ONE Gas, Inc.
Form 10-K
February 20, 2019
UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
WASHINGTON, D.C. 20549

FORM 10-K

X ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2018.
OR
__ TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from __________ to __________.
Commission file number 001-36108
ONE Gas, Inc.

(Exact name of registrant as specified in its charter)

Oklahoma	46-3561936
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
15 East Fifth Street, Tulsa, OK	74103
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code (918) 947-7000
Securities registered pursuant to Section 12(b) of the Act:

Common stock, par value of $0.01	New York Stock Exchange
(Title of each class)	(Name of each exchange on which registered)

Securities registered pursuant to Section 12(g) of the Act: None
Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes X No__

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes __ No X

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes X No __

Indicate by check mark whether the registrant has submitted electronically every Interactive Data File required to be submitted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit such files). Yes X No _

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Registration S-K (§229.405 of this chapter) is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. _

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, a smaller reporting company, or an emerging growth company. See the definitions of "large accelerated filer," "accelerated

filer,” “smaller reporting company,” and “emerging growth company” in Rule 12b-2 of the Exchange Act. (Check one)
Large accelerated filer X Accelerated filer __ Non-accelerated filer __
Smaller reporting company __ Emerging growth company __

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes__ No X
The aggregate market value of the equity securities held by nonaffiliates based on the closing trade price of the registrant on June 30, 2018, was $3.7 billion.

On February 8, 2019, we had 52,573,267 shares of common stock outstanding.
DOCUMENTS INCORPORATED BY REFERENCE:
Portions of the definitive proxy statement to be delivered to shareholders in connection with the Annual Meeting of Shareholders to be held May 23, 2019, are incorporated by reference in Part III.

1

ONE Gas, Inc.
2018 ANNUAL REPORT

As used in this Annual Report, references to “we,” “our,” “us” or the “company” refer to ONE Gas, Inc., an Oklahoma corporation, and its predecessors and subsidiaries, unless the context indicates otherwise.

GLOSSARY

The abbreviations, acronyms and industry terminology used in this Annual Report are defined as follows:

AAO	Accounting Authority Order
ADIT	Accumulated deferred income tax
ACA	Annual Cost Adjustment
AFUDC	Allowance for funds used during construction
Annual Report	Annual Report on Form 10-K for the year ended December 31, 2018
ASC	Accounting Standards Codification
ASU	Accounting Standards Update
ATSR	Ad-Valorem Tax Surcharge Rider
Bcf	Billion cubic feet
CERCLA	Federal Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended
CFTC	Commodities Futures Trading Commission
Clean Air Act	Federal Clean Air Act, as amended
Clean Water Act	Federal Water Pollution Control Amendments of 1972, as amended
CNG	Compressed natural gas
Code	Internal Revenue Code of 1986, as amended
COG	Cost of gas
COGR	Cost of gas rider
COSA	Cost-of-Service Adjustment
DOT	United States Department of Transportation
Dth	Dekatherm
ECP	The ONE Gas, Inc. Amended and Restated Equity Compensation Plan (2018)
EPA	United States Environmental Protection Agency
EPARR	El Paso Annual Rate Review
EPS	Earnings per share
EPSA	El Paso Service Area
ESPP	The ONE Gas, Inc. Employee Stock Purchase Plan
Exchange Act	Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
GAAP	Accounting principles generally accepted in the United States of America
GPAC	Gas Pipeline Advisory Committee
GRIP	Texas Gas Reliability Infrastructure Program
GSRS	Gas System Reliability Surcharge
Heating Degree Day or HDD	A measure designed to reflect the demand for energy needed for heating based on the extent to which the daily average temperature falls below a reference temperature for which no heating is required, usually 65 degrees Fahrenheit
IRS	U.S. Internal Revenue Service
IRS Ruling	Private Letter Ruling from IRS
KCC	Kansas Corporation Commission
KDHE	Kansas Department of Health and Environment
kWh	Kilowatt hour
LDC	Local distribution company
LIBOR	London Interbank Offered Rate
MGP	Manufactured gas plant
MMcf	Million cubic feet
Moody’s	Moody’s Investors Service, Inc.

Net Margin	Non-GAAP measure defined as total revenues less cost of natural gas
NOL	Net operating loss
NPRM	Notice of proposed rulemaking
NYMEX	New York Mercantile Exchange

NYSE	New York Stock Exchange
OCC	Oklahoma Corporation Commission
ONE Gas	ONE Gas, Inc.
ONE Gas Credit Agreement	ONE Gas’ $700 million amended and restated revolving credit agreement, which expires on October 5, 2023
ONEOK	ONEOK, Inc. and its subsidiaries
OSHA	Occupational Safety and Health Administration
PBRC	Performance-Based Rate Change
PGA	Purchased Gas Adjustment
PHMSA	United States Department of Transportation Pipeline and Hazardous Materials Safety Administration
Pipeline Safety Improvement Act	Pipeline Safety Improvement Act of 2002, as amended
Pipeline Safety, Regulatory Certainty and Job Creation Act	Pipeline Safety, Regulatory Certainty and Job Creation Act of 2011, as amended
ROE	Return on equity calculated consistent with utility ratemaking principles in each jurisdiction in which we operate
RRC	Railroad Commission of Texas
S&P	Standard and Poor’s Rating Services
SAB	Staff Accounting Bulletin
SEC	Securities and Exchange Commission
Securities Act	Securities Act of 1933, as amended
Senior Notes	ONE Gas’ registered notes consisting of $300 million of 3.61 percent senior notes due 2024, $600 million of 4.658 percent notes due 2044, and $400 million of 4.50 percent senior notes due 2048
Separation and Distribution Agreement	Separation and Distribution Agreement dated January 14, 2014, between ONEOK and ONE Gas
TAC	Temperature Adjustment Clause
WNA	Weather normalization adjustments
XBRL	eXtensible Business Reporting Language

The statements in this Annual Report that are not historical information, including statements concerning plans and objectives of management for future operations, economic performance or related assumptions, are forward-looking statements. Forward-looking statements may include words such as “anticipate,” “estimate,” “expect,” “project,” “intend,” “pla “believe,” “should,” “goal,” “forecast,” “guidance,” “could,” “may,” “continue,” “might,” “potential,” “scheduled” and other w of similar meaning. Although we believe that our expectations regarding future events are based on reasonable assumptions, we can give no assurance that such expectations and assumptions will be achieved. Important factors that could cause actual results to differ materially from those in the forward-looking statements are described under Part I, Item 1A, Risk Factors, and Part II, Item 7, Management’s Discussion and Analysis of Financial Condition and Results of Operation, Forward-Looking Statements, in this Annual Report.

PART I

ITEM 1. BUSINESS

OUR BUSINESS

ONE Gas, Inc. is incorporated under the laws of the state of Oklahoma. Our common stock is listed on the NYSE under the trading symbol "OGS," and is included in the S&P MidCap 400 Index. We are a 100-percent regulated natural gas distribution utility, headquartered in Tulsa, Oklahoma, and one of the largest publicly traded natural gas utilities in the United States. We are successor to the company founded in 1906 as Oklahoma Natural Gas Company, which became ONEOK, Inc. (NYSE: OKE) in 1980. On January 31, 2014, ONE Gas officially separated from ONEOK.

We provide natural gas distribution services to our 2.2 million customers and are the largest natural gas distributor in Oklahoma and Kansas and the third largest in Texas, in terms of customers. We serve residential, commercial and industrial, transportation and wholesale, and public authority customers in all three states. Our largest natural gas distribution markets in terms of customers are Oklahoma City and Tulsa, Oklahoma; Kansas City, Wichita and Topeka, Kansas; and Austin and El Paso, Texas. Our three divisions, Oklahoma Natural Gas, Kansas Gas Service and Texas Gas Service, distribute natural gas to approximately 88 percent, 72 percent and 13 percent of the natural gas distribution customers in Oklahoma, Kansas and Texas, respectively.

OUR STRATEGY

Our mission is to deliver natural gas for a better tomorrow. Our vision is to be a premier natural gas distribution company, creating exceptional value for all stakeholders. Our business strategy is focused on operating our systems in a safe, reliable and environmentally responsible manner and growing our business strategically, while delivering quality customer service. We believe this will enable us to generate a competitive total return for our shareholders and maintain our financial stability, leading to our strategic goals of zero harm, a fair return and satisfied customers.

We intend to accomplish our objectives by executing on the following strategies:

- Focus on Safety, Reliability and Compliance - We are committed, first and foremost, to pursuing a zero-incident safety and 100-percent compliance culture through programs, procedures, policies, guidelines and other internal controls designed to mitigate risk and incidents that may harm our employees, contractors, customers, the public or the environment. Additionally, a significant portion of our capital spending is focused on the safety, integrity, reliability and efficiency of our natural gas distribution system. We are committed to compliance with all federal, state and local laws and regulations.

- High-performing Workforce - The foundation of our company is our employees. Our success begins with our people and a commitment to attracting, selecting, retaining and developing a high-performing, ethical workforce where every employee understands that they can and do make a difference. We embrace an inclusive and diverse culture that encourages collaboration. We expect a high standard of performance from our employees and encourage our workforce to measure their productivity and be accountable for the best work possible. Each day that we do our best to safely, efficiently and ethically meet the needs of our customers is a day that leads to individual success and, ultimately, the success of the company.

- Increase Our Achieved ROE - We continually seek to increase our achieved ROE through improved operational performance, regulatory mechanisms and incremental revenues. The difference between our achieved and allowed ROE is related primarily to regulatory lag. We make investments that increase our rate base and we incur increases in our costs that are above the amounts reflected in the rates we charge for our service.

We continue to leverage technology to improve our operational performance. Ongoing initiatives to expand the use of technology in key areas of operations and customer service are expected to result in increased customer satisfaction and efficiency, thereby helping reduce the rate of increasing expenses.

Our focus on credit metrics and maintaining a balanced approach to capital management are significant objectives in providing reasonable rates to customers while also providing a fair return to shareholders. We believe that maintaining an investment-grade credit rating is prudent for our business as we seek to access the capital markets to finance capital investments. As a 100-percent regulated utility, we intend to maintain strong credit metrics while we pursue a balanced approach to capital investment and a return of capital to shareholders via a dividend that we believe will be competitive with our peer group.

- Advocate Constructive Relationships with Key Stakeholders - We plan to continue our constructive, transparent relationships with our key stakeholders, which include our customers, employees, investors, legislators and regulators. Our strategy includes meeting the needs of our customers through the delivery of safe and reliable natural gas service while seeking outcomes in future rate proceedings that provide recovery of our costs and a fair return on our infrastructure investments.

- Identify and Pursue Growth Opportunities - Our growth opportunities are a result of capital investments related to the safety and reliability of our existing system, as identified by our system integrity program, in addition to system expansion related to the economic and population growth in our service territories. As a result of our commitment to enhance the integrity, reliability and safety of our existing infrastructure, we are making significant investments in our existing system, which we expect to further grow our rate base. In addition, as some of our service territories continue to experience economic growth, we expect to grow our rate base through capital investments in new service lines and main line extensions, predominately in the seven major metropolitan areas we serve.

We believe the competitiveness of natural gas is increasing, creating new market opportunities for natural gas as an energy source within our existing service territories. Our emphasis on safety and a satisfying customer service experience makes our business an important part of the communities we serve. Natural gas remains positioned within the United States energy economy to support sustainable growth opportunities, energy independence and national security.

We remain committed to maintaining our status as a 100-percent regulated natural gas utility. We will, however, follow a disciplined financial and operational approach to evaluating both strategic acquisition opportunities and continued investments in our existing rate base.

REGULATORY OVERVIEW

We are subject to the regulations and oversight of the state and local regulatory authorities of the territories in which we operate. Rates and charges for natural gas distribution services are established by the OCC for Oklahoma Natural Gas and by the KCC for Kansas Gas Service. Texas Gas Service is subject to regulatory oversight by the various incorporated cities that it serves, which have primary jurisdiction for their respective service areas. Rates in unincorporated areas of Texas and all appellate matters are subject to regulatory oversight by the RRC. These regulatory authorities have the responsibility of ensuring that the utilities in their jurisdictions provide safe and reliable service at a reasonable cost, while providing utility companies the opportunity to earn a fair and reasonable return on their investments.

Generally, our rates and charges are established in rate case proceedings. Regulatory authorities may also approve mechanisms that allow for adjustments for specific costs or investments made between rate cases. Due to the nature of the regulatory process, there is an inherent lag between the time that we make investments or incur additional costs and the setting of new rates and/or charges to recover those investments or costs. Additionally, we are not allowed recovery of certain costs we incur.

The following provides additional detail on the regulatory mechanisms in the jurisdictions we serve.

Oklahoma - Oklahoma Natural Gas currently operates under a PBRC mechanism, which provides for streamlined annual rate reviews between rate cases and includes adjustments for incremental capital investment and allowed expenses. Under this mechanism, we have an authorized ROE of 9.5 percent, with a 100 basis point dead-band of 9 to

10 percent. If our achieved ROE is below 9 percent, our base rates are increased upon OCC approval to an amount necessary to restore the ROE to 9.5 percent. If our achieved ROE exceeds 10 percent, the portion of the earnings that exceeds 10 percent is shared with our customers, who receive the benefit of 75 percent of those earnings. We receive the benefit of the remaining 25 percent. Oklahoma Natural Gas is required to file a rate case on or before June 30, 2021, based on a test year consisting of the twelve months ending December 31, 2020. Other regulatory mechanisms in Oklahoma include the following:

- Rate Design for Residential Customers - Oklahoma Natural Gas has an authorized rate structure providing customers with two rate choices. Rate Choice “A” is designed for customers whose annual normalized volume is less than 50 Dth. These customers pay a fixed monthly service charge and a per Dth delivery fee. Although a portion of the delivery charges for customers in Rate Choice “A” is dependent on usage, these customers use relatively small quantities of natural gas and therefore the delivery charge that is dependent on usage is not significant. The fixed monthly residential customer charge is $15.77, with a delivery fee of $4.1143 per Dth for these customers. Rate

Choice "B" is designed for customers whose annual normalized volume is 50 Dth or greater. These customers pay a fixed monthly service charge of $32.91, with no delivery fee. At December 31, 2018, 71 percent of Oklahoma Natural Gas' residential customers were on Rate Choice "B."

- Rate Design for Commercial and Industrial Customers - Oklahoma Natural Gas is authorized to provide two different rate choices for its Small Commercial and Industrial, or SCI, customers. Rate Choice "A" is designed for SCI customers whose annual normalized volume is less than 40 Dth. These customers pay both a fixed monthly service charge of $21.65 and a delivery fee of $4.5599 per Dth. Rate Choice "B" is designed for SCI customers whose annual normalized volume is 40 Dth or greater but less than 150 Dth. These customers pay a fixed monthly service charge of $36.85, with no delivery fee. All of Oklahoma Natural Gas' Large Commercial and Industrial, or LCI, customers, whose annual volume is 150 Dth or greater, but less than 5,000 Dth, pay a fixed monthly service charge of $88.92. At December 31, 2018, 80 percent of Oklahoma Natural Gas' commercial and industrial customers were on either SCI Rate Choice "B" or LCI.
- PGA Clause - Oklahoma Natural Gas' commodity, transportation, storage and gas purchase operations and maintenance costs are passed through to its sales customers, without profit, via the PGA. Any costs associated with natural gas that is lost, used or unaccounted for in operations and the fuel-related portion of bad debts are also recovered through the PGA.
- TAC - The TAC is a weather normalization mechanism designed to reduce the delivery charge component of customers' bills for the additional volumes used when actual HDDs exceed normalized HDDs and to increase the delivery charge component of customers' bills for volumes not used when actual HDDs are less than the normal HDDs. Normalized HDDs established through our most recent rate proceeding are based on 10-year weighted average HDDs as of December 31, 2014, for years 2005-2014, as calculated using 11 weather stations across Oklahoma and weighted on average customer count for Oklahoma. The TAC is in effect from November through April.
- Energy Efficiency Programs - Oklahoma Natural Gas has energy efficiency programs, available to all sales customers. The costs associated with these programs and an incentive to offer these programs are recovered through a monthly surcharge on customer bills. Oklahoma Natural Gas collects approximately $15.4 million each year from sales customers to fund the programs, which provides rebates for energy-efficient natural gas appliances.
- CNG Rebate Program - The CNG rebate program is designed to promote and support the CNG market in the state of Oklahoma by offering rebates to Oklahoma residents and companies who purchase dedicated and bi-fueled natural gas vehicles or install residential CNG fueling stations. The rebates are funded by a $0.25 per gasoline gallon equivalent surcharge that Oklahoma Natural Gas is authorized to collect on fuel purchased from publicly accessible CNG dispensers owned by Oklahoma Natural Gas. Collections from the surcharge to fund the program were not material in 2018.

For the year ended December 31, 2018, approximately 86 percent of Oklahoma Natural Gas' Net Margin from its sales customers was recovered from fixed charges.

Kansas - Kansas Gas Service files periodic rate cases with the KCC as needed to increase base rates to reflect Kansas Gas Service's authorized revenue requirement. Other regulatory mechanisms in Kansas include the following:

- COGR and ACA - These mechanisms allow Kansas Gas Service to recover the actual cost of the natural gas it sells to its customers. The COGR includes a monthly estimate of the cost Kansas Gas Service incurs in transporting, storing and purchasing natural gas supply for its sales customers, the ACA and other charges and credits. The ACA is an annual component of the COGR that compares the cost of gas recovered through the COGR for the preceding year with the actual natural gas supply costs and the fuel-related portion of bad debts for the same period. Any over- or under-recovery is reflected in the subsequent year's COGR.
- WNA Clause - In 2016, the WNA Clause required Kansas Gas Service to accrue the variation in delivery charges resulting from actual weather differing from normal weather occurring from November through March. Beginning in April 2017, the WNA mechanism requires an accrual each month of the year. The WNA is designed to reduce the delivery charge component of customers' bills for the additional volumes used when actual HDDs exceed normalized HDDs and to increase the delivery charge component of customers' bills for the reduction in volumes used when

actual HDDs are less than normal HDDs. Normal HDDs are established through rate proceedings and are based on a 30-year average for years 1981-2010 published by the National Oceanic and Atmospheric Administration, as calculated using four weather stations across Kansas and weighted on HDDs by weather station and customers for Kansas. Annually, the amount of the adjustment is determined and is then applied to customers' bills over the subsequent 12-month period.

- ATSR - This rider requires Kansas Gas Service to recover the difference each year between the property tax costs included in its base rates and its actual property tax costs incurred without having to file a rate case. The amount of the adjustment is determined annually and recovered over the subsequent 12 months as a change in the delivery charge component of customers' bills.

- Pension and Other Postemployment Benefits Trackers - These trackers require Kansas Gas Service to track and defer for recovery in its next rate case the difference between the pension and other postemployment benefit costs included in base rates and actual expense as determined in accordance with GAAP.
- MGP Remediation Expense Tracker - This tracker allows Kansas Gas Service to record and defer for recovery expenses incurred after January 1, 2017, related to MGP site remediation. Kansas Gas Service is allowed to seek recovery of its costs within a general rate case application. In the first such rate case application, approved MGP costs will be amortized over 15 years.
- GSRS - This surcharge allows Kansas Gas Service to file for a rate adjustment providing a recovery of and return on qualifying infrastructure investments incurred between rate case filings, including all investments to replace, upgrade or modernize obsolete facilities, as well as projects that enhance the integrity of pipeline system components or extend the useful life of such assets. Safety-related investments also include expenditures for physical and cyber security. The filing cannot occur more often than once every 12 months and the rate adjustment cannot increase the monthly charge by more than $0.80 per residential customer per month compared with the most recent GSRS filing. After five annual filings, Kansas Gas Service is required to file a rate case or cease collection of the surcharge.

The fixed monthly residential customer charge for Kansas Gas Service was $16.70, and for the year ended December 31, 2018, approximately 54 percent of Kansas Gas Service's Net Margin from its sales customers was recovered from fixed charges.

Texas - Texas Gas Service has grouped its customers into six service areas. These service areas are further divided into the incorporated cities and the unincorporated areas, referred to as the environs. The incorporated cities in the service areas have original jurisdiction, with the RRC having appellate authority, and the RRC has original jurisdiction for the environs. Periodic rate cases are filed with the cities or the RRC, as needed, to increase rates to reflect the respective service area's authorized revenue requirement. Other regulatory mechanisms and constructs in Texas include the following:

- GRIP Statute - For the incorporated cities in three of the service areas and for the environs in all six service areas, comprising 81 percent of Texas Gas Service's customers, Texas Gas Service makes an annual filing under the GRIP statute, which allows it to recover taxes and depreciation and to earn a return on the annual net increase in investment for the service area. After five annual GRIP filings, Texas Gas Service is required to file a full rate case. A full rate case may be filed at shorter intervals if desired by either Texas Gas Service or the regulator.
- COSA Filings - In three of the service areas, comprising 19 percent of its customers, Texas Gas Service makes an annual COSA filing for the incorporated cities. COSA tariffs permit Texas Gas Service to recover return, taxes and depreciation on the annual increases in net investment, as well as annual increases or decreases in certain expenses and revenues. The COSAs have a cap of 3.25 percent to 5 percent on the expense portion of the increase. A full rate case may be filed when desired by Texas Gas Service or the regulator, but is not required.
- WNA Clause - Texas Gas Service employs WNA clauses in all six service areas. The WNA clause is designed to reduce the delivery charge component of customers' bills for the additional volumes used when actual HDDs exceed normalized HDDs and to increase the delivery charge component of customers' bills for the reduction in volumes used when actual HDDs are less than normal HDDs. Normal HDDs are established through rate proceedings in each of our service areas and are generally based on a 10-year average of HDDs in each service area. The WNA clause is in effect from September through May.
- COG Clause - In all service areas, Texas Gas Service recovers 100 percent of its natural gas costs, including transportation and storage costs, interest on natural gas in storage and the natural gas cost component of bad debts, subject to a limitation of 5 percent on lost-and-unaccounted-for natural gas. Annually, natural gas costs recovered through the COG are compared with actual natural gas supply costs. Any over- or under-recovery is refunded or recovered, as applicable, in the subsequent year.
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- Pension and Other Postemployment Benefits - Texas Gas Service is authorized by statute to defer pension and other postemployment benefit costs that exceed the amount recovered in base rates and to seek recovery of the deferred costs in a future rate case.
- Pipeline-Integrity Testing Riders - Texas Gas Service recovers 100 percent of its non-labor related pipeline-integrity testing expenses via riders.
- Safety-Related Plant Replacements - Texas Gas Service is authorized by RRC rule to defer interest cost, taxes and depreciation expense on safety-related plant replacements from the time the replacements are in service until the plant is reflected in base rates, and to seek recovery of those accrued amounts in a future rate proceeding.
- Energy Conservation Programs - Texas Gas Service has energy conservation programs in the incorporated cities of our Central Texas and Rio Grande Valley service areas, comprising 46 percent of total customers. Texas Gas Service collects approximately $3.5 million per year from customers to fund the programs, which provide energy audits, weatherization and appliance rebates to promote energy conservation.

The average fixed monthly residential customer charge for Texas Gas Service was $16.85. For the year ended December 31, 2018, approximately 68 percent of Texas Gas Service's Net Margin from its sales customers was recovered from fixed charges.

MARKET CONDITIONS AND SEASONALITY

Supply - We purchased 180 Bcf and 137 Bcf of natural gas supply in 2018 and 2017, respectively. Our natural gas supply portfolio consists of long-term, seasonal and short-term contracts from a diverse group of suppliers. We award these contracts through competitive-bidding processes to ensure reliable and competitively priced natural gas supply. We acquire our natural gas supply from natural gas processors, marketers and producers.

An objective of our supply-sourcing strategy is to provide value to our customers through reliable, competitively priced and flexible natural gas supply and transportation from multiple production areas and suppliers. This strategy is designed to mitigate the impact on our supply from physical interruption, financial difficulties of a single supplier, natural disasters and other unforeseen force majeure events, as well as to ensure these resources are reliable and flexible to meet the variations of customer demands.

We do not anticipate problems with securing natural gas supply to satisfy customer demand; however, if supply shortages were to occur, we have curtailment provisions in our tariffs that allow us to reduce or discontinue natural gas service to large industrial users and to request that residential and commercial customers reduce their natural gas requirements to an amount essential for public health and safety. In addition, during times of critical supply disruptions, curtailments of deliveries to customers with firm contracts may be made in accordance with guidelines established by appropriate federal, state and local regulatory agencies.

Natural gas supply requirements are affected by weather conditions. In addition, economic conditions impact the requirements of our commercial and industrial customers. Natural gas usage per residential customer may decline as customers change their consumption patterns in response to a variety of factors, including:

- more volatile and higher natural gas prices;
- more energy-efficient construction;
- fuel switching from natural gas to electricity; and
- customers improving the energy efficiency of existing homes by replacing doors and windows, adding insulation and replacing appliances with more efficient appliances.

In each jurisdiction in which we operate, changes in customer-usage profiles are considered in the periodic redesign of our rates.

As of December 31, 2018, we had 48.4 Bcf of natural gas storage capacity under contract with remaining terms ranging from one to ten years and maximum allowable daily withdrawal capacity of approximately 1.3 Bcf. This storage capacity allows us to purchase natural gas during the off-peak season and store it for use in the winter periods. This storage is also needed to assure the reliability of gas deliveries during peak demands for natural gas. Approximately 26 percent of our winter natural gas supply needs for our sales customers is expected to be supplied from storage.

In managing our natural gas supply portfolios, we partially mitigate price volatility using a combination of financial derivatives and natural gas in storage. We have natural gas financial hedging programs that have been authorized by the OCC, KCC and certain jurisdictions in Texas. We do not utilize financial derivatives for speculative purposes, nor do we have trading operations associated with our business.

Demand - See discussion below under Seasonality, Competition and CNG for factors affecting demand for our services.

Seasonality - Natural gas sales to residential and commercial customers are seasonal, as a substantial portion of their natural gas requirements are for heating. Accordingly, the volume of natural gas sales is higher normally during the months of November through March than in other months of the year. The impact on our margins resulting from weather temperatures that are above or below normal is offset partially through our TAC and WNA mechanisms. See discussion above under Regulatory Overview.

Competition - We encounter competition based on customers' preference for natural gas, compared with other energy alternatives and their comparative prices. We compete primarily to supply energy for space and water heating, cooking and clothes drying. Significant energy usage competition occurs between natural gas and electricity in the residential and small commercial markets. Customers and builders typically make the decision on the type of equipment, and therefore the energy source, at initial installation, generally locking in the chosen energy source for the life of the equipment. Changes in the competitive position of natural gas relative to electricity and other energy alternatives have the potential to cause a decline in consumption of natural gas or in the number of natural gas customers.

The U.S. Department of Energy issued a statement of policy that it will use full fuel-cycle measures of energy use and emissions when evaluating energy-conservation standards for appliances. In addition, the EPA has determined that source energy is the most equitable unit for evaluating energy consumption. Assessing energy efficiency in terms of a full fuel-cycle or source-energy analysis, which takes all energy use into account, including transmission, delivery and production losses, in addition to energy consumed at the site, highlights the high overall efficiency of natural gas in residential and commercial uses compared with electricity.

The table below contains data related to the cost of delivered gas relative to electricity based on current market conditions:

Natural Gas vs. Electricity	Oklahoma	Kansas	Texas
Average retail price of electricity / kWh(1)	10.34¢	13.23¢	11.40¢
ONE Gas delivered cost of natural gas / kWh(2)	3.16¢	3.15¢	3.76¢
Natural gas advantage ratio(3)	3.3x	4.2x	3.0x

(1) Source: United States Energy Information Agency, www.eia.gov, for the eleven-month period ended November 30, 2018.
(2) Represents the average delivered cost of natural gas per kWh equivalent to a residential customer, including the cost of the natural gas supplied, fixed customer charge, delivery charges and charges for riders, surcharges and other regulatory mechanisms associated with the services we provide, for the year ended December 31, 2018.
(3) Calculated as the ratio of the ONE Gas delivered average cost of natural gas per kWh equivalent to the average retail price of electricity per kWh.

We are subject to competition from other pipelines for our large industrial and commercial customers, and this competition has and may continue to impact margins. Under our transportation tariffs, qualifying industrial and commercial customers are able to purchase their natural gas needs from the supplier of their choice and have us transport it for a fee. A portion of the transportation services that we provide are at negotiated rates that are below the maximum approved transportation tariff rates. Reduced-rate transportation service may be negotiated when a competitive pipeline is in close proximity or another viable energy option is available to the customer.

CNG - In meeting demand for CNG for motor vehicle transportation, particularly from fleet operators, we have continued to invest in our system to support the supply of natural gas to CNG fueling stations. As of December 31, 2018, we supply 151 fueling stations, 31 of which we operate. Of the 120 remaining stations, 68 are retail and 52 are private stations. We transported 2.9 million Dth to CNG stations in 2018, which represents an increase of 9 percent compared with 2017.

We will continue to support industry efforts to continue tax incentives for CNG. Our strategy is to support third-party investment in CNG fueling stations. We deploy a minimum amount of capital to connect CNG stations and allow the free market to build and operate the stations.

ENVIRONMENTAL AND SAFETY MATTERS

See Note 15 of the Notes to Consolidated Financial Statements and Management’s Discussion and Analysis of Financial Condition and Results of Operations in this Annual Report for information regarding environmental and safety matters.

EMPLOYEES

We employed approximately 3,500 people at February 1, 2019, including approximately 700 people at Kansas Gas Service who are subject to collective bargaining agreements. The following table sets forth our contracts with collective bargaining units at February 1, 2019:

Union	Approximate Employees	Contract Expires
The United Steelworkers	400	October 31, 2019
International Brotherhood of Electrical Workers ("IBEW")	300	June 30, 2021

EXECUTIVE OFFICERS OF THE REGISTRANT

All executive officers are elected annually by our Board of Directors and each serves until such person resigns, is removed or is otherwise disqualified to serve or until such officer's successor is duly elected. Our executive officers listed below include the officers who have been designated by our Board of Directors as our Section 16 executive officers.

Name	Age*		Business Experience in Past Five Years
Pierce H. Norton II	58	2014 to present	President, Chief Executive Officer and Director
Curtis L. Dinan	51	2018 to present	Senior Vice President and Chief Financial Officer
		2014 to 2018	Senior Vice President, Chief Financial Officer and Treasurer
Joseph L. McCormick	59	2014 to present	Senior Vice President, General Counsel and Assistant Secretary
Caron A. Lawhorn	57	2014 to present	Senior Vice President, Commercial
Robert S. McAnnally	55	2015 to present	Senior Vice President, Operations
		2014 to 2015	Senior Vice President, Marketing and Customer Service, Alabama Gas Corporation, a subsidiary of The Laclede Group, Inc. (now Spire Inc.)
Mark A. Bender	54	2015 to present	Senior Vice President, Administration

			and Chief Information Officer
		2014 to 2015	Vice President and Chief Information Officer
Jeffrey J. Husen	47	2018 to present	Vice President, Chief Accounting Officer and Controller
		2014 to 2018	Controller

* As of January 1, 2019

No family relationship exists between any of the executive officers, nor is there any arrangement or understanding between any executive officer and any other person pursuant to which the officer was selected.

AVAILABLE INFORMATION

We make available, free of charge, on our website (www.onegas.com) copies of our Annual Report, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K, amendments to those reports filed or furnished to the SEC pursuant to Section 13(a) or 15(d) of the Exchange Act and reports of holdings of our securities filed by our officers and directors under Section 16 of the Exchange Act as soon as reasonably practicable after filing such material electronically or otherwise furnishing it to the SEC, which also makes these materials available on its website (www.sec.gov). Copies of our Code of Business Conduct and Ethics, Corporate Governance Guidelines, Certificate of Incorporation, bylaws, the written charters of our Audit Committee, Executive Compensation Committee, Corporate Governance Committee and Executive Committee and our Corporate Responsibility Report are also available on our website, and copies of these documents are available upon request.

In addition to filings with the SEC and materials posted on our website, we also use social media platforms as channels of information distribution to reach public investors. Information contained on our website, posted on or disseminated through our social media accounts are not incorporated by reference into this report.

ITEM 1A. RISK FACTORS

Our investors should consider the following risks that could affect us and our business. Although we have tried to discuss key factors, our investors need to be aware that other risks may prove to be important in the future. New risks may emerge at any time, and we cannot predict such risks or estimate the extent to which they may affect our financial performance. Investors should carefully consider the following discussion of risks and the other information included or incorporated by reference in this Annual Report, including Forward-Looking Statements, which are included in Part 2, Item 7, Management’s Discussion and Analysis of Financial Condition and Results of Operations.

RISK FACTORS INHERENT IN OUR BUSINESS

Regulatory actions could impact our ability to earn a reasonable rate of return on our invested capital and to fully recover our operating costs.

In addition to regulation by other governmental authorities, we are subject to regulation by the OCC, KCC, RRC and various municipalities in Texas. These authorities set the rates that we charge our customers for our services. Our ability to obtain timely future rate increases depends on regulatory discretion. As such, there can be no assurance that we will be able to obtain rate increases or that our authorized rates of return will continue at the current levels. We monitor and compare the rates of return we achieve with our allowed rates of return and initiate general and specific rate proceedings as needed. If a regulatory agency were to prohibit us from setting rates that allow for the timely recovery of our costs and a reasonable return by significantly lowering our allowed return or adversely altering our cost allocation, rate design or other tariff provisions, modifying or eliminating cost trackers, prohibiting recovery of regulatory assets or disallowing portions of our expenses, then our earnings could be adversely impacted. Regulatory proceedings also involve a risk of rate reduction, because once a proceeding has been filed, it is subject to challenge by various interveners. Risks and uncertainties relating to delays in obtaining, or failure to obtain, regulatory approvals, conditions imposed in regulatory approvals, and determinations in regulatory investigations can also impact financial performance. In particular, the timing and amount of rate relief can materially impact results of operations, financial condition and cash flows.

Further, accounting principles that govern our company permit certain assets that result from the regulatory process to be recorded on our Consolidated Balance Sheets that could not be recorded under GAAP for nonregulated entities. We consider factors such as rate orders from regulators, previous rate orders for substantially similar costs, written approval from the regulators and analysis of recoverability by internal and external legal counsel to determine the probability of future recovery of these assets. If we determine future recovery is no longer probable, we would be required to write off the regulatory assets at that time, which would also adversely affect our results of operations and cash flows. Regulatory authorities also review whether our natural gas costs are prudent and can adjust the amount of our natural gas costs that we pass through to our customers. If any of our natural gas costs were disallowed, our results of operations and cash flows would also be adversely affected.

In the normal course of business in the regulatory environment, assets are placed in service before regulatory action is taken, such as filing a rate case or for interim recovery under a capital tracking mechanism that could result in an adjustment of our returns. Once we make a regulatory filing, regulatory bodies have the authority to suspend implementation of the new rates while studying the filing. Because of this process, we may suffer the negative financial effects of having placed in service assets that do not initially earn our authorized rate of return or may not be allowed recovery on such expenditures at all.

The profitability of our operations is dependent on our ability to timely recover the costs related to providing natural gas service to our customers. However, we are unable to predict the impact that new regulatory requirements will have on our operating expenses or the level of capital expenditures and we cannot give assurance that our regulators will continue to allow recovery of such expenditures in the future. Changes in the regulatory environment applicable to our business or the imposition of additional regulation could impair our ability to recover costs absorbed historically by our customers, and adversely impact our results of operations, financial condition and cash flows.

We are subject to comprehensive energy regulation by governmental agencies, and the recovery of our costs is dependent on regulatory action.

We are subject to comprehensive regulation by several state and municipal utility regulatory agencies, which significantly influences our operating environment and our ability to recover our costs from utility customers. The utility regulatory authorities in Oklahoma, Kansas and Texas regulate many aspects of our utility operations, including organization, safety, financing, affiliate transactions, customer service and the terms of service to customers, including the rates that we can charge customers.

The profitability of our operations is dependent on our ability to recover costs, including income taxes, related to providing natural gas to our customers by filing periodic rate cases. The regulatory environment applicable to our operations could impair our ability to recover costs historically included in the rates billed to our customers. In addition, as the regulatory environment applicable to our operations increases in complexity, the risk of inadvertent noncompliance could also increase. Our failure to comply with applicable laws and regulations could result in the imposition of fines, penalties or other enforcement action by the authorities that regulate our operations that would not be recoverable in our rates.

We are unable to predict the impact that the future regulatory activities of these agencies will have on our operations. Changes in regulations or the imposition of additional regulations could have an adverse impact on our business, financial condition and results of operations. Further, the results of our operations could be impacted adversely if our authorized cost-recovery mechanisms do not function as anticipated.

We are involved in legal or administrative proceedings before various courts and governmental bodies that could adversely affect our financial condition, results of operations and cash flows.

In the normal course of business, we are involved in legal or administrative proceedings before various courts and governmental bodies with respect to general claims, rates, environmental issues, gas cost prudence reviews and other matters. Adverse decisions regarding these matters, to the extent they require us to make payments in excess of amounts provided for in our consolidated financial statements, or to the extent they are not covered by insurance, could adversely affect our financial condition, results of operations and cash flows.

Unfavorable economic and market conditions could adversely affect our earnings.

Weakening economic activity in our markets could result in a loss of existing customers, fewer new customers, especially in newly constructed homes and other buildings, or a decline in energy consumption, any of which could adversely affect our revenues or restrict our future growth. It may become more difficult for customers to pay their natural gas bills, leading to slow collections and higher-than-normal levels of accounts receivable, which in turn could increase our financing requirements and bad debt expense. We cannot predict the timing, strength, or duration of any future economic slowdowns. Fluctuations and uncertainties in the economy make it challenging for us to accurately forecast and plan future business activities and to identify risks that may affect our business, financial condition, results of operations and cash flows. Changes in monetary or other policies of the federal or state governments may adversely affect the economic climate for the United States, the regions in which we operate or particular industries, such as ours or those of our customers. The foregoing could adversely affect our business, financial condition, results of operations and cash flows.

Increases in the price of natural gas could reduce our earnings, increase our working capital requirements, and adversely impact our customer base.

Changes in supply and demand within the natural gas markets, as well as other factors, could cause an increase in the price of natural gas. The increased production in the U.S. of natural gas from shale formations has put downward pressure on the wholesale cost of natural gas; however, other factors could put upward pressure on natural gas prices, including restrictions or regulations on shale natural gas production and waste water disposal, increased demand from natural gas fueled electric power generation and increases in natural gas exports. Additionally, the CFTC under the 2010 Dodd-Frank Wall Street Reform and Consumer Protection Act has regulatory authority of the over-the-counter derivatives markets. Regulations affecting derivatives could increase the price of our natural gas supply. Also, the threat of terrorist activities or heightened international tensions could lead to increased economic instability and volatility in the price of natural gas.

Natural gas costs are passed through to our customers based on the actual cost of the natural gas we purchase. However, an increase in the price of natural gas could cause us to experience a significant increase in short-term debt because we must pay suppliers for natural gas when purchased. Costs are recovered through our collection on customer bills following consumption by our customers. The delay in recovery of our natural gas costs could adversely affect our financial condition and cash flows.

Further, higher and more volatile natural gas prices may adversely impact our customers' perception of natural gas. Substantial fluctuations in natural gas prices can occur from year to year and sustained periods of high natural gas prices or of pronounced natural gas price volatility may lead to customers selecting other energy alternatives, such as electricity, and to increased scrutiny of the prudency of our natural gas procurement strategies and practices by our regulators. It may also cause new home developers, builders and new customers to select alternative sources of energy. Additionally, high natural gas prices may cause customers to conserve more and may also adversely impact our accounts receivable collections, resulting in higher bad debt expense. The occurrence of any of the foregoing could adversely affect our business, financial condition, results of operations and cash flows, as well as our future growth opportunities.

Our risk-management policies and procedures may not be effective, and employees may violate our risk-management policies.

We have implemented a set of policies and procedures that involve both our senior management and the Audit Committee of our Board of Directors to assist us in managing risks associated with our business. These risk-management policies and procedures are intended to align strategies, processes, people, information technology and business knowledge so that risk is managed throughout the organization. However, as conditions change and become more complex, current risk measures may fail to assess adequately the relevant risk due to changes in the market and the presence of risks previously unknown to us. Additionally, if employees fail to adhere to our policies and procedures or if our policies and procedures are not effective, potentially because of future conditions or risks outside of our control, we may be exposed to greater risk than we had intended. Ineffective risk-management policies and procedures or violation of risk-management policies and procedures could have an adverse effect on our earnings, financial condition and cash flows.

Our business is subject to competition that could adversely affect our results of operations.

The natural gas distribution business is competitive, and we face competition from other companies that supply energy, including electric companies, private generation, solar, propane dealers, renewable energy providers and coal companies in relation to sources of energy for electric power plants, as well as nuclear energy. Significant competitive factors include efficiency, quality and reliability of the services we provide and price.

The most significant product competition occurs between natural gas and electricity in the residential and small commercial markets. Natural gas competes with electricity for water and space heating, cooking, clothes drying and other general energy needs. Increases in the price of natural gas or decreases in the price of other energy sources could adversely impact our competitive position by decreasing the price benefits of natural gas to the consumer. Customers and builders typically make the decision on the type of equipment at initial installation and use the chosen energy source for the life of the equipment. Changes in the competitive position of natural gas relative to electricity and other energy products have the potential to cause a decline in consumption or in the number of natural gas customers.

Consumer or government-mandated conservation efforts, higher natural gas costs or decreases in the price of other energy sources also may encourage decreases in natural gas consumption and allow competition from alternative energy sources for applications that have used natural gas, encouraging some customers to move away from natural gas-powered equipment to equipment fueled by other energy sources. Competition between natural gas and other forms of energy is also based on efficiency, performance, reliability, safety, environmental and other nonprice factors. Technological improvements in other energy sources, energy storage, conservation, efficiency and events that impair the public perception of the nonprice attributes of natural gas could erode our competitive advantage. These factors in turn could decrease the demand for natural gas, impair our ability to attract new customers, and cause existing customers to switch to other forms of energy or to bypass our systems in favor of alternative competitive sources. This could result in slow or no customer growth and could cause customers to reduce or cease using our product, thereby reducing our ability to make capital expenditures and otherwise grow our business and adversely affecting our financial condition, results of operations and cash flows.

Our business activities are concentrated in three states.

We provide natural gas distribution services to customers in Oklahoma, Kansas and Texas. Changes in the regional economies, politics, regulations and weather patterns of these states could adversely impact the growth opportunities available to us and the usage patterns and financial condition of our customers. This could adversely affect our financial condition, results of operations and cash flows.

The availability of adequate natural gas pipeline transportation and storage capacity and natural gas supply may decrease and impair our ability to meet customers' natural gas requirements and reduce our earnings.

In order to meet customers' natural gas demands, we rely on and must obtain sufficient natural gas supplies, pipeline transportation and storage capacity from third parties. We must contract for reliable and adequate delivery capacity for our distribution system, while considering the dynamics of the interstate and intrastate pipeline capacity markets, our own in-system resources, as well as the characteristics of our customer base. If we are unable to obtain these, our ability to meet our customers' natural gas requirements could be impaired and our financial condition, cash flow and results of operations may be impacted adversely. A significant disruption to or reduction in natural gas supply, pipeline capacity or storage capacity due to events including, but not limited to, operational failures or disruptions, hurricanes, tornadoes, floods, freeze off of natural gas wells, terrorist or cyber-attacks or other acts of war, or legislative or regulatory actions, could reduce our normal supply of natural gas and thereby reduce our earnings.

A downgrade in our credit ratings could adversely affect our cost of and ability to access capital.

Our ability to obtain adequate and cost-effective financing depends in part on our credit ratings. Our credit ratings are subject to change at any time in the discretion of the applicable rating agencies. Numerous factors, including many of which are not within our control, are considered by the rating agencies in connection with assigning credit ratings. A reduction in our ratings by our rating agencies could adversely affect our costs of borrowing and/or access to sources of liquidity and capital. Such a downgrade could further limit or delay our access to public and private credit markets and increase the costs of borrowing under available credit lines. Should our credit ratings be downgraded, it could limit or delay our ability to obtain additional financing in the future for working capital, capital expenditures and acquisitions when necessary or desirable. In addition, our pool of investors and prospective creditors would likely decrease. An increase in borrowing costs without the ability to recover these higher costs in the rates charged to our customers could adversely affect our results of operations, financial condition and cash flows by limiting our ability to earn our allowed rate of return.

We are subject to new and existing laws and regulations that may require significant expenditures or result in significant increases in operating costs or significant fines or penalties for noncompliance.

Our business and operations are subject to regulation by a number of federal agencies, including FERC, DOT, OSHA, EPA, CFTC and various regulatory agencies in Oklahoma, Kansas and Texas, and we are subject to numerous federal and state laws and regulations. Future changes to laws, regulations and policies may impair our ability to compete for business or to recover costs and may increase the cost of our operations. Furthermore, because the language in some laws and regulations is not prescriptive, there is a risk that our interpretation of these laws and regulations may not be consistent with expectations of regulators. Any compliance failure related to these laws and regulations may result in fines, penalties or injunctive measures affecting our operating assets. For example, under the Energy Policy Act of 2005, the FERC has civil penalty authority under the Natural Gas Act of 1938, as amended, to impose penalties for current violations of up to $1 million per day for each violation. In addition, as the regulatory environment for our industry increases in complexity, the risk of inadvertent noncompliance could also increase. The fines or penalties for noncompliance with laws and regulations may not be recoverable through our rates. Our failure to comply with applicable regulations could result in a material adverse effect on our business, financial condition, results of operations and cash flows, credit rating or reputation.

We are subject to strict regulations at many of our facilities regarding employee safety, and failure to comply with these regulations could adversely affect our financial results or result in significant fines or penalties.

The workplaces associated with our facilities are subject to the requirements of DOT and OSHA, and comparable state statutes that regulate the protection of the health and safety of workers. The failure to comply with DOT, OSHA and state requirements or general industry standards, including keeping adequate records or preventing occupational exposure to regulated substances, could expose us to civil or criminal liability, enforcement actions, and regulatory fines and penalties that may not be recoverable through our rates and could have a material adverse effect on our business, financial condition, results of operations and cash flows.

We are subject to environmental regulations and failure to comply with these regulations could result in significant fines or penalties and could adversely affect our operations or financial results.

We are subject to laws, regulations and other legal requirements enacted or adopted by federal, state and local governmental authorities relating to environmental and health and safety matters, including those legal requirements that govern discharges of substances into the air and water, the management and disposal of hazardous substances and waste, the clean-up of contaminated sites, groundwater quality and availability, plant and wildlife protection, as well as work practices related to employee health and safety. Environmental legislation also requires that our facilities, sites and other properties associated with our operations be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. The failure to comply with these laws, regulations and other requirements, or the discovery of presently unknown environmental conditions, could expose us to civil or criminal liability, enforcement actions and regulatory fines and penalties that may not be recoverable through our rates and could have a material adverse effect on our business, financial condition, results of operations and cash flows.

We also own or retain legal responsibility for certain environmental conditions at certain former MGP sites. A number of environmental issues may exist with respect to these former MGP sites. Accordingly, future costs are dependent on the final determination and regulatory approval of any remedial actions, the complexity of the site, level of remediation, changing technology and governmental regulations and could be material to our financial condition, results of operations and cash flows.

With the trend toward stricter standards, greater regulation and more extensive permit requirements for the types of assets operated by us that are subject to environmental regulation, our environmental expenditures could increase in the future, and such expenditures may not be fully recovered by insurance or recoverable in rates from our customers, which could adversely affect our financial condition, results of operations and cash flows.

We are subject to pipeline safety and system integrity laws and regulations that may require significant expenditures, significant increases in operating costs or, in the case of noncompliance, substantial fines or penalties.

We are subject to the Pipeline Safety Improvement Act, which requires companies like us that operate high-pressure pipelines to perform integrity assessments on pipeline segments that pass through densely populated areas or near specifically designated high-consequence areas. Further, the Pipeline Safety, Regulatory Certainty and Job Creation Act increased the maximum penalties for violating federal pipeline safety regulations and directed the DOT and Secretary of Transportation to conduct further review or studies on issues that may or may not be material to us. Compliance with existing or new laws and regulations may result in increased capital, operating and other costs which may not be recoverable in rates from our customers or may impact materially our competitive position relative to other energy providers. The failure to comply with these laws, regulations and other requirements could expose us to civil or criminal liability, enforcement actions, fines, penalties or injunctive measures that may not be recoverable from customers in rates and could have a material adverse effect on our business, financial condition, results of operations and cash flows, and reputation.

Carbon neutral, energy-efficiency or other legislation or regulations intended to address climate change could increase our operating costs or restrict our market opportunities, adversely affecting our financial results, growth, cash flows and results of operations.

International, federal, regional and/or state legislative and/or regulatory initiatives may attempt to control or limit the causes of climate change, including greenhouse gas emissions, such as carbon dioxide and methane. Such laws or regulations could impose costs tied to carbon emissions, operational requirements or restrictions, or additional charges to fund energy efficiency activities. They could also provide a cost advantage to alternative energy sources, impose costs or restrictions on end users of natural gas, or result in other costs or requirements, such as costs associated with the adoption of new infrastructure and technology to respond to new mandates. The focus on climate change could adversely impact the reputation of fossil fuel products or services. The occurrence of the foregoing events could put upward pressure on the cost of natural gas relative to other energy sources, increase our costs and the prices we charge to customers, reduce the demand for natural gas or cause fuel switching to other energy sources, and impact the competitive position of natural gas and the ability to serve new or existing customers, adversely affecting our business, results of operations and cash flows.

We are subject to physical and financial risks associated with climate change, which may adversely affect our financial results, growth, cash flows and results of operations.

There is a growing belief that emissions of greenhouse gases may be linked to global climate change. Climate change creates physical and financial risks. Our customers’ energy needs vary with weather conditions, primarily temperature and humidity. For residential customers, heating and cooling represent their largest energy use. To the extent weather conditions may be affected by climate change, customers’ energy use could increase or decrease depending on the duration and magnitude of any changes. To the extent climate change adversely impacts the economic health of our operating territory, it could adversely impact customer demand or our customers’ ability to pay. A decrease in energy use due to weather changes may affect our financial condition through decreased revenues and cash flows. Extreme weather conditions in general require more system backup, adding to costs, and can contribute to increased system stresses, including service interruptions. Weather conditions outside of our operating territory could also have an impact on our revenues and cash flows by affecting natural gas prices. Severe weather impacts our operating territories primarily through thunderstorms, tornados and snow or ice storms. To the extent the frequency of extreme weather events increases, our cost of providing service could increase. We may not be able to pass on the higher costs to our customers or recover all the costs related to mitigating these physical risks. To the extent financial markets view climate change and emissions of greenhouse gases as a financial risk, this could adversely affect our ability to access capital markets or cause us to receive less favorable terms and conditions in future financings. Our business could be affected by the potential for lawsuits related to or against greenhouse gas emitters based on the claimed connection between greenhouse gas emissions and climate change, which could adversely impact our business, results of operations and cash flows.

Demand for natural gas is highly weather sensitive and seasonal, and weather conditions may cause our earnings to vary from year to year.

Our earnings can vary from year to year, depending in part on weather conditions, which directly influence the volume of natural gas delivered to customers. Natural gas sales to residential and commercial customers are seasonal, as a substantial portion of their natural gas requirements are for heating during the winter months. Warmer-than-normal weather can reduce our utility margins as customer consumption declines. We have implemented weather normalization mechanisms for our sales to customers in Oklahoma, Kansas and Texas, which are designed to reduce our earnings sensitivity to weather. Weather normalization mechanisms require us to increase customer billings to offset lower natural gas usage when weather is warmer than normal and decrease customer billings to offset higher natural gas usage when weather is colder than normal. If our rates and tariffs are modified to curtail such weather protection programs, then we would be exposed to additional risk associated with weather. As a result of occurrences of the foregoing, our results of operations, financial condition and cash flows could vary and be impacted adversely.

We may not be able to complete necessary or desirable expansion or infrastructure development projects, which may delay or prevent us from serving our customers or expanding our business.

In order to serve new customers or expand our service to existing customers, we may need to maintain, expand or upgrade our distribution and/or transmission infrastructure, including laying new distribution lines. Various factors may prevent or delay us from completing such projects or make completion more costly, such as the inability to obtain required approvals from local, state and/or federal regulatory and governmental bodies, public opposition to the project, inability to obtain adequate financing, competition for labor and materials, construction delays, cost overruns, and inability to negotiate acceptable agreements relating to construction or other material components of an infrastructure development project. As a result, we may not be able to adequately serve existing customers or support customer growth, which would adversely impact our business, stakeholder perception, financial condition, results of operations and cash flows.

We may pursue acquisitions, divestitures and other strategic opportunities, the success of which may adversely impact our results of operations, cash flows and financial condition.

As part of our strategic objectives, we may pursue acquisitions to complement or expand our business, as well as divestitures and other strategic opportunities. We may not be able to successfully negotiate, finance or receive regulatory approval for future acquisitions or integrate the acquired businesses with our existing business and services. These efforts may also distract our management and employees from day-to-day operations and require substantial commitments of time and resources. Future acquisitions could result in potentially dilutive issuances of equity securities, a decrease in our liquidity as a result of our using a significant portion of our available cash or borrowing capacity to finance the acquisition, the incurrence of debt, contingent liabilities and amortization expenses and substantial goodwill. The effects of these strategic decisions may have long-term implications that are not likely to be known to us in the short-term. Changing political climates and public attitudes may adversely affect the ongoing acceptability of strategic decisions that have been made (and, in some cases, previously approved by regulators) to the detriment of the company. We may be affected materially and adversely if we are unable to successfully integrate businesses that we acquire.

An impairment of goodwill and long-lived assets could reduce our earnings.

At December 31, 2018, we had approximately $158 million of goodwill recorded on our Consolidated Balance Sheet. Goodwill is recorded when the purchase price of a business exceeds the fair market value of the tangible and separately measurable intangible net assets. GAAP requires us to test goodwill for impairment on an annual basis or when events or circumstances occur indicating that goodwill might be impaired. Long-lived assets with finite useful lives are reviewed for impairment whenever events or changes in circumstances indicate that the carrying amount may not be recoverable. If we determine that impairment is indicated, we would be required to take an immediate noncash charge to earnings with a correlative effect on our equity and balance sheet leverage as measured by debt to total capitalization, which could adversely impact our financial condition and results of operations.

We may be unable to access capital or our cost of capital may increase significantly which may adversely affect our results of operations, cash flows and financial condition.

Our ability to obtain adequate and cost-effective financing is dependent upon the liquidity of the financial markets, in addition to our financial condition and credit ratings. Disruptions in the capital and credit markets could adversely affect our ability to access short-term and long-term capital. Access to funds under our ONE Gas Credit Agreement will be dependent on the ability of the participating banks to meet their funding commitments. Those banks may not be able to meet their funding commitments if they experience shortages of capital and liquidity. Disruptions and volatility in the global credit markets could cause the interest rate we pay on our ONE Gas Credit Agreement, which is based on LIBOR, to increase. This could result in higher interest rates on future financings and could impact the liquidity of the lenders under our ONE Gas Credit Agreement, potentially impairing their ability to meet their funding commitments to us. Disruptions in the capital and credit markets as a result of uncertainty, changing or increased regulation or failures of significant financial institutions could adversely affect our access to capital needed for our business. The inability to access adequate capital or an increase in the cost of capital may require us to conserve cash, prevent or delay us from making capital expenditures, and require us to reduce or eliminate our dividend or other discretionary uses of cash. A significant reduction in our liquidity could cause a negative change in our ratings outlook or even a reduction in our credit ratings. This could in turn further limit our access to credit markets and increase our costs of borrowing.

Changes in federal and state fiscal, tax and monetary policy could significantly increase our costs or decrease our cash flows.

Changes in federal and state fiscal, tax and monetary policy may result in increased taxes, interest rates, and inflationary pressures on the costs of goods, services and labor or may result in refunding amounts previously collected for deferred taxes to customers on an accelerated basis. This could increase our expenses and capital spending and decrease our cash flows if we are not able to recover or recover timely such increased costs from our customers. This series of events may increase our rates to customers and thus may adversely impact customer billings and customer growth. Changes in tax rates, including the effects of the Tax Cuts and Jobs Act of 2017, could adversely affect our cash flows and may increase the cash we pay for income taxes in the future. Any of these events may cause us to increase debt, conserve cash, adversely affect our ability to make capital expenditures to grow the business or other discretionary uses of cash and could adversely affect our cash flows.

Federal, state and local jurisdictions may challenge our tax return positions.

The preparation of our federal and state tax return filings requires significant judgments, use of estimates and the interpretation and application of complex tax laws. Significant judgment also is required in assessing the timing and amounts of deductible and taxable items, and in determining the amount of any reserves for potential adverse outcomes regarding tax positions that have been taken that may be subject to challenge by taxing authorities. Despite management’s expectation that our tax return positions will be fully supportable, certain positions may be challenged successfully by federal, state and local jurisdictions, which could adversely impact our results of operations, cash flows and financial condition.

As a result of cross-default provisions in our borrowing arrangements, we may be unable to satisfy all of our outstanding obligations in the event of a default on our part, which may adversely affect our results of operations, cash flows and financial condition.

The terms of our debt agreements contain cross-default provisions, which provide that we will be in default under such agreements in the event of certain defaults under other debt agreements. Accordingly, should an event of default occur under any of those agreements, we would face the prospect of being in default under many or all of our debt agreements, obliged in such instance to satisfy all of our outstanding indebtedness under many or all such agreements simultaneously. In such an event, we may not be able to obtain alternative financing or, if we are able to obtain such financing, we may not be able to obtain it on terms acceptable to us, which would adversely affect our ability to implement our business plan, have flexibility in planning for, or reacting to, changes in our business, make capital expenditures and finance our operations.

The cost of providing pension and other postemployment health care benefits to eligible employees and qualified retirees is subject to changes in pension fund values and changing demographics and may increase our costs. In addition, the passage of the Patient Protection and Affordable Care Act in 2010 and its potential revision, repeal and/or replacement could increase the cost of health care benefits for our employees. Further, the costs to us of providing such benefits and related funding requirements are subject to the continued and timely recovery of such costs through our rates which may adversely affect our cash flows and earnings.

We have defined benefit pension plans and other postemployment welfare plans for certain eligible employees. Our defined benefit plans are closed to new participants. Our other postemployment welfare plans only subsidize costs for providing postemployment medical benefits and life insurance. The cost of providing these benefits to eligible current and former employees is subject to changes in the market value of our pension and other postemployment benefit plan assets, changing demographics, including longer life expectancy of plan participants and their beneficiaries, current and future legislative changes, changes in health care costs, changes in discount rates used to calculate liability, and various actuarial calculations and assumptions.

Any sustained declines in equity markets and reductions in bond values may have a material adverse effect on the value of our pension and other postemployment benefit plan assets. In these circumstances, additional cash contributions to our pension and other postemployment benefit plans may be required, which could have a material adverse impact on our financial condition and cash flows.

In addition, the costs of providing health care benefits to our employees could increase over the next five to ten years due in large part to the Patient Protection and Affordable Care Act of 2010, and its potential revision, repeal and/or replacement. The future costs of compliance with the provisions are difficult to measure at this time. Also, our costs of providing such benefits and related funding requirements could also materially increase in the future, depending on the timing of the recovery, if any, of such costs through our rates, which could adversely impact our financial condition and cash flows.

Our business is subject to operational hazards and unforeseen interruptions that could materially and adversely affect our business and for which we may not be insured adequately, which may adversely affect our cash flows and earnings.

We are subject to all of the risks and hazards typically associated with the natural gas distribution business. Operating risks include, but are not limited to, leaks, pipeline ruptures and the breakdown or failure of equipment or processes. Other operational hazards and unforeseen interruptions include adverse weather conditions, accidents, explosions, fires, the collision of equipment or vehicles with our pipeline facilities (for example, this may occur if a third-party were to perform excavation or construction work near our facilities or vehicles colliding with above-ground pipeline facilities) and catastrophic events, such as tornados, hurricanes, earthquakes, floods or other similar events beyond our control. It is also possible that our facilities could be direct targets or indirect casualties of an act of terrorism, including cyber-attacks. A casualty occurrence might result in injury or loss of life, extensive property damage or environmental damage caused to or by employees, customers, contractors, vendors and other third parties. The location of pipeline facilities near populated areas, including residential areas, commercial business centers and industrial gathering places, could increase the level of damages resulting from these risks. Liabilities incurred and interruptions to the operations of our pipelines or other facilities caused by such an event could reduce revenues generated by us and increase expenses, which could have a material adverse effect on our financial condition, results of operations and cash flows. Additionally, our regulators may not allow us to recover part or all of the increased cost related to the foregoing events from our customers, which would adversely affect our earnings and cash flows.

Unanticipated events or a combination of events, failure in resources needed to respond to events, or slow or inadequate response to events may have an adverse impact on our financial condition, results of operations and cash flows.

While we have general liability and property insurance currently in place in amounts that we consider appropriate based on our assessment of business risk and best practices in our industry and in general business, such policies are subject to certain limits, deductibles and policy exclusions. Further, we are not fully insured against all risks inherent in our business, including certain types of catastrophic events. As a result of market conditions, premiums and deductibles for certain insurance policies can increase substantially, and, in some instances, certain insurance may become unavailable or available only for reduced amounts of coverage. Consequently, we may not be able to renew existing insurance policies or purchase other desirable insurance on commercially reasonable terms, if at all.

The insurance proceeds received for any loss of, or any damage to, any of our facilities or to third parties may not be sufficient to restore the total loss or damage. Further, the proceeds of any such insurance may not be paid in a timely manner. The occurrence of any of the foregoing could have a material adverse effect on our financial condition, results of operations and cash flows.

Our business increasingly relies on technology, the failure of which, or the occurrence of cyber or physical security attacks thereon, or those of third parties, may adversely affect our financial results and cash flows.

Due to increased technology advances, we have become more reliant on technology to help increase efficiency in our business. We use computer programs to help run our financial and operations organizations, including an enterprise resource planning system that integrates data and reporting activities across our company. The failure of these or other similarly important technologies, the lack of alternative technologies, or our inability to have these technologies supported, updated, expanded or integrated into other technologies, could hinder our operations and adversely impact our financial condition and results of operations. The use of technological programs, systems and tools may subject our business to increased risks.

Our business is dependent upon our operational systems to process a large amount of data and complex transactions. As part of our operations, we come into contact with sensitive information, including personally identifiable information. If any of our financial, operational or other data processing systems fail or have other significant shortcomings, our financial results could be affected adversely. Our financial results could also be affected adversely if an employee or third party causes our operational systems to fail, either as a result of inadvertent error or by deliberately tampering with or manipulating our operational systems. In addition, dependence upon automated systems may further increase the risk that operational system flaws, employee or third-party tampering or manipulation of those systems will result in losses that are difficult to detect or mitigate.

Additionally, certain portions of our information technology, customer service, resource management, pipeline and infrastructure installation and maintenance, engineering, payroll and human resources functions that we rely on are provided by third-party vendors. Services provided by third-parties could be disrupted due to events and circumstances beyond our control which could adversely impact our business, financial condition, results of operations and cash flows.

Any cyber or physical security attacks, or threats of such attacks, that affect our distribution facilities, our customers, our suppliers and third-party service providers or any financial data could disrupt normal business operations, expose sensitive information, and/or lead to physical damages that may have a material adverse effect on our businesses. Physical damage due to a cyber security incident or acts of cyber terrorism could impact services and could lead to material liabilities. As potential cyber or physical security attacks become more common and sophisticated, we could be required to incur increased costs to strengthen our systems or to obtain additional insurance coverage against potential losses. Federal and state regulatory agencies are increasingly focused on risk related to physical security and cybersecurity in general, and specifically in critical infrastructure sectors, including natural gas distribution. In addition, cyber or physical attacks or threats on our company, customer and employee data may result in a financial loss and may adversely impact our reputation. Third-party systems on which we rely could also suffer operational system failure.

While we have implemented and continue to evaluate and improve policies, procedures, protective technologies, and controls to prevent and detect cyber or physical security attacks, there is no guarantee that these efforts will protect us from unauthorized access to our systems. A severe attack or security breach could adversely affect our business reputation, diminish customer confidence, disrupt operations, subject us to financial liability or increased regulation, increase our costs and expose us to material legal claims and liability, and our business, financial condition, results of operations and cash flows could be affected adversely.

Our business could be adversely affected by strikes or work stoppages by our unionized employees, which may impact our operations, cash flows and earnings.

At February 1, 2019, approximately 700 of our estimated 3,500 employees were represented by collective-bargaining units under collective-bargaining agreements. We are involved periodically in discussions with collective-bargaining units representing some of our employees to negotiate or renegotiate labor agreements. We cannot predict the results of these negotiations, including whether any failure to reach new agreements will have a negative effect on our business, financial condition and results of operations or whether we will be able to reach any agreement with the collective-bargaining units. Any failure to reach agreement on new labor contracts might result in a work stoppage. Any future work stoppage could, depending on the operations and the length of the work stoppage, have a material adverse effect on our financial condition, results of operations and cash flows.

A shortage of skilled labor may make it difficult for us to maintain labor productivity and competitive costs, which could adversely affect operations, cash flows and earnings. Further, we may be unable to attract and retain management and professional and technical employees, which could adversely impact our operations, earnings and cash flows.

Our operations require skilled and experienced workers with proficiency in multiple tasks. In recent years, a shortage of workers trained in various skills associated with the natural gas distribution business has caused us to conduct certain operations without full staff, thus hiring outside resources, which may decrease productivity and increase costs. This shortage of trained workers is the result of experienced workers reaching retirement age and increased competition for workers in certain areas, combined with the challenges of attracting new qualified workers to the natural gas distribution industry. This shortage of skilled labor could continue over an extended period. If the shortage of experienced labor continues or worsens, it could have an adverse impact on labor productivity and costs and our ability to meet the needs of our customers in the event there is an increase in the demand for our products and services, which could adversely affect our business and cash flows.

Our ability to implement our business strategy, satisfy our regulatory requirements, and serve our customers is dependent upon our ability to continue to recruit and employ talented management and professionals while retaining a skilled, high-performing workforce. We are subject to the risk that we will not be able to effectively replace or transfer the knowledge and expertise of retiring management or employees. Without effective succession, our ability to provide quality service to our customers and satisfy our regulatory requirements will be challenged, and this could adversely impact our business, financial condition, results of operations and cash flows.

Changes in accounting standards may adversely impact our financial condition, results of operations and cash flows.

We are subject to additional changes in GAAP, SEC regulations and other interpretations of financial reporting requirements for public utilities. We neither have control over the impact these changes may have on our financial condition or results of operations nor the timing of such changes.

Our financing arrangements subject us to various restrictions that could limit our operating flexibility, earnings and cash flows.

The covenants in the indenture governing our Senior Notes and our ONE Gas Credit Agreement restrict our ability to create or permit certain liens, to consolidate or merge or to convey, transfer or lease substantially all of our properties and assets.

The ONE Gas Credit Agreement includes a requirement that our debt to total capital ratio may not exceed 70 percent as of the end of any calendar quarter. Events beyond our control could impair our ability to satisfy this requirement. As long as our indebtedness remains outstanding, these restrictive covenants could impair our ability to expand or pursue our growth strategy. In addition, the breach of any covenants or any payment obligations in any of these debt agreements will result in an event of default under the applicable debt instrument. If there were an event of default under one of our debt agreements, the holders of the defaulted debt may have the ability to cause all amounts outstanding with respect to that debt to be due and payable, subject to applicable grace periods. This could trigger cross-defaults under our other debt agreements, including our Senior Notes. Forced repayment of some or all of our indebtedness would reduce our available cash and have an adverse impact on our financial condition, results of operations and cash flows.

Some of our debt, including borrowings under our ONE Gas Credit Agreement and our commercial paper program, is based on variable rates of interest, which could result in higher interest expenses in the event of an increase in interest rates.

We are exposed to fluctuations in variable interest rates. This increases our exposure to fluctuations in market interest rates. Amounts borrowed under the ONE Gas Credit Agreement and commercial paper program are based on variable rates of interest. If these rates rise, the interest rate on this debt will also increase. Therefore, an increase in these rates will increase our interest payment obligations and have a negative effect on our cash flows and financial position.

Emerging technologies may cause disruption in utility services, which may adversely affect our customer growth, earnings and cash flows.

Commercial technologies that advance electrification and increase energy efficiency in some aspects of the economy, such as transportation or heating, could negatively impact the demand for natural gas. We may not be able to quickly adapt to changes resulting from rapidly advancing technologies that may result in a reduction in demand for our services. This could slow customer growth and even cause customers to reduce or cease using natural gas which could have an adverse effect on our financial condition, results of operations and cash flows.

RISKS RELATING TO THE SEPARATION

We are responsible for certain contingent and other liabilities related to the historical natural gas distribution business of ONEOK, as well as a portion of any contingent corporate liabilities of ONEOK that do not relate to either the natural gas distribution business or ONEOK’s remaining businesses.

Under the Separation and Distribution Agreement between us and ONEOK, we assumed and are responsible for certain contingent and other corporate liabilities related to the historical natural gas distribution business of ONEOK (including associated costs and expenses, whether arising prior to, at, or after our separation). In addition, under the Separation and Distribution Agreement we are also responsible for a portion of any contingent corporate liabilities of ONEOK that do not relate to either our business or the business of ONEOK following the separation (for example, liabilities associated with certain corporate activities not specifically attributable to either business). If we are required to indemnify ONEOK or are otherwise liable for these liabilities, they may have a material adverse effect on our financial condition, results of operations and cash flows.

Third parties may seek to hold us responsible for liabilities of ONEOK that we did not assume in our agreements.

Third parties may seek to hold us responsible for retained liabilities of ONEOK. Under our agreements with ONEOK, ONEOK has agreed to indemnify us for claims and losses relating to these retained liabilities. However, if those liabilities are significant and we are ultimately held liable for them, we cannot assure that we will be able to recover the full amount of our losses from ONEOK.

Our prior relationship with ONEOK exposes us to risks attributable to businesses of ONEOK.

ONEOK is obligated to indemnify us for losses that a party may seek to impose upon us or our affiliates for liabilities relating to the business of ONEOK. Any claims made against us that are properly attributable to ONEOK in accordance with these arrangements require us to exercise our rights under our agreements with ONEOK to obtain payment from ONEOK. We are exposed to the risk that, in these circumstances, ONEOK cannot, or will not, make the required payment.

If the distribution, together with certain related transactions, were to fail to qualify as a tax-free transaction for U.S. federal income tax purposes under Sections 355, 368(a)(1)(D) and other related provisions of the Code, then ONEOK and/or its shareholders could incur significant U.S. federal income tax liabilities, and we could incur significant indemnity obligations.

ONEOK received an IRS Ruling to the effect that the distribution, together with certain related transactions, qualified as tax-free to ONEOK, us and the ONEOK shareholders under Sections 355, 368(a)(1)(D) and other related provisions of the Code. ONEOK also received an opinion of Skadden, Arps, Slate, Meagher & Flom LLP, tax counsel to ONEOK, which opinion relies on the continued validity of the IRS Ruling, with respect to certain issues relating to the tax-free nature of the transactions that were not addressed in or covered by the IRS Ruling.

The IRS Ruling and the tax opinion rely upon certain assumptions, as well as statements, representations and certain undertakings made by our officers and the officers of ONEOK regarding the past and future conduct of the companies' respective businesses and other matters. If any of those statements, representations or assumptions are incorrect or untrue in any material respect or any of those undertakings are not complied with, the conclusions reached in the IRS Ruling or the opinion could be affected adversely, and ONEOK and/or its shareholders could be subject to significant tax liabilities. Notwithstanding the IRS Ruling and opinion of tax counsel, the IRS could determine on audit that the distribution, together with certain related transactions, was taxable if it determines that any of these statements, representations, assumptions, or undertakings were not correct or have been violated or if it disagrees with the conclusions in the opinion that were not covered by the IRS Ruling, or for other reasons, including as a result of certain significant changes in the stock ownership of ONEOK or us after the distribution.
If the distribution were subsequently determined, for whatever reason, not to qualify as a transaction that is tax-free for U.S. federal income tax purposes under Sections 355, 368(a)(1)(D), and other related provisions of the Code, ONEOK and/or the holders of ONEOK common stock immediately prior to the distribution could incur significant tax liabilities, and, in certain circumstances we will be required to indemnify ONEOK, its subsidiaries, and certain related persons for taxes and related expenses resulting from the distribution, which could be material. Any such indemnity obligation could have a materially adverse impact on our financial condition, results of operations and cash flows.

RISKS RELATING TO OUR COMMON STOCK

Provisions in our certificate of incorporation, our bylaws and Oklahoma law as well as regulatory approvals may prevent or delay an acquisition of our company, which could decrease the trading price of our common stock.

Our certificate of incorporation, bylaws and Oklahoma law contain provisions that are intended to deter coercive takeover practices and inadequate takeover bids by making such practices or bids unacceptably expensive to the raider and to encourage prospective acquirers to negotiate with our Board of Directors rather than to attempt a hostile takeover. These provisions include, among others:

- rules regarding how shareholders may present proposals or nominate directors for election at shareholder meetings; and
- the right of our Board of Directors to issue preferred stock without shareholder approval.

Oklahoma law also imposes some restrictions on mergers and other business combinations between us and any holder of 15 percent or more of our outstanding common stock.

We believe these provisions protect our shareholders from coercive or otherwise potentially unfair takeover tactics by requiring potential acquirers to negotiate with our board of directors and by providing our Board of Directors with more time to assess any acquisition proposal. These provisions are not intended to make our company immune from takeovers. However, these provisions apply even if the offer may be considered beneficial by some shareholders and could delay or prevent an acquisition that our Board of Directors determines is not in the best interests of our company and our shareholders.

Additionally, any acquisition of our company would need to be approved by certain regulatory bodies including the OCC, KCC and various regulators in Texas, which could delay or prevent an acquisition.

Our ability to pay dividends on our common stock will depend on our ability to generate sufficient positive earnings and cash flows.

Our ability to pay dividends in the future will depend upon, among other things, our future earnings, cash flows and restrictive covenants, if any, under future credit agreements to which we may be a party. Our cash available for dividends will principally be generated from our operations. Because the cash we generate from operations will fluctuate from quarter to quarter, we may not be able to maintain future dividends at the levels we expect or at all. Our ability to pay dividends depends primarily on cash flows, including cash flows from changes in working capital, and not solely on profitability, which is affected by noncash items. As a result, we may pay dividends during periods when we record net losses and may be unable to pay cash dividends during periods when we record net income.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 2. PROPERTIES

The following table sets forth the approximate miles of distribution mains and transmission pipeline as of December 31, 2018:

Properties (miles)	OK	KS	TX	Total
Distribution	18,600	11,400	10,300	40,300
Transmission	700	1,600	300	2,600
Total properties	19,300	13,000	10,600	42,900

We lease approximately 400 thousand square feet of office space and other facilities for our operations. In addition, we have 48.4 Bcf of natural gas storage capacity under contract, with maximum allowable daily withdrawal capacity of approximately 1.3 Bcf.

ITEM 3. LEGAL PROCEEDINGS

See Note 15 of the Notes to Consolidated Financial Statements in this Annual Report for information regarding legal proceedings.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

MARKET HOLDERS AND DIVIDENDS

Our common stock is listed on the NYSE under the trading symbol "OGS."

At February 8, 2019, there were 12,318 registered shareholders of the company's common stock.

In January 2019, we declared a dividend of $0.50 per share ($2.00 per share on an annualized basis) for shareholders of record as of February 22, 2019, payable on March 8, 2019.

Employee Stock Award Program

Under the Employee Stock Award Program, we issued, for no monetary consideration, one share of our common stock to all eligible employees when the per-share closing price of our common stock on the NYSE closed for the first time at or above each $1.00 increment above $34. The total number of shares of our common stock authorized for issuance under this program was 125,000. Shares issued to employees under this program during 2017 and 2016 totaled 13,791 and 50,573, respectively. Compensation expense, before taxes, related to the Employee Stock Award Program was $0.9 million and $3.0 million for 2017 and 2016, respectively. The Employee Stock Award Program was discontinued in May 2017.

The shares issued under this program have not been registered under the Securities Act, in reliance upon the position taken by the SEC (see Release No. 6188, dated February 1, 1980) that the issuance of shares to employees pursuant to a program of this kind does not require registration under the Securities Act. See Note 11 of the Notes to Consolidated Financial Statements in this Annual Report for additional information.

Performance Graph

The following performance graph compares the performance of our common stock with the S&P MidCap 400 Index, the Dow Jones Industrial Average and a ONE Gas peer group during the period beginning February 3, 2014 and ending on December 31, 2018. February 3, 2014 was the first day of "regular way" trading for ONE Gas common stock on the NYSE. This graph assumes a $100 investment in our common stock and in each of the indices at the beginning of the period and a reinvestment of dividends paid on such investments throughout the period.

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	Cumulative Total Return As of Each Semi-Annual Period Ending									
	2014		2015		2016		2017		2018	
	6/30	12/31	6/30	12/31	6/30	12/31	6/30	12/31	6/30	12/31
ONE Gas, Inc.[1]	$113.12	$125.39	$131.32	$156.83	$210.61	$204.61	$226.17	$240.01	$248.14	$267.36
S&P MidCap 400 Utilities Index	$115.89	$118.29	$104.63	$111.26	$141.94	$141.69	$150.20	$157.40	$163.94	$168.12
S&P MidCap 400 Index	$113.95	$116.36	$121.24	$113.82	$122.85	$137.43	$145.66	$159.75	$165.33	$142.05
Dow Jones Industrial Average	$110.59	$118.52	$118.56	$118.77	$123.90	$138.37	$151.30	$177.26	$175.97	$171.09
ONE Gas Peer Group[2]	$116.87	$126.01	$116.84	$131.71	$169.03	$160.34	$175.13	$184.58	$190.34	$189.75

[1] February 3, 2014 was the first day of "regular way" trading for ONE Gas, Inc. on the NYSE.

[2] The ONE Gas peer group used in this graph is the same peer group that will be used in determining our level of performance under our 2018 performance units at the end of the three-year performance period and is comprised of the following companies: Alliant Energy Corporation; Atmos Energy Corporation; Avista Corporation; CenterPoint Energy, Inc.; Chesapeake Utilities Corporation; CMS Energy Corporation; New Jersey Resources Corporation; NiSource Inc.; Northwest Natural Gas Company; NorthWestern Corporation; South Jersey Industries, Inc.; Southwest Gas Corporation; and Spire Inc.

ITEM 6. SELECTED FINANCIAL DATA

The following table sets forth our selected financial data for each of the periods indicated:

	Years Ended December 31,				
	2018	2017	2016	2015	2014
	(Millions of dollars except per share data)				
Consolidated Statements of Income data:					
Total revenues (a)	$1,633.7	$1,539.6	$1,427.2	$1,547.7	$1,818.9
Cost of natural gas	$714.6	$614.5	$541.8	$706.0	$991.9
Net margin (b)	$919.1	$925.1	$885.4	$841.7	$827.0
Operating income (a)	$288.4	$316.7	$288.9	$265.2	$243.2
Net income	$172.2	$163.0	$140.1	$119.0	$109.8
Basic earnings per share	$3.27	$3.10	$2.67	$2.26	$2.10
Diluted earnings per share	$3.25	$3.08	$2.65	$2.24	$2.07
Dividends declared per common share	$1.84	$1.68	$1.40	$1.20	$0.84

(a) Reflects the impact of the adoption of new accounting standards in fiscal year 2018 related to revenue recognition and the presentation of net periodic benefit costs. See Note 1 of the Notes to Consolidated Financial Statements in this Annual Report for additional information regarding our adoption of these standards.
(b) Net margin is considered a non-GAAP financial measure. See additional discussion under Management's Discussion and Analysis of Financial Condition and Results of Operations in this Annual Report.

	December 31,				
	2018	2017	2016	2015	2014
	(Millions of dollars)				
Consolidated Balance Sheets data:					
Total assets	$5,468.6	$5,206.9	$4,942.8	$4,634.8	$4,638.8
Long-term debt, including current maturities	$1,285.5	$1,193.3	$1,192.5	$1,191.7	$1,190.9

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis should be read in conjunction with our audited consolidated financial statements and Notes to Consolidated Financial Statements in this Annual Report.

EXECUTIVE SUMMARY

We are a 100-percent regulated natural gas distribution company. As such, our regulators determine the rates we are allowed to charge for our service based on our revenue requirements needed to achieve our authorized rates of return. We earn revenues from the delivery of natural gas, but do not earn a profit on the natural gas that we deliver, as those costs are passed through to our customers at cost. The primary components of our revenue requirements are the amount of capital invested in our business, which is also known as rate base, our allowed rate of return on our capital investments and our recoverable operating expenses, including depreciation, interest expense and income taxes. Our rates have both a fixed and a variable component, with approximately 71 percent of our natural gas sales Net Margin in 2018 derived from fixed monthly charges to our customers. The variable component of our rates is dependent on the consumption of natural gas, which is impacted primarily by the weather and, to a lesser extent, economic activity. While we have weather normalization mechanisms that adjust customers' bills when actual HDDs differ from normalized HDDs, these mechanisms are in place for only a portion of the year and do not offset all fluctuations in usage resulting from weather variability. Accordingly, the weather can have either a positive or negative impact on our financial performance.

Our financial performance, therefore, is contingent on a number of factors, including: (1) regulatory outcomes, which determine the returns we are authorized to earn and the rates we are allowed to charge for our service; (2) the consumption of natural gas, which impacts the amount of our Net Margin derived from the variable component of our rates; (3) our operating performance, which impacts our operating expenses; and (4) the perceived value of natural gas relative to other energy sources, particularly electricity, which influences our customers' choice of natural gas to provide a portion of their energy needs.

We are subject to regulatory requirements for pipeline integrity and environmental compliance. These requirements impact our operating expenses and the level of capital expenditures required for compliance. Historically, our regulators have allowed recovery of these expenditures. However, because integrity and environmental regulation is changing constantly, our capital and operating expenditures to comply will change, as well. Although we believe our regulators will continue to allow recovery of such expenditures in the future, we will continue to make these expenditures with no assurance about if, or over what period, we will be permitted to recover them.

RECENT DEVELOPMENTS

Tax Reform - In December 2017, the Tax Cuts and Jobs Act of 2017 was signed into law. The new law includes significant changes to the Code, including amendments which significantly change the taxation of business entities, and includes specific provisions related to regulated utilities. The more significant changes that impact us include reductions in the corporate federal statutory income tax rate to 21 percent from 35 percent, and several technical provisions including, among others, the elimination of full expensing for tax purposes of certain property acquired after December 31, 2017, the continuation of certain rate normalization requirements for accelerated depreciation benefits and the general allowance for the continued deductibility of interest expense. Additionally, the new law limits the utilization of NOLs arising after December 31, 2017, to 80 percent of taxable income with an indefinite carryforward.

As a result of the enactment of the Tax Cuts and Jobs Act of 2017, we remeasured our ADIT. As a regulated entity, the change in ADIT was recorded as a regulatory liability and is subject to refund to our customers. The Tax Cuts and Jobs Act of 2017 retains the tax normalization provisions of the Code that stipulate how these excess deferred income taxes are to be refunded to customers for certain accelerated tax depreciation benefits. The effect on the net deferred income tax liability for the enacted decrease in the federal income tax rate was $518.7 million, of which $520.9 million was recorded as a reduction to the deferred income tax liabilities and deferred as a regulatory liability for ratemaking purposes, offset by $2.2 million recorded as an increase in deferred income tax expense in 2017 attributable to the remeasured deferred income taxes associated with certain expenses not recovered in our rates. These adjustments had no impact on our 2018 or 2017 cash flows. Our customers will receive refunds as determined by our regulators beginning in 2019. For further discussion see “Liquidity and Capital Resources - Tax Reform” in Management’s Discussion and Analysis of Financial Condition and Results of Operations in this Annual Report.

We are working with our regulators to address the impact of the Tax Cuts and Jobs Act of 2017 on our rates. In each state, we have received accounting orders requiring us to refund the reduction in ADIT due to the remeasurement and to establish a separate regulatory liability for the difference in taxes included in our rates that have been calculated based on a 35 percent federal statutory income tax rate and the new 21 percent federal statutory income tax rate effective in January 2018. The establishment of this separate regulatory liability associated with the change in tax rates collected in our rates resulted in a reduction to our revenues of $36.6 million for the year ended December 31, 2018. See Regulatory Activities below for information regarding the amount, period and timing of the return of these regulatory liabilities to our customers as well as additional information on the impact of the Tax Cuts and Jobs Act of 2017.

Dividend - In January 2019, we declared a dividend of $0.50 per share ($2.00 per share on an annualized basis) for shareholders of record as of February 22, 2019, payable on March 8, 2019.

REGULATORY ACTIVITIES

Oklahoma - On March 15, 2018, Oklahoma Natural Gas filed its second annual PBRC application following the general rate case that was approved in January 2016. This filing was based on a calendar test year of 2017. On January 8, 2019, the OCC approved an order requiring a reduction in customer base rates of $11.3 million annually beginning in February 2019. This reduction represents a decrease in base rates based on the company's authorized return on equity of 9.5 percent and includes the reduction in the corporate federal income tax rate pursuant to the Tax Cuts and Jobs Act of 2017. In addition, the order requires that any earnings, including amounts attributable to tax savings, occurring in the 2018 calendar year that are above the authorized return on equity be returned to customers through the PBRC filing to be made on or before March 15, 2019. The order also approved an energy efficiency incentive of $2.1 million and a program true-up adjustment of $0.5 million. As required, PBRC filings are made annually on or before March 15, until the next general rate case, which is currently required to be filed on or before June 30, 2021, based on a calendar 2020 test year.

In March 2017, Oklahoma Natural Gas filed its first annual PBRC following the general rate case that was approved in January 2016. This filing was based on a calendar test year of 2016. The PBRC filing demonstrated that Oklahoma Natural Gas was earning within the 100 basis point dead-band of 9.0 to 10.0 percent. Therefore, Oklahoma Natural Gas did not seek a modification to base rates. The filing also requested a utility incentive adjustment of approximately $1.9 million and an energy efficiency program true-up adjustment of $2.3 million. A joint stipulation and settlement agreement was approved by the OCC in August 2017.

In March 2016, Oklahoma Natural Gas filed its energy efficiency program true-up application for its 2015 program year, requesting a utility incentive of $1.9 million and a program true-up adjustment of $3.1 million. This filing also sought approval for the demand portfolio of conservation and energy efficiency programs for calendar years 2017 through 2019. In October 2016, the OCC approved the joint stipulation and settlement agreement.

Kansas - In November 2018, Kansas Gas Service submitted an application to the KCC requesting approval of its contract to own, operate and maintain the natural gas distribution system at Fort Riley, a United States Army installation for approximately $5.8 million. The KCC has up to 240 days to consider Kansas Gas Service’s filing. If approved, we will start the transition process with an intent to acquire the assets in the second quarter of 2020.

In August 2018, Kansas Gas Service submitted an application to the KCC requesting an increase of approximately $2.4 million related to its GSRS. In November 2018, the KCC approved the increase effective December 2018.

In June 2018, Kansas Gas Service filed a request with the KCC for an increase in base rates, reflecting investments in system improvements and changes in operating costs necessary to maintain the safety and reliability of its natural gas distribution system. In February 2019, the KCC issued an order that included a net base rate increase of $18.6 million and a GSRS pre-tax carrying charge of approximately 9.1%. Kansas Gas Service is already recovering $2.9 million from customers through the GSRS, therefore, this order represents a total base rate increase of $21.5 million. The increase in base rates reflects an amortization credit for the refund of excess ADIT over a period in compliance with the tax normalization rules for the portions stipulated by the Code and five years for all other components of excess ADIT. Additionally, the settlement provides for extending application of the weather normalization adjustment rider to small transportation customers and the implementation of a cybersecurity tracker. The residential service charge will be $18.70 per month and the delivery charge will be $2.3485 per Mcf. Still outstanding is whether Kansas Gas Service should be required to refund to customers the tax reform regulatory liability accrued pursuant to the KCC order. In accordance with Kansas law, the KCC has until February 25, 2019 to rule on the tax refund issue.

In April 2018, a bill amending the GSRS statute was approved. Beginning January 1, 2019, the scope of projects eligible for recovery under the statute will include all investments to replace, upgrade or modernize obsolete facilities, as well as projects that enhance the integrity of pipeline system components or extend the useful life of such assets. Safety-related investments will also include expenditures for physical and cyber security. Additionally, the cap on the monthly residential surcharge will increase to $0.80 from $0.40.

In August 2017, Kansas Gas Service submitted an application to the KCC requesting an increase of approximately $2.9 million related to its GSRS. In November 2017, the KCC approved the increase effective December 2017.

In April 2017, Kansas Gas Service filed an application with the KCC seeking approval of an AAO associated with the costs incurred at, and nearby, the 12 former MGP sites which we own or retain responsibility for certain environmental conditions. In October 2017, Kansas Gas Service, the KCC staff and the Citizens’ Utility Ratepayer Board filed a unanimous settlement agreement with the KCC. The agreement allows Kansas Gas Service to defer and seek recovery of costs that are necessary for investigation and remediation at the 12 former MGP sites incurred after January 1, 2017, up to a cap of $15.0 million, net of any related insurance recoveries. Costs approved in a future rate proceeding would then be amortized over a 15-year period. The unamortized amounts will not be included in rate base or accumulate carrying charges. At the time future investigation and remediation work, net of any related insurance recoveries, is expected to exceed $15.0 million, Kansas Gas Service will be required to file an application with the KCC for approval to increase the $15.0 million cap. The KCC issued an order approving the settlement agreement in November 2017. A regulatory asset of approximately $5.9 million was recorded for estimated costs that have been accrued at January 1, 2017. See discussion below in Environmental, Safety and Regulatory Matters for additional information concerning the 12 former MGP sites.

In May 2016, Kansas Gas Service filed a request with the KCC for an increase in base rates, reflecting system investments and operating costs necessary to maintain the safety and reliability of its natural gas distribution system. In October 2016, Kansas Gas Service reached a unanimous settlement agreement with all parties for a net increase in base rates of approximately $8.1 million. Including the GSRS of approximately $7.4 million, the total base rate increase was $15.5 million. The agreement was a “black-box settlement,” meaning the parties agreed to a specific revenue number but no specific return on equity or determination with respect to other contested issues. Additionally, the agreement modified the weather normalization clause to accrue the variation in delivery charges resulting from the difference in actual weather relative to normal weather over 12 months, rather than five months. The KCC approved the new rates effective January 1, 2017.

Texas - West Texas Service Area - In March 2018, Texas Gas Service made GRIP filings for all customers in the West Texas service area. In June 2018, the RRC and the cities in the West Texas service area agreed to an increase of $3.5 million, and new rates became effective in July 2018.

In March 2017, Texas Gas Service made GRIP filings for all customers in the West Texas service area. The RRC and the cities approved an increase of $4.3 million, and new rates became effective in July 2017.

In November 2015, Texas Gas Service notified the EPSA that it would be filing a full rate case in 2016 in lieu of the previously agreed to annual rate review mechanism called EPARR. In March 2016, Texas Gas Service filed a rate case for its El Paso, Dell City and Permian service areas, which included a request to consolidate these three areas. In September 2016, the RRC approved the consolidation and a base rate increase of $8.8 million, which was based on a 9.5 percent return on equity and a 60.1 percent common equity ratio. In October 2016, new rates went into effect for all customers, except for those in the cities of the former Permian service area. Texas Gas Service filed for these new rates for customers in the cities of the former Permian service area in October 2016, and the rates became effective in December 2016.

Central Texas Service Area - In March 2018, Texas Gas Service made GRIP filings for all customers in the Central Texas service area. In June 2018, the RRC and the cities in the Central Texas service area agreed to an increase of $3.3 million, and new rates became effective in July 2018.

In March 2017, Texas Gas Service made GRIP filings for all customers in the Central Texas service area. The cities and the RRC approved an increase of $4.9 million, and new rates became effective in June 2017.

In June 2016, Texas Gas Service filed a rate case for its Central Texas and South Texas service areas. The filing included a request to consolidate the South Texas service area with the Central Texas service area. Texas Gas Service filed this rate case directly with the cities of the Central Texas service area, which includes the city of Austin, and the RRC for the unincorporated areas. In October 2016, all parties to the filing reached a unanimous settlement agreement for an increase in revenues of $6.8 million for the new consolidated service area. New rates were effective in November 2016, for customers in the cities of the former Central Texas service area. RRC approval was received in November 2016 and new rates became effective for customers in the unincorporated areas of the new consolidated Central Texas service area the same month. Texas Gas Service received approval for the same rates in the incorporated areas of the former South Texas service area, with new rates effective in January 2017.

Other Texas Service Areas - In the normal course of business, Texas Gas Service has filed rate cases and sought GRIP and COSA increases in various other Texas jurisdictions to address investments in rate base and changes in expenses. Annual rate increases associated with these filings that were approved totaled $1.6 million, $5.0 million and $4.3 million in 2018, 2017 and 2016, respectively.

Tax Reform - Oklahoma - In December 2017, the Oklahoma Attorney General filed a motion on behalf of customers in Oklahoma requesting that the OCC take action for an immediate reduction in rates and protection of rate payers' interests. On January 9, 2018, the OCC approved an order directing Oklahoma Natural Gas to record a deferred liability beginning on the effective date of the order, January 9, 2018, to reflect the reduced federal corporate tax rate of 21 percent and the associated savings in excess ADIT and any other tax implications of the Tax Cuts and Jobs Act of 2017 on an interim basis, subject to refund, until utility rates are adjusted to reflect the federal tax savings and a final order is issued in Oklahoma Natural Gas' next scheduled PBRC proceeding. This order also directs Oklahoma Natural Gas, to the extent not already accounted for in Oklahoma Natural Gas' current PBRC tariff, to accrue interest at a rate equivalent to Oklahoma Natural Gas' cost of capital as recognized in the most recent PBRC filing on the amounts of any refunds determined to be owed to customers until issuance of a final order in the upcoming PBRC proceeding. This order also dismissed the Oklahoma Attorney General's motion.

In compliance with the order, Oklahoma Natural Gas' March 15, 2018, PBRC filing contained two deferred liabilities subject to review and potential refund. First, a regulatory liability has been established reflecting the remeasurement of ADIT for the change in the federal corporate income tax rate. In January 2019, the OCC issued an order requiring Oklahoma Natural Gas to credit customers for the reduction in ADIT based upon an amortization period in compliance with the tax normalization rules for the portions of excess ADIT stipulated by the Code and ten years for all other components of excess ADIT.

An additional $15.8 million liability has also been established for the estimated earnings, including amounts attributable to tax savings, above the 9.5 percent approved ROE in the 2018 review period, which are to be returned to customers as part of the 2019 PBRC filing. See "Regulatory Activities - Oklahoma" in Management's Discussion and Analysis of Financial Condition and Results of Operations in this Annual Report.

Kansas - On January 18, 2018, the KCC opened a general investigation for the purposes of examining the financial impact of the Tax Cuts and Jobs Act of 2017 on regulated public utilities operating in Kansas and made the following findings and conclusions: (1) utilities are to track and accumulate, in a deferred revenue account, the portion of their revenue that results from the use of a 35 percent federal corporate tax rate for its last KCC-approved revenue determination instead of the new lower federal corporate tax rate; (2) deferrals are to commence on the effective date of the new federal corporate tax rate;
(3) excess ADIT should be captured in a manner consistent with tax normalization rules; and (4) the portion of current rates affected by the Tax Cuts and Jobs Act of 2017 should be considered interim and subject to refund, with interest compounded monthly at the rate for customer deposits, until the KCC has an opportunity to evaluate the reasonableness of those rates with new lower federal tax rates.

In March 2018, the KCC approved a settlement with Kansas Gas Service, the KCC Staff and the Citizens' Utility Ratepayer Board related to the Tax Cuts and Jobs Act of 2017. The agreement indicates for the period between January 1, 2018, and through the date on which the KCC issues a final order in Kansas Gas Service's next general rate case, Kansas Gas Service agrees to accrue monthly, as a regulatory liability on its general ledger, the portion of its revenue representing the difference between the 21 percent and 35 percent federal corporate tax rate. The annual amount of the regulatory liability is $14.2 million, excluding interest to be applied based on the customer deposit interest rate, currently 1.62 percent. Through this agreement, Kansas Gas Service also established a regulatory liability to account for the remeasurement of ADIT for the change in the federal corporate income tax rate. Issues regarding the treatment of these regulatory liabilities are included in Kansas Gas Service's general rate proceeding filed in June 2018.

The KCC issued an order in February 2019 approving the unanimous settlement agreement regarding Kansas Gas Service's rate case filed in June 2018. As provided for in the agreement, the base rates approved for Kansas Gas Service include an amortization credit associated with the refund of ADIT based on an amortization period in compliance with the tax normalization rules for the portion of excess ADIT stipulated by the Code and five years for all other components of excess ADIT. Still outstanding is whether Kansas Gas Service should be required to refund to customers the amount of the regulatory liability for the difference between the 21 percent and 35 percent federal corporate income tax rate. In accordance with Kansas law, the KCC has until February 25, 2019 to rule on the tax refund issue.

Texas - In February 2018, the RRC issued an accounting order for determining how the impact of the Tax Cuts and Jobs Act of 2017 would be reflected in gas utility rates in Texas. Gas utilities were ordered to either file a new rate case or voluntarily reduce rates by September 1, 2018, to reflect the reduction of the federal corporate income tax rate to 21 percent from 35 percent. Gas utilities were further ordered to calculate, defer and refund rate reductions resulting from changes to the corporate tax rate that occurred between January 1, 2018 and the effective date of new rates. Per the order, the impact of the Tax Cuts and Jobs Act of 2017 on ADIT remeasurement is to be determined in the next rate case in each jurisdiction.

In 2018, Texas Gas Service requested a total of $11.1 million of decreases to rates for customers in its service areas due to the reduction of the federal corporate income tax rate, and one-time refunds totaling $6.6 million for the reduction in the federal corporate income tax rate for the period between January 1, 2018, to the dates new rates were implemented. The requests for the decreases in rates and the one-time refunds were approved and new rates, where applicable, became effective in the second half of 2018.

We continue to work with our regulators in Texas to address our excess ADIT. The treatment of our excess ADIT and the degree to which it impacts us will not be known until we finalize our current regulatory filings and make future regulatory filings.

The treatment of excess ADIT by our regulators is not expected to have a material impact on earnings as any reduction or credit in rates is offset by the amortization of the regulatory liability as a credit in income tax expense. We will begin refunding or crediting the excess ADIT regulatory liability to customers in 2019. See "Liquidity and Capital Resources - Tax Reform" and Note 13 of the Notes to Consolidated Financial Statements for additional discussion of the Tax Cuts and Jobs Act of 2017.

OTHER

Certain costs to be recovered through the ratemaking process have been capitalized as regulatory assets. Should recovery cease due to regulatory actions, certain of these assets may no longer meet the criteria for recognition and accordingly, a writeoff of regulatory assets and stranded costs may be required. There were no writeoffs of regulatory assets resulting from the failure to meet the criteria for capitalization during 2018, 2017 and 2016.

In 2017, we formed a wholly-owned captive insurance company in the state of Oklahoma to provide insurance to our divisions.

FINANCIAL RESULTS AND OPERATING INFORMATION

Selected Financial Results - Net income was $172.2 million, or $3.25 per diluted share, $163.0 million, or $3.08 per diluted share, and $140.1 million, or $2.65 per diluted share, for the years ended December 31, 2018, 2017 and 2016, respectively. We operate in one reportable business segment: regulated public utilities that deliver natural gas to residential, commercial, industrial, wholesale, public authority and transportation customers. We evaluate our financial performance principally on operating income.

The following table sets forth certain selected financial results for our operations for the periods indicated:

Financial Results	Years Ended December 31, 2018	2017	2016	Variances 2018 vs. 2017 Increase (Decrease)		Variances 2017 vs. 2016 Increase (Decrease)	
	(Millions of dollars, except percentages)						
Natural gas sales	$1,492.4	$1,409.1	$1,300.1	$83.3	6 %	$109.0	8 %
Transportation revenues	109.7	100.9	98.1	8.8	9 %	2.8	3 %
Other revenues	31.6	29.6	29.0	2.0	7 %	0.6	2 %
Total revenues	1,633.7	1,539.6	1,427.2	94.1	6 %	112.4	8 %
Cost of natural gas	714.6	614.5	541.8	100.1	16 %	72.7	13 %
Net margin	919.1	925.1	885.4	(6.0)	(1)%	39.7	4 %
Operating costs (a)	470.6	456.5	452.7	14.1	3 %	3.8	1 %
Depreciation and amortization	160.1	151.9	143.8	8.2	5 %	8.1	6 %
Operating income (a)	$288.4	$316.7	$288.9	$(28.3)	(9)%	$27.8	10 %
Capital expenditures	$394.5	$356.4	$309.0	$38.1	11 %	$47.4	15 %
Asset removal costs	$52.9	$52.4	$53.4	$0.5	1 %	$(1.0)	(2)%

(a) Reflects the impact of the adoption of a new accounting standard in fiscal year 2018 related to the presentation of net periodic benefit costs. See Note 1 of the Notes to Consolidated Financial Statements in this Annual Report for additional information regarding our adoption of this standard.

Natural gas sales to customers represent revenue from contracts with customers through implied contracts established by our tariff rates approved by the regulatory authorities, as well as revenues from regulatory mechanisms related to natural gas sales that do not meet the requirements under FASB's ASU 2014-09, "Revenue from Contracts with Customers" ("ASC 606"), which are included in the consolidated statements of income and in our footnotes as other revenues.

Transportation revenues represent revenue from contracts with customers through implied contracts established by our tariff rates approved by the regulatory authorities and tariff-based negotiated contracts.

Other utility revenues include primarily miscellaneous service charges which represent implied contracts with customers established by our tariff rates approved by the regulatory authorities and other revenues from regulatory mechanisms that do not meet the requirements of ASC 606.

Non-GAAP Financial Measure - We have disclosed Net Margin, which is considered a non-GAAP financial measure, in our selected financial data and selected financial results. Net Margin is comprised of total revenues less cost of natural gas. Cost of natural gas includes commodity purchases, fuel, storage, transportation and other gas purchase costs recovered through our cost of natural gas regulatory mechanisms, as required by our regulators, and does not include an allocation of general operating costs or depreciation and amortization. In addition, our cost of natural gas regulatory mechanisms provide a method of recovering natural gas costs on an ongoing basis without a profit. Therefore, although our revenues will fluctuate with the cost of natural gas that we pass-through to our customers, Net Margin is not affected by fluctuations in the cost of natural gas. Accordingly, we routinely use Net Margin in the analysis of our financial performance. We believe that Net Margin provides investors a more relevant and useful measure to analyze our financial performance as a 100 percent regulated natural gas utility than total revenues because the change in the cost of natural gas from period to period does not impact our operating income. As such, the following discussion and analysis of our financial performance will reference Net Margin rather than total revenues and cost of natural gas individually.

The following table sets forth reconciliation of Net Margin to the most directly comparable GAAP measure for the periods indicated:

Non-GAAP Reconciliation	Years Ended December 31, 2018	2017	2016	Variances 2018 vs. 2017 Increase (Decrease)		Variances 2017 vs. 2016 Increase (Decrease)	
	(Millions of dollars, except percentages)						
Total revenues	$1,633.7	$1,539.6	$1,427.2	$94.1	6 %	$112.4	8 %
Cost of natural gas	714.6	614.5	541.8	100.1	16 %	72.7	13%
Net margin	$919.1	$925.1	$885.4	$(6.0)	(1)%	$39.7	4 %

The following table sets forth our Net Margin by type of customer for the periods indicated:

Net Margin	Years Ended December 31, 2018	2017	2016	Variances 2018 vs. 2017 Increase (Decrease)		Variances 2017 vs. 2016 Increase (Decrease)	
Natural gas sales	(Millions of dollars, except percentages)						
Residential	$644.1	$663.8	$629.8	$(19.7)	(3)%	$34.0	5 %
Commercial and industrial	127.1	124.2	121.7	2.9	2 %	2.5	2 %
Wholesale and public authority	6.6	6.6	6.8	—	— %	(0.2)	(3)%
Net margin on natural gas sales	777.8	794.6	758.3	(16.8)	(2)%	36.3	5 %
Transportation revenues	109.7	100.9	98.1	8.8	9 %	2.8	3 %
Other revenues	31.6	29.6	29.0	2.0	7 %	0.6	2 %
Net margin	$919.1	$925.1	$885.4	$(6.0)	(1)%	$39.7	4 %

Our Net Margin on natural gas sales is comprised of two components, fixed and variable margin. Fixed margin reflects the portion of our net margin attributable to the monthly fixed customer charge component of our rates, which does not fluctuate based on customer usage in each period. Variable margin reflects the portion of our net margin that fluctuates with the volumes delivered and billed and the effects of weather normalization. The following table sets forth our Net Margin on natural gas sales by revenue type for the periods indicated:

Net Margin on Natural Gas Sales	Years Ended December 31, 2018	2017	2016	Variances 2018 vs. 2017 Increase (Decrease)		Variances 2017 vs. 2016 Increase (Decrease)	
Net margin on natural gas sales	(Millions of dollars, except percentages)						
Fixed margin	$553.9	$567.1	$557.5	$(13.2)	(2)%	$9.6	2 %
Variable margin	223.9	227.5	200.8	(3.6)	(2)%	26.7	13%
Net margin on natural gas sales	$777.8	$794.6	$758.3	$(16.8)	(2)%	$36.3	5 %

2018 vs. 2017 - Net Margin decreased $6.0 million due primarily to the following:

- an increase of $15.9 million due to new rates in Texas and Kansas;
- an increase of $6.1 million due primarily to higher transportation volumes;
- an increase of $5.7 million due to higher sales volumes, net of weather normalization, primarily from colder weather in 2018 compared with 2017;
- an increase of $4.9 million in residential sales due primarily to net customer growth in Oklahoma and Texas;

- an increase of $1.7 million in rider and surcharge recoveries due to higher ad-valorem surcharge in Kansas, offset by higher regulatory amortization in depreciation and amortization expense below; and
- an increase of $0.9 million due to the benefit of the retroactive 2017 compressed natural gas federal excise tax credit enacted in February 2018; offset by
- a decrease of $42.3 million related to the deferral of potential refund obligations associated with the Tax Cuts and Jobs Act of 2017 and related rate adjustments.

Operating costs increased $14.1 million due primarily to the following:
- an increase of $8.4 million in employee-related costs resulting from higher labor and benefit costs;
- an increase of $5.9 million resulting from the 2017 deferral of MGP costs previously accrued, as discussed further in our Environmental, Safety and Regulatory Matters, which was approved in Kansas as a regulatory asset;
- an increase of $2.4 million in legal-related costs; and
- an increase of $1.2 million in bad debt expense; offset by
- a decrease of $1.9 million in outside service costs as certain pipeline maintenance activities were completed with internal resources; and
- a decrease of $1.0 million in insurance expense.

Depreciation and amortization expense increased $8.2 million due primarily to a $7.5 million increase in depreciation from our capital expenditures being placed into service and an increase in the amortization of the ad-valorem surcharge rider in Kansas.

2017 vs. 2016 - Net Margin increased $39.7 million due primarily to the following:
- an increase of $26.7 million from new rates primarily in Texas and Kansas;
- an increase of $5.3 million from the impact of weather normalization mechanisms, which offset warmer than normal weather in 2017;
- an increase of $3.8 million due primarily to higher transportation volumes from customers in Kansas and Oklahoma; and
- an increase of $3.4 million in residential sales due primarily to net customer growth in Oklahoma and Texas.

Operating costs increased $3.8 million due primarily to the following:
- an increase of $8.4 million in employee-related costs resulting from higher labor and compensation costs;
- an increase of $2.9 million from the deferral in the first quarter of 2016 of certain information technology costs incurred as a result of our separation from ONEOK in 2014, which was approved in Oklahoma as a regulatory asset, and a deferral of regulatory expenses incurred previously in the fourth quarter of 2016, which was approved in the West Texas rate case as a regulatory asset;
- an increase of $2.6 million in net periodic benefit costs other than service costs;
- an increase of $1.9 million in bad debt expense; and
- an increase of $1.2 million in information technology costs; offset by
- a decrease of $5.9 million from the deferral of MGP costs previously accrued, as discussed further in our Environmental, Safety and Regulatory Matters, which was approved in Kansas as a regulatory asset;
- a decrease of $4.0 million related to the higher environmental remediation costs in 2016 discussed further in our Environmental, Safety and Regulatory Matters; and
- a decrease of $3.4 million in legal-related costs.

Depreciation and amortization expense increased $8.1 million due primarily to an $11.0 million increase in depreciation from our capital expenditures being placed into service, offset partially by a decrease in the amortization of other postemployment benefit deferrals in Kansas.

Other Factors Affecting Net Income - Other factors that affect net income include other expenses, interest expense, and income tax expense as follows:

2018 vs. 2017

- a decrease of $3.2 million in other expenses, net, primarily due to lower net periodic benefit costs other than service costs;
- an increase of $5.2 million in interest expense related to additional borrowings to fund capital expenditures; and
- a decrease of $39.6 million in income tax expense primarily associated with the reduction in the federal statutory income tax rate to 21 percent in 2018 from 35 percent in 2017 as a result of the Tax Cuts and Jobs Act of 2017. Tax expense also includes a credit of $2.8 million due to the tax benefits on vested long-term incentive awards in 2018.

2017 vs. 2016

- a decrease of $5.3 million in other expenses, net, primarily due to lower net periodic benefit costs other than service costs;
- an increase of $2.3 million in interest expense related to additional borrowings to fund capital expenditures; and
- an increase of $7.9 million in income tax expense due to higher taxable income, offset by $5.2 million in excess tax benefits due to the change in accounting for tax benefits on vested long-term incentive awards in tax expense in the first quarter of 2017 compared to awards vested in the first quarter of 2016.

Capital Expenditures and Asset Removal Costs - Our capital expenditures program includes expenditures for pipeline integrity, extending service to new areas, modifications to customer service lines, increasing system capabilities, pipeline replacements, automated meter reading, government-mandated pipeline relocations, fleet, facilities and information technology assets. It is our practice to maintain and upgrade our infrastructure, facilities and systems to ensure safe, reliable and efficient operations. Asset removal costs include expenditures associated with the replacement or retirement of long-lived assets that result from the construction, development and/or normal use of our assets, primarily our pipeline assets.

Capital expenditures increased $38.1 million for 2018, compared with 2017 and $47.4 million for 2017, compared with 2016, due primarily to increased system integrity activities and extending service to new areas. Asset removal costs increased $0.5 million for 2018, compared to 2017 and decreased $1.0 million for 2017, compared to 2016. Our capital expenditures and asset removal costs are expected to be approximately $450.0 million for 2019.

Selected Operating Information - The following tables set forth certain selected operating information for the periods indicated:

	Years Ended December 31,								Variances 2018 vs. 2017			
(in thousands)	2018				2017				Increase (Decrease)			
Average Number of Customers	OK	KS	TX	Total	OK	KS	TX	Total	OK	KS	TX	Total
Residential	798	583	624	2,005	793	582	618	1,993	5	1	6	12
Commercial and industrial	74	50	35	159	73	50	35	158	1	—	—	1
Wholesale and public authority	—	—	3	3	—	—	3	3	—	—	—	—
Transportation	5	6	1	12	5	6	1	12	—	—	—	—
Total customers	877	639	663	2,179	871	638	657	2,166	6	1	6	13

	Years Ended December 31,								Variances 2017 vs. 2016			
(in thousands)	2017				2016				Increase (Decrease)			
Average Number of Customers	OK	KS	TX	Total	OK	KS	TX	Total	OK	KS	TX	Total
Residential	793	582	618	1,993	787	581	612	1,980	6	1	6	13
Commercial and industrial	73	50	35	158	73	50	34	157	—	—	1	1
Wholesale and public authority	—	—	3	3	—	—	3	3	—	—	—	—
Transportation	5	6	1	12	5	6	1	12	—	—	—	—
Total customers	871	638	657	2,166	865	637	650	2,152	6	1	7	14

The following table reflects the total volumes delivered, excluding the effects of weather normalization mechanisms on sales volumes.

	Years Ended December 31,		
Volumes (MMcf)	2018	2017	2016
Natural gas sales			
Residential	128,393	99,940	101,956
Commercial and industrial	40,743	32,242	32,276
Wholesale and public authority	2,505	1,933	2,414
Total sales volumes delivered	171,641	134,115	136,646
Transportation	220,884	209,551	208,141
Total volumes delivered	392,525	343,666	344,787

Total sales volumes delivered increased for 2018, compared with 2017, due primarily to colder temperatures in our service areas. Total sales volumes delivered decreased for 2017, compared with 2016, due primarily to warmer temperatures in our service areas. The impact of weather on residential and commercial Net Margin is mitigated by weather normalization mechanisms in all jurisdictions. Transportation volumes increased for 2018 compared with 2017 due to colder temperatures in our service areas. Transportation volumes increased slightly for 2017 compared with 2016 due to higher consumption by our transportation customers in Oklahoma.

Wholesale sales represent contracted natural gas volumes that exceed the needs of our residential, commercial and industrial customer base and are available for sale to other parties. The impact to Net Margin from changes in volumes associated with these customers is minimal.

	Years Ended December 31,						
	2018		2017		2018 vs. 2017	2018	2017
HDDs	Actual	Normal	Actual	Normal	Actual Variance	Actual as a percent of Normal	
Oklahoma	3,771	3,263	2,849	3,264	32 %	116%	87%
Kansas	5,012	4,914	4,088	4,889	23 %	102%	84%
Texas	1,738	1,782	1,247	1,785	39 %	98 %	70%

	Years Ended December 31,						
	2017		2016		2017 vs. 2016	2017	2016
HDDs	Actual	Normal	Actual	Normal	Actual Variance	Actual as a percent of Normal	
Oklahoma	2,849	3,264	2,843	3,264	— %	87%	87%
Kansas	4,088	4,889	4,016	4,860	2 %	84%	83%
Texas	1,247	1,785	1,455	1,785	(14)%	70%	82%

Normal HDDs are established through rate proceedings in each of our rate jurisdictions for use primarily in weather normalization billing calculations. Normal HDDs disclosed above are based on:

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Oklahoma - For years 2016-2018, 10-year weighted average HDDs as of December 31, 2014, for years 2005-2014, as calculated using 11 weather stations across Oklahoma and weighted on average customer count.

- Kansas - For years 2018 and 2017, 30-year average for years 1981-2010 published by the National Oceanic and Atmospheric Administration, as calculated using four weather stations across Kansas and weighted on HDDs by weather station and customers, and for 2016, 30-year average for years 1981-2010 published by the National Oceanic and Atmospheric Administration, as calculated using 13 weather stations across Kansas and weighted on HDDs by weather station and customers.

- Texas - An average of HDDs authorized in our most recent rate proceeding in each jurisdiction and weighted using a rolling 10-year average of actual natural gas distribution sales volumes by jurisdiction.

Actual HDDs are based on year-to-date, weighted average of:

- 11 weather stations and customers by month for Oklahoma;
- 4 weather stations and customers by month for 2018 and 2017 for Kansas;
- 13 weather stations and customers by month for 2016 for Kansas; and
- 9 weather stations and natural gas distribution sales volumes by service area for Texas.

Through March 31, 2017, Kansas Gas Services' WNA clause required it to accrue the variation in Net Margin resulting from actual weather differing from normal weather occurring from November through March. Beginning in April 2017, Kansas Gas Services' WNA clause requires an accrual each month of the year.

CONTINGENCIES

We are a party to various litigation matters and claims that have arisen in the normal course of our operations. While the results of litigation and claims cannot be predicted with certainty, we believe the reasonably possible losses from such matters, individually and in the aggregate, are not material. Additionally, we believe the probable final outcome of such matters will not have a material adverse effect on our results of operations, financial position or cash flows. See Note 15 of the Notes to Consolidated Financial Statements in this Annual Report for information with respect to legal proceedings.

LIQUIDITY AND CAPITAL RESOURCES

General - We have relied primarily on operating cash flow and commercial paper for our liquidity and capital resource requirements. We fund operating expenses, working capital requirements, including purchases of natural gas, and capital expenditures primarily with cash from operations and commercial paper.

We believe that the combination of the significant residential component of our customer base, the fixed-charge component of our natural gas sales and our regulatory rate mechanisms that we have in place result in a stable cash flow profile. Because the energy consumption of residential customers is less volatile compared with commercial and industrial customers, our business historically has generated stable and predictable earnings and cash flows. Additionally, we have several regulatory rate mechanisms in place to reduce the lag in earning a return on our capital expenditures. We anticipate that our cash flow generated from operations and our expected short- and long-term financing arrangements will enable us to maintain our current and planned level of operations and provide us flexibility to finance our infrastructure investments.

Our ability to access capital markets for debt and equity financing under reasonable terms depends on market conditions and our financial condition and credit ratings. By maintaining a conservative financial profile and stable revenue base, we believe that we will be able to maintain an investment-grade credit rating, which we believe will provide us access to diverse sources of capital at favorable rates in order to finance our infrastructure investments.

Tax Reform - The Tax Cuts and Jobs Act of 2017 had an overall negative impact on our operating cash flow due to several dynamics. The reduction in the tax rate resulted in less revenues collected from customers related to the recovery of tax expense included in our rates. Although cash collected from this revenue is ultimately used to remit our income tax expense payments, under the new law, we will lose a portion of the timing benefit when we collect and remit tax payments, thereby reducing cash that may have been retained for several years. Under the new tax law, natural gas utilities are not eligible to take bonus depreciation, but they are also not subject to the new limitations on the deduction of interest expense. The loss of bonus depreciation will result in earlier cash tax payments, as compared to the previous tax law, once accumulated NOLs are utilized. Additionally, the lowering of the tax rate effectively resulted in an over-collection of tax expenses, as customers' rates include tax expenses based on the statutory tax rate.

We have addressed excess ADIT in Oklahoma and Kansas. In Texas, the timing of these changes in our cash flows and the degree to which it impacts us will not be known until we finalize our current regulatory filings and make future regulatory filings. We expect cash flows in 2019 will be reduced by approximately $23.0 million as we begin refunding the excess ADIT regulatory liability to customers.

In Oklahoma and Texas, the manner and timing in which we refund the difference in the 21 percent and 35 percent federal corporate income tax rate to customers has been addressed. Still outstanding is whether Kansas Gas Service will be required to refund to customers the amount of the regulatory liability accrued. In accordance with Kansas law, the KCC has until February 25, 2019 to rule on the tax refund issue. We believe that our capital structure and available liquidity resources will be adequate to adjust for these changes. See additional discussion under Regulatory Activities - Tax Reform and Note 13 of Notes to Consolidated Financial Statements in this Annual Report.

Short-term Financing - In October 2018, we exercised a one-year extension of the ONE Gas Credit Agreement. The ONE Gas Credit Agreement remains a $700.0 million revolving unsecured credit facility and includes a $20.0 million letter of credit subfacility and a $60.0 million swingline subfacility. We are able to request an increase in commitments of up to an additional $500.0 million upon satisfaction of customary conditions, including receipt of commitments from either new lenders or increased commitments from existing lenders. The ONE Gas Credit Agreement expires in October 2023, and is available to provide liquidity for working capital, capital expenditures, acquisitions and mergers, the issuance of letters of credit and for other general corporate purposes.

The ONE Gas Credit Agreement contains customary events of default. Upon the occurrence of certain events of default, the obligations under the ONE Gas Credit Agreement may be accelerated and the commitments may be terminated. The ONE Gas Credit Agreement also contains certain financial, operational and legal covenants. Among other things, these covenants include maintaining ONE Gas’ total debt-to-capital ratio of no more than 70 percent at the end of any calendar quarter. The ONE Gas Credit Agreement also contains customary affirmative and negative covenants, including covenants relating to liens, indebtedness of subsidiaries, investments, changes in the nature of business, fundamental changes, transactions with affiliates, burdensome agreements, and use of proceeds. In the event of a breach of certain covenants by ONE Gas, amounts outstanding under the ONE Gas Credit Agreement may become due and payable immediately. At December 31, 2018, our total debt-to-capital ratio was 44 percent, and we were in compliance with all covenants under the ONE Gas Credit Agreement.

The ONE Gas Credit Agreement contains provisions for an applicable margin rate and an annual facility fee, both of which adjust with changes in our credit rating. Based on our current credit ratings, borrowings, if any, will accrue interest at LIBOR plus 79.5 basis points, and the annual facility fee is 8 basis points.

We have a commercial paper program under which we may issue unsecured commercial paper up to a maximum amount of $700 million to fund short-term borrowing needs. The maturities of the commercial paper notes may vary but may not exceed 270 days from the date of issue. The commercial paper notes are generally sold at par less a discount representing an interest factor.

The ONE Gas Credit Agreement is available to repay the commercial paper notes, if necessary. Amounts outstanding under the commercial paper program reduce the borrowing capacity under the ONE Gas Credit Agreement.

At December 31, 2018, we had $299.5 million of short-term debt outstanding in the form of commercial paper, $1.2 million in letters of credit outstanding and had approximately $21.3 million of cash and cash equivalents. At December 31, 2018, we had no borrowings and $399.3 million of credit available under the ONE Gas Credit Agreement. The weighted-average interest rate on our commercial paper was 2.54 percent at December 31, 2018.

Long-Term Debt - In November 2018, we issued $400 million of 4.50 percent senior notes due 2048. The proceeds from the issuance were used to retire the $300 million 2.07 percent senior notes due 2019, to reduce commercial paper and for general corporate purposes.

The indenture governing our Senior Notes includes an event of default upon the acceleration of other indebtedness of $100 million or more. Such events of default would entitle the trustee or the holders of 25 percent in aggregate principal amount of the outstanding Senior Notes to declare those Senior Notes immediately due and payable in full.

At December 31, 2018, our long-term debt-to-capital ratio was 39 percent.

Depending on the series, we may redeem our Senior Notes at par, plus accrued and unpaid interest to the redemption date, starting three months or six months before their maturity dates. Prior to these dates, we may redeem these Senior Notes, in whole or in part, at a redemption price equal to the principal amount, plus accrued and unpaid interest and a make-whole premium. The redemption price will never be less than 100 percent of the principal amount of the respective Senior Notes plus accrued and unpaid interest to the redemption date. Our Senior Notes are senior unsecured obligations, ranking equally in right of payment with all of our existing and future unsecured senior indebtedness.

Credit Ratings - Our credit ratings as of December 31, 2018, were:

Rating Agency	Rating	Outlook
Moody’s	A2	Negative
S&P	A	Stable

On January 28, 2019, Moody’s affirmed our A2 rating and changed our outlook to stable from negative.

Our commercial paper is rated Prime-1 by Moody’s and A-1 by S&P. We intend to maintain strong credit metrics while we pursue a balanced approach to capital investment and a return of capital to shareholders via a dividend that we believe will be competitive with our peer group.

Pension and Other Postemployment Benefit Plans - During 2018, we contributed $42.4 million to our defined benefit pension plan and $7.7 million to our other postemployment benefit plans. During 2017, we contributed $111.9 million to our defined benefit pension plan and $6.2 million to our other postemployment benefit plans. Information about our pension and other postemployment benefits plans, including anticipated contributions, is included under Note 12 of the Notes to Consolidated Financial Statements in this Annual Report.

CASH FLOW ANALYSIS

We use the indirect method to prepare our Consolidated Statements of Cash Flows. Under this method, we reconcile net income to cash flows provided by operating activities by adjusting net income for those items that impact net income but may not result in actual cash receipts or payments and changes in our assets and liabilities not classified as investing or financing activities during the period. Items that impact net income but may not result in actual cash receipts or payments include, but are not limited to, depreciation and amortization, deferred income taxes, share-based compensation expense and provision for doubtful accounts.

The following table sets forth the changes in cash flows by operating, investing and financing activities for the periods indicated:

	Years Ended December 31,			Variances	
	2018	2017	2016	2018 vs. 2017	2017 vs. 2016
	(Millions of dollars)				
Total cash provided by (used in):					
Operating activities	$467.7	$253.8	$290.6	$213.9	$(36.8)
Investing activities	(394.5)	(355.8)	(308.5)	(38.7)	(47.3)
Financing activities	(66.3)	101.7	30.2	(168.0)	71.5
Change in cash and cash equivalents	6.9	(0.3)	12.3	7.2	(12.6)
Cash and cash equivalents at beginning of period	14.4	14.7	2.4	(0.3)	12.3
Cash and cash equivalents at end of period	$21.3	$14.4	$14.7	$6.9	$(0.3)

Operating Cash Flows - Changes in cash flows from operating activities are due primarily to changes in Net Margin and operating expenses discussed in Financial Results and Operating Information. Changes in natural gas prices and demand for our services or natural gas, whether because of general economic conditions, changes in supply or increased competition from other service providers, could affect our earnings and operating cash flows. Typically, our cash flows from operations are greater in the first half of the year compared with the second half of the year.

2018 vs. 2017 - Cash flows from operating activities were higher in 2018 compared with 2017, due in part to working capital changes related to the timing of recoveries of purchased-gas costs, natural gas in storage and weather normalization adjustments which were impacted by higher volumes of natural gas delivered in 2018 compared with 2017 due to colder weather. Cash flows were also higher due to a $68.0 million reduction in contributions to our pension and other postemployment benefit plans. Operating cash flows for 2018 include $30.9 million of revenues that have been collected that are subject to refund due to the impact of the Tax Cuts and Jobs Act of 2017 on our rates billed to customers. Potential refunds of these amounts will be determined by our regulators in our rate proceedings discussed in “Regulatory Activities - Tax Reform” in Management’s Discussions and Analysis of Financial Condition and Results in Operations in this Annual Report.

2017 vs. 2016 - Cash flows from operating activities were lower in 2017 compared with 2016. Before considering the impacts of operating asset and liability changes, cash flows were higher in 2017 compared with 2016 due primarily to an increase in net income, higher noncash expenses for depreciation and amortization and deferred income taxes. The increase in operating asset and liability changes more than offset these increases. The largest decrease in working capital relates to a decrease in employee benefit obligation attributed to the $111.9 million contribution to our defined benefit pension plan and $6.2 million contribution to our other postemployment benefit plans in 2017.

Investing Cash Flows - 2018 vs. 2017 - Cash used in investing activities increased for 2018, compared to 2017, due primarily to capital expenditures for increased system integrity activities and extending service to new areas.

2017 vs. 2016 - Cash used in investing activities increased for 2017, compared to 2016, due primarily to capital expenditures for increased system integrity activities and extending service to new areas.

Financing Cash Flows - 2018 vs. 2017 - Cash provided by financing activities for 2018 decreased, compared with 2017, due to larger repayments of notes payable and repayment of long-term debt, offset by proceeds from issuance of long-term debt in 2018.

2017 vs. 2016 - Cash provided by financing activities for 2017 increased, compared with 2016, due primarily to net borrowings on our notes payable to fund working capital and capital investments, offset partially by the 28 cent per share increase in annual dividends.

ENVIRONMENTAL, SAFETY AND REGULATORY MATTERS

Environmental Matters - We are subject to multiple historical, wildlife preservation and environmental laws and/or regulations, which affect many aspects of our present and future operations. Regulated activities include, but are not limited to, those involving air emissions, storm water and wastewater discharges, handling and disposal of solid and hazardous wastes, wetland preservation, hazardous materials transportation, and pipeline and facility construction. These laws and regulations require us to obtain and/or comply with a wide variety of environmental clearances, registrations, licenses, permits and other approvals. Failure to comply with these laws, regulations, licenses and permits or the discovery of presently unknown environmental conditions may expose us to fines, penalties and/or interruptions in our operations that could be material to our results of operations. In addition, emission controls and/or other regulatory or permitting mandates under the Clean Air Act and other similar federal and state laws could require unexpected capital expenditures. We cannot assure that existing environmental statutes and regulations will not be revised or that new regulations will not be adopted or become applicable to us. Revised or additional statutes or regulations that result in increased compliance costs or additional operating restrictions could have a material adverse effect on our business, financial condition and results of operations. Our expenditures for environmental investigation, and remediation compliance to-date have not been significant in relation to our financial position, results of operations or cash flows, and our expenditures related to environmental matters had no material effects on earnings or cash flows during 2018, 2017 or 2016.

We own or retain legal responsibility for certain environmental conditions at 12 former MGP sites in Kansas. These sites contain contaminants generally associated with MGP sites and are subject to control or remediation under various environmental laws and regulations. A consent agreement with the KDHE governs all environmental investigation and remediation work at these sites. The terms of the consent agreement require us to investigate these sites and set remediation activities based upon the results of the investigations and risk analysis. Remediation typically involves the management of contaminated soils and may involve removal of structures and monitoring and/or remediation of groundwater. Regulatory closure has been achieved at three of the 12 sites, but these sites remain subject to potential future requirements that may result in additional costs.

We have completed or are addressing removal of the source of soil contamination at all 12 sites and continue to monitor groundwater at eight of the 12 sites according to plans approved by the KDHE. During the fourth quarter of 2018, we began a project to remove the source of contamination and associated contaminated materials at the twelfth site where no active soil remediation had previously occurred. We are also finalizing a study of the feasibility of various options to address the remainder of the site. Costs associated with the remediation at this site are not expected to be material to our results of operations or financial position.

With regard to one of our former MGP sites in Kansas, periodic monitoring and a 2016 interim site investigation indicated elevated levels of contaminants generally associated with MGP sites. In 2016, we estimated the potential costs associated with additional investigation and remediation to be in the range of $4.0 million to $7.0 million. We have submitted a remediation plan to the KDHE for this site. The KDHE is currently reviewing our plan. In the second quarter of 2018, we revised our estimate of the potential costs associated with additional investigation and remediation to be in the range of $5.6 million to $7.0 million. A single reliable estimate of the remediation costs was not feasible due to the amount of uncertainty in the ultimate remediation approach that will be utilized. Accordingly, we recorded in the second quarter of 2018 an adjustment to the reserve of $1.6 million bringing the total to $5.6 million for this site, which also increased our regulatory asset pursuant to our AAO in Kansas.

In April 2017, Kansas Gas Service filed an application with the KCC seeking approval of an AAO associated with the costs incurred at, and nearby, the 12 former MGP sites which we own or retain responsibility for certain environmental conditions. In October 2017, Kansas Gas Service, the KCC staff and the Citizens' Utility Ratepayer Board filed a unanimous settlement agreement with the KCC. The agreement allows Kansas Gas Service to defer and seek recovery of costs that are necessary for investigation and remediation at the 12 former MGP sites incurred after January 1, 2017, up to a cap of $15.0 million, net of any related insurance recoveries. Costs approved in a future rate proceeding would then be amortized over a 15-year period. The unamortized amounts will not be included in rate base or accumulate carrying charges. At the time future investigation and remediation work, net of any related insurance recoveries, is expected to exceed $15.0 million, Kansas Gas Service will be required to file an application with the KCC for approval to increase the $15.0 million cap. The KCC issued an order approving the settlement agreement in November 2017. A regulatory asset of approximately $5.9 million was recorded for estimated costs that have been accrued at January 1, 2017.

We also own or retain legal responsibility for certain environmental conditions at a former MGP site in Texas. At the request of the Texas Commission on Environmental Quality, we began investigating the level and extent of contamination associated with the site under their Texas Risk Reduction Program. A preliminary site investigation revealed that this site contains contaminants generally associated with MGP sites and is subject to control or remediation under various environmental laws and regulations. Until the investigation is complete, we are unable to determine what, if any, active remediation will be required. A reliable estimate of potential remediation costs is not feasible at this point due to the amount of uncertainty as to the levels and extent of contamination.

Our expenditures for environmental evaluation, mitigation, remediation and compliance to date have not been significant in relation to our financial position, results of operations or cash flows, and our expenditures related to environmental matters had no material effects on earnings or cash flows during 2018, 2017 or 2016. A number of environmental issues may exist with respect to MGP sites that are unknown to us. Accordingly, future costs are dependent on the final determination and regulatory approval of any remedial actions, the complexity of the site, level of remediation required, changing technology and governmental regulations, and to the extent not recovered by insurance or recoverable in rates from our customers, could be material to our financial condition, results of operations or cash flows.

We are subject to environmental regulation by federal, state and local authorities. Due to the inherent uncertainties surrounding the development of federal and state environmental laws and regulations, we cannot determine with specificity the impact such laws and regulations may have on its existing and future facilities. With the trend toward stricter standards, greater regulation and more extensive permit requirements for the types of assets operated by us, our environmental expenditures could increase in the future, and such expenditures may not be fully recovered by insurance or recoverable in rates from our customers, and those costs may adversely affect our financial condition, results of operations and cash flows. We do not expect expenditures for these matters to have a material adverse effect on our financial condition, results of operations or cash flows.

Pipeline Safety - We are subject to PHMSA regulations, including integrity-management regulations. PHMSA regulations require pipeline companies operating high-pressure transmission pipelines to perform integrity assessments on pipeline segments that pass through densely populated areas or near specifically designated high-consequence areas. In January 2012, the Pipeline Safety, Regulatory Certainty and Job Creation Act was signed into law. The law increased maximum penalties for violating federal pipeline safety regulations and directs the DOT and the Secretary of Transportation to conduct further review or studies on issues that may or may not be material to us. These issues include, but are not limited to, the following:

- an evaluation of whether natural gas pipeline integrity-management requirements should be expanded beyond current high-consequence areas;
- a verification of records for pipelines in class 3 and 4 locations and high-consequence areas to confirm maximum allowable operating pressures; and
- a requirement to test previously untested pipelines operating above 30 percent yield strength in high-consequence areas.

In April 2016, PHMSA published a NPRM, the Safety of Gas Transmission & Gathering Lines Rule, in the Federal Register to revise pipeline safety regulations applicable to the safety of onshore natural gas transmission and gathering pipelines.

Proposals include changes to pipeline integrity management requirements and other safety-related requirements. The NPRM comment period ended July 7, 2016, and comments are under review by PHMSA. As part of the comment review process, PHMSA is being advised by the Technical Pipeline Safety Standards Committee, informally known by PHMSA as the GPAC, a statutorily mandated advisory committee that advises PHMSA on proposed safety policies for natural gas pipelines. The GPAC reviews PHMSA's proposed regulatory initiatives to assure the technical feasibility, reasonableness, cost-effectiveness and practicality of each proposal. The GPAC has met five times since January 2017 to review public comments and make recommendations to PHMSA. The GPAC completed their review of the NPRM on March 28, 2018, except for gas gathering. The next GPAC meeting will focus on gas gathering. In addition to reviewing public and committee comments, PHMSA announced they will split this NPRM into three separate final rulemakings:

- the first final rule will address the legislative mandates from the Pipeline Safety, Regulatory Certainty and Jobs Creation Act and will be called the Safety of Gas Transmission Pipelines: Maximum Allowable Operating Pressure Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments;
- the second final rule will be called the Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments and will cover all remaining elements of the NPRM (except for gas gathering); and
- the third final rule will be called the Safety of Gas Gathering Pipelines and will address gas gathering.

A significant number of recommendations have been made to PHMSA to improve the NPRM. The industry trade associations filed joint comments to the “legislative mandates” rulemaking to amend the federal safety regulations applicable to gas transmission and gathering pipelines. The timing of each final rule being published is unknown, but they are expected to be published during 2019. The potential capital and operating expenditures associated with compliance with the proposed rules are currently being evaluated and could be significant depending on the final regulations.

Air and Water Emissions - The Clean Air Act, the Clean Water Act, analogous state laws and/or regulations promulgated thereunder, impose restrictions and controls regarding the discharge of pollutants into the air and water in the United States. Under the Clean Air Act, a federally enforceable operating permit is required for sources of significant air emissions. We may be required to incur certain capital expenditures for air-pollution-control equipment in connection with obtaining or maintaining permits and approvals for sources of air emissions. We do not expect that these expenditures will have a material impact on our respective results of operations, financial position or cash flows. The Clean Water Act imposes substantial potential liability for the removal of pollutants discharged to waters of the United States and remediation of waters affected by such discharge.

International, federal, regional and/or state legislative and/or regulatory initiatives may attempt to regulate greenhouse gas emissions. We monitor relevant legislation and regulatory initiatives to assess the potential impact on our operations. The EPA’s Mandatory Greenhouse Gas Reporting Rule requires annual greenhouse gas emissions reporting as carbon dioxide equivalents from affected facilities and for the natural gas delivered by us to our natural gas distribution customers who are not otherwise required to report their own emissions. The additional cost to gather and report this emission data did not have, and we do not expect it to have, a material impact on our results of operations, financial position or cash flows. In addition, Congress has considered, and may consider in the future, legislation to reduce greenhouse gas emissions, including carbon dioxide and methane. Likewise, the EPA may institute additional regulatory rulemaking associated with greenhouse gas emissions. At this time, no rule or legislation has been enacted for natural gas distribution that assesses any costs, fees or expenses on any of these emissions.

CERCLA - The CERCLA, also commonly known as Superfund, imposes strict, joint and several liability, without regard to fault or the legality of the original act, on certain classes of “persons” (defined under CERCLA) that caused and/or contributed to the release of a hazardous substance into the environment. These persons include, but are not limited to, the owner or operator of a facility where the release occurred and/or companies that disposed or arranged for the disposal of the hazardous substances found at the facility. Under CERCLA, these persons may be liable for the costs of cleaning up the hazardous substances released into the environment, damages to natural resources and the costs of certain health studies. We do not expect that our responsibilities under CERCLA will have a material impact on our respective results of operations, financial position or cash flows.

Pipeline Security - The U.S. Department of Homeland Security's Transportation Security Administration issued updated pipeline security guidelines in March 2018. Our pipeline facilities have been reviewed according to the current guidelines and no material changes have been required to date.

Environmental Footprint - Our environmental and climate change strategy focuses on taking steps to minimize the impact of our operations on the environment. These strategies include: (1) developing and maintaining an accurate greenhouse gas emissions inventory according to current rules issued by the EPA; (2) improving the integrity of our various pipelines; (3) following developing technologies for emission control; and (4) utilizing practices to reduce the loss of methane from our facilities.

We participate in the EPA's Natural Gas STAR Program to voluntarily reduce methane emissions. We continue to focus on maintaining low rates of lost-and-unaccounted-for natural gas through expanded implementation of best practices to limit the release of natural gas during pipeline and facility maintenance and operations. Additionally, in March 2016, we were one of 40 founding partners to launch the EPA's Natural Gas STAR Methane Challenge Program, whereby oil and natural gas companies agree to promote and track commitments to reduce methane emissions beyond what is federally required. Our Methane Challenge Program commitment to annually replace or rehabilitate at least two percent of our combined inventory of cast iron and noncathodically-protected steel pipe aligns with our planned system integrity expenditures for infrastructure replacements. We exceeded our goal by achieving an overall replacement rate between six and seven percent in both 2017 and 2016. We anticipate reporting in 2019 our calendar year 2018 performance relative to our commitment.

Additional information about our environmental matters is included in the section entitled Environmental Matters in Note 15 of the Notes to Consolidated Financial Statements in this Annual Report. We cannot assure that existing environmental statutes and regulations will not be revised or that new regulations will not be adopted or become applicable to us. Revised or additional regulations that result in increased compliance costs or additional operating restrictions could have a material adverse effect on our business, financial condition and results of operations. Our expenditures for environmental investigation, and remediation compliance to-date have not been significant in relation to our financial position, results of operations or cash flows, and our expenditures related to environmental matters had no material effects on earnings or cash flows during 2018, 2017 or 2016.

Regulatory - Several regulatory initiatives impacted the earnings and future earnings potential of our business. See additional information regarding our regulatory initiatives in "Regulatory Activities" in Management's Discussion and Analysis of Financial Condition and Results of Operations.

IMPACT OF NEW ACCOUNTING STANDARDS

Information about the impact of new accounting standards is included in Note 1 of the Notes to Consolidated Financial Statements in this Annual Report.

ESTIMATES AND CRITICAL ACCOUNTING POLICIES

The preparation of our consolidated financial statements and related disclosures in accordance with GAAP requires us to make estimates and assumptions with respect to values or conditions that cannot be known with certainty that affect the reported amounts of assets and liabilities and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements. These estimates and assumptions also affect the reported amounts of revenue and expenses during the reporting period. Although we believe these estimates and assumptions are reasonable, actual results could differ from our estimates. See our Risk Factors and/or Forward-Looking Statements for factors which could impact our estimates.

The following summary sets forth what we consider to be our most critical estimates and accounting policies. Our critical accounting policies are defined as those estimates and policies most important to the portrayal of our financial condition and results of operations and that require management's most difficult, subjective or complex judgment, particularly because of the need to make estimates concerning the impact of inherently uncertain matters.

Regulation - Our operations are subject to regulation with respect to rates, service, maintenance of accounting records and various other matters by the respective regulatory authorities in the states in which we operate. We account for the financial effects of the ratemaking and accounting practices and policies of the various regulatory commissions in our consolidated financial statements. We record regulatory assets for costs that have been deferred for which future recovery through customer rates is considered probable and regulatory liabilities when it is probable that revenues will be reduced for amounts that will be returned to customers through the ratemaking process. As a result, certain costs that would normally be expensed under GAAP are capitalized or deferred on the balance sheet because it is probable they can be recovered through rates. Discontinuing the application of this method of accounting for regulatory assets and liabilities could significantly increase our operating expenses, as fewer costs would likely be capitalized or deferred on the balance sheet, which could reduce our net income. Further, regulation may impact the period in which revenues or expenses are recognized. The amounts to be recovered or recognized are based upon historical experience and our understanding of the regulations. The impact of regulation on our operations may be affected by decisions of the regulatory authorities or the issuance of new regulations.

For further discussion of regulatory assets and liabilities, see Note 9 of the Notes to Consolidated Financial Statements in this Annual Report.

Impairment of Goodwill - We assess our goodwill for impairment at least annually as of July 1. Our goodwill impairment analysis performed in 2018 and 2017, utilized a qualitative assessment and did not result in any impairment indicators. Subsequent to July 1, 2018, no event has occurred indicating that our fair value is less than the carrying value of our net assets.

As part of our goodwill impairment test, we first assess qualitative factors (including macroeconomic conditions, industry and market considerations, cost factors and overall financial performance) to determine whether it is more likely than not that our fair value is less than the carrying amount of our net assets. If further testing is necessary, we perform an impairment test for goodwill. Our impairment test is made by comparing our fair value with our book value, including goodwill. If the fair value is less than the book value, an impairment is measured by the amount of our carrying value that exceeds our fair value, not to exceed the carrying amount of our goodwill.

To estimate our fair value, we use two generally accepted valuation approaches, an income approach and a market approach, using assumptions consistent with a market participant’s perspective. Under the income approach, we use anticipated cash flows over a period of years plus a terminal value and discount these amounts to their present value using appropriate discount rates. Under the market approach, we apply acquisition multiples to forecasted cash flows. The acquisition multiples used are consistent with historical asset transactions. The forecasted cash flows are based on average forecasted cash flows over a period of years.

Our impairment tests require the use of assumptions and estimates, such as industry economic factors and the profitability of future business strategies. If actual results are not consistent with our assumptions and estimates or our assumptions and estimates change due to new information, we may be exposed to future impairment charges.

See Note 1 of the Notes to Consolidated Financial Statements in this Annual Report for further discussion of goodwill.

Pension and Other Postemployment Benefits - We have defined benefit retirement plans covering eligible retirees and full-time employees. We also sponsor welfare plans that provide other postemployment medical and life insurance benefits to eligible retirees and employees who retire with at least five years of service.

To calculate the expense and liabilities related to our plans, we utilize an outside actuarial consultant, which uses statistical and other factors to anticipate future events. These factors include assumptions about the discount rate, expected return on plan assets, rate of future compensation increases, age and mortality and employment periods. We use tables issued by the Society of Actuaries to estimate mortality rates. In determining the projected benefit costs, assumptions can change from period to period and may result in material changes in the costs and liabilities we recognize.

During 2018, we contributed approximately $42.4 million to our defined benefit pension plan and $7.7 million to our other postemployment benefit plans. In 2019, we expect to contribute approximately $1.0 million to our defined benefit pension plan and $3.0 million to our other postemployment benefit plans. In 2017, we purchased group annuity contracts and transferred approximately $46.7 million of the assets and liabilities related to certain participants in our defined benefit pension plan to a third-party insurance company.

During 2018, we recorded net periodic benefit costs of $29.1 million and a credit of $3.5 million related to our pension plans and other postemployment benefit plans, respectively, prior to regulatory deferrals. We estimate that in 2019 we will record expenses of approximately $23.8 million related to pension plans prior to regulatory deferrals.

The following table sets forth the significant assumptions used to determine our estimated 2019 net periodic benefit cost related to our defined pension and other postemployment benefit plans, and sensitivity to changes with respect to these assumptions:

	Rate Used	Cost Sensitivity (a)	Obligation Sensitivity (b)
		(Millions of dollars)	
Discount rate for pension	4.40%	$3.0	$ 29.7
Discount rate for other postemployment benefits	4.40%	$0.5	$ 5.4
Expected long-term return on plan assets (c)	7.20%/7.35%	$2.6	$ —

(a) Approximate impact a quarter percentage point decrease in the assumed rate would have on net periodic pension costs.
(b) Approximate impact a quarter percentage point decrease in the assumed rate would have on defined benefit pension obligation.
(c) Expected long-term return on plan assets for pension and other postemployment benefits are 7.20 percent and 7.35 percent, respectively.

Assumed health care cost-trend rates have a significant effect on the amounts reported for our other postemployment benefit plans. A one percentage point change in assumed health care cost trend rates would have the following effects:

	One Percentage Point Increase	One Percentage Point Decrease
	(Millions of dollars)	
Effect on total of service and interest cost	$0.2	$ (0.2)
Effect on other postemployment benefit obligation	$2.3	$ (2.4)

Revenue Recognition - For regulated deliveries of natural gas, we read meters and bill customers on a monthly cycle. We recognize revenues upon the delivery of natural gas commodity or services rendered to customers. The billing cycles for customers do not necessarily coincide with the accounting periods used for financial reporting purposes. We accrue unbilled revenues for natural gas that has been delivered but not yet billed at the end of an accounting period. Accrued unbilled revenue is based on a percentage estimate of amounts unbilled each month, which is dependent upon a number of factors, some of which require management's judgment. These factors include customer consumption patterns and the impact of weather on usage.

We adopted ASC 606 which clarifies and converges the revenue recognition principles under GAAP and International Financial Reporting Standards, for our interim and annual reports beginning in the first quarter 2018, using the modified retrospective method. We evaluated all of our sources of revenue to determine the potential effect of the new standard on our financial position, results of operations, cash flows and the related accounting policies and business processes. Upon adoption, there was no cumulative adjustment to our opening retained earnings. The only impact of adopting ASC 606 is that we reclassified certain revenues that do not meet the requirements under ASC 606 as revenues from contracts with customers, but will continue to be reflected as other revenues in determining total revenue. The items we reclassified relate primarily to the weather normalization mechanism in Kansas, where the KCC determines how we reflect variations in weather in our rates billed to customers.

We have determined the majority of our natural gas sales and transportation tariffs to be implied contracts with customers, which are settled over time, where our performance obligation is settled with our customer when natural gas is delivered and simultaneously consumed by the customer. In addition, we used the invoice method practical expedient, where we recognized revenue for volumes delivered for which we have a right to invoice. For our other utility revenue, which are primarily one-time service fees that meet the requirements under ASC 606, the performance obligation is satisfied at a point in time when services are rendered to the customer. As a result, we estimated unbilled revenues at the end of each accounting period consistent with past practice. The accrued unbilled natural gas sales revenue at December 31, 2018 and 2017 was $127.6 million and $138.5 million, respectively, and is included in accounts receivable on our Consolidated Balance Sheets. See Note 2 of the Notes to Consolidated Financial Statements in this Annual Report for additional information regarding our revenues.

Contingencies - Our accounting for contingencies covers a variety of business activities, including contingencies for legal and environmental exposures. We accrue these contingencies when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered and an amount can be reasonably estimated. We expense legal fees as incurred and base our legal liability estimates on currently available facts and our assessments of the ultimate outcome or resolution. Accruals for estimated losses from environmental remediation obligations generally are recognized no later than the completion of a remediation feasibility study. Recoveries of environmental remediation costs from other parties are recorded as assets when their receipt is deemed probable. In 2016, we recorded a reserve of $4.0 million for potential costs associated with further investigation and remediation at one of the former MGP sites in Kansas. In 2017, we recorded a regulatory asset of approximately $5.9 million for estimated costs incurred at, and nearby, our 12 former MGP sites in Kansas that was accrued at January 1, 2017. In the second quarter of 2018, we revised our estimate of the potential costs associated with additional investigation and remediation of this Kansas site to be in the range of $5.6 million to $7.0 million. Accordingly, we recorded in the second quarter of 2018 an adjustment to the reserve of $1.6 million bringing the total to $5.6 million for this site. Our expenditures for environmental evaluation, mitigation, remediation and compliance to date have not been significant in relation to our financial position or results of operations, and our expenditures related to environmental matters had no material effect on earnings or cash flows for 2018, 2017 or 2016. Actual results may differ from our estimates resulting in an impact, positive or negative, on earnings.

See Note 15 of the Notes to Consolidated Financial Statements in this Annual Report for additional discussion of contingencies.

CONTRACTUAL OBLIGATIONS

The following table sets forth our contractual obligations at December 31, 2018:

	Contractual Obligations (Millions of dollars)						
	2019	2020	2021	2022	2023	Thereafter	Total
Long-term debt, including current maturities	$—	$—	$—	$—	$—	$ 1,301.3	$1,301.3
Commercial paper	299.5	—	—	—	—	—	299.5
Interest payments on debt	56.9	56.9	56.9	56.9	56.9	1,012.7	1,297.2
Firm transportation and storage capacity contracts	184.0	172.3	151.9	117.1	89.4	55.8	770.5
Natural gas purchase commitments	168.6	0.1	0.1	0.1	0.1	0.1	169.1
Employee benefit plans	4.0	3.0	3.0	3.0	3.0	—	16.0
Operating leases	6.3	5.1	4.5	4.3	4.2	3.8	28.2
Total	$719.3	$237.4	$216.4	$181.4	$153.6	$ 2,373.7	$3,881.8

Long-term debt, commercial paper borrowings and interest payments on debt - Long-term debt includes our three debt issuances at their due dates. Interest payments on debt are calculated by multiplying our long-term debt by the respective coupon rates.

Firm transportation and storage contracts - We are party to fixed-price contracts providing us with firm transportation and storage capacity. The commitments associated with these contracts are recoverable through our purchased-gas cost mechanisms as allowed by the applicable regulatory authority.

Natural gas purchase commitments - We are party to fixed-price and variable-price contracts for the purchase of natural gas. Future variable-price natural gas purchase commitments are estimated based on market price information. Actual future variable-price purchase commitments may vary depending on market prices at the time of delivery. As market information changes daily and is potentially volatile, these values may change significantly. The commitments associated with these contracts are recoverable through our purchased-gas cost mechanisms as allowed by the applicable regulatory authority.

Employee benefit plans - Employee benefit plans include our anticipated contribution to maintain the minimum required funding level for our pension and other postemployment benefit plans. See Note 12 of the Notes to Consolidated Financial Statements in this Annual Report for discussion of employee benefit plans.

Operating leases - Our operating leases consist primarily of office facilities and information technology leases.

FORWARD-LOOKING STATEMENTS

Some of the statements contained and incorporated in this Annual Report are forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. The forward-looking statements relate to our anticipated financial performance, liquidity, management’s plans and objectives for our future operations, our business prospects, the outcome of regulatory and legal proceedings, market conditions and other matters. We make these forward-looking statements in reliance on the safe harbor protections provided under the Private Securities Litigation Reform Act of 1995. The following discussion is intended to identify important factors that could cause future outcomes to differ materially from those set forth in the forward-looking statements.

Forward-looking statements include the items identified in the preceding paragraph, the information concerning possible or assumed future results of our operations and other statements contained or incorporated in this Annual Report identified by words such as “anticipate,” “estimate,” “expect,” “project,” “intend,” “plan,” “believe,” “should,” “goal,” “guidance,” “could,” “may,” “continue,” “might,” “potential,” “scheduled,” “likely,” and other words and terms of similar mea One should not place undue reliance on forward-looking statements, which are applicable only as of the date of this Annual Report. Known and unknown risks, uncertainties and other factors may cause our actual results, performance or achievements to be materially different from any future results, performance or achievements expressed or implied by forward-looking statements. Those factors may affect our operations, markets, products, services and prices. In addition to any assumptions and other factors referred to specifically in connection with the forward-looking statements, factors that could cause our actual results to differ materially from those contemplated in any forward-looking statement include, among others, the following:

- our ability to recover operating costs and amounts equivalent to income taxes, costs of property, plant and equipment and regulatory assets in our regulated rates;
- our ability to manage our operations and maintenance costs;
- changes in regulation of natural gas distribution services, particularly those in Oklahoma, Kansas and Texas;
- the economic climate and, particularly, its effect on the natural gas requirements of our residential and commercial industrial customers;
- competition from alternative forms of energy, including, but not limited to, electricity, solar power, wind power, geothermal energy and biofuels;
- conservation and energy storage efforts of our customers;
- variations in weather, including seasonal effects on demand, the occurrence of storms and disasters, and climate change;
- indebtedness could make us more vulnerable to general adverse economic and industry conditions, limit our ability to borrow additional funds and/or place us at competitive disadvantage compared with competitors;
- our ability to secure reliable, competitively priced and flexible natural gas transportation and supply, including decisions by natural gas producers to reduce production or shut-in producing natural gas wells and expiration of existing supply, and transportation and storage arrangements that are not replaced with contracts with similar terms and pricing;
- the mechanical integrity of facilities operated;
- operational hazards and unforeseen operational interruptions;
- adverse labor relations;
- the effectiveness of our strategies to reduce earnings lag, margin protection strategies and risk mitigation strategies, which may be affected by risks beyond our control such as commodity price volatility and counterparty creditworthiness;
- our ability to generate sufficient cash flows to meet all our liquidity needs;
- changes in the financial markets during the periods covered by the forward-looking statements, particularly those affecting the availability of capital and our ability to refinance existing debt and fund investments and acquisitions;
- actions of rating agencies, including the ratings of debt, general corporate ratings and changes in the rating agencies’ ratings criteria;
- changes in inflation and interest rates;
- our ability to recover the costs of natural gas purchased for our customers;
- impact of potential impairment charges;
- volatility and changes in markets for natural gas;
- possible loss of LDC franchises or other adverse effects caused by the actions of municipalities;
- payment and performance by counterparties and customers as contracted and when due;
- changes in existing or the addition of new environmental, safety, tax and other laws to which we and our subsidiaries are subject;
- the uncertainty of estimates, including accruals and costs of environmental remediation;
- advances in technology, including technologies that increase efficiency or that improve electricity’s competitive position relative to natural gas;
- population growth rates and changes in the demographic patterns of the markets we serve;
- acts of nature and the potential effects of threatened or actual terrorism and war;

- cyber attacks or breaches of technology systems that could disrupt our operations or result in the loss or exposure of confidential or sensitive customer, employee or company information;
- the sufficiency of insurance coverage to cover losses;
- the effects of our strategies to reduce tax payments;
- the effects of litigation and regulatory investigations, proceedings, including our rate cases, or inquiries and the requirements of our regulators as a result of the Tax Cuts and Jobs Act of 2017;
- changes in accounting standards;
- changes in corporate governance standards;
- discovery of material weaknesses in our internal controls;

- our ability to comply with all covenants in our indentures and the ONE Gas Credit Agreement, a violation of which, if not cured in a timely manner, could trigger a default of our obligations;
- our ability to attract and retain talented employees, management and directors;
- declines in the discount rates on, declines in the market value of the debt and equity securities of, and increases in funding requirements for, our defined benefit plans;
- the ability to successfully complete merger, acquisition or divestiture plans, regulatory or other limitations imposed as a result of a merger, acquisition or divestiture, and the success of the business following a merger, acquisition or divestiture;
- the final resolutions or outcomes with respect to our contingent and other corporate liabilities related to the natural gas distribution business and any related actions for indemnification made pursuant to the Separation and Distribution Agreement with ONEOK; and
- the costs associated with increased regulation and enhanced disclosure and corporate governance requirements pursuant to the Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010.

These factors are not necessarily all of the important factors that could cause actual results to differ materially from those expressed in any of our forward-looking statements. Other factors could also have material adverse effects on our future results. These and other risks are described in greater detail in Part 1, Item 1A, Risk Factors, in this Annual Report. All forward-looking statements attributable to us or persons acting on our behalf are expressly qualified in their entirety by these factors. Other than as required under securities laws, we undertake no obligation to update publicly any forward-looking statement whether as a result of new information, subsequent events or change in circumstances, expectations or otherwise.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Our exposure to market risk discussed below includes forward-looking statements. Our views on market risk are not necessarily indicative of actual results that may occur and do not represent the maximum possible gains and losses that may occur since actual gains and losses will differ from those estimated based on actual fluctuations in commodity prices or interest rates and the timing of transactions.

Commodity Price Risk

Our commodity price risk, driven primarily by fluctuations in the price of natural gas, is mitigated by our purchased-gas cost adjustment mechanisms. We use derivative instruments to economically hedge the cost of anticipated natural gas purchases during the winter heating months to protect our customers from upward market price volatility of natural gas. Additionally, we inject natural gas into storage during the summer months and withdraw the natural gas during the winter heating season. Gains or losses associated with these derivative instruments and storage activities are included in, and recoverable through our purchased-gas cost adjustment mechanisms, which are subject to review by regulatory authorities.

Interest-Rate Risk

We are exposed to interest-rate risk primarily associated with commercial paper and new debt financing needed to fund capital requirements, including future contractual obligations and maturities of long-term and short-term debt. We expect to manage interest-rate risk on future borrowings through the use of fixed-rate debt, floating-rate debt and, at times, interest-rate swaps. Fixed-rate swaps may be used to reduce our risk of increased interest costs during periods of rising interest rates. Floating-rate swaps may be used to convert the fixed rates of long-term borrowings into short-term variable rates.

Counterparty Credit Risk

We assess the creditworthiness of our customers. Those customers who do not meet minimum standards are required to provide security, including deposits and other forms of collateral, when appropriate and allowed by tariff. With 2.2 million customers across three states, we are not exposed materially to a concentration of credit risk. We maintain a provision for doubtful accounts based upon factors surrounding the credit risk of customers, historical trends, consideration of the current credit environment and other information. We are able to recover natural gas costs related to uncollectible accounts through our purchased-gas cost adjustment mechanisms.

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ITEM 8. CONSOLIDATED FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Report of Independent Registered Public Accounting Firm

To the Board of Directors and Shareholders of ONE Gas, Inc.:

Opinions on the Financial Statements and Internal Control over Financial Reporting

We have audited the accompanying consolidated balance sheets of ONE Gas, Inc. and its subsidiaries (the “Company”) as of December 31, 2018 and December 31, 2017, and the related consolidated statements of income, comprehensive income, equity and cash flows for each of the three years in the period ended December 31, 2018, including the related notes (collectively referred to as the “consolidated financial statements”). We also have audited the Company's internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO).

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the financial position of the Company as of December 31, 2018 and December 31, 2017, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2018 in conformity with accounting principles generally accepted in the United States of America. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2018, based on criteria established in Internal Control - Integrated Framework (2013) issued by the COSO.

Basis for Opinions

The Company's management is responsible for these consolidated financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing in Item 9A. Our responsibility is to express opinions on the Company’s consolidated financial statements and on the Company's internal control over financial reporting based on our audits. We are a public accounting firm registered with the Public Company Accounting Oversight Board (United States) (PCAOB) and are required to be independent with respect to the Company in accordance with the U.S. federal securities laws and the applicable rules and regulations of the Securities and Exchange Commission and the PCAOB.

We conducted our audits in accordance with the standards of the PCAOB. Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the consolidated financial statements are free of material misstatement, whether due to error or fraud, and whether effective internal control over financial reporting was maintained in all material respects.

Our audits of the consolidated financial statements included performing procedures to assess the risks of material misstatement of the consolidated financial statements, whether due to error or fraud, and performing procedures that respond to those risks. Such procedures included examining, on a test basis, evidence regarding the amounts and disclosures in the consolidated financial statements. Our audits also included evaluating the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the consolidated financial statements. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

Definition and Limitations of Internal Control over Financial Reporting

A company’s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company’s internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/PricewaterhouseCoopers, LLP

Tulsa, Oklahoma
February 20, 2019

We have served as the Company's auditor since 2013.

ONE Gas, Inc.
CONSOLIDATED STATEMENTS OF INCOME

	Years Ended December 31,		
	2018	2017	2016
	(Thousands of dollars, except per share amounts)		
Total revenues	$1,633,731	$1,539,633	$1,427,232
Cost of natural gas	714,636	614,501	541,797
Operating expenses			
Operations and maintenance	411,702	399,290	397,315
Depreciation and amortization	160,086	151,889	143,829
General taxes	58,878	57,225	55,344
Total operating expenses	630,666	608,404	596,488
Operating income	288,429	316,728	288,947
Other expense, net	(11,359)	(14,525)	(19,870)
Interest expense, net	(51,305)	(46,065)	(43,739)
Income before income taxes	225,765	256,138	225,338
Income taxes	(53,531)	(93,143)	(85,243)
Net income	$172,234	$162,995	$140,095
Earnings per share			
Basic	$3.27	$3.10	$2.67
Diluted	$3.25	$3.08	$2.65
Average shares (thousands)			
Basic	52,693	52,527	52,453
Diluted	53,029	52,979	52,963
Dividends declared per share of stock	$1.84	$1.68	$1.40

See accompanying Notes to Consolidated Financial Statements.

ONE Gas, Inc.
CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME

	Years Ended December 31,		
	2018	2017	2016
	(Thousands of dollars)		
Net income	$172,234	$162,995	$140,095
Other comprehensive income (loss), net of tax			
Change in pension and other postemployment benefit plans liability, net of tax of $(848), $486, and $197, respectively	1,407	(778)	(314)
Total other comprehensive income (loss), net of tax	1,407	(778)	(314)
Comprehensive income	$173,641	$162,217	$139,781

See accompanying Notes to Consolidated Financial Statements.

ONE Gas, Inc.
CONSOLIDATED BALANCE SHEETS

	December 31, 2018	December 31, 2017
Assets	(Thousands of dollars)	
Property, plant and equipment		
Property, plant and equipment	$6,073,143	$5,713,912
Accumulated depreciation and amortization	1,789,431	1,706,327
Net property, plant and equipment	4,283,712	4,007,585
Current assets		
Cash and cash equivalents	21,323	14,413
Accounts receivable, net	295,421	298,768
Materials and supplies	44,333	39,672
Natural gas in storage	107,295	130,154
Regulatory assets	54,420	88,180
Other current assets	20,495	17,807
Total current assets	543,287	588,994
Goodwill and other assets		
Regulatory assets	437,479	405,189
Goodwill	157,953	157,953
Other assets	46,211	47,157
Total goodwill and other assets	641,643	610,299
Total assets	$5,468,642	$5,206,878

See accompanying Notes to Consolidated Financial Statements.

ONE Gas, Inc.
CONSOLIDATED BALANCE SHEETS
(Continued)

Equity and Liabilities	December 31, 2018	December 31, 2017
	(Thousands of dollars)	
Equity and long-term debt		
Common stock, $0.01 par value:		
authorized 250,000,000 shares; issued 52,598,005 shares and outstanding 52,564,902 shares at	$526	$526
December 31, 2018; issued 52,598,005 shares and outstanding 52,312,516 shares at December 31, 2017		
Paid-in capital	1,727,492	1,737,551
Retained earnings	320,869	246,121
Accumulated other comprehensive loss	(4,086)	(5,493)
Treasury stock, at cost: 33,103 shares at December 31, 2018 and 285,489 shares at December 31, 2017	(2,145)	(18,496)
Total equity	2,042,656	1,960,209
Long-term debt, excluding current maturities, and net of issuance costs of $11,457 and $8,033, respectively	1,285,483	1,193,257
Total equity and long-term debt	3,328,139	3,153,466
Current liabilities		
Notes payable	299,500	357,215
Accounts payable	174,510	143,681
Accrued interest	18,924	18,776
Accrued taxes other than income	47,640	41,324
Accrued liabilities	30,294	30,058
Regulatory liabilities	48,394	9,438
Customer deposits	61,183	60,811
Other current liabilities	18,446	12,027
Total current liabilities	698,891	673,330
Deferred credits and other liabilities		
Deferred income taxes	652,426	599,945
Regulatory liabilities	520,866	519,421
Employee benefit obligations	178,720	172,938
Other deferred credits	89,600	87,778
Total deferred credits and other liabilities	1,441,612	1,380,082
Commitments and contingencies		
Total liabilities and equity	$5,468,642	$5,206,878

See accompanying Notes to Consolidated Financial Statements.

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ONE Gas, Inc.
CONSOLIDATED STATEMENTS OF CASH FLOWS

	Years Ended December 31,		
	2018	2017	2016
	(Thousands of dollars)		
Operating activities			
Net income	$172,234	$162,995	$140,095
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation and amortization	160,086	151,889	143,829
Deferred income taxes	53,242	92,393	86,788
Share-based compensation expense	8,195	8,876	11,219
Provision for doubtful accounts	8,506	7,323	5,427
Changes in assets and liabilities:			
Accounts receivable	(5,159)	(15,147)	(80,028)
Materials and supplies	(4,661)	(5,588)	(759)
Income tax receivable	—	—	37,480
Natural gas in storage	22,859	(4,722)	16,721
Asset removal costs	(52,855)	(52,376)	(53,430)
Accounts payable	36,885	1,945	27,596
Accrued interest	148	(78)	(19)
Accrued taxes other than income	6,316	(1,247)	5,322
Accrued liabilities	236	7,127	(8,539)
Customer deposits	372	(398)	884
Regulatory assets and liabilities	109,437	29,250	(49,472)
Employee benefit obligation	(50,100)	(118,095)	(25,666)
Other assets and liabilities	1,953	(10,347)	33,141
Cash provided by operating activities	467,694	253,800	290,589
Investing activities			
Capital expenditures	(394,450)	(356,361)	(309,071)
Other	—	618	492
Cash used in investing activities	(394,450)	(355,743)	(308,579)
Financing activities			
Borrowings (repayment) on notes payable, net	(57,715)	212,215	132,500
Repurchase of common stock	—	(17,512)	(24,066)
Issuance of debt, net of discounts	395,648	—	—
Long-term debt financing costs	(4,324)	—	—
Issuance of common stock	4,803	4,457	4,017
Repayment of long-term debt	(300,000)	—	—
Dividends paid	(96,594)	(87,951)	(73,209)
Tax withholdings related to net share settlements of stock compensation	(8,152)	(9,516)	(9,022)
Cash provided by (used in) financing activities	(66,334)	101,693	30,220
Change in cash and cash equivalents	6,910	(250)	12,230
Cash and cash equivalents at beginning of period	14,413	14,663	2,433
Cash and cash equivalents at end of period	$21,323	$14,413	$14,663
Supplemental cash flow information:			
Cash paid for interest, net of amounts capitalized	$49,371	$44,436	$42,129
Cash paid (received) for income taxes, net	$800	$(1,389)	$(35,702)

See accompanying Notes to Consolidated Financial Statements.

ONE Gas, Inc.
CONSOLIDATED STATEMENTS OF EQUITY

	Common Stock Issued (Shares)	Common Stock (Thousands of dollars)	Paid-in Capital
January 1, 2016	52,598,005	$526	$1,764,875
Net income	—	—	—
Other comprehensive loss	—	—	—
Repurchase of common stock	—	—	—
Common stock issued	—	—	(16,212)
Common stock dividends - $1.40 per share	—	—	911
December 31, 2016	52,598,005	526	1,749,574
Cumulative effect of accounting change	—	—	—
Net income	—	—	—
Other comprehensive loss	—	—	—
Repurchase of common stock	—	—	—
Common stock issued and other	—	—	(12,949)
Common stock dividends - $1.68 per share	—	—	926
December 31, 2017	52,598,005	526	1,737,551
Net income	—	—	—
Other comprehensive income	—	—	—
Common stock issued and other	—	—	(10,951)
Common stock dividends - $1.84 per share	—	—	892
December 31, 2018	52,598,005	$526	$1,727,492

See accompanying Notes to Consolidated Financial Statements.

ONE Gas, Inc.
CONSOLIDATED STATEMENTS OF EQUITY
(Continued)

	Retained Earnings	Treasury Stock	Accumulated Other Comprehensive Loss	Total Equity
	(Thousands of dollars)			
January 1, 2016	$95,046	$(14,491)	$ (4,401)	$1,841,555
Net income	140,095	—	—	140,095
Other comprehensive loss	—	—	(314)	(314)
Repurchase of common stock	—	(24,066)	—	(24,066)
Common stock issued	—	20,431	—	4,219
Common stock dividends - $1.40 per share	(74,120)	—	—	(73,209)
December 31, 2016	161,021	(18,126)	(4,715)	1,888,280
Cumulative effect of accounting change	10,982	—	—	10,982
Net income	162,995	—	—	162,995
Other comprehensive loss	—	—	(778)	(778)
Repurchase of common stock	—	(17,512)	—	(17,512)
Common stock issued and other	—	17,142	—	4,193
Common stock dividends - $1.68 per share	(88,877)	—	—	(87,951)
December 31, 2017	246,121	(18,496)	(5,493)	1,960,209
Net income	172,234	—	—	172,234
Other comprehensive income	—	—	1,407	1,407
Common stock issued and other	—	16,351	—	5,400
Common stock dividends - $1.84 per share	(97,486)	—	—	(96,594)
December 31, 2018	$320,869	$(2,145)	$ (4,086)	$2,042,656

See accompanying Notes to Consolidated Financial Statements.

ONE Gas, Inc.
NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Organization and Nature of Operations - We provide natural gas distribution services to our 2.2 million customers through our divisions in Oklahoma, Kansas and Texas through Oklahoma Natural Gas, Kansas Gas Service and Texas Gas Service, respectively. We serve residential, commercial, industrial and transportation customers in all three states. In addition, we also provide natural gas distribution services to wholesale and public authority customers. We are a corporation incorporated under the laws of the state of Oklahoma, and our common stock is listed on the NYSE under the trading symbol “OGS.” In 2017, we formed a wholly-owned captive insurance company in the state of Oklahoma to provide insurance to our divisions.

Basis of Presentation - The consolidated financial statements include the accounts of the natural gas distribution business as set forth in “Organization and Nature of Operations” above. All significant balances and transactions between our subsidiaries have been eliminated.

Use of Estimates - The preparation of our consolidated financial statements and related disclosures in accordance with GAAP requires us to make estimates and assumptions with respect to values or conditions that cannot be known with certainty that affect the reported amount of assets and liabilities, and the disclosure of contingent assets and liabilities at the date of the consolidated financial statements. These estimates and assumptions also affect the reported amounts of revenue and expenses during the reporting period. Items that may be estimated include, but are not limited to, the economic useful life of assets, fair value of assets and liabilities, provisions for doubtful accounts receivable, unbilled revenues for natural gas delivered but for which meters have not been read, natural gas purchased but for which no invoice has been received, provision for income taxes, including any deferred income tax valuation allowances, the results of litigation and various other recorded or disclosed amounts.

We evaluate these estimates on an ongoing basis using historical experience and other methods we consider reasonable based on the particular circumstances. Nevertheless, actual results may differ significantly from the estimates. Any effects on our financial position or results of operations from revisions to these estimates are recorded in the period when the facts that give rise to the revision become known.

Cash and Cash Equivalents - Cash equivalents consist of highly liquid investments, which are readily convertible into cash and have original maturities of three months or less.

Cost of Natural Gas - Cost of natural gas includes commodity purchases, fuel, storage, transportation and other gas purchase costs recovered through our cost of natural gas regulatory mechanisms and does not include an allocation of general operating costs or depreciation and amortization. In addition, our cost of natural gas regulatory mechanisms provide a method of recovering natural gas costs on an ongoing basis without a profit. See Note 9 for additional discussion of purchased gas cost recoveries.

Accounts Receivable - Accounts receivable represent valid claims against nonaffiliated customers for natural gas sold or services rendered, net of allowances for doubtful accounts. We assess the creditworthiness of our customers. Those customers who do not meet minimum standards are required to provide security, including deposits and other forms of collateral, when appropriate. With 2.2 million customers across three states, we are not exposed materially to a concentration of credit risk. We maintain an allowance for doubtful accounts based upon factors surrounding the credit risk of customers, historical trends, consideration of the current credit environment and other information. We are able to recover natural gas costs related to doubtful accounts through purchased-gas cost adjustment mechanisms. At December 31, 2018 and 2017, our allowance for doubtful accounts was $4.7 million and $4.8 million, respectively.

Inventories - Natural gas in storage is maintained on the basis of weighted-average cost. Natural gas inventories that are injected into storage are recorded in inventory based on actual purchase costs, including storage and transportation costs. Natural gas inventories that are withdrawn from storage are accounted for in our purchased-gas cost adjustment mechanisms at the weighted-average inventory cost.

Materials and supplies inventories are stated at the lower of weighted-average cost or net realizable value.

Derivatives and Risk Management Activities - We record all derivative instruments at fair value, with the exception of normal purchases and normal sales that are expected to result in physical delivery. The accounting for changes in the fair value of a derivative instrument depends on whether it has been designated and qualifies as part of a hedging relationship and, if so, the reason for holding it, or if regulatory rulings require a different accounting treatment.

If certain conditions are met, we may elect to designate a derivative instrument as a hedge of exposure to changes in fair values or cash flows.

The table below summarizes the various ways in which we account for our derivative instruments and the impact on our consolidated financial statements:

	Recognition and Measurement	
Accounting Treatment	Balance Sheet	Income Statement
Normal purchases and normal sales	- Fair value not recorded	- Change in fair value not recognized in earnings
Mark-to-market	- Recorded at fair value	- Change in fair value recognized in, and recoverable through, the purchased-gas cost adjustment mechanisms

We have not elected to formally designate any of our derivative instruments as hedges. Gains or losses associated with the fair value of commodity derivative instruments entered into by us are included in, and recoverable through, the purchased-gas cost adjustment mechanisms.

See Note 8 for additional information regarding our hedging activities using derivatives.

Fair Value Measurements - We define fair value as the price that would be received from the sale of an asset or the transfer of a liability in an orderly transaction between market participants at the measurement date. We use the market and income approaches to determine the fair value of our assets and liabilities and consider the markets in which the transactions are executed. We measure the fair value of a group of financial assets and liabilities consistent with how a market participant would price the net risk exposure at the measurement date.

Fair Value Hierarchy - At each balance sheet date, we utilize a fair value hierarchy to classify fair value amounts recognized or disclosed in our consolidated financial statements based on the observability of inputs used to estimate such fair value. The levels of the hierarchy are described below:

- Level 1 - Unadjusted quoted prices in active markets for identical assets or liabilities;
- Level 2 - Significant observable pricing inputs other than quoted prices included within Level 1 that are, either directly or indirectly, observable as of the reporting date. Essentially, this represents inputs that are derived principally from or corroborated by observable market data; and
- Level 3 - May include one or more unobservable inputs that are significant in establishing a fair value estimate. These unobservable inputs are developed based on the best information available and may include our own internal data.

We recognize transfers into and out of the levels as of the end of each reporting period.

Determining the appropriate classification of our fair value measurements within the fair value hierarchy requires management’s judgment regarding the degree to which market data is observable or corroborated by observable market data. We categorize derivatives for which fair value is determined using multiple inputs within a single level, based on the lowest level input that is significant to the fair value measurement in its entirety. See Note 8 for additional information regarding our fair value measurements.

Property, Plant and Equipment - Our properties are stated at cost, which includes direct construction costs such as direct labor, materials, burden and AFUDC. Generally, the cost of our property retired or sold, plus removal costs, less salvage, is charged to accumulated depreciation. Gains and losses from sales or retirement of an entire operating unit or system of our properties are recognized in income. Maintenance and repairs are charged directly to expense.

AFUDC represents the cost of borrowed funds used to finance construction activities. We capitalize interest costs during the construction or upgrade of qualifying assets. Capitalized interest is recorded as a reduction to interest expense.

Our properties are depreciated using the straight-line method over their estimated useful lives. Generally, we apply composite depreciation rates to functional groups of property having similar economic circumstances. We periodically conduct depreciation studies to assess the economic lives of our assets. These depreciation studies are completed as a part of our regulatory proceedings, and the changes in economic lives, if applicable, are implemented prospectively when the new rates are approved by our regulators and become effective. Changes in the estimated economic lives of our property, plant and equipment could have a material effect on our financial position, results of operations or cash flows.

Property, plant and equipment on our Consolidated Balance Sheets includes construction work in process for capital projects that have not yet been placed in service and therefore are not being depreciated. Assets are transferred out of construction work in process when they are substantially complete and ready for their intended use.

See Note 10 for additional information regarding our property, plant and equipment.

Impairment of Goodwill and Long-Lived Assets - We assess our goodwill for impairment at least annually as of July 1. Our goodwill impairment analysis performed in 2018, 2017 and 2016, utilized a qualitative assessment and did not result in any impairment indicators. Subsequent to July 1, 2018, no event has occurred indicating that it is more likely than not that our fair value is less than the carrying value of our net assets.

As part of our goodwill impairment test, we first assess qualitative factors (including macroeconomic conditions, industry and market considerations, cost factors and overall financial performance) to determine whether it is more likely than not that our fair value is less than the carrying amount of our net assets. If further testing is necessary, we perform an impairment test for goodwill. Our impairment test is made by comparing our fair value with our book value, including goodwill. If the fair value is less than the book value, an impairment is measured by the amount of our carrying value that exceeds our fair value, not to exceed the carrying amount of our goodwill.

To estimate our fair value, we use two generally accepted valuation approaches, an income approach and a market approach, using assumptions consistent with a market participant's perspective. Under the income approach, we use anticipated cash flows over a period of years plus a terminal value and discount these amounts to their present value using appropriate discount rates. Under the market approach, we apply acquisition multiples to forecasted cash flows. The acquisition multiples used are consistent with historical market transactions. The forecasted cash flows are based on average forecasted cash flows over a period of years.

We assess our long-lived assets for impairment whenever events or changes in circumstances indicate that an asset's carrying amount may not be recoverable. An impairment is indicated if the carrying amount of a long-lived asset exceeds the sum of the undiscounted future cash flows expected to result from the use and eventual disposition of the asset. If an impairment is indicated, we record an impairment loss equal to the difference between the carrying value and the fair value of the long-lived asset. We determined that there were no asset impairments in 2018, 2017 or 2016.

Regulation - We are subject to the rate regulation and accounting requirements of the OCC, KCC, RRC and various municipalities in Texas. We follow the accounting and reporting guidance for regulated operations. During the ratemaking process, regulatory authorities set the framework for what we can charge customers for our services and establish the manner that our costs are accounted for, including allowing us to defer recognition of certain costs and permitting recovery of the amounts through rates over time, as opposed to expensing such costs as incurred. Examples include weather normalization, unrecovered purchased-gas costs, pension and postemployment benefit costs and ad-valorem taxes. This allows us to stabilize rates over time rather than passing such costs on to the customer for immediate recovery. Actions by regulatory authorities could have an effect on the amount recovered from rate payers. Any difference in the amount recoverable and the amount deferred is recorded as income or expense at the time of the regulatory action. A write-off of regulatory assets and costs not recovered may be required if all or a portion of the regulated operations have rates that are no longer:

- established by independent regulators;
- designed to recover the specific entity's costs of providing regulated services; and
- set at levels that will recover our costs when considering the demand and competition for our services.

See Note 9 for additional information regarding our regulatory assets and liabilities disclosures.

Pension and Other Postemployment Employee Benefits - We have defined benefit retirement plans covering eligible employees. We also sponsor welfare plans that provide other postemployment medical and life insurance benefits to eligible employees who retire with at least five years of service. To calculate the costs and liabilities related to our plans, we utilize an outside actuarial consultant, which uses statistical and other factors to anticipate future events. These factors include assumptions about the discount rate, expected return on plan assets, rate of future compensation increases, age and mortality and employment periods. We use tables issued by the Society of Actuaries to estimate mortality rates. In determining the projected benefit obligations and costs, assumptions can change from period to period and may result in material changes in the cost and liabilities we recognize.

Income Taxes - Deferred income taxes are recorded for the difference between the financial statement and income tax basis of assets and liabilities and carryforward items, based on income tax laws and rates existing at the time the temporary differences are expected to reverse. The effect on deferred income taxes of a change in tax rates is deferred and amortized for operations regulated by the OCC, KCC, RRC and various municipalities in Texas, if, as a result of an action by a regulator, it is probable that the effect of the change in tax rates will be recovered from or returned to customers through future rates. We continue to amortize previously deferred investment tax credits for ratemaking purposes over the periods prescribed by our regulators.

A valuation allowance for deferred income tax assets is recognized when it is more likely than not that some or all of the benefit from the deferred income tax asset will not be realized. To assess that likelihood, we use estimates and judgment regarding our future taxable income, as well as the jurisdiction in which such taxable income is generated, to determine whether a valuation allowance is required. Such evidence can include our current financial position, our results of operations, both actual and forecasted, the reversal of deferred income tax liabilities, as well as the current and forecasted business economics of our industry. We had no valuation allowance at December 31, 2018 and 2017.

We utilize a more-likely-than-not recognition threshold and measurement attribute for the financial statement recognition and measurement of a tax position that is taken or expected to be taken in a tax return. We reflect penalties and interest as part of income tax expense as they become applicable for tax provisions that do not meet the more-likely-than-not recognition threshold and measurement attribute. There were no material uncertain tax positions at December 31, 2018 and 2017.

See Note 13 for additional information regarding income taxes.

Asset Retirement Obligations - Asset retirement obligations represent legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or normal use of the asset. Certain long-lived assets that comprise our natural gas distribution systems, primarily our pipeline assets, are subject to agreements or regulations that give rise to an asset retirement obligation for removal or other disposition costs associated with retiring the assets in place upon the discontinued use of the natural gas distribution system. We recognize the fair value of a liability for an asset retirement obligation in the period when it is incurred if a reasonable estimate of the fair value can be made. We are not able to estimate reasonably the fair value of the asset retirement obligations for portions of our assets because the settlement dates are indeterminable given our expected continued use of the assets with proper maintenance. We expect our natural gas distribution systems will continue in operation as long as natural gas supply and demand for natural gas distribution service exists. Based on the widespread use of natural gas for heating and cooking activities by residential and commercial customers in our service areas, management expects supply and demand to exist for the foreseeable future.

In accordance with long-standing regulatory treatment, we collect through rates the estimated costs of removal on certain regulated properties through depreciation expense, with a corresponding credit to accumulated depreciation and amortization. These removal costs collected through our rates include costs attributable to legal and nonlegal removal obligations; however, the amounts collected that are in excess of these nonlegal asset-removal costs incurred are accounted for as a regulatory liability for financial reporting purposes. Historically, with the exception of the regulatory authority in Kansas, the regulatory authorities that have jurisdiction over our regulated operations have not required us to quantify or disclose this amount; rather, these costs are addressed prospectively in depreciation rates and are set in each general rate order. We have made an estimate of our regulatory liability using current rates since the last general rate order in each of our jurisdictions if the removal costs collected have exceeded our removal cost incurred; however, for financial reporting purposes, significant uncertainty exists regarding the future disposition of this regulatory liability, pending, among other issues, clarification of regulatory intent. We continue to monitor the regulatory requirements, and the liability may be adjusted as more information is obtained. We record the estimated asset removal obligation in noncurrent liabilities in other deferred credits on our Consolidated Balance Sheets. To the extent this estimated liability is adjusted, such amounts will be reclassified between accumulated depreciation and amortization and other deferred credits and therefore will not have an impact on earnings.

Contingencies - Our accounting for contingencies covers a variety of business activities, including contingencies for legal and environmental exposures. We accrue these contingencies when our assessments indicate that it is probable that a liability has been incurred or an asset will not be recovered and an amount can be estimated reasonably. We expense legal fees as incurred and base our legal liability estimates on currently available facts and our estimates of the ultimate outcome or resolution. Accruals for estimated losses from environmental remediation obligations generally are recognized no later than the completion of a remediation feasibility study. Recoveries of environmental remediation costs from other parties are recorded as assets when their receipt is deemed probable. Actual results may differ from our estimates resulting in an impact, positive or negative, on earnings.

See Note 15 for additional information regarding contingencies.

Share-Based Payments - We expense the fair value of share-based payments net of estimated forfeitures. We estimate forfeiture rates based on historical forfeitures under our share-based payment plans.

Earnings per share - Basic EPS is based on net income and is calculated based upon the daily weighted-average number of common shares outstanding during the periods presented. Also, this calculation includes fully vested stock awards that have not yet been issued as common stock. Diluted EPS includes the above, plus unvested stock awards granted under our compensation plans, but only to the extent these instruments dilute earnings per share.

Segments - We operate in one reportable business segment: regulated public utilities that deliver natural gas to residential, commercial, industrial, wholesale, public authority and transportation customers. We define reportable business segments as components of an organization for which discrete financial information is available and operating results are evaluated on a regular basis by the chief operating decision maker (“CODM”) in order to assess performance and allocate resources. Our CODM is our Chief Executive Officer (“CEO”). Characteristics of our organization that were relied upon in making this determination include the similar nature of services we provide, the functional alignment of our organizational structure, and the reports that are regularly reviewed by the CODM for the purpose of assessing performance and allocating resources. Our management is functionally aligned and centralized, with performance evaluated based upon results of the entire distribution business. Capital allocation decisions are driven by asset integrity management, operating efficiency, growth opportunities and government relocations, not geographic location or regulatory jurisdiction.

In 2018, 2017 and 2016, we had no single external customer from which we received 10 percent or more of our gross revenues.

Treasury Stock - We record treasury stock purchases at cost, which includes incremental direct transaction costs. Amounts are recorded as reductions in equity in our Consolidated Balance Sheets. We record the reissuance of treasury stock at our weighted average cost of treasury shares recorded in equity in our Consolidated Balance Sheets.

Recently Issued Accounting Standards Update - In August 2018, the FASB issued ASU 2018-15, “Intangibles - Goodwill and Other - Internal-Use Software (Subtopic 350-40): Customer’s Accounting for Implementation Costs Incurred in a Cloud Computing Arrangement That Is a Service Contract (a consensus of the FASB Emerging Issues Task Force).” Under this guidance, a company should defer implementation costs that it incurs if the company would capitalize those same costs under the internal-use software guidance for an arrangement that is a software license. This standard is effective for interim and annual periods in fiscal years beginning after December 15, 2019, and early adoption is permitted. We are currently assessing the timing and impacts of adopting this standard.

In March 2018, the FASB issued ASU 2018-05, “Income Taxes (Topic 740): Amendments to SEC Paragraphs Pursuant to SEC Staff Accounting Bulletin No. 118,” which updates the FASB’s Accounting Standards Codification to reflect the guidance in SAB 118, which adds Section EE, “Income Tax Accounting Implications of the Tax Cuts and Jobs Act,” to SAB Topic 5, “Miscellaneous Accounting.” SAB 118 also provides guidance on applying ASC 740, Income Taxes, if the accounting for certain income tax effects of the Tax Cuts and Jobs Act of 2017 is incomplete when the financial statements are issued for a reporting period. See Note 13 for additional discussion regarding SAB 118.

In February 2018, the FASB issued ASU 2018-02, “Income Statement - Reporting Comprehensive Income (Topic 220): Reclassification of Certain Tax Effects from Accumulated Other Comprehensive Income,’’ which allows a reclassification from accumulated other comprehensive income to retained earnings for stranded tax effects resulting from the Tax Cuts and Jobs Act of 2017. This new guidance is required for our interim and annual reports for periods beginning after December 15, 2018, and early adoption is permitted. We have assessed the timing and impacts of adopting this standard, and do not expect a material impact to our consolidated financial statements.

In March 2017, the FASB issued ASU 2017-07, “Compensation - Retirement Benefits (Topic 715): Improving the Presentation of Net Periodic Pension Cost and Net Periodic Postretirement Benefit Cost,” which requires (1) separation of net periodic service costs for pension and other postemployment benefits into service cost and other components, (2) presentation of the service cost component in the same line as other compensation costs rendered by pertinent employees during the period, and (3) reporting the other components of net periodic benefit costs separately from the service cost component and outside a subtotal of income from operations. Additionally, only the service cost component is eligible for capitalization for GAAP, when applicable. However, all of our cost components remain eligible for capitalization under the accounting requirements for rate regulated entities. We adopted this guidance in the first quarter of 2018. The presentation changes required for net periodic benefit costs did not impact previously reported net income; however, the reclassification of the other components of benefits costs resulted in an increase in operating income and an increase in other expenses of $8.8 million, $17.3 million, and $19.8 million for the years ended December 31, 2018, 2017, and 2016, respectively. We elected the practical expedient to use the retroactive presentation of the amounts disclosed for the various components of net benefit cost in our Employee Benefit Plans footnote as the basis for the retrospective application. In addition, we updated our information systems for the capitalization of service costs to property, plant and equipment and non-service costs to a regulatory asset on a prospective basis, as well as the appropriate accounts for non-service costs to apply retroactive reclassification.

In June 2016, the FASB issued ASU 2016-13, “Financial Instruments - Credit Losses: Measurement of Credit Losses on Financial Instruments,’’ which introduces new guidance to the accounting for credit losses on instruments within its scope, including trade receivables. It is effective for fiscal years beginning after December 15, 2019, including interim periods within those fiscal years, and early adoption is permitted for fiscal years beginning after December 15, 2018. The new guidance will be initially applied through a cumulative-effect adjustment to retained earnings as of the beginning of the period of adoption. We are currently assessing the timing and impacts of adopting this standard, which must be adopted by the first quarter of 2020.

In February 2016, the FASB issued ASU 2016-02, “Leases (Topic 842),” as amended, which prescribes recognizing lease assets and liabilities on the balance sheet and includes disclosure of key information about leasing arrangements. We will adopt this new guidance effective January 1, 2019, and apply the modified retrospective approach to all existing leases. We do not expect a material impact to our results of operations or cash flows. We plan to utilize the practical expedients that allow us to: (1) not reassess expired or existing contracts to determine whether they are subject to lease accounting guidance, (2) not reconsider lease classification at transition, and (3) not evaluate previously capitalized initial direct costs under the revised requirements. We also plan to utilize the practical expedients that allow us to: (1) not evaluate under Topic 842 existing or expired land easements that were not previously accounted for as leases under the current lease guidance in Topic 840 and (2) use an additional transition method in which an entity initially applies the new leases standard at the adoption date and recognizes a cumulative-effect adjustment to the opening balance of retained earnings in the period of adoption.

Our population of leases consists primarily of operating leases for office facilities, information technology, and right-of-way contracts. We expect that upon adoption we will recognize lease liabilities of approximately $32 million, with corresponding right-of-use assets of the same amount based on the present value of the remaining minimum rental payments for existing operating leases. The operating lease right-of-use assets include any lease payments made and excludes lease incentives. Our lease terms may include options to extend or terminate the lease when it is reasonably certain that we will exercise that option. Lease expense for lease payments is recognized on a straight-line basis over the lease term. We have lease agreements with lease and non-lease components, which are generally accounted for separately. Additionally, for certain office equipment leases, we apply a portfolio approach to effectively account for the operating lease right-of-use assets and liabilities. We will adopt an accounting policy that exempts leases with terms of less than one year from the recognition requirements of ASC Topic 842, and disclose such leases in our interim and annual disclosures upon adoption.

In May 2014, the FASB issued ASU 2014-09, “Revenue from Contracts with Customers” (“ASC 606”), which clarifies and converges the revenue recognition principles under GAAP and International Financial Reporting Standards. We adopted this new guidance in the first quarter 2018, using the modified retrospective method. We evaluated all of our sources of revenue to determine the potential effect of the new standard on our financial position, results of operations, cash flows and the related accounting policies and business processes. Our adoption did not result in a cumulative adjustment to our opening retained earnings. Our adoption resulted in a reclassification of certain revenues associated with certain regulatory mechanisms that do not meet the requirements under ASC 606 as revenue from contracts with customers, but will continue to be reflected as other revenues in determining total revenues. The reclassified revenues relate primarily to the weather normalization mechanism in Kansas, where the KCC determines how we reflect variations in weather in our rates billed to customers. See Note 2 for additional information regarding our revenues.

2. REVENUE

We recognize revenue from contracts with customers to depict the transfers of goods and services to customers at an amount that we expect to be entitled to receive in exchange for these goods and services. Our sources of revenue are disaggregated by natural gas sales, transportation revenues, and miscellaneous revenues, which are primarily one-time service fees, that meet the requirements of ASC 606. Certain revenues that do not meet the requirements of ASC 606 are classified as other revenues in our Notes to Consolidated Financial Statements in this Annual Report.

Our natural gas sales to customers represent revenue from contracts with customers through implied contracts established by our tariff rates approved by the regulatory authorities. For natural gas sales, the customer receives the benefits of our performance when the commodity is received and simultaneously consumed by the customer. The performance obligation is satisfied over time as the customer consumes the natural gas.

Our transportation revenues represent revenue from contracts with customers through implied contracts established by our tariff rates approved by the regulatory authorities and tariff-based negotiated contracts. The customer receives the benefits of our performance when the commodity is delivered to the customer and the performance obligation is satisfied over time as the customer receives the natural gas.

For regulated deliveries of natural gas, we read meters and bill customers on a monthly cycle. We recognize revenues upon the delivery of natural gas commodity or services rendered to customers. The billing cycles for customers do not necessarily coincide with the accounting periods used for financial reporting purposes. We accrue unbilled revenues for natural gas that has been delivered but not yet billed at the end of an accounting period. We use the invoice method practical expedient, where we recognize revenue for volumes delivered for which we have a right to invoice. As a result, we estimated unbilled revenues at the end of each accounting period consistent with past practice. Accrued unbilled revenue is based on a percentage estimate of amounts unbilled each month, which is dependent upon a number of factors, some of which require management’s judgment. These factors include customer consumption patterns and the impact of weather on usage. The accrued unbilled natural gas sales revenue at December 31, 2018 and 2017 was $127.6 million and $138.5 million, respectively, and is included in accounts receivable on our Consolidated Balance Sheets.

Our miscellaneous revenues from contracts with customers represent implied contracts established by our tariff rates approved by the regulatory authorities and includes miscellaneous utility services with the performance obligation satisfied at a point in time when services are rendered to the customer.

Total other revenues consist of revenues associated with regulatory mechanisms that do not meet the requirements of ASC 606 as revenue from contracts with customers, but authorize us to accrue revenues earned based on tariffs approved by the regulatory authorities. Total other revenues primarily reflect our natural gas sales related weather normalization mechanism in Kansas. This mechanism adjusts our revenues earned for the variance between actual and normal HDDs. This mechanism can have either positive (warmer than normal) or negative (colder than normal) effects on revenues.

We collect and remit other taxes on behalf of governmental authorities, and we record these amounts in accrued taxes other than income in our Consolidated Balance Sheets on a net basis.

The following table sets forth our revenues disaggregated by source for the period indicated:

	Year Ended December 31, 2018

	(Thousands of dollars)
Natural gas sales to customers	$1,495,250
Transportation revenues	109,658
Miscellaneous revenues	21,710
Total revenues from contracts with customers	1,626,618
Other revenues - natural gas sales related	(2,806)
Other revenues	9,919
Total other revenues	7,113
Total revenues	$1,633,731

3. CREDIT FACILITY AND SHORT-TERM NOTES PAYABLE

In October 2018, we exercised a one-year extension of the ONE Gas Credit Agreement. The ONE Gas Credit Agreement remains a $700 million revolving unsecured credit facility and includes a $20 million letter of credit subfacility and a $60 million swingline subfacility. We are able to request an increase in commitments of up to an additional $500 million upon satisfaction of customary conditions, including receipt of commitments from either new lenders or increased commitments from existing lenders. The ONE Gas Credit Agreement expires in October 2023, and is available to provide liquidity for working capital, capital expenditures, acquisitions and mergers, the issuance of letters of credit and for other general corporate purposes.

The ONE Gas Credit Agreement contains customary events of default. Upon the occurrence of certain events of default, the obligations under the ONE Gas Credit Agreement may be accelerated and the commitments may be terminated. The ONE Gas Credit Agreement also contains certain financial, operational and legal covenants. Among other things, these covenants include maintaining ONE Gas' total debt-to-capital ratio of no more than 70 percent at the end of any calendar quarter. The ONE Gas Credit Agreement also contains customary affirmative and negative covenants, including covenants relating to liens, indebtedness of subsidiaries, investments, changes in the nature of business, fundamental changes, transactions with affiliates, burdensome agreements, and use of proceeds. In the event of a breach of certain covenants by ONE Gas, amounts outstanding under the ONE Gas Credit Agreement may become due and payable immediately. At December 31, 2018, our total debt-to-capital ratio was 44 percent and we were in compliance with all covenants under the ONE Gas Credit Agreement.

The ONE Gas Credit Agreement contains provisions for an applicable margin rate and an annual facility fee, both of which adjust with changes in our credit rating. Based on our current credit ratings, borrowings, if any, will accrue interest at LIBOR plus 79.5 basis points, and the annual facility fee is 8 basis points.

We have a commercial paper program under which we may issue unsecured commercial paper up to a maximum amount of $700 million to fund short-term borrowing needs. The maturities of the commercial paper notes may vary but may not exceed 270 days from the date of issue. The commercial paper notes are sold generally at par less a discount representing an interest factor.

The ONE Gas Credit Agreement is available to repay the commercial paper notes, if necessary. Amounts outstanding under the commercial paper program reduce the borrowing capacity under the ONE Gas Credit Agreement.

At December 31, 2018, we had $299.5 million of commercial paper, $1.2 million in letters of credit issued under the ONE Gas Credit Agreement, with no borrowings and $399.3 million of remaining credit available under the ONE Gas Credit Agreement. The weighted-average interest rate on our commercial paper was 2.54 percent and 1.55 percent at December 31, 2018 and 2017, respectively.

4. LONG-TERM DEBT

In November 2018, ONE Gas issued $400 million of 4.50 percent senior notes due 2048. The proceeds from the issuance were used to retire the $300 million of 2.07 percent senior notes due 2019, to reduce the commercial paper and for general corporate purposes.

Our senior notes consist of $300 million of 3.61 percent senior notes due 2024, $600 million of 4.658 percent senior notes due 2044, and $400 million of 4.50 percent senior notes due 2048. The indenture governing our Senior Notes includes an event of default upon the acceleration of other indebtedness of $100 million or more. Such events of default would entitle the trustee or the holders of 25 percent in the aggregate principal amount of the outstanding Senior Notes to declare those senior notes immediately due and payable in full.

Depending on the series, we may redeem our Senior Notes at par, plus accrued and unpaid interest to the redemption date, starting three months, or six months, respectively, before their maturity dates. Prior to these dates, we may redeem these Senior Notes, in whole or in part, at a redemption price equal to the principal amount, plus accrued and unpaid interest and a make-whole premium. The redemption price will never be less than 100 percent of the principal amount of the respective note plus accrued and unpaid interest to the redemption date. Our Senior Notes are senior unsecured obligations, ranking equally in right of payment with all of our existing and future unsecured senior indebtedness.

5. EQUITY

Preferred Stock - At December 31, 2018, we had 50 million, $0.01 par value, authorized shares of preferred stock available. We have not issued or established any classes or series of shares of preferred stock.

Common Stock - At December 31, 2018, we had approximately 197.4 million shares of authorized common stock available for issuance.

Treasury Shares - We are authorized to purchase treasury shares to be used to offset shares issued under our equity compensation plan and the ESPP. Our Board of Directors established an annual limit of $20 million of treasury stock purchases, exclusive of funds received through the dividend reinvestment and the ESPP. Stock purchases may be made in the open market or in private transactions at times, and in amounts that we deem appropriate. There is no guarantee as to the exact number of shares that we purchase, and we can terminate or limit the program at any time.

Dividends Declared - In 2018 and 2017, we declared and paid dividends of $1.84 per share ($0.46 per share quarterly) and $1.68 per share ($0.42 per share quarterly), respectively. In January 2019, we declared a dividend of $0.50 per share ($2.00 per share on an annualized basis) for shareholders of record on February 22, 2019, payable March 8, 2019.

6. ACCUMULATED OTHER COMPREHENSIVE LOSS

The following table sets forth the balance in accumulated other comprehensive loss for the period indicated:

	Accumulated Other Comprehensive Loss (Thousands of dollars)
January 1, 2017	$ (4,715)
Pension and other postemployment benefit plans obligations	
Other comprehensive loss before reclassification, net of tax of $808	(1,293)
Amounts reclassified from accumulated other comprehensive income, net of tax of $(322)	515
Other comprehensive loss	(778)
December 31, 2017	(5,493)
Pension and other postemployment benefit plans obligations	
Other comprehensive income before reclassification, net of tax of $(577)	596
Amounts reclassified from accumulated other comprehensive loss, net of tax of $(271)	811
Other comprehensive income	1,407
December 31, 2018	$ (4,086)

The following table sets forth the effect of reclassifications from accumulated other comprehensive loss on our Consolidated Statements of Income for the period indicated:

Details about Accumulated Other Comprehensive Loss Components	Years Ended December 31, 2018	2017	2016	Affected Line Item in the Consolidated Statements of Income
	(Thousands of dollars)			
Pension and other postemployment benefit plan obligations (a)				
Amortization of net loss	$43,800	$42,591	$40,912	
Amortization of unrecognized prior service cost	(4,567)	(4,597)	(3,316)	
	39,233	37,994	37,596	
Regulatory adjustments (b)	(38,151)	(37,157)	(36,845)	
	1,082	837	751	Income before income taxes
	(271)	(322)	(289)	Income tax expense
Total reclassifications for the period	$811	$515	$462	Net income

(a) These components of accumulated other comprehensive loss are included in the computation of net periodic benefit cost. See Note 12 for additional information regarding our net periodic benefit cost.
(b) Regulatory adjustments represent pension and other postemployment benefit costs expected to be recovered through rates and are deferred as part of our regulatory assets. See Note 9 for additional information regarding our regulatory assets and liabilities.

7. EARNINGS PER SHARE

The following tables set forth the computation of basic and diluted EPS from continuing operations for the periods indicated:

	Year Ended December 31, 2018		
	Income	Shares	Per Share Amount
	(Thousands, except per share amounts)		
Basic EPS Calculation			
Net income available for common stock	$172,234	52,693	$ 3.27
Diluted EPS Calculation			
Effect of dilutive securities	—	336	
Net income available for common stock and common stock equivalents	$172,234	53,029	$ 3.25

	Year Ended December 31, 2017		
	Income	Shares	Per Share Amount
	(Thousands, except per share amounts)		
Basic EPS Calculation			
Net income available for common stock	$162,995	52,527	$ 3.10
Diluted EPS Calculation			
Effect of dilutive securities	—	452	

Net income available for common stock and common stock equivalents	$ 162,995	52,979	$ 3.08

	Year Ended December 31, 2016		
	Income	Shares	Per Share Amount
	(Thousands, except per share amounts)		
Basic EPS Calculation			
Net income available for common stock	$ 140,095	52,453	$ 2.67
Diluted EPS Calculation			
Effect of dilutive securities	—	510	
Net income available for common stock and common stock equivalents	$ 140,095	52,963	$ 2.65

8. DERIVATIVE FINANCIAL INSTRUMENTS AND FAIR VALUE MEASUREMENTS

Derivative Instruments - At December 31, 2018, we held purchased natural gas call options for the heating season ending March 2019, with total notional amounts of 14.3 Bcf, for which we paid premiums of $4.1 million, and which had a fair value of $2.1 million. At December 31, 2017, we held purchased natural gas call options for the heating season ended March 2018, with total notional amounts of 14.1 Bcf, for which we paid premiums of $5.5 million, and which had a fair value of $1.1 million. The premiums paid and any cash settlements received are recorded as part of our unrecovered purchased-gas costs in current regulatory assets as these contracts are included in, and recoverable through, the purchased-gas cost adjustment mechanisms. Additionally, changes in fair value associated with these contracts are deferred as part of our unrecovered purchased-gas costs in our Consolidated Balance Sheets. Our natural gas call options are classified as Level 1 as fair value amounts are based on unadjusted quoted prices in active markets including NYMEX-settled prices. There were no transfers between levels for the periods presented.

Other Financial Instruments - The approximate fair value of cash and cash equivalents, accounts receivable and accounts payable is equal to book value, due to the short-term nature of these items. Our cash and cash equivalents are comprised of bank and money market accounts and are classified as Level 1.

Short-term notes payable and commercial paper are due upon demand and, therefore, the carrying amounts approximate fair value and are classified as Level 1. The book value of our long-term debt, including current maturities, was $1.3 billion and $1.2 billion at December 31, 2018 and 2017, respectively. The estimated fair value of our long-term debt, including current maturities, was $1.4 billion and $1.3 billion at December 31, 2018 and 2017, respectively. The estimated fair value of our Senior Notes was determined using quoted market prices and are considered Level 2.

9. REGULATORY ASSETS AND LIABILITIES

The table below presents a summary of regulatory assets, net of amortization, and liabilities for the periods indicated:

		December 31, 2018		
	Remaining Recovery Period	Current	Noncurrent	Total
		(Thousands of dollars)		
Under-recovered purchased-gas costs	1 year	$25,083	$—	$25,083
Pension and other postemployment benefit costs	See Note 12	23,384	421,726	445,110
Reacquired debt costs	9 years	812	6,487	7,299
MGP remediation costs	15 years	—	7,724	7,724
Ad-valorem tax	1 year	1,070	—	1,070
Other	1 to 20 years	4,071	1,542	5,613
Total regulatory assets, net of amortization		54,420	437,479	491,899
Federal income tax rate changes (a)	See Note 13	(30,934)	(520,866)	(551,800)
Over-recovered purchased-gas costs	1 year	(13,668)	—	(13,668)
Weather normalization	1 year	(3,792)	—	(3,792)
Total regulatory liabilities		(48,394)	(520,866)	(569,260)
Net regulatory assets and liabilities		$6,026	$(83,387)	$(77,361)

(a) See Note 13 for additional information regarding our federal income tax rate changes regulatory liabilities.

	Remaining Recovery Period	December 31, 2017 Current	Noncurrent	Total
		(Thousands of dollars)		
Under-recovered purchased-gas costs	1 year	$41,238	$—	$41,238
Pension and other postemployment benefit costs	See Note 12	25,156	387,582	412,738
Weather normalization	1 year	17,461	—	17,461
Reacquired debt costs	10 years	812	7,298	8,110
MGP remediation costs	15 years	—	6,104	6,104
Other	1 to 21 years	3,513	4,205	7,718
Total regulatory assets, net of amortization		88,180	405,189	493,369
Federal income tax rate changes (a)	See Note 13	—	(519,421)	(519,421)
Over-recovered purchased-gas costs	1 year	(9,434)	—	(9,434)
Ad-valorem tax	1 year	(4)	—	(4)
Total regulatory liabilities		(9,438)	(519,421)	(528,859)
Net regulatory assets and liabilities		$78,742	$(114,232)	$(35,490)

(a) See Note 13 for additional information regarding our federal income tax rate changes regulatory liabilities.

Regulatory assets on our Consolidated Balance Sheets, as authorized by the various regulatory authorities, are probable of recovery. Base rates are designed to provide a recovery of cost during the period rates are in effect but do not generally provide for a return on investment for amounts we have deferred as regulatory assets. All of our regulatory assets recoverable through base rates are subject to review by the respective regulatory authorities during future rate proceedings. We are not aware of any evidence that these costs will not be recoverable through either rate riders or base rates, and we believe that we will be able to recover such costs, consistent with our historical recoveries.

Purchased-gas costs represent the natural gas costs that have been over- or under-recovered from customers through the purchased-gas cost adjustment mechanisms, and includes natural gas utilized in our operations and premiums paid and any cash settlements received from our purchased natural gas call options.

We amortize reacquired debt costs in accordance with the accounting guidelines prescribed by the OCC and KCC.

Weather normalization represents revenue over- or under-recovered through the WNA rider in Kansas. This amount is deferred as a regulatory asset or liability for a 12-month period. Kansas Gas Service then applies an adjustment to the customers' bills for 12 months to refund the over-collected revenue or bill the under-collected revenue.

Ad-valorem tax represents an increase or decrease in Kansas Gas Service's taxes above or below the amount approved in a rate case. This amount is deferred as a regulatory asset or liability for a 12-month period. Kansas Gas Service then applies an adjustment to the customers' bills for 12 months to refund the over-collected revenue or bill the under-collected revenue.

Recovery through rates resulted in amortization of regulatory assets of approximately $1.7 million, $1.0 million and $3.8 million for the years ended December 31, 2018, 2017 and 2016, respectively.

In 2017, we recorded a regulatory asset of approximately $5.9 million for estimated costs expected to be incurred at, and nearby, our 12 former MGP sites in Kansas which we own or retain responsibility for certain environmental conditions.

10. PROPERTY, PLANT AND EQUIPMENT

The following table sets forth our property, plant and equipment by property type, for the periods indicated:

	December 31, 2018	December 31, 2017
	(Thousands of dollars)	
Natural gas distribution pipelines and related equipment	$4,861,340	$4,572,343
Natural gas transmission pipelines and related equipment	517,697	497,791
General plant and other	567,580	513,445
Construction work in process	126,526	130,333
Property, plant and equipment	6,073,143	5,713,912
Accumulated depreciation and amortization	(1,789,431)	(1,706,327)
Net property, plant and equipment	$4,283,712	$4,007,585

We compute depreciation expense by applying composite, straight-line rates of 2.0 percent to 3.0 percent that were approved by various regulatory authorities.

We recorded capitalized interest of $3.4 million, $3.0 million and $3.6 million for the years ended December 31, 2018, 2017 and 2016, respectively. We incurred liabilities for construction work in process and asset removal costs that had not been paid at December 31, 2018, 2017 and 2016 of $15.6 million, $21.7 million and $11.9 million, respectively. Such amounts are not included in capital expenditures or in the change of working capital items on our Consolidated Statements of Cash Flows.

11. SHARE-BASED PAYMENTS

The ECP provides for the granting of stock-based compensation, including incentive stock options, nonstatutory stock options, stock bonus awards, restricted stock awards, restricted stock unit awards, performance stock awards and performance unit awards to eligible employees and the granting of stock awards to nonemployee directors. At December 31, 2018, we have 4.3 million shares of common stock reserved for issuance under the ECP. In May 2018, shareholders approved making an additional 1.8 million shares available under the ECP, less the number of shares remaining available for future grants on the effective date. At December 31, 2018, we had approximately 2.1 million shares available for issuance under the ECP, which reflect shares issued and estimated shares expected to be issued upon vesting of outstanding awards granted under the plan, less forfeitures. The plan allows for the deferral of awards granted in stock or cash, in accordance with Internal Revenue Code section 409A requirements.

Compensation cost expensed for our share-based payment plans was $6.1 million, net of tax benefits of $2.1 million, for 2018, $4.9 million, net of tax benefits of $3.0 million, for 2017, and $7.0 million, net of tax benefits of $4.3 million, for 2016.

Restricted Stock Unit Awards - We have granted restricted stock unit awards to key employees that vest over a service period of generally three years and entitle the grantee to receive shares of our common stock. Restricted stock unit awards granted accrue dividend equivalents in the form of additional restricted stock units prior to vesting. Restricted stock unit awards are measured at fair value as if they were vested and issued on the grant date, reduced by expected dividend payments for awards that do not accrue dividends and adjusted for estimated forfeitures. Compensation expense is recognized on a straight-line basis over the vesting period of the award. A forfeiture rate of 3 percent per year based on historical forfeitures under our share-based payment plans is used.

Performance Stock Unit Awards - We have granted performance stock unit awards to key employees. The shares of common stock underlying the performance stock units vest at the expiration of a service period of generally three years if certain performance criteria are met by us as determined by the Executive Compensation Committee of the Board of Directors. Upon vesting, a holder of performance stock units is entitled to receive a number of shares of common stock equal to a percentage (0 percent to 200 percent) of the performance stock units granted, based on our total shareholder return over the vesting period, compared with the total shareholder return of a peer group of other utilities over the same period.

If paid, the outstanding performance stock unit awards entitle the grantee to receive shares of our common stock. The outstanding performance stock unit awards are equity awards with a market-based condition, which results in the compensation expense for these awards being recognized on a straight-line basis over the requisite service period, provided that the requisite service period is fulfilled, regardless of when, if ever, the market condition is satisfied. The performance stock unit awards granted accrue dividend equivalents in the form of additional performance stock units prior to vesting. The fair value of these performance stock units was estimated on the grant date based on a Monte Carlo model. The compensation expense on these awards will only be adjusted for changes in forfeitures. A forfeiture rate of 3 percent per year based on historical forfeitures under our share-based payment plans was used.

Restricted Stock Unit Award Activity

As of December 31, 2018, there was $2.6 million of total unrecognized compensation costs related to the nonvested restricted stock unit awards, which is expected to be recognized over a weighted-average period of 1.7 years. The following tables set forth activity and various statistics for restricted stock unit awards outstanding under the respective plans for the period indicated:

	Number of Units	Weighted-Average Price
Nonvested at December 31, 2017	140,665	$ 51.97
Granted	37,893	$ 68.17
Vested	(66,543)	$ 41.92
Forfeited	(2,509)	$ 62.44
Nonvested at December 31, 2018	109,506	$ 63.45

	2018	2017	2016
Weighted-average grant date fair value (per share)	$68.17	$63.97	$58.30
Fair value of shares granted (thousands of dollars)	$2,583	$2,420	$2,503

The fair value of restricted stock vested was $4.7 million and $5.5 million in 2018 and 2017, respectively.

Performance Stock Unit Award Activity

As of December 31, 2018, there was $5.8 million of total unrecognized compensation cost related to the nonvested performance stock unit awards, which is expected to be recognized over a weighted-average period of 1.8 years. The following tables set forth activity and various statistics related to our performance stock unit awards and the assumptions used by us in the valuations of the 2018, 2017 and 2016 grants at the grant date:

	Number of Units	Weighted-Average Price
Nonvested at December 31, 2017	237,324	$ 57.78
Granted	79,447	$ 74.04
Vested	(93,976)	$ 44.48
Forfeited	(3,464)	$ 67.97
Nonvested at December 31, 2018	219,331	$ 69.21

	2018	2017	2016
Volatility (a)	18.80%	20.70%	18.20%
Dividend yield	2.70%	2.63%	2.40%
Risk-free interest rate	2.38%	1.48%	0.91%

(a) - Volatility based on historical volatility over three years using daily stock price observations of our peer utilities.

	2018	2017	2016
Weighted-average grant date fair value (per share)	$74.04	$68.94	$64.06
Fair value of shares granted (thousands of dollars)	$5,882	$5,110	$4,766

The fair value of performance stock vested was $13.7 million and $15.6 million in 2018 and 2017, respectively.

Employee Stock Purchase Plan

We have reserved a total of 700 thousand shares of common stock for issuance under our ESPP. Subject to certain exclusions, all employees who work more than 20 hours per week are eligible to participate in the ESPP. Employees can choose to have up to 10 percent of their annual base pay withheld to purchase our common stock, subject to terms and limitations of the plan. The purchase price of the stock is 85 percent of the lower of the average market price of our common stock on the grant date or exercise date. Approximately 45 percent, 43 percent and 41 percent of employees participated in the plan in 2018, 2017 and 2016, respectively, and purchased 76,231 shares at $63.01 in 2018, 78,472 shares at $56.80 in 2017, and 83,431 shares at $54.51 in 2016. Compensation expense, before taxes, was $1.0 million, $1.2 million and $1.4 million in 2018, 2017 and 2016, respectively.

Employee Stock Award Program

Under the Employee Stock Award Program, we issued, for no monetary consideration, one share of our common stock to all eligible employees when the per-share closing price of our common stock on the NYSE closed for the first time at or above each $1.00 increment above $34. The total number of shares of our common stock authorized for issuance under this program was 125,000. Shares issued to employees under this program during 2017 and 2016 totaled 13,791 and 50,573, respectively. Compensation expense, before taxes, related to the Employee Stock Award Program was $0.9 million and $3.0 million for 2017 and 2016, respectively. The Employee Stock Award Program was discontinued in May 2017.

12. EMPLOYEE BENEFIT PLANS

Retirement and Other Postemployment Benefit Plans

Retirement Plans - We have a defined benefit pension plan covering nonbargaining-unit employees hired before January 1, 2005, and certain bargaining-unit employees hired before December 15, 2011. Nonbargaining-unit employees hired after December 31, 2004; employees represented by Local No. 304 of the International Brotherhood of Electrical Workers (“IBEW”) hired on or after July 1, 2010; employees represented by the United Steelworkers hired on or after December 15, 2011; and employees who accepted a one-time opportunity to opt out of the defined benefit pension plan are covered by a profit-sharing plan. Certain employees of the Texas Gas Service division are entitled to benefits under a frozen cash-balance pension plan. In addition, we have a supplemental executive retirement plan for the benefit of certain officers. No new participants in the supplemental executive retirement plan have been approved since 2005, and it was formally closed to new participants as of January 1, 2014. We fund our defined benefit pension costs at a level needed to maintain or exceed the minimum funding levels required by the Employee Retirement Income Security Act of 1974, as amended, and the Pension Protection Act of 2006.

Other Postemployment Benefit Plans - We sponsor health and welfare plans that provide postemployment medical and life insurance benefits to certain employees who retire with at least five years of service. The postemployment medical plan is contributory based on hire date, age and years of service, with retiree contributions adjusted periodically, and contains other cost-sharing features such as deductibles and coinsurance.

Actuarial Assumptions - The following table sets forth the weighted-average assumptions used to determine benefit obligations for pension and postemployment benefits for the periods indicated:

	December 31,	
	2018	2017
Discount rate - pension plans	4.40%	3.80%
Discount rate - other postemployment plans	4.40%	3.70%
Compensation increase rate	3.20% - 4.00%	3.25% - 3.35%

The following table sets forth the weighted-average assumptions used by us to determine the periodic benefit costs for the periods indicated:

	Years Ended December 31,			
	2018	2017	2016	
Discount rate - pension plans	3.80%	4.30%	4.75%	
Discount rate - other postemployment plans	3.70%	4.20%	4.75%/3.75%	(a)
Expected long-term return on plan assets - pension plans	7.25%	7.75%	7.75%	
Expected long-term return on plan assets - other postemployment plans	7.60%	7.60%	8.00%/7.75%	(b)
Compensation increase rate	3.25% - 3.35%	3.25% - 3.40%	3.35% - 3.40%	

(a) Discount rate for the nine months ended September 30, 2016, and three months ended December 31, 2016, respectively.
(b) Expected long-term return on plan assets for the nine months ended September 30, 2016, and three months ended December 31, 2016, respectively.

We determine our overall expected long-term rate of return on plan assets, based on our review of historical returns and economic growth models. In 2017, we updated our assumed mortality rates to incorporate the new set of mortality tables issued by the Society of Actuaries.

We determine our discount rates annually. We estimate our discount rate based upon a comparison of the expected cash flows associated with our future payments under our defined benefit pension and other postemployment obligations to a hypothetical bond portfolio created using high-quality bonds that closely match expected cash flows. Bond portfolios are developed by selecting a bond for each of the next 60 years based on the maturity dates of the bonds. Bonds selected to be included in the portfolios are only those rated by Moody’s as AA- or better and exclude callable bonds, bonds with less than a minimum issue size, yield outliers and other filtering criteria to remove unsuitable bonds.

Regulatory Treatment - The OCC, KCC and regulatory authorities in Texas have approved the recovery of pension costs and other postemployment benefits costs through rates for Oklahoma Natural Gas, Kansas Gas Service and Texas Gas Service, respectively. The costs recovered through rates are based on current funding requirements and the net periodic benefit cost for defined benefit pension and other postemployment costs. Differences, if any, between the expense and the amount recovered through rates would be reflected in earnings, net of authorized deferrals.

We historically have recovered defined benefit pension and other postemployment benefit costs through rates. We believe it is probable that regulators will continue to include the net periodic pension and other postemployment benefit costs in our cost of service.

Upon adoption of FASB’s ASU 2017-07, we recognized a regulatory asset of $1.5 million, which includes the non-service costs incurred on our pension and other postemployment benefit plans that were capitalized as regulatory assets defined by Topic 980 (Regulated Operations).

Obligations and Funded Status - The following table sets forth our defined benefit pension and other postemployment benefit plans, benefit obligations and fair value of plan assets for the periods indicated:

	Pension Benefits		Other Postemployment Benefits	
	December 31,		December 31,	
	2018	2017	2018	2017
Changes in Benefit Obligation	(Thousands of dollars)			
Benefit obligation, beginning of period	$993,891	$966,531	$255,040	$243,548
Service cost	12,919	12,176	2,354	2,509
Interest cost	36,801	40,453	9,117	9,890
Plan participants' contributions	—	—	3,563	3,483
Actuarial loss (gain)	(42,540)	76,325	(31,607)	12,129
Benefits paid	(50,561)	(55,107)	(18,323)	(16,690)
Plan amendment	—	—	—	171
Settlements	—	(46,487)	—	—
Benefit obligation, end of period	950,510	993,891	220,144	255,040
Change in Plan Assets				
Fair value of plan assets, beginning of period	884,804	739,586	190,226	166,046
Actual return (loss) on plan assets	(62,752)	135,056	(6,325)	31,228
Employer contributions	42,386	111,936	7,718	6,159
Plan participants' contributions	—	—	3,563	3,483
Benefits paid	(50,561)	(55,107)	(18,323)	(16,690)
Settlements	235	(46,667)	—	—
Fair value of assets, end of period	814,112	884,804	176,859	190,226
Balance at December 31	$(136,398)	$(109,087)	$(43,285)	$(64,814)
Current liabilities	$(962)	$(963)	$—	$—
Noncurrent liabilities	(135,436)	(108,124)	(43,285)	(64,814)
Balance at December 31	$(136,398)	$(109,087)	$(43,285)	$(64,814)

During 2017, we purchased group annuity contracts for $46.7 million, and transferred to a third-party insurance company liabilities of approximately $46.5 million related to certain participants in our defined benefit pension plan.

The accumulated benefit obligation for our defined benefit pension plans was $890.4 million and $936.7 million at December 31, 2018 and 2017, respectively.

In 2019, we expect to contribute $1.0 million to our defined benefit pension plans and expect to contribute $3.0 million to our other postemployment benefit plans. There are no plan assets expected to be withdrawn and returned to us in 2019.

Components of Net Periodic Benefit Cost - The following tables set forth the components of net periodic benefit cost, prior to regulatory deferrals, for our defined benefit pension and other postemployment benefit plans for the period indicated:

	Pension Benefits		
	Year Ended December 31,		
	2018	2017	2016
	(Thousands of dollars)		
Components of net periodic benefit cost			
Service cost	$12,919	$12,176	$12,055
Interest cost (a)	36,801	40,453	45,550
Expected return on assets (a)	(60,579)	(58,496)	(61,183)
Amortization of net loss (a)	39,913	36,107	35,543
Net periodic benefit cost	$29,054	$30,240	$31,965

(a) These amounts, net of any amounts capitalized as a regulatory asset since adoption of ASU 2017-07 on January 1, 2018, have been recognized as other income (expense), net in the Consolidated Statements of Income. See Note 14 for additional detail of our other income (expense), net.

	Other Postemployment Benefits		
	Year Ended December 31,		
	2018	2017	2016
	(Thousands of dollars)		
Components of net periodic benefit cost			
Service cost	$2,354	$2,509	$2,675
Interest cost (a)	9,117	9,890	10,235
Expected return on assets (a)	(14,284)	(12,590)	(12,370)
Amortization of unrecognized prior service cost (a)	(4,567)	(4,597)	(3,316)
Amortization of net loss (a)	3,887	6,484	5,369
Net periodic benefit cost (credit)	$(3,493)	$1,696	$2,593

(a) These amounts, net of any amounts capitalized as a regulatory asset since adoption of ASU 2017-07 on January 1, 2018, have been recognized as other income (expense), net in the Consolidated Statements of Income. See Note 14 for additional detail of our other income (expense), net.

Other Comprehensive Income (Loss) - The following table sets forth the amounts recognized in other comprehensive income (loss), net of regulatory deferrals, related to our defined benefit pension benefits for the period indicated:

	Pension Benefits		
	Year Ended December 31,		
	2018	2017	2016
	(Thousands of dollars)		
Net gain (loss) arising during the period	$1,173	$(2,101)	$(1,262)
Amortization of loss	1,082	837	751
Deferred income taxes	(848)	486	197
Total recognized in other comprehensive income (loss)	$1,407	$(778)	$(314)

Due to our regulatory deferrals, there were no amounts recognized in other comprehensive income (loss) related to our other postemployment benefits for the periods presented.

The tables below set forth the amounts in accumulated other comprehensive loss that had not yet been recognized as components of net periodic benefit expense for the periods indicated:

	Pension Benefits	
	December 31,	
	2018	2017
	(Thousands of dollars)	
Accumulated loss	$(419,238)	$(378,595)
Accumulated other comprehensive loss before regulatory assets	(419,238)	(378,595)
Regulatory asset for regulated entities	412,545	369,647
Accumulated other comprehensive loss after regulatory assets	(6,693)	(8,948)
Deferred income taxes	2,607	3,455
Accumulated other comprehensive loss, net of tax	$(4,086)	$(5,493)

	Other Postemployment Benefits	
	December 31,	
	2018	2017
	(Thousands of dollars)	
Prior service credit (cost)	$875	$5,442
Accumulated loss	(34,144)	(49,030)
Accumulated other comprehensive loss before regulatory assets	$(33,269)	$(43,588)
Regulatory asset for regulated entities	33,269	43,588
Accumulated other comprehensive loss after regulatory assets	$—	$—

The following table sets forth the amounts recognized in either accumulated comprehensive income (loss) or regulatory assets expected to be recognized as components of net periodic benefit expense in the next fiscal year:

	Pension Benefits	Other Postemployment Benefits
Amounts to be recognized in 2019	(Thousands of dollars)	
Prior service credit (cost)	$—	$ (673)
Actuarial net loss	$33,039	$ 2,244

Health Care Cost Trend Rates - The following table sets forth the assumed health care cost-trend rates for the periods indicated:

	2018	2017
Health care cost-trend rate assumed for next year	7.00%	7.00%
Rate to which the cost-trend rate is assumed to decline (the ultimate trend rate)	5.00%	5.00%
Year that the rate reaches the ultimate trend rate	2024	2023

77

Assumed health care cost-trend rates have a significant effect on the amounts reported for our other postemployment benefit plans. A one percentage point change in assumed health care cost-trend rates would have the following effects:

	One Percentage Point Increase	One Percentage Point Decrease
	(Millions of dollars)	
Effect on total of service and interest cost	$0.2	$ (0.2)
Effect on other postemployment benefit obligation	$2.3	$ (2.4)

Plan Assets - Our investment strategy is to invest plan assets in accordance with sound investment practices that emphasize long-term fundamentals. The goal of this strategy is to maximize investment returns while managing risk in order to meet the plan's current and projected financial obligations. To achieve this strategy, we have established a liability-driven investment strategy to change the allocations as the plan reaches certain funded status. The plan's investments include a diverse blend of various domestic and international equities, investment-grade debt securities which mirror the cash flows of our liability, insurance contracts and alternative investments. The current target allocation for the assets of our defined benefit pension plan is as follows:

Investment-grade bonds	40.0 %
U.S. large-cap equities	18.0 %
Alternative investments	14.0 %
Developed foreign large-cap equities	10.0 %
Mid-cap equities	7.0 %
Emerging markets equities	6.0 %
Small-cap equities	5.0 %
Total	100 %

As part of our risk management for the plans, minimums and maximums have been set for each of the asset classes listed above. All investment managers for the plan are subject to certain restrictions on the securities they purchase and, with the exception of indexing purposes, are prohibited from owning our stock.

The current target allocation for the assets of our other postemployment benefits plan is 30 percent fixed income securities and 70 percent equity securities.

The following tables set forth our pension benefits and other postemployment benefits plan assets by fair value category as of the measurement date:

	Pension Benefits			
	December 31, 2018			
Asset Category	Level 1	Level 2	Level 3	Total
	(Thousands of dollars)			
Investments:				
Equity securities (a)	$282,668	$35,870	$—	$318,538
Government obligations	—	69,475	—	69,475
Corporate obligations (b)	—	240,900	—	240,900
Cash and money market funds (c)	2,419	71,991	—	74,410
Insurance contracts and group annuity contracts	—	—	30,445	30,445
Other investments (d)	—	1,139	79,205	80,344
Total assets	$285,087	$419,375	$109,650	$814,112

(a) - This category represents securities of the various market sectors from diverse industries.
(b) - This category represents bonds from diverse industries.
(c) - This category is primarily money market funds.
(d) - This category represents alternative investments such as hedge funds and other financial instruments.

	Pension Benefits			
	December 31, 2017			
Asset Category	Level 1	Level 2	Level 3	Total
	(Thousands of dollars)			
Investments:				
Equity securities (a)	$301,911	$91,014	$—	$392,925
Government obligations	—	74,596	—	74,596
Corporate obligations (b)	—	260,907	—	260,907
Cash and money market funds (c)	21,139	20,787	—	41,926
Insurance contracts and group annuity contracts	—	—	35,158	35,158
Other investments (d)	—	585	78,707	79,292
Total assets	$323,050	$447,889	$113,865	$884,804

(a) - This category represents securities of the various market sectors from diverse industries.
(b) - This category represents bonds from diverse industries.
(c) - This category is primarily money market funds.
(d) - This category represents alternative investments such as hedge funds and other financial instruments.

Asset Category	Other Postemployment Benefits December 31, 2018 Level 1	Level 2	Level 3	Total
	(Thousands of dollars)			
Investments:				
Equity securities (a)	$58,087	$2,382	$ —	$60,469
Government obligations	—	74	—	74
Corporate obligations (b)	—	25,857	—	25,857
Cash and money market funds (c)	1,249	300	—	1,549
Insurance contracts and group annuity contracts (d)	—	88,910	—	88,910
Total assets	$59,336	$117,523	$ —	$176,859

(a) - This category represents securities of the various market sectors from diverse industries.
(b) - This category represents bonds from diverse industries.
(c) - This category is primarily money market funds.
(d) - This category includes equity securities and bonds held in a captive insurance product.

Asset Category	Other Postemployment Benefits December 31, 2017 Level 1	Level 2	Level 3	Total
	(Thousands of dollars)			
Investments:				
Equity securities (a)	$63,180	$123	$ —	$63,303
Government obligations	—	101	—	101
Corporate obligations (b)	—	25,905	—	25,905
Cash and money market funds (c)	4,512	28	—	4,540
Insurance contracts and group annuity contracts	—	96,377	—	96,377
Total assets	$67,692	$122,534	$ —	$190,226

(a) - This category represents securities of the various market sectors from diverse industries.
(b) - This category represents bonds from diverse industries.
(c) - This category is primarily money market funds.

The following table sets forth the reconciliation of Level 3 fair value measurements of our pension plans for the periods indicated:

	Pension Benefits Insurance Contracts	Other Investments	Total
	(Thousands of dollars)		
January 1, 2017	$45,140	$ 57,352	$102,492
Net realized and unrealized gains (losses)	2,569	5,055	7,624
Purchases	—	16,300	16,300
Settlements	(12,551)	—	(12,551)
December 31, 2017	$35,158	$ 78,707	$113,865
Net realized and unrealized gains (losses)	(611)	496	(115)
Purchases	—	—	—
Sales and settlements	(4,100)	—	(4,100)
December 31, 2018	$30,445	$ 79,205	$109,650

80

Pension and Other Postemployment Benefit Payments - Benefit payments for our defined benefit pension and other postemployment benefit plans for the period ended December 31, 2018 were $50.6 million and $18.3 million, respectively. The following table sets forth the pension benefits and other postemployment benefits payments expected to be paid in 2019-2028:

	Pension Benefits	Other Postemployment Benefits
Benefits to be paid in:	(Thousands of dollars)	
2019	$52,368	$ 16,746
2020	$53,332	$ 16,737
2021	$54,245	$ 16,632
2022	$55,474	$ 16,603
2023	$56,477	$ 16,424
2024 through 2028	$295,565	$ 77,769

The expected benefits to be paid are based on the same assumptions used to measure our benefit obligation at December 31, 2018 and include estimated future employee service.

Other Employee Benefit Plans

401(k) Plan - We have a 401(k) Plan which covers all full-time employees, and employee contributions are discretionary. We match 100 percent of each participant’s eligible contribution up to 6 percent of eligible compensation, subject to certain limits. Our contributions made to the plan were $12.1 million, $11.7 million and $10.8 million in 2018, 2017 and 2016, respectively.

Profit Sharing Plan - We have a profit sharing plan for all employees who do not participate in our defined benefit pension plan. We plan to make a contribution to the profit sharing plan each quarter equal to 1 percent of each participant’s eligible compensation during the quarter. Additional discretionary employer contributions may be made at the end of each year. Employee contributions are not allowed under the plan. Our contributions made to the plan were $7.4 million, $8.1 million and $6.0 million in 2018, 2017 and 2016, respectively.

13. INCOME TAXES

In December 2017, the Tax Cuts and Jobs Act of 2017 was signed into law. Substantially all of the provisions of the new law are effective for taxable years beginning after December 31, 2017. The new law includes significant changes to the Code, including amendments which significantly change the taxation of business entities and includes specific provisions related to regulated public utilities. The more significant changes that impact us include reductions in the corporate federal statutory income tax rate to 21 percent from 35 percent, and several technical provisions including, among others, the elimination of full expensing for tax purposes of certain property acquired after December 31, 2017, the continuation of certain rate normalization requirements for accelerated depreciation benefits and the general allowance for the continued deductibility of interest expense. Additionally, the new law limits the utilization of NOLs arising after December 31, 2017, to 80 percent of taxable income with an indefinite carryforward.

The staff of the SEC issued guidance in SAB 118 which clarifies accounting for income taxes under ASC 740 if information is not yet available or complete and provides for up to a one-year period in which to complete the required analyses and accounting. We have completed or made a reasonable estimate for the measurement and accounting of the effects of the Tax Cuts and Jobs Act of 2017, which were reflected in our December 31, 2017, consolidated financial statements. While we still expect additional guidance from the U.S. Department of the Treasury and the IRS, we have finalized our calculations using available guidance. Any additional issued guidance or future actions of our regulators could potentially affect the final determination of the accounting effects arising from the implementation of the Tax Cuts and Jobs Act of 2017.

The following table sets forth our provision for income taxes for the periods indicated:

	Years Ended December 31,		
	2018	2017	2016
	(Thousands of dollars)		
Current income tax provision			
Federal	$—	$—	$(2,016)
State	289	750	471
Total current income tax provision	289	750	(1,545)
Deferred income tax provision			
Federal	42,413	83,138	76,247
State	10,829	9,255	10,541
Total deferred income tax provision	53,242	92,393	86,788
Total provision for income taxes	$53,531	$93,143	$85,243

The following table is a reconciliation of our income tax provision for the periods indicated:

	Years Ended December 31,		
	2018	2017	2016
	(Thousands of dollars)		
Income before income taxes	$225,765	$256,138	$225,338
Federal statutory income tax rate	21 %	35 %	35 %
Provision for federal income taxes	47,411	89,648	78,868
State income taxes, net of federal tax benefit	8,783	6,503	7,158
Nonregulated deferred tax rate decrease	74	2,162	—
Tax benefit of employee share-based compensation	(2,770)	(5,162)	—
Other, net	33	(8)	(783)
Total provision for income taxes	$53,531	$93,143	$85,243

The following table sets forth the tax effects of temporary differences that gave rise to significant portions of the deferred tax assets and liabilities for the periods indicated:

	December 31,	
	2018	2017
	(Thousands of dollars)	
Deferred tax assets		
Employee benefits and other accrued liabilities	$48,243	$40,277
Regulatory adjustments for enacted tax rate changes	129,201	129,421
Net operating loss	2,778	24,712
Other	34	2,984
Total deferred tax assets	180,256	197,394
Deferred tax liabilities		
Excess of tax over book depreciation	717,903	677,249
Purchased-gas cost adjustment	8,981	13,805
Other regulatory assets and liabilities, net	105,798	106,285
Total deferred tax liabilities	832,682	797,339
Net deferred tax liabilities	$652,426	$599,945

As a result of the enactment of the Tax Cuts and Jobs Act of 2017, we remeasured our ADIT. As a regulated entity, the change in ADIT was recorded as a regulatory liability and is subject to refund to our customers. The Tax Cuts and Jobs Act of 2017 retains the tax normalization provisions of the Code that stipulate how these excess deferred income taxes are to be refunded to customers for certain accelerated tax depreciation benefits. Our customers will receive refunds as determined by our regulators beginning in 2019. The effect on the net deferred income tax liability for the enacted decrease in the federal income tax rate was $518.7 million, of which $520.9 million was recorded as a reduction to the deferred income tax liabilities and deferred as a regulatory liability for ratemaking purposes, offset by $2.2 million recorded as an increase in deferred income tax expense in

2017 attributable to the remeasured deferred income taxes associated with certain expenses not recovered in our rates. These adjustments had no impact on our 2018 or 2017 cash flows.

We are working with our regulators to address the impact of the Tax Cuts and Jobs Act of 2017 on our rates. In each state, we have received accounting orders requiring us to refund the reduction in ADIT due to the remeasurement and to establish a separate regulatory liability for the difference in taxes included in our rates that have been calculated based on a 35 percent federal statutory income tax rate and the new 21 percent federal statutory income tax rate effective in January 2018. In January 2019, the OCC issued an order in Oklahoma Natural Gas' March 2018 PBRC filing requiring Oklahoma Natural Gas to credit customers for the reduction in ADIT based upon an amortization period in compliance with the tax normalization rules for the portions of excess ADIT stipulated by the Code and ten years for all other components of excess ADIT. In February 2019, the KCC issued an order adjusting base rates, which included an amortization credit associated with the refund of ADIT based on an amortization period in compliance with the tax normalization rules for the portion of excess ADIT stipulated by the Code and five years for all other components of excess ADIT. In Texas, we continue to work with our regulators to address the reduction in ADIT due to the remeasurement. The treatment of our excess ADIT and the degree to which it impacts us will not be known until we finalize our current regulatory filings and make future regulatory filings.

In 2018, we accrued a separate regulatory liability associated with the change in tax rates collected in our rates resulting in a reduction to our revenues of $36.6 million for the year ended December 31, 2018. In January 2019, the OCC issued an order that resulted in the establishment of a $15.8 million liability, including interest, for the estimated impact on customer rates of earnings, including amounts attributable to tax savings, above the 9.5 percent approved ROE in the 2018 review period to be returned to customers within the 2019 PBRC filing. In March 2018, the KCC issued an order requiring Kansas Gas Service to accrue a regulatory liability for the portion of its revenue representing the difference between the 21 percent and 35 percent federal corporate tax rate totaling, $14.2 million, excluding interest in 2018. Still outstanding is whether Kansas Gas Service should be required to refund to customers the amount of the regulatory liability accrued. In accordance with Kansas law, the KCC has until February 25, 2019 to rule on the tax refund issue. In 2018, Texas Gas Service issued one-time refunds totaling $6.6 million for the reduction in the federal corporate income tax rate for the period between January 1, 2018, to the dates new rates were implemented.

As of December 31, 2018, we have no federal income tax NOL carryforwards and state income tax NOL carryforwards of $50.2 million, which will expire at various dates from 2025 through 2037. We believe that it is more likely than not that the tax benefits of the NOL carryforwards will be utilized prior to their expirations; therefore, no valuation allowance is necessary.

We have filed our consolidated federal and state income tax returns for years 2015, 2016 and 2017. We are no longer subject to income tax examination for years prior to 2015.

14. OTHER INCOME AND OTHER EXPENSE

The following table sets forth the components of other income and other expense for the periods indicated:

	Years Ended December 31,		
	2018	2017	2016
	(Thousands of dollars)		
Net periodic benefit cost other than service cost	$(8,824)	$(17,252)	$(19,827)
Other, net	(2,535)	2,727	(43)
Total other expense, net	$(11,359)	$(14,525)	$(19,870)

15. COMMITMENTS AND CONTINGENCIES

Commitments - Operating leases represent future minimum lease payments under noncancelable leases covering office space, facilities and information technology hardware and software. Rental expense was $8.2 million, $8.7 million and $8.6 million in 2018, 2017 and 2016, respectively. The following table sets forth our operating lease payments for the periods indicated:

Operating Leases (Millions of dollars)	
2019	$6.3
2020	5.1
2021	4.5
2022	4.3
2023	4.2
Thereafter	3.8
Total	$28.2

Environmental Matters - We are subject to multiple historical, wildlife preservation and environmental laws and/or regulations, which affect many aspects of our present and future operations. Regulated activities include, but are not limited to, those involving air emissions, storm water and wastewater discharges, handling and disposal of solid and hazardous wastes, wetland preservation, hazardous materials transportation, and pipeline and facility construction. These laws and regulations require us to obtain and/or comply with a wide variety of environmental clearances, registrations, licenses, permits and other approvals. Failure to comply with these laws, regulations, licenses and permits or the discovery of presently unknown environmental conditions may expose us to fines, penalties and/or interruptions in our operations that could be material to our results of operations. In addition, emission controls and/or other regulatory or permitting mandates under the Clean Air Act and other similar federal and state laws could require unexpected capital expenditures. We cannot assure that existing environmental statutes and regulations will not be revised or that new regulations will not be adopted or become applicable to us. Revised or additional statutes or regulations that result in increased compliance costs or additional operating restrictions could have a material adverse effect on our business, financial condition and results of operations. Our expenditures for environmental investigation and remediation compliance to-date have not been significant in relation to our financial position, results of operations or cash flows, and our expenditures related to environmental matters had no material effects on earnings or cash flows during 2018, 2017 or 2016.

We own or retain legal responsibility for certain environmental conditions at 12 former MGP sites in Kansas. These sites contain contaminants generally associated with MGP sites and are subject to control or remediation under various environmental laws and regulations. A consent agreement with the KDHE governs all environmental investigation and remediation work at these sites. The terms of the consent agreement require us to investigate these sites and set remediation activities based upon the results of the investigations and risk analysis. Remediation typically involves the management of contaminated soils and may involve removal of structures and monitoring and/or remediation of groundwater. Regulatory closure has been achieved at three of the 12 sites, but these sites remain subject to potential future requirements that may result in additional costs.

We have completed or are addressing removal of the source of soil contamination at all 12 sites and continue to monitor groundwater at eight of the 12 sites according to plans approved by the KDHE. During the fourth quarter of 2018, we began a project to remove the source of contamination and associated contaminated materials at the twelfth site where no active soil remediation had previously occurred. We are also finalizing a study of the feasibility of various options to address the remainder of the site. Costs associated with the remediation at this site are not expected to be material to our results of operations or financial position.

With regard to one of our former MGP sites in Kansas, periodic monitoring and a 2016 interim site investigation indicated elevated levels of contaminants generally associated with MGP sites. In 2016, we estimated the potential costs associated with additional investigation and remediation to be in the range of $4.0 million to $7.0 million. We have submitted a remediation plan to the KDHE for this site. The KDHE is currently reviewing our plan. In the second quarter of 2018, we revised our estimate of the potential costs associated with additional investigation and remediation to be in the range of $5.6 million to $7.0 million. A single reliable estimate of the remediation costs was not feasible due to the amount of uncertainty in the ultimate remediation approach that will be utilized. Accordingly, we recorded in the second quarter of 2018 an adjustment to the reserve of $1.6 million bringing the total to $5.6 million for this site, which also increased our regulatory asset pursuant to our AAO in Kansas.

In April 2017, Kansas Gas Service filed an application with the KCC seeking approval of an AAO associated with the costs incurred at, and nearby, the 12 former MGP sites which we own or retain responsibility for certain environmental conditions. In October 2017, Kansas Gas Service, the KCC staff and the Citizens' Utility Ratepayer Board filed a unanimous settlement agreement with the KCC. The agreement allows Kansas Gas Service to defer and seek recovery of costs that are necessary for investigation and remediation at the 12 former MGP sites incurred after January 1, 2017, up to a cap of $15.0 million, net of any related insurance recoveries. Costs approved in a future rate proceeding would then be amortized over a 15-year period. The unamortized amounts will not be included in rate base or accumulate carrying charges. At the time future investigation and remediation work, net of any related insurance recoveries, is expected to exceed $15.0 million, Kansas Gas Service will be required to file an application with the KCC for approval to increase the $15.0 million cap. The KCC issued an order approving the settlement agreement in November 2017. A regulatory asset of approximately $5.9 million was recorded for estimated costs that have been accrued at January 1, 2017.

We also own or retain legal responsibility for certain environmental conditions at a former MGP site in Texas. At the request of the Texas Commission on Environmental Quality, we began investigating the level and extent of contamination associated with the site under their Texas Risk Reduction Program. A preliminary site investigation revealed that this site contains contaminants generally associated with MGP sites and is subject to control or remediation under various environmental laws and regulations. Until the investigation is complete, we are unable to determine what, if any, active remediation will be required. A reliable estimate of potential remediation costs is not feasible at this point due to the amount of uncertainty as to the levels and extent of contamination.

Our expenditures for environmental evaluation, mitigation, remediation and compliance to date have not been significant in relation to our financial position, results of operations or cash flows, and our expenditures related to environmental matters had no material effects on earnings or cash flows during 2018, 2017 or 2016. A number of environmental issues may exist with respect to MGP sites that are unknown to us. Accordingly, future costs are dependent on the final determination and regulatory approval of any remedial actions, the complexity of the site, level of remediation required, changing technology and governmental regulations, and to the extent not recovered by insurance or recoverable in rates from our customers, could be material to our financial condition, results of operations or cash flows.

We are subject to environmental regulation by federal, state and local authorities. Due to the inherent uncertainties surrounding the development of federal and state environmental laws and regulations, we cannot determine with specificity the impact such laws and regulations may have on our existing and future facilities. With the trend toward stricter standards, greater regulation and more extensive permit requirements for the types of assets operated by us, our environmental expenditures could increase in the future, and such expenditures may not be fully recovered by insurance or recoverable in rates from our customers, and those costs may adversely affect our financial condition, results of operations and cash flows. We do not expect expenditures for these matters to have a material adverse effect on our financial condition, results of operations or cash flows.

Pipeline Safety - We are subject to PHMSA regulations, including integrity-management regulations. PHMSA regulations require pipeline companies operating high-pressure transmission pipelines to perform integrity assessments on pipeline segments that pass through densely populated areas or near specifically designated high-consequence areas. In January 2012, the Pipeline Safety, Regulatory Certainty and Job Creation Act was signed into law. The law increased maximum penalties for violating federal pipeline safety regulations and directs the DOT and the Secretary of Transportation to conduct further review or studies on issues that may or may not be material to us. These issues include, but are not limited to, the following:

- an evaluation of whether natural gas pipeline integrity-management requirements should be expanded beyond current high-consequence areas;
- a verification of records for pipelines in class 3 and 4 locations and high-consequence areas to confirm maximum allowable operating pressures; and

- a requirement to test previously untested pipelines operating above 30 percent yield strength in high-consequence areas.

In April 2016, PHMSA published a NPRM, the Safety of Gas Transmission & Gathering Lines Rule, in the Federal Register to revise pipeline safety regulations applicable to the safety of onshore natural gas transmission and gathering pipelines. Proposals include changes to pipeline integrity management requirements and other safety-related requirements. The NPRM comment period ended July 7, 2016, and comments are under review by PHMSA. As part of the comment review process, PHMSA is being advised by the Technical Pipeline Safety Standards Committee, informally known by PHMSA as the GPAC, a statutorily mandated advisory committee that advises PHMSA on proposed safety policies for natural gas pipelines. The GPAC reviews PHMSA's proposed regulatory initiatives to assure the technical feasibility, reasonableness, cost-effectiveness and practicality of each proposal. The GPAC has met five times since January 2017 to review public comments and make recommendations to PHMSA. The GPAC completed their review of the NPRM on March 28, 2018, except for gas gathering.

The next GPAC meeting will focus on gas gathering. In addition to reviewing public and committee comments, PHMSA announced they will split this NPRM into three separate final rulemakings:

- the first final rule will address the legislative mandates from the Pipeline Safety, Regulatory Certainty and Jobs Creation Act and will be called the Safety of Gas Transmission Pipelines: Maximum Allowable Operating Pressure Reconfirmation, Expansion of Assessment Requirements, and Other Related Amendments;
- the second final rule will be called the Safety of Gas Transmission Pipelines: Repair Criteria, Integrity Management Improvements, Cathodic Protection, Management of Change, and Other Related Amendments and will cover all remaining elements of the NPRM (except for gas gathering); and
- the third final rule will be called the Safety of Gas Gathering Pipelines and will address gas gathering.

A significant number of recommendations have been made to PHMSA to improve the NPRM. The industry trade associations filed joint comments to the "legislative mandates" rulemaking to amend the federal safety regulations applicable to gas transmission and gathering pipelines. The timing of each final rule being published is unknown, but they are expected to be published during 2019. The potential capital and operating expenditures associated with compliance with the proposed rules are currently being evaluated and could be significant depending on the final regulations.

Legal Proceedings - We are a party to various litigation matters and claims that have arisen in the normal course of our operations. While the results of litigation and claims cannot be predicted with certainty, we believe the reasonably possible losses from such matters, individually and in the aggregate, are not material. Additionally, we believe the probable final outcome of such matters will not have a material adverse effect on our results of operations, financial position or cash flows.

16. QUARTERLY FINANCIAL DATA (UNAUDITED)

Year Ended December 31, 2018	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(Thousands of dollars)			
Revenues	$638,464	$292,521	$238,280	$464,466
Operating income (a)	$130,290	$41,043	$36,241	$80,855
Net income	$90,835	$20,419	$16,276	$44,704
Earnings per share				
Basic	$1.73	$0.39	$0.31	$0.85
Diluted	$1.72	$0.39	$0.31	$0.84

(a) Reflects the impact of the adoption of a new accounting standard in fiscal year 2018 related to the presentation of net periodic benefit costs. See Note 1 for additional information regarding our adoption of this standard.

Year Ended December 31, 2017	First Quarter	Second Quarter	Third Quarter	Fourth Quarter
	(Thousands of dollars)			
Revenues	$550,408	$279,689	$247,142	$462,394
Operating income (a)	$129,445	$48,365	$45,093	$93,825
Net income	$76,456	$20,623	$18,797	$47,119
Earnings per share				
Basic	$1.45	$0.39	$0.36	$0.90
Diluted	$1.44	$0.39	$0.36	$0.89

(a) Reflects the impact of the adoption of a new accounting standard in fiscal year 2018 related to the presentation of net periodic benefit costs. See Note 1 for additional information regarding our adoption of this standard.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Disclosure Controls and Procedures

Our Chief Executive Officer (Principal Executive Officer) and Chief Financial Officer (Principal Financial Officer) have concluded that our disclosure controls and procedures were effective as of the end of the period covered by this report based on the evaluation of the controls and procedures required by Rule 13a-15(b) of the Exchange Act.

Management's Report on Internal Control Over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rule 13a-15(f). Under the supervision and with the participation of our management, including our Principal Executive Officer and Principal Financial Officer, we evaluated the effectiveness of our internal control over financial reporting based on the framework in Internal Control-Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission. Because of inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. Based on our evaluation under that framework and applicable SEC rules, our management concluded that our internal control over financial reporting was effective as of December 31, 2018.

The effectiveness of our internal control over financial reporting as of December 31, 2018, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their reports which are included herein (Item 8).

Changes in Internal Control Over Financial Reporting

There have been no changes in our internal control over financial reporting during the quarter ended December 31, 2018, that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

Not applicable.

PART III.

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

Directors of the Registrant

Information concerning our directors is set forth in our 2019 definitive Proxy Statement and is incorporated herein by this reference.

Executive Officers of the Registrant

Information concerning our executive officers is included in Part I, Item 1, Business, of this Annual Report.

Compliance with Section 16(a) of the Exchange Act

Information on compliance with Section 16(a) of the Exchange Act is set forth in our 2019 definitive Proxy Statement and is incorporated herein by this reference.

Code of Ethics

Information concerning the code of ethics, or code of business conduct, is set forth in our 2019 definitive Proxy Statement and is incorporated herein by this reference.

Nominating Procedures

Information concerning the nominating procedures is set forth in our 2019 definitive Proxy Statement and is incorporated herein by this reference.

The Audit Committee

Information concerning the Audit Committee is set forth in our 2019 definitive Proxy Statement and is incorporated herein by this reference.

The Audit Committee Financial Experts

Information concerning the Audit Committee Financial Experts is set forth in our 2019 definitive Proxy Statement and is incorporated herein by this reference.

The Executive Compensation Committee

Information concerning the Executive Compensation Committee is set forth in our 2019 definitive Proxy Statement and is incorporated herein by this reference.

The Corporate Governance Committee

Information concerning the Corporate Governance Committee is set forth in our 2019 definitive Proxy Statement and is incorporated herein by this reference.

The Executive Committee

Information concerning the Executive Committee is set forth in our 2019 definitive Proxy Statement and is incorporated herein by this reference.

Committee Charters

The full text of our Audit Committee charter, Executive Compensation Committee charter, Corporate Governance Committee charter and Executive Committee charter are published on and may be printed from our website at www.onegas.com and are also available from our corporate secretary upon request.

ITEM 11. EXECUTIVE COMPENSATION

Information on executive compensation is set forth in our 2019 definitive Proxy Statement and is incorporated herein by this reference.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

Security Ownership of Certain Beneficial Owners

Information concerning the ownership of certain beneficial owners is set forth in our 2019 definitive Proxy Statement and is incorporated herein by this reference.

Security Ownership of Management

Information on security ownership of directors and officers is set forth in our 2019 definitive Proxy Statement and is incorporated herein by this reference.

Equity Compensation Plan Information

The following table sets forth certain information concerning our equity compensation plans as of December 31, 2018:

Plan Category	Number of Securities Issued Upon Exercise of Outstanding Options, Warrants and Rights (a)	Weighted-Average Exercise Price of Outstanding Options, Warrants and Rights (b)	Number of Securities Remaining Available For Future Issuance Under Equity Compensation Plans (Excluding Securities in Column (a)) (c)
Equity compensation plans approved by security holders (1)	—	$ —(3)	3,057,153
Equity compensation plans not approved by security holders (2)	—	$ —	309,922
Total	—	$ —	3,367,075

(1) Includes restricted stock incentive units and performance-unit awards granted under our ECP and our Nonqualified Deferred Compensation Plan for Nonemployee Directors. For a brief description of the material features of this plan, see Note 11 of the Notes to Consolidated Financial Statements in this Annual Report.
(2) Includes shares granted under our ESPP and Employee Stock Award Program. For a brief description of the material features of these plans, see Note 11 of the Notes to Consolidated Financial Statements in this Annual Report. Column (c) includes 308,110 and 1,812 shares available for future issuance under our ESPP and Employee Stock Award Program, respectively.
(3) Compensation deferred into our common stock under our Non-Qualified Deferred Compensation Plan and Deferred Compensation Plan for Nonemployee Directors is distributed to participants at fair market value on the date of distribution. The price used for these plans to calculate the weighted-average exercise price in the table is $79.60, which represents the year-end closing price of our common stock on the NYSE.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

Information on certain relationships and related transactions and director independence is set forth in our 2019 definitive Proxy Statement and is incorporated herein by this reference.

ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

Information on the principal accountant’s fees and services is set forth in our 2019 definitive Proxy Statement and is incorporated herein by this reference.

PART IV.

ITEM 15. EXHIBITS, FINANCIAL STATEMENT SCHEDULES

(1) Consolidated Financial Statements