Kansas Gas Service
A Division of ONE Gas

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May 16, 2019

Kansas Corporation Commission
Attn: Lynn Retz, Secretary to the Commission
1500 Arrowhead Road
Topeka, Kansas 66604

Re: In the Matter of the Kansas Gas Service Compliance Docket No. 11-KGSG-820-CPL, as Established in Docket No. 06-GIMX-181-GIV.

Dear Ms. Lynn Retz:

In accordance with the Commission's order in Docket No. 06-GIMX-181-GIV, Kansas Gas Service, a Division of ONE Gas, Inc., ("Kansas Gas Service") submits for filing certain documents and schedules in conformity with the agreed upon procedures set forth in the order by the Kansas Corporation Commission.

The documents and information filed in this docket include the filing of certain information the Company and its contractors have deemed and treats as confidential. In accordance with Kansas law and Commission regulation, Kansas Gas Service has clearly designated the appropriate documents "*CONFIDENTIAL*".

Further, in accordance with the Report of the Commission Staff and the Active Participating Utilities dated October 27, 2010, and the Commission's Order of December 3, 2010, in Docket No. 06-GIMX- 181-GIV, Kansas Gas Service's filing includes following attached documents:

- A.1. Cost Allocation Manual (CAM).
- A.2. Not applicable.
- B.1. Corporate Organization Chart.
- B.2. List of Associated Companies and Descriptions.
- B.3. List of Officers and Directors.
- B.4. Summaries of Debt Agreements.
- B.5. Balance Sheet and Income Statement for Consolidated Utility Operations.
- B.6. Financial Ratios for consolidated Utility Operations.
- C.1. Not applicable.
- C.2. Not applicable.

C.3. A *CONFIDENTIAL* copy of Moody's ONE Gas, credit report dated January 29, 2019 and a *CONFIDENTIAL* copy of S&P's ONE Gas credit report dated March 14, 2019.

Please accept the filing as being made subject to the procedures set forth in the Report of the Commission Staff and the Active Participating Utilities in Docket No. 06-GIMX- 181-GIV.

If you have any questions or concerns regarding this filing, please feel free to contact me.

Sincerely,

Judy Jenkins Hitchye
Managing Attorney

BEFORE THE STATE CORPORATION COMMISSION

OF THE STATE OF KANSAS

In the Matter of the Kansas Gas Service Compliance	)	Docket No. 11-KGSG-820-CPL
Docket as Established in Docket No. 06-GIMX-181-GIV.	)	

The Kansas Gas Service, a Division of ONE Gas, Inc., ("Kansas Gas Service" or "KGS") in compliance with the Commission Orders issued in Docket No. 06-GIMX-181-GIV (commonly referred to as the "ring-fencing docket"), hereby provides its annual responses to the required information below. Each response is preceded by a summary of the specific Commission requirement and references the designation of any attachments. Kansas Gas Service responds as follows:

<u>KCC Requirement:</u>

A. To ensure proper allocation or assignment of joint or common costs for non-power goods and services, so a regulated utility bears only its fair share of costs, the public utility shall submit the following information on an annual basis by May 31st:

   1. A Cost Allocation Manual (CAM) on a calendar year basis that:

      a. Explains the methodology used for all costs allocated or assigned for non-power goods and services provided by: (i) the regulated utility, (ii) a holding company, or (iii) a centralized corporate services subsidiary to any associate company that is a jurisdictional public utility;

      b. Demonstrates that all costs are allocated or assigned justly and reasonably and that the allocation or assignment of costs is not unduly discriminatory or preferential; and,

      c. If a fully distributed cost methodology is not used, an explanation supporting use of the alternative method of allocation.

   With respect to the CAM, it should be filed in the individual utility compliance docket, but if no changes are made to the CAM, a letter in place of the CAM indicating no changes have been made may be filed by the May 31st annual filing date. If the annual filing reflects changes made in the CAM, those changes should be noted and fully described.

   2. Any centralized corporate services subsidiary, within a holding company that includes a jurisdictional public utility, required to file FERC Form No. 60, shall file a copy with the Commission by May 31st of the calendar year following the year subject of the report.

KGS Response:

A.

1. See, the Cost Allocation Manual that was revised April 22, 2019, attached hereto as "Attachment A-1". The attachment is a red-line version of the Cost Allocation Manual to highlight changes that have occurred.

2. Not applicable.

KCC Requirement:

B. Each jurisdictional public utility shall provide, annually by May 31st, the following information using diagrams, schedules or narrative discussion as may be appropriate:

   1. A complete detailed organization chart identifying each regulated utility and each associate company;

   2. A detailed description of the activities and business conducted at each non-utility associate company;

   3. An organizational chart of personnel that includes a list of all directors, corporate officers, and other key personnel shared by any jurisdictional public utility and any non-utility associate company or holding company, if any, along with a description of each person's duties and responsibilities to each entity;

   4. Summaries of each mortgage, loan document and debt agreement, including a discussion of the type of collateral or security pledged to support the debt. The utility will also describe any loan or debt agreement taken out to finance an unregulated affiliate that encumbers utility property or cash-flow for security;

   5. To the extent financial separations are maintained for either legal or financial accounting purposes and at a level in which financial statements are reasonably capable of being produced by the utility's accounting system, each jurisdictional public utility shall file income statements, balance sheets and cash flow statements for: (1) consolidated utility operations; (2) consolidated non-regulated operations; and (3) consolidated corporate financials; (this information is confidential) and

   6. To the extent financial separations are maintained for either legal or financial accounting purposes and at a level in which financial statements are reasonably capable of being produced by the utility's accounting system, each jurisdictional public utility shall file a summary of financial ratios as of the end of the last completed fiscal year, as described by way of example in the attachment to these rules and consistent with the method used to report such information to the principal bond rating agency or Standard & Poor's for: (1) consolidated utility operations; (2) consolidated non-regulated operations; and (3) consolidated corporate financials (this information is confidential).

KGS Response

B.

1. Please see, the attached organization chart, containing KGS affiliated companies within ONE Gas, Inc., as of December 31, 2018, attached as "Attachment B-1".
2. Please see, "Attachment B-2" for a description of associated companies.
3. Please see, "Attachment B-3" for a list of Officers and Directors.
4. Please see, "Attachment B-4" for a summary of debt agreements. There is no utility debt that encumbers utility property used to finance unregulated affiliates.
5. Please see, the attached income statements and balance sheet information for ONE Gas, Inc., which were included in the Fiscal 2018 10-K filing, attached here as "Attachment B-5".
6. Please see, the attached financial ratios for the consolidated utility operation, attached here as "Attachment B-6".

KCC Requirement:

C. Each jurisdictional public utility shall provide to the Director of Utilities and the Chief of Accounting and Financial Analysis at the Commission concurrent with the filing of 8-K disclosures the following:

   1. Written or verbal notice of any affiliate of the jurisdictional public utility or holding company, if any, that has an affiliate that has defaulted on a material obligation or debt for the purpose of 8-K reporting.
   2. Written or verbal notice of any requests by any jurisdictional public utility or holding company, if any, for material waivers or amendments as provided for the purpose of 8-K reporting to debt agreements that secure, encumber, or finance any jurisdictional public utility's assets.
   3. Each jurisdictional public utility shall file reports published by credit rating agencies and equity analysts regarding the utility's regulated and unregulated business within 10 days after publication of the report and its receipt by the utility. A public utility shall not be required to file reports that the utility has not received, or reports that cannot be disseminated or reproduced because of copyright or contractual restrictions.
   4. A summary of any debt secured or encumbered, in any way, by the assets of any jurisdictional public utility on behalf of a non-utility affiliate or holding company, if any.

KGS Response

C.

1. KGS will provide written or verbal notice concurrently, in the event that any affiliate defaults on a material obligation or debt for the purpose of 8-K reporting. For the purposes of this reporting period, neither ONE Gas, Inc., nor any of its affiliates, have defaulted on a material obligation or debt.

2. KGS will provide written or verbal notice of any requests by a jurisdictional public utility or holding company if it seeks a material waiver or amendments as provided for the purpose of 8-K reporting to debt agreements that secure, encumber, or finance any jurisdictional public utility's assets. For the reporting period subject to this filing, no such requests have been made.

3. ONE Gas receives credit rating and equity analyst reports under an agreement with an outside vendor. According to the terms of the agreement, ONE Gas is prohibited from releasing these reports to third parties, without prior expressed consent. For the purposes of this filing, ONE Gas, Inc.has obtained permission to provide a *Confidential* copy of Moodys' ONE Gas credit report dated 1/29/2019 and a *Confidential* copy of S&P's ONE Gas credit report dated 3/14/2019.

   Additionally, the Equity analysts covering ONE Gas, Inc. include:

   Bank of America Merrill Lynch
   Edward Jones
   Jefferies
   Morgan Stanley
   Seaport Global
   UBS
   Wells Fargo

4. ONE Gas, Inc. does not have any debt issuances that are secured or encumbered with the assets of KGS.

ONE Gas CORPORATE ALLOCATION MANUAL

The Corporate Allocation Manual provides documentation for current practices used by ONE Gas, Inc. (ONE Gas) for allocation of corporate administrative costs to ONE Gas business entities. A business entity is defined as a division or subsidiary of ONE Gas. Corporate administrative costs that are incurred for the direct benefit of one specific business entity, known as direct costs, are not addressed in this manual because the objective and scope of this manual pertains to general charges that cannot be assigned to a single operating business entity.

ONE Gas maintains a fully distributed cost model that provides a reasonable and justifiable method of cost assignment, so that each business entity receives its proportionate share of corporate administrative costs and prevents subsidization.

Proper classification of costs is the responsibility of each employee and his or her supervisor when preparing, approving, and processing any accounting document (invoices, amortizations, journal entries, etc.). The classification of costs includes assigning the appropriate account coding string as defined in our Classification of Accounts Manual (which includes codes for company, cost center, natural account, expense indicator and RFU) when processing the transaction. The account coding string is the basis upon which costs are identified as costs to be allocated in our process.

Three-Step Allocation Process

The application of our fully distributed cost allocations occurs through a "three-step" allocation method. The first step begins with the premise that to the extent practical, direct costs specifically attributed to a business entity are charged directly to that business entity. In the second step, indirect costs that are significant in amount, but which cannot be charged directly are allocated to business entities on the basis of a causal relationship.
The causal relationships are specific measurements based on the type of cost, which can be a measure of participation level, activity level, output level, or resource consumption. In the third step, any remaining costs, which cannot be charged directly or associated with an identifiable causal relationship, are allocated to business entities using the ONE Gas's Modified Distrigas Allocation methodology (ONE Gas Distrigas).

ONE GAS Distrigas Methodology

The Distrigas Cost Allocation Methodology (Distrigas Method) was first approved by the Federal Energy Regulatory Commission (FERC) in a rate proceeding for a natural gas transmission company, Distrigas of Massachusetts, L.L.C. The Distrigas formula is a slight modification of the Massachusetts Allocation Method (a three part formula consisting of gross plant, gross revenues and payroll) which, prior to the acceptance of the Distrigas formula, was widely accepted by numerous regulatory agencies across the country as a just and reasonable method of allocating corporate overhead and other costs. In its preceding at the FERC, Distrigas of Massachusetts, L.L.C. argued that the Massachusetts formula was flawed in that ~~it~~the formula over-allocated costs to utilities due to its inclusion of the cost of fuel in gross revenues. This had the effect of inflating the allocation of costs to utility operations which benefitted non-utility operations. The FERC agreed and accepted the modified version of the formula, which is generally known as the Distrigas Method, as a reasonable and acceptable methodology for allocating costs for ratemaking purposes

ONE Gas, Inc. has used the Distrigas Method as the basis for its methodology to allocate corporate administrative costs since 1994. It is important to ONE Gas to have a common allocation methodology that is broadly accepted by our regulatory authorities and that results in a justifiable and reasonable allocation of corporate administrative costs to each of ONE Gas's business entities.

The ONE Gas Distrigas methodology uses a three factor formula comprised of the average of gross plant and investments, net operating income and labor expenses (excluding contract labor).

To calculate the overall allocation factor for each business entity, the three allocation factor amounts are determined for each business entity and calculated as a percentage of the consolidated total. In cases when a business entity has an operating loss, a factor of zero is used for the operating income allocation factor. The three component allocation factors for each business entity are then combined using a simple average to derive the overall allocation factor.

ONE Gas periodically reviews its existing allocation methodologies to ensure that costs are being appropriately allocated. ONE Gas's Distrigas allocation factors are updated quarterly or when significant changes to its corporate structure occur, such as acquisitions, divestitures, or corporate restructuring.

ONE Gas uses the following methodology to allocate costs when costs cannot be charged directly or allocated using a causal relationship to a business entity. The allocation methodology allows the allocation of costs to the business entities that receive the benefit of the administrative costs. The allocation methodology is described as follows:

Methodology Name	Cost Center	Description
OGS-Distrigas	1007	Calculates allocation percentages using the respective allocation factors for the business entities of ONE Gas's business entities including Oklahoma Natural Gas, Kansas Gas Service, Texas Gas Service, and Utility Insurance Company

Appendix A provides an example calculation of ONE Gas's Distrigas methodology.

Allocated Costs

Costs to be allocated can be aggregated in the following general categories:

- Executive
- Human Resources (HR)
- Information Technology (IT)
- Finance and Accounting
- General Counsel
- Corporate Communications
- Corporate Services (includes Environmental Health & Safety, Engineering, and Resource Management)
- Customer Service
- Other

The costs allocated in these general categories are allocated in accordance with our "three step allocation methodology" described above. The following sections provide a general description of the types of costs allocated in each general category and the method in which those costs are allocated.

Executive

The executive organization provides leadership and strategic direction for ONE Gas's business activities. Examples of costs incurred in this area are related to salaries and expenses of the President and Chief Executive Officer, his or her direct reports, and corporate officers with responsibility for corporate administrative functions that are not assigned to a specific business entity. These costs are primarily allocated through the OGS-Distrigas methodology.

Human Resources

The HR organization supports our various business entities and the employees of ONE Gas by developing and administering plans and processes related to compensation, employee benefits, employee development and payroll. Typical examples of costs incurred in this area are related to:

Types of Costs	Allocation Methodology
Administrative fees for all defined plans, health & welfare and retirement plans	1. These costs are allocated using the causal relationship of plan participant count for each respective business entity. 2. Cost allocated to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.
Health and welfare benefits for active employees	1. These costs are allocated using the causal relationship of employee headcount or plan participant count for each respective business entity. 2. Cost allocated to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.

Retirement benefits for active and retired employees	1. These costs are allocated using the causal relationship of plan participant count for each respective business entity where the plan participant works at each measurement date or where the plan participant worked immediately prior to retirement. 2. Plan participant or retiree costs allocated to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.
Workforce development support and training programs for all active employees	Allocated through the OGS-Distrigas methodology.
HR administration and financial services support, including compensation, payroll and benefits accounting and IT support	1. These costs are allocated using the causal relationship of employee headcount for each respective business entity. 2. Cost allocated to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.

Information Technology

The IT organization supports our various business entities by developing and administering plans and processes related to technology solutions and security to facilitate day to day business activities. Typical examples of costs incurred in this area are related to:

Types of Costs	Allocation Methodology
IT administrative functions such as administration, financial planning, accounting and reporting	Allocated through the OGS-Distrigas methodology
Disaster recovery, data backup and recovery, change management and problem management	Allocated through the OGS-Distrigas methodology.
Websites, intranet, business intelligence, legal applications, imaging and scanning, and document management technologies	Allocated through the OGS-Distrigas methodology.
ONE Gas customer billing system	Allocated using the causal relationship of customer count for each of the business entities.
Data center and support of all of the company technology	1. Allocated through the OGS- Distrigas methodology. 2. Labor and benefits for employees supporting ONE Gas's business entities are allocated equally.
Cell phones, local and long-distance telephone service, pagers and internet expenses	1. Charged directly to the business entity receiving benefit of the service. 2. Costs not attributable to a specific business entity or costs charged directly to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.
Financial and HR systems and related systems such as fixed asset accounting, project estimation and accounting, financial reporting and HR reporting	Allocated through the OGS-Distrigas methodology.

Supporting the operational accounting systems and the measurement systems used for non-residential gas meters	Charged directly to the business entity that is providing service to the non-residential gas meter.
Support and maintenance of the corporate and operations applications such as cash management systems	1. Labor and benefit costs are allocated based on an internally developed analysis. 2. Other costs are charged directly to the business entity receiving benefit of the service. 3. Costs not attributable to a specific business entity or costs charged directly to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.
Supporting systems related to field operations including construction and engineering	1. Charged directly to the business entity receiving benefit of the service. 2. Costs not attributable to a specific business entity are allocated to the business entities through the OGS-Distrigas methodology.
Support of the Sarbanes-Oxley compliance software and network security monitoring (cyber security)	Allocated through the OGS-Distrigas methodology.
Pipeline Support Systems	Charged directly to the business entity receiving benefit of the service.

The Finance and accounting organization supports our various business entities by administering processes related to corporate accounting, financial reporting, tax, credit, risk and insurance, internal audit, financial planning and business development. Typical examples of costs incurred in this area are related to payroll and business expenses associated with departments responsible for:

Types of Costs	Allocation Methodology
Corporate general accounting and consolidations, corporate financial planning and business development	Allocated through the OGS-Distrigas methodology.
SEC and external reporting for ONE Gas	Allocated through the OGS- Distrigas methodology.
Accounts payable	1. Allocated using a causal relationship derived from an internally developed analysis of invoice processing volume by business entity. 2. Costs not attributable to a specific business entity or costs charged directly to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.
Investor relations	Allocated through the OGS-Distrigas methodology.
Treasury Services	Allocated through the OGS-Distrigas methodology.
Federal and state income tax, ad valorem, sales & use tax and franchise tax filings	1. Taxes incurred are charged directly to the business entity incurring the tax obligation. 2. General administrative costs, including labor and benefits are charged directly to the business entity receiving benefit of the service.

	3. Costs not attributable to a specific business entity or costs charged directly to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.
Maintaining long-term financing and short-term working capital	1. General administrative costs associated with our finance department are allocated through the OGS-Distrigas methodology.
Risk mitigation and insurance	1. Labor, benefits and administrative expenses associated with administration of our insurance programs are allocated to the business entities through the OGS- Distrigas methodology. 2. Costs associated with specific insurance programs are allocated as follows: a. Primary & Excess Workers' Compensation: Allocated using the causal relationship of employee headcount for each respective business entity. b. Vehicle: Allocated using the causal relationship of vehicle count for each respective business entity. c. Excess Liability: Allocated through the OGS-Distrigas methodology. d. Directors & Officers Liability: Allocated through the OGS-Distrigas. e. Property and Terrorism: Allocated using the causal relationship of property values

	for each respective business entity. f. Various others (e.g. Fiduciary Liability, Blanket Crime, Mail and Transit, etc.): Allocated through the OGS- Distrigas methodology
Internal audit services (which includes our costs related to compliance with the Sarbanes-Oxley Act of 2002)	1. Charged directly to the business entity being audited. 2. Costs not attributable to a specific business entity or costs charged directly to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.
Independent auditor fees	1. Charged directly to the business entity being audited. 2. Costs not attributable to a specific business entity or costs charged directly to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.
Property Accounting - centralized accounting for the property, plant & equipment	1. Labor and benefits are charged directly to each business entity for which the employee has accounting responsibility. 2. General and administrative supplies and expenses are allocated based on the causal relationship of gross property, plant, and equipment values.
Billing Control - centralized accounting for the customer billing process	Allocated to the business entity based on the causal relationship of customer count.

General Counsel

The general counsel organization supports our various business entities by administering processes related to legal aspects of our day-to-day business activities. Typical examples of costs incurred in this area are related payroll and business expenses (including third party legal costs) associated with departments responsible for:

Types of Costs	Allocation Methodology
Third-party damages and workers' compensation claims	1. Charged directly to the business entity incurring the damages or workers' compensation claim. 2. Costs not attributable to a specific business entity or costs charged directly to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.
Commercial contracts	1. Charged directly to the business entity named in the commercial contract. 2. Costs not attributable to a specific business entity or costs charged directly to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.
Regulatory affairs	1. Allocated directly based on the business entity receiving benefits of the services provided. 2. Cost charged directly to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.
Human resources	1. Allocated using the causal relationship of employee headcount for each respective business entity.

	2. Cost charged directly to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.
Litigation	1. Charged directly to the business entity receiving benefits of the services provided. 2. Cost charged directly to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.
Corporate secretary and board of directors	Allocated through the OGS- Distrigas methodology.
General legal matters	1. Charged directly to the business entity receiving benefit of the legal services. 2. Costs not attributable to a specific business entity are allocated through the OGS- Distrigas methodology.

Corporate Communications

The corporate communications organization supports our various business entities by administering processes related our corporate communications efforts with employees and external stakeholders. Typical examples of costs incurred in this area are related payroll and business expenses associated with departments responsible for:

Types of Costs	Allocation Methodology
Governmental affairs	1. Costs are charged directly to the business entity receiving benefit of the services provided. 2. All other costs are allocated to the business entities

	through the OGS-Distrigas methodology.
Corporate communications (including advertising costs ,costs associated with electronic communications and costs associated with general employee communications)	1. Costs are charged directly to the business entity receiving benefit of the services provided. 2. All other costs are allocated to the business entities through the OGS-Distrigas methodology.
Corporate responsibility (includes civic donations)	Allocated through the OGS-Distrigas methodology.

Corporate Services (includes Environmental Health & Safety)

The corporate services organization supports our various business entities by developing and administering programs and processes that facilitate general day-to-day business activities and environmental safety and health initiatives. Typical examples of costs incurred in this area are related to payroll and business expenses associated with departments responsible for:

Types of Costs	Allocation Methodology
Purchasing and materials management	1. Allocated using a causal relationship derived from an internally developed analysis of business entities usage of departments' services. 2. Costs not attributable to a specific business entity or costs charged directly to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.
Facilities and fleet management	1. Allocated using a causal relationship derived from an

	internally developed analysis of business entities usage of departments' services 2. Costs not attributable to a specific business entity or costs charged directly to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.
Right-of-way management	1. Allocated using a causal relationship derived from miles of pipe in the ground for each respective business entity. 2. Costs not attributable to a specific business entity are allocated to the business entities through the OGS-Distrigas methodology.
Business continuity planning	These costs are allocated using the causal relationship of employee headcount for each respective business entity.
Environmental management	1. Charged directly to the business entity responsible for the environmental cost incurred. 2. Costs not attributable to a specific business entity or costs charged directly to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated through the OGS-Distrigas methodology.
Safety programs	1. Charged directly to the business entity responsible for the cost incurred. 2. Costs not attributable to a specific business entity or costs charged directly to corporate departments (Executive, HR, Accounting, IT,

	etc.) are allocated to the business entities through the OGS-Distrigas methodology.
Aviation services	Allocated through the OGS-Distrigas methodology.
Engineering	1. Allocated using a causal relationship derived from miles of pipe in the ground for each respective business entity. 2. Costs not attributable to a specific business entity are allocated to the business entities through the OGS-Distrigas methodology
Resource Management (includes costs for workforce strategy and planning, contractor)	1. Allocated using a causal relationship derived from miles of pipe in the ground, employee headcount, or customer count for each respective business. 2. Costs not attributable to a specific business entity are allocated to the business entities through the OGS-Distrigas methodology.

Customer Service

The customer service organization supports our various business entities by providing responsive, flexible, efficient service to our customers. Typical examples of costs incurred in this area are related to payroll and business expenses associated with departments responsible for:

Types of Costs	Allocation Methodology
Customer Service Support	1. Allocated to the business entity based on the causal relationship of customer count.

Other

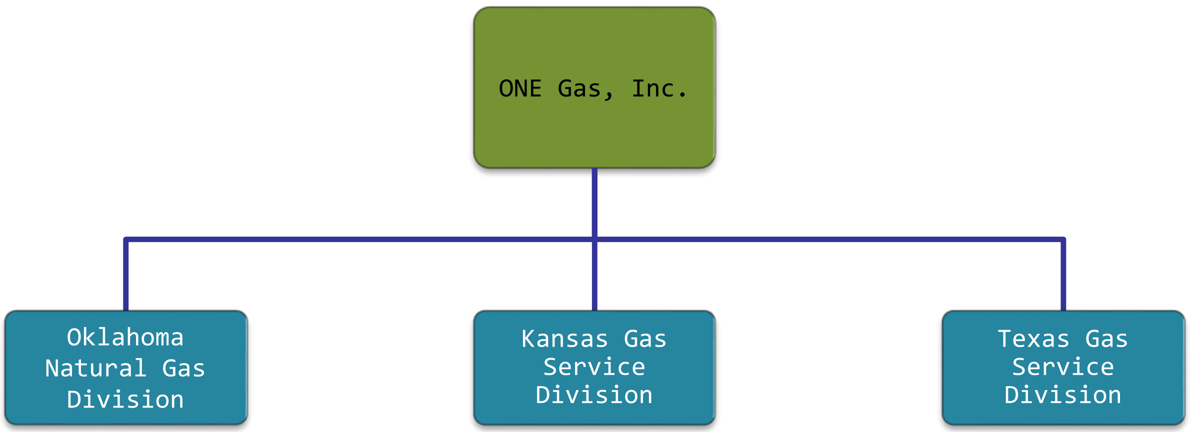
This section represents miscellaneous costs impacting multiple business entities

Types of Costs	Allocation Methodology
Incentives, short- and long-term (stock-based compensation)	1. These costs are allocated using the causal relationship of plan participant count for each respective business entity. 2. Cost charged directly to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.
Employee stock purchase program and employee stock awards, excluding long-term incentives	1. These costs are allocated using the causal relationship of plan participant count for each respective business entity. 2. Costs charged directly to corporate departments (Executive, HR, Accounting, IT, etc.) or to ONE Gas Partners are allocated to the business entities through the OGS-Distrigas methodology.
ONE Gas rent and utilities	1. Charged directly to the business entities with operations in the corporate building based on square footage utilized. 2. Costs charged directly to corporate departments (Executive, HR, Accounting, IT, etc.) or to

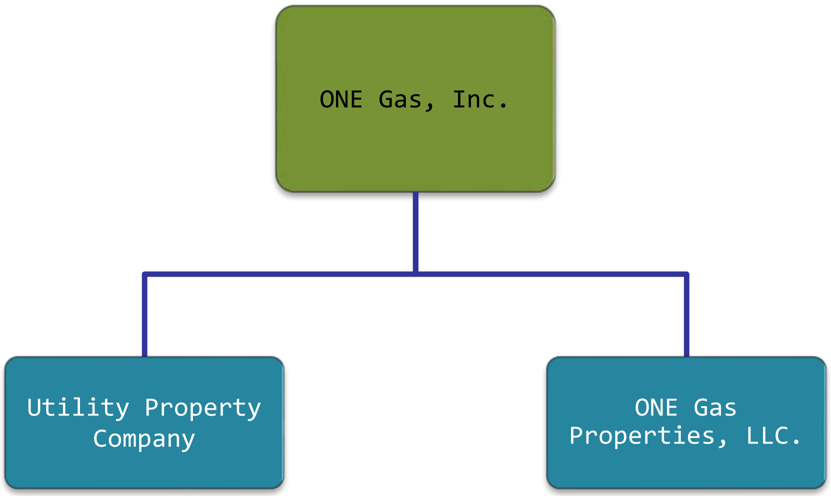
	ONE Gas are allocated to the business entities through the OGS-Distrigas methodology.
Payroll taxes	1. Charged directly to each employee's respective payroll organization. 2. Cost charged directly to corporate departments (Executive, HR, Accounting, IT, etc.) are allocated to the business entities through the OGS-Distrigas methodology.
Other taxes (ad valorem, franchise, etc.)	1. Charged directly to the business entity incurring the tax obligation. 2. Costs not identifiable to a specific business entity are allocated to the business entities through the OGS-Distrigas methodology.
Depreciation associated with general corporate assets	Allocated through the OGS-Distrigas methodology except as follows: a. Banner Customer Information System: Allocated using the causal relationship of customer count for each business entity. b. PowerPlant Fixed Asset Accounting System: Allocated using the causal relationship of Gross PP&E value attributable to each business entity.

	c. Maximo: Allocated using the causal relationship of user count for each business entity. d. Concur: Allocated using the causal relationship of employee count for each business entity. e. Journey: Allocated using the causal relationship of employee count for each business entity.

ONE Gas, Inc.
Regulated Operating Divisions



ONE Gas, Inc.
Affiliated Companies



ONE Gas, Inc. December 31, 2018
Company Descriptions

ONE Gas Associated Company Description:

ONE Gas Foundation, Inc. is an Oklahoma not-for-profit corporation. The entity is a charitable foundation exempt under Section 501(c)(3) of the Internal Revenue Code.

ONE Gas Affiliated Company Descriptions:

Utility Insurance Company is wholly owned by ONE Gas. UIC provides ONE Gas' distribution companies, Kansas Gas Service, Oklahoma Natural Gas and Texas Gas Service, insurance coverage. UIC is regulated by the Oklahoma Insurance Department.

ONE Gas Properties, L.L.C. is an Oklahoma limited liability company. The entity owns intellectual property including the ONE Gas logo and the trade names Kansas Gas Service, Oklahoma Natural Gas and Texas Gas Service. ONE Gas Properties, L.L.C. charges ONG, KGS and TGS a monthly royalty fee for the use of the intellectual properties it owns.

ONE GAS, INC.
DIRECTOR & OFFICER LIST
December 4, 2018

ONE Gas, Inc.
(Oklahoma Corporation, Formed 8/30/13)

Directors
John W. Gibson, Chairman
Pierce H. Norton II
Arcilia C. Acosta
Robert B. Evans
Tracy E. Hart
Michael G. Hutchinson
Pattye L. Moore
Eduardo A. Rodriguez
Douglas H. Yaeger

Positions Appointed by OGS Board

Pierce H. Norton II	President and Chief Executive Officer
Curtis L. Dinan	Senior Vice President and Chief Financial Officer
Joseph L. McCormick	Senior Vice President, General Counsel and Assistant Secretary
Caron A. Lawhorn	Senior Vice President, Commercial
Robert S. McAnnally	Senior Vice President, Operations
Mark A. Bender	Senior Vice President, Administration and Chief Information Officer
Brian K. Shore	Vice President, Associate General Counsel and Secretary
Julie A. White	Vice President, Communications, Public Affairs and Inclusion and Diversity
Jeffrey J. Husen	Vice President, Chief Accounting Officer and Controller
Mark W. Smith	Vice President, Treasurer

Positions Appointed by OGS CEO

W. Kent Shortridge	Managing Vice President, Field Operations
Jim Jarrett	Vice President, Operations, Oklahoma Natural Gas
Dennis J. Okenfuss	Vice President, Operations, Kansas Gas Service
Shantel H. Norman	Vice President, Operations, Texas Gas Service
Rick A. Grundman	Vice President, Government Affairs
Ronald D. Bridgewater	Vice President, System Integrity
Teryl C. Rose	Vice President, Environmental, Safety & Health
Brian Burke	Vice President, Customer Service
Jeff Johns	Vice President, Resource Management
James E. Langster	Vice President, Information Technology
David G. Scalf	Vice President, Rates and Regulatory Affairs
Jason Ketchum	Vice President, Commercial Activities

ONE GAS PROPERTIES, L.L.C.
(Oklahoma Corporation, Formed 10/30/13, OGS Sole Member)

Pierce H. Norton II	Chairman, President and Chief Executive Officer
Curtis L. Dinan	Senior Vice President and Chief Financial Officer
Joseph L. McCormick	Senior Vice President, General Counsel and Assistant Secretary
Caron A. Lawhorn	Senior Vice President, Commercial
Robert S. McAnnally	Senior Vice President, Operations
Mark A. Bender	Senior Vice President, Administration and Chief Information Officer
Jeffrey J. Husen	Vice President, Chief Accounting Officer and Controller
Mark W. Smith	Vice President and Treasurer
Brian K. Shore	Vice President, Associate General Counsel and Secretary
Julie A. White	Vice President, Communications, Public Affairs and Inclusion and Diversity

UTILITY INSURANCE COMPANY
(Oklahoma Corporation, Formed 8/29/17)

Directors

Pierce H. Norton II	Director
Curtis L. Dinan	Director
Joseph L. McCormick	Director

Officers:

Pierce H. Norton II	Chairman, Chief Executive Officer and President
Curtis L. Dinan	Senior Vice President and Chief Financial Officer
Joseph L. McCormick	Senior Vice President, General Counsel and Assistant Secretary
Brian K. Shore	Vice President, Associate General Counsel & Secretary
Mark W. Smith	Vice President and Treasurer

ONE Gas, Inc.

Maturity	2024	2044	2048	5-Year Credit Agreement	Indenture - US Bank
Issue Date	1/27/14	1/27/14	11/1/18	10/5/18	1/27/14
Maturity Date	2/1/24	2/1/44	11/1/48	10/5/23	-
Rate	3.61%	4.66%	4.50%	Eurodollar plus 1%, Prime, or Fed Funds plus 0.5%	-
Principal	$300,000,000	$600,000,000	$400,000,000	$700,000,000	-
Annual Interest	$10,830,000	$27,948,000	$18,000,000	$560,000 (Facility Fee)	-
Payments	2/1, 8/1	2/1, 8/1	5/1, 11/1	-	-
CUSIP	68235PAE8	68235PAF5	68235PAG3	-	-
Trustee	US Bank	US Bank	US Bank	BOA (Administrative Agent)	-
Lead Bank(s)	Morgan Stanley JPM / BOA / RBS	Morgan Stanley JPM / BOA / RBS	US Bank / JPM BOA / Mizuho	JPMorgan Mizuho US Bank	US Bank
Callable	anytime prior to 11/1/2023	anytime prior to 8/1/2043	anytime prior to 5/1/2048	-	-
Premium	None	None	None	-	-
Indenture	1/27/14	1/27/14	11/5/18	-	-
Filing	Same as Indenture (Annual compliance cert)	Same as Indenture (Annual compliance cert)	Same as Indenture (Annual compliance cert)	Compliance Certificates	Compliance Certificates Certain SEC filings
Events of Def	Fail to pay Int/Princ/Prem Interest: 30 days Covenants: 90 days Def on Agmt>$100MM Bankruptcy, Reorganization	Fail to pay Int/Princ/Prem Interest: 30 days Covenants: 90 days Def on Agmt>$100MM Bankruptcy, Reorganization	Fail to pay Int/Princ/Prem Interest: 30 days Covenants: 90 days Def on Agmt>$100MM Bankruptcy, Reorganization	CF Events of Default (Sec 8.01)	See Indenture Events of Default
Limitations on Liens	Liens Language 1	Liens Language 1	Liens Language 1	See CF Covenants (Sec 7.01)	See Indenture Limitation on Liens
Lim on S/L	S/L Language 1	S/L Language 1	S/L Language 1	None	See Indenture Limitation on SaleLeaseback
Amendments, Supplements and Waivers	ASW 1	ASW 1	ASW 1	None	See each note
Defeasance	Defeasance Language 1	Defeasance Language 1	Defeasance Language 1	None	See each note
Covenants	See Covenants 1	See Covenants 1	See Covenants 2	See CF Covenants (Sec 6.01 - 7.10)	See Indenture Covenants

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)

	December 31, 2018	December 31, 2017
Equity and Liabilities	*(Thousands of dollars)*	
Equity and long-term debt		
Common stock, $0.01 par value: authorized 250,000,000 shares; issued 52,598,005 shares and outstanding 52,564,902 shares at December 31, 2018; issued 52,598,005 shares and outstanding 52,312,516 shares at December 31, 2017	**$ 526**	$ 526
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		Common Stock		Paid-in Capital
	(Shares)		*(Thousands of dollars)*		
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:

	Remaining Recovery Period	December 31, 2018 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

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**

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.

ONE Gas, Inc.
Financial Ratios
For the Year Ended December 31, 2018

	Utility Operations
Total debt to total capitalization	
Notes payable (includes commercial paper)	299,500
Current maturities of long-term debt	9
Current portion of capitalized lease obligations	-
Long-term debt	1,301,289
Capitalized lease obligation	-
Total off balance sheet debt	1,600,798
Notes payable (includes commercial paper)	299,500
Current maturities of long-term debt	9
Current portion of capitalized lease obligations	-
Long-term debt	1,301,289
Capitalized lease obligation	-
Total equity	2,042,656
Total capitalization	3,643,454
Total debt to total capitalization	**44%**
Funds from operations interest coverage	
Net income from continuing operations	172,234
Depreciation & amortization	160,086
Deferred income taxes (excluding investment tax credit)	53,242
Investment tax credit	-
Allowance for debt funds used during construction	(3,393)
Allowance for equity funds used during construction	-
Equity earnings from investments	-
Distributions received	-
Gain (loss) on sale of assets	-
Deferred income tax adjustment	-
	382,169
Cash paid for interest, net of amounts capitalized	49,371
Allowance for debt funds used during construction	3,393
Interest expense adjustment	-
Interest on off balance sheet debt	-
	52,764
	434,933

Interest expense, net	51,305
Interest expense adjustment	
Allowance for debt funds used during construction	3,393
Interest on off balance sheet debt	-
	54,698
Funds from operations interest coverage	**7.95**
Funds from operations as a percentage of total debt	
Net income from continuing operations	172,234
Depreciation & amortization	160,086
Deferred income taxes (excluding investment tax credit)	53,242
Investment tax credit	-
Allowance for equity funds used during construction	-
Allowance for debt funds used during construction	(3,393)
Equity earnings from investments	-
Distributions received	-
Gain (loss) on sale of assets	-
Deferred income tax adjustment	-
	382,169
Depreciation adj for operating leases	-
Notes payable (includes commercial paper)	299,500
Current maturities of long-term debt	9
Current portion of capitalized lease obligations	-
Long-term debt	1,301,289
Capitalized lease obligations	-
Total off balance sheet debt	-
	1,600,798
Funds from operations as a percentage of total debt	**24%**

Attachment C-3

THIS DOCUMENT CONTAINS CONFIDENTIAL INFORMATION NOT AVAILABLE TO THE PUBLIC