred tax liabilities	**93.7**	90.9
Deferred tax liability, net	**$ 88.0**	$ 85.6

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

Deferred tax credit carryforwards at December 31, 2015, included $0.2 million of alternative minimum tax credits, which can be carried forward indefinitely. We also had $0.3 million of deferred state tax credit carryforwards, which have a carryforward period of five years. The majority of the state tax credit carryforwards will expire in 2016.

At December 31, 2015, we had deferred income tax assets of $0.1 million reflecting federal operating loss carryforwards, which have a carryback period of two years and a carryforward period of 20 years and will expire in 2032.

Valuation allowances have not been established for deferred income tax assets based on our projected ability to realize these benefits by offsetting future taxable income.

Unrecognized Tax Benefits

We had no unrecognized tax benefits at December 31, 2015 and 2014.

We had no accrued interest or accrued penalties related to unrecognized tax benefits at December 31, 2015 and 2014.

We do not expect any unrecognized tax benefits to affect our effective tax rate in periods after December 31, 2015.

We file income tax returns in the United States federal jurisdiction and in our major state operating jurisdictions as part of Integrys's filings up to June 29, 2015, and as part of WEC Energy Group's filings for periods after June 29, 2015.

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 2012.

We file state tax returns based on income in Illinois, our major state operating jurisdiction. With a few exceptions, we are no longer subject to examinations for years prior to 2011. As of December 31, 2015, we were subject to examination by the Illinois taxing authority for the 2011 through 2015 tax years. During 2015, the Illinois taxing authority commenced its examination of the 2011 and 2012 tax years.

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

NOTE 12—EMPLOYEE BENEFITS

Pension and Other Postretirement Employee Benefits

We participate in the Integrys retirement plan, a noncontributory, qualified pension plan sponsored by WBS. In addition, we offer an OPEB plan to employees, which is sponsored by PELLC. The benefits are funded through an irrevocable trust, as allowed for income tax purposes. We are responsible for our share of the plan assets and obligations of these plans. Our balance sheets reflect only the liabilities associated with our past and current employees and our share of the plan assets. Integrys 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) plan, which is calculated based on age, wages, and full years of vesting service as of December 31 each year. In March 2014, we remeasured the obligations of our OPEB plan as a result of a plan design change to move participants age 65 and older to a Medicare Advantage plan starting January 1, 2015.

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

The following tables provide a reconciliation of the changes in our share of the plans' benefit obligations and fair value of assets:

	Pension Costs		OPEB Costs	
(in millions)	**2015**	**2014**	**2015**	**2014**
Change in benefit obligation				
Obligation at January 1	**$ 56.0**	$ 48.8	**$ 24.8**	$ 22.7
Service cost	**2.1**	1.8	**1.6**	1.4
Interest cost	**2.2**	2.3	**1.0**	1.0
Plan amendments	**—**	—	**—**	(0.4)
Transfers to affiliates	**1.2**	(1.1)	**0.1**	—
Actuarial loss (gain)	**(2.0)**	5.9	**(7.1)**	0.9
Participant contributions	**—**	—	**0.4**	0.6
Benefit payments	**(1.8)**	(1.7)	**(1.2)**	(1.5)
Federal subsidy on benefits paid	**—**	—	**—**	0.1
Obligation at December 31	**$ 57.7**	$ 56.0	**$ 19.6**	$ 24.8
Change in fair value of plan assets				
Fair Value at January 1	**$ 40.0**	$ 35.2	**$ 19.7**	$ 19.3
Actual return on plan assets	**(1.5)**	2.5	**(0.3)**	0.9
Employer contributions	**—**	5.1	**0.4**	0.4
Transfers to affiliates	**1.2**	(1.1)	**0.1**	—
Participant contributions	**—**	—	**0.4**	0.6
Benefit payments	**(1.8)**	(1.7)	**(1.2)**	(1.5)
Fair value at December 31	**$ 37.9**	$ 40.0	**$ 19.1**	$ 19.7

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

	Pension Costs		OPEB Costs	
(in millions)	**2015**	**2014**	**2015**	**2014**
Pension and OPEB obligations	**$ 19.8**	$ 16.0	**$ 0.5**	$ 5.1

The following table shows information for the pension plans for which we have an accumulated benefit obligation in excess of plan assets. Amounts presented are as of December 31:

(in millions)	2015	2014
Projected benefit obligation	**$ 57.7**	$ 56.0
Accumulated benefit obligation	**49.4**	46.6
Fair value of plan assets	**37.9**	40.0

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)	2015	2014	2015	2014
Net regulatory assets (liabilities)				
Net actuarial loss (gain)	**$ 16.7**	$ 11.4	**$ (4.1)**	$ (0.5)
Prior service credits	**0.8**	—	**(0.3)**	(0.4)
Total	**$ 17.5**	$ 11.4	**$ (4.4)**	$ (0.9)

The following table shows the estimated amounts that will be amortized into net periodic benefit cost during 2016:

(in millions)	Pension Costs	OPEB Costs
Net actuarial loss	$ 1.7	$ 0.1
Prior service costs	0.1	—
Total 2016 – estimated amortization	$ 1.8	$ 0.1

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

	Pension Costs			OPEB Costs		
(in millions)	2015	2014	2013	2015	2014	2013
Service cost	**$ 2.1**	$ 1.8	$ 2.0	**$ 1.6**	$ 1.4	$ 1.5
Interest cost	**2.2**	2.3	2.2	**1.0**	1.0	0.9
Expected return on plan assets	**(2.8)**	(2.9)	(2.3)	**(1.5)**	(1.5)	(1.4)
Amortization of prior service credit	**0.1**	—	—	**(0.1)**	—	—
Amortization of net actuarial loss	**2.1**	1.0	1.7	**0.5**	—	—
Net periodic benefit cost	**$ 3.7**	$ 2.2	$ 3.6	**$ 1.5**	$ 0.9	$ 1.0

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

	Pension Costs		OPEB Costs	
	2015	2014	2015	2014
Discount rate	**4.50%**	4.10%	**4.20%**	3.90%
Rate of compensation increase	**4.00%**	4.11%	**N/A**	N/A
Assumed medical cost trend rate	**N/A**	N/A	**7.50%**	6.00%
Ultimate trend rate	**N/A**	N/A	**5.00%**	5.00%
Year ultimate trend rate is reached	**N/A**	N/A	**2021**	2023

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

	Pension Costs		
	2015	2014	2013
Discount rate	**4.10%**	4.95%	4.10%
Expected return on assets	**7.75%**	8.00%	8.00%
Rate of compensation increase	**4.11%**	4.11%	4.13%

	OPEB Costs		
	2015	**2014**	**2013**
Discount rate	**3.90%**	4.48%	3.90%
Expected return on assets	**7.75%**	8.00%	8.00%
Assumed medical cost trend rate (Pre 65/Post 65)	**6.00%**	6.50%	7.00%
Ultimate trend rate	**5.00%**	5.00%	5.00%
Year ultimate trend rate is reached	**2023**	2019	2019

WEC Energy Group consults with its investment advisors on an annual basis to help forecast expected long-term returns on plan assets by reviewing historical returns as well as calculating expected total trust returns using the weighted-average of long-term market returns for each of the major target asset categories utilized in the fund. For 2016, the expected return on assets assumption for the pension and OPEB plans is 7.25%.

Assumed health care cost trend rates have a significant effect on the amounts reported by us for our health care plans. For the year ended December 31, 2015, a one-percentage-point change in assumed health care cost trend rates would have had the following effects:

(in millions)	**1% Increase**	**1% Decrease**
Effect on total of service and interest cost components of net periodic postretirement health care benefit cost	$ 0.3	$ (0.3)
Effect on the health care component of the accumulated postretirement benefit obligation	1.8	(1.6)

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

Central to the policy are target allocation ranges by major asset categories. The objectives of the target allocations are to maintain investment portfolios that diversify risk through prudent asset allocation parameters and to achieve asset returns that meet or exceed the plans' actuarial assumptions and that are competitive with like instruments employing similar investment strategies. The portfolio diversification provides protection against significant concentrations of risk in the plan assets. In 2014, the pension plan target asset allocation was 70% equity securities and 30% fixed income securities. In December 2014, we changed the pension plan target asset allocation to 60% equity securities and 40% fixed income securities for 2015. The target asset allocation for OPEB plans that have significant assets is 70% equity securities and 30% fixed income securities. Equity securities primarily include investments in large-cap and small-cap companies. Fixed income securities primarily include corporate bonds of companies from diversified industries, United States government securities, and mortgage-backed securities.

Pension and OPEB plan investments are recorded at fair value. See Note 1(l), 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, 2015							
	Pension Plan Assets				OPEB Plan Assets			
(in millions)	Level 1	Level 2	Level 3	Total	Level 1	Level 2	Level 3	Total
Asset class								
Cash and cash equivalents	$ —	$ 1.5	$ —	$ 1.5	$ 0.5	$ —	$ —	$ 0.5
Equity securities:								
United States Equity	2.1	8.8	—	10.9	0.5	6.0	—	6.5
International Equity	2.2	9.7	—	11.9	—	5.6	—	5.6
Fixed income securities: (1)								
United States Bonds	0.3	11.8	—	12.1	5.2	—	—	5.2
International Bonds	—	3.0	—	3.0	—	—	—	—
	4.6	34.8	—	39.4	6.2	11.6	—	17.8
401(h) other benefit plan assets invested as pension assets (2)	(0.1)	(1.2)	—	(1.3)	0.1	1.2	—	1.3
Total (3)	$ 4.5	$ 33.6	$ —	$ 38.1	$ 6.3	$ 12.8	$ —	$ 19.1

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

(2) Pension trust assets are used to pay other postretirement benefits as allowed under Internal Revenue Code Section 401(h).

(3) Investments do not include accruals or pending transactions that are included in the table reconciling the change in fair value of plan assets.

	December 31, 2014							
	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	$ —	$ 1.2	$ —	$ 1.2	$ 0.2	$ 0.1	$ —	$ 0.3
Equity securities:								
United States Equity	2.4	9.0	—	11.4	0.6	6.5	—	7.1
International Equity	2.5	10.3	—	12.8	—	5.5	—	5.5
Fixed income securities: (1)								
United States Bonds	1.9	11.9	—	13.8	5.4	—	—	5.4
International Bonds	—	2.0	—	2.0	—	—	—	—
	6.8	34.4	—	41.2	6.2	12.1	—	18.3
401(h) other benefit plan assets invested as pension assets (2)	(0.2)	(1.1)	—	(1.3)	0.2	1.1	—	1.3
Total (3)	$ 6.6	$ 33.3	$ —	$ 39.9	$ 6.4	$ 13.2	$ —	$ 19.6

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

(2) Pension trust assets are used to pay other postretirement benefits as allowed under Internal Revenue Code Section 401(h).

(3) Investments do not include accruals or pending transactions that are included in the table reconciling the change in fair value of plan assets.

The following table sets forth a reconciliation of changes in the fair value of pension plan assets categorized as Level 3 in the fair value hierarchy during 2014. There was no level 3 activity in 2015.

(in millions)	International Bonds
Beginning balance at January 1, 2014	$ 0.1
Sales	(0.1)
Ending balance at December 31, 2014	$ —

Cash Flows

We expect to contribute $0.2 million to OPEB plans in 2016. We do not expect to make any contributions to our pension plan in 2016. Contributions are dependent on various factors affecting us, including our liquidity position and possible tax law changes.

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

(in millions)	Pension Costs	OPEB Costs
2016	$ 4.9	$ 0.9
2017	4.0	1.0
2018	4.0	1.0
2019	4.4	1.1
2020	4.6	1.3
2021 through 2025	23.6	8.6

Savings Plans

WEC Energy Group maintains a 401(k) Savings Plan for substantially all of our full-time employees. A percentage of employee contributions are matched through an employee stock ownership plan contribution up to certain limits. Certain employees participate in a defined contribution pension plan, in which certain amounts are contributed to an employee's 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 $0.8 million in 2015, and $0.7 million in each of 2014 and 2013.

NOTE 13—COMMITMENTS AND CONTINGENCIES

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

Unconditional Purchase Obligations Related to Natural Gas

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

The following table shows our minimum future commitments related to these purchase obligations as of December 31, 2015.

			Payments Due By Period					
(in millions)	Date Contracts Extend Through	Total Amounts Committed	2016	2017	2018	2019	2020	Later Years
Natural gas supply and transportation	**2022**	**$ 50.6**	**$ 21.6**	**$ 16.7**	**$ 6.7**	**$ 1.4**	**$ 1.4**	**$ 2.8**

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 GHG 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 air quality standards and federal clean air rules; and
- the remediation of former manufactured gas plant sites.

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 2014, we reported aggregated CO_2 equivalent emissions of approximately 2.0 million metric tonnes to the EPA related to our distribution and sale of natural gas. Based upon our preliminary analysis of the data, we estimate that we will report CO_2 equivalent emissions of approximately 1.7 million metric tonnes to the EPA for 2015.

Manufactured Gas Plant Remediation

We have identified sites at which we or a predecessor company owned or operated a manufactured gas plant or stored manufactured gas. We have also identified other sites that may have been impacted by historical manufactured gas plant activities. We are responsible for the environmental remediation of these sites, some of which are in the EPA Superfund Program. We are also working with the Illinois EPA in our investigation and remediation planning. These sites are at various stages of investigation, monitoring, remediation, and closure.

In addition, some of these sites are coordinating the investigation and cleanup subject to the jurisdiction of the EPA under what is called a "multisite" program. This program involves prioritizing the work to be done at the sites, preparation and approval of documents common to all of the sites, and use of a consistent approach in selecting remedies. At this time, we cannot estimate future remediation costs associated with these sites beyond those described below.

The future costs for detailed site investigation, future remediation, and monitoring are dependent upon several variables including, among other things, the extent of remediation, changes in technology, and changes in regulation. Historically, our regulators have allowed us to recover incurred costs, net of insurance recoveries and recoveries from potentially responsible parties, associated with the remediation of manufactured gas plant sites. Accordingly, we have established regulatory assets for costs associated with these sites.

We have established the following regulatory assets and reserves related to manufactured gas plant sites as of December 31:

(in millions)	2015	2014
Regulatory assets	**$ 46.8**	$ 48.9
Reserves for future remediation	**45.0**	38.0

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 14—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, 2015			
(in millions)	Level 1	Level 2	Level 3	Total
Derivative assets				
Natural gas contracts	**$ —**	**$ 0.2**	**$ —**	**$ 0.2**
Derivative liabilities				
Natural gas contracts	**—**	**4.3**	**—**	**4.3**

(in millions)	December 31, 2014 Level 1	Level 2	Level 3	Total
Derivative assets				
Natural gas contracts	$ —	$ 0.2	$ —	$ 0.2
Derivative liabilities				
Natural gas contracts	—	5.5	3.4	8.9

The derivative assets and liabilities listed in the tables above include options, swaps, and natural gas purchase contracts used to manage volatility in natural gas supply costs. See Note 15, Derivative Instruments, for more information.

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

(in millions)	2015	2014
Balance at the beginning of the period	**$ (3.4)**	$ —
Realized and unrealized losses	**—**	(3.4)
Settlements	**3.4**	—
Balance at the end of the period	**$ —**	$ (3.4)

Unrealized gains and losses on Level 3 derivatives are deferred as regulatory assets or liabilities. Therefore, these fair value measurements have no impact on earnings. Realized gains and losses on these instruments flow through cost of natural gas on the income statements.

Fair Value of Financial Instruments

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

	2015		2014	
(in millions)	Carrying Amount	Fair Value	Carrying Amount	Fair Value
Long-term debt	**$ 81.5**	**$ 76.1**	$ 81.4	$ 79.5

NOTE 15—DERIVATIVE INSTRUMENTS

The following table shows our derivative assets and derivative liabilities:

		December 31, 2015		December 31, 2014	
(in millions)	Balance Sheet Presentation	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Natural gas contracts	Other current	**$ 0.1**	**$ 4.0**	$ 0.1	$ 8.1
Natural gas contracts	Other long-term	**0.1**	**0.3**	0.1	0.8
Total		**$ 0.2**	**$ 4.3**	$ 0.2	$ 8.9

Our estimated notional volumes and (losses) gains were as follows:

	December 31, 2015		December 31, 2014		December 31, 2013	
(in millions)	Volume	Losses	Volume	Gains	Volume	Losses
Natural gas contracts	**8.7 Dth**	**$ (7.9)**	7.9 Dth	$ 0.6	8.4 Dth	$ (2.5)

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

	December 31, 2015		December 31, 2014	
(in millions)	Derivative Assets	Derivative Liabilities	Derivative Assets	Derivative Liabilities
Gross amount recognized on the balance sheet	**$ 0.2**	**$ 4.3**	$ 0.2	$ 8.9
Gross amount not offset on the balance sheet	**(0.2)**	**(0.2)**	(0.2)	(0.2)
Net amount	**$ —**	**$ 4.1**	$ —	$ 8.7

At December 31, 2015 and 2014, we did not have any collateral posted in our margin accounts. Certain of our derivative and non-derivative commodity instruments contain provisions that could require "adequate assurance" in the event of a material change in our creditworthiness, or the posting of additional collateral for instruments in net liability positions, if triggered by a decrease in credit ratings. The aggregate fair value of all derivative instruments with specific credit risk-related contingent features that were in a net liability position at December 31, 2015 and 2014, was $4.0 million and $5.6 million, respectively. At December 31, 2015 and 2014, we had not posted any cash collateral related to the credit risk-related contingent features of these commodity instruments. If all of the credit risk-related contingent features contained in derivative instruments in a net liability position had been triggered at December 31, 2015 and 2014, we would have been required to post collateral of $3.0 million and $4.9 million, respectively.

NOTE 16—REGULATORY ENVIRONMENT

Base Rate Freeze

In June 2015, the ICC approved the WEC Merger subject to the condition that we will not seek an increase of our base rates that would become effective earlier than two years after the close of the merger.

2015 Illinois Rate Order

In February 2014, we initiated a rate proceeding with the ICC. In January 2015, the ICC issued a final written order, effective January 28, 2015. The order authorized a retail natural gas rate increase of $3.7 million. In February 2015, the ICC issued an amendatory order that revised the increase to $3.5 million, effective February 26, 2015, to reflect the extension of bonus depreciation in 2014. The rates reflect a 9.05% ROE and a common equity component average of 50.48%. The rate order allowed us to continue the use of our decoupling mechanism and uncollectible expense true-up mechanism. In February 2015, the Attorney General (AG) and certain intervenors filed requests for rehearing on certain issues, which the ICC denied in March 2015. No appeals were filed related to the rehearing requests.

2013 Illinois Rate Order

In July 2012, we initiated a rate proceeding with the ICC. In June 2013, the ICC issued a final written order, effective June 27, 2013. The order authorized a retail natural gas rate increase of $6.6 million. The rates reflected a 9.28% ROE and a common equity component average of 50.32%. The rate order also allowed us to continue the use of our decoupling mechanism, as affirmed by the Illinois Supreme Court as discussed below.

In August 2013, the ICC granted certain rehearing requests on tax-related issues filed by us, PGL, and other intervenors. We asked for a correction of the revenue requirement for deferred tax assets related to tax net operating losses (NOLs) incurred in 2012 and 2013. In the ICC's order, these deferred tax assets were included in rate base, but computational errors were made. Other intervenors requested the exclusion from rate base of the deferred tax asset related to the 2012 tax NOL. The tax NOLs in question resulted from claiming accelerated depreciation deductions in 2012 and 2013. In December 2013, the ICC evaluated and approved a correction of the computational errors and rejected the intervenors' proposed exclusion of the 2012 tax NOL. Customer rates were increased $0.1 million for the impact of this correction, effective January 1, 2014. In January 2014, the AG and Citizens Utility Board each filed an appeal with the Illinois Appellate Court (Court). In April 2015, the Citizens Utility Board appeal was withdrawn, and, in May 2015, the Court dismissed the appeal from the AG.

2012 Decoupling

The ICC issued a final written order, effective January 21, 2012, which approved a permanent decoupling mechanism for us. The AG and Citizens Utility Board appealed to the Court the ICC's authority to approve our decoupling mechanism and filed a motion to stay the implementation of the permanent decoupling mechanism or make collections subject to refund. In May 2012, the ICC issued a revised amendatory order granting the AG's motion to make revenues collected under the permanent decoupling mechanism subject to refund. Refunds would have been required if the Court found that the ICC did not have authority to approve decoupling and ordered a refund. As a result, the recovery of amounts related to decoupling in 2012 were uncertain, and we established offsetting reserves equal to decoupling amounts accrued. In March 2013, the Court issued an opinion that affirmed the ICC's order approving the permanent decoupling mechanism. As a result, the reserves recorded in 2012 were reversed in the first quarter of 2013. Our permanent decoupling mechanism was in place for 2013. In June 2013, the AG and Citizens Utility Board petitioned the Illinois Supreme Court to appeal the Court's decision. In January 2015, the Illinois Supreme Court affirmed the ICC's authority to approve the permanent decoupling mechanism. As a result, decoupling amounts recorded in 2014 were refunded to customers in 2015 as planned, and decoupling amounts in the future will continue to be accrued.

NOTE 17—SEGMENT INFORMATION

At December 31, 2015, we reported two segments. Our utility operations are reported in the natural gas utility segment. Our non-utility operations are reported in the other segment. No significant items were reported in the other segment for any of the years presented. All of our operations and assets are located within the United States.

NOTE 18—NEW ACCOUNTING PRONOUNCEMENTS

Revenue Recognition

In May 2014, the FASB and the International Accounting Standards Board issued their joint revenue recognition standard, ASU 2014-09, Revenue from Contracts with Customers. This guidance is effective for fiscal years and interim periods beginning after December 15, 2018, and can either be applied retrospectively or as a cumulative-effect adjustment as of the date of adoption. We are currently assessing the effects this guidance may have on our financial statements.

Classification and Measurement of Financial Instruments

In January 2016, the FASB issued ASU 2016-01, Classification and Measurement of Financial Assets and Liabilities. This guidance is effective for fiscal years and interim periods beginning after December 15, 2018, and will be recorded with a cumulative-effect adjustment to beginning retained earnings as of the beginning of the fiscal year in which the guidance is effective. We are currently assessing the effects this guidance may have on our financial statements.

Leases

In February 2016, the FASB issued ASU 2016-02, Leases. This guidance is effective for fiscal years, and interim periods within those fiscal years, beginning after December 15, 2019. We are currently assessing the effects this guidance may have on our financial statements.